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Research into the characteristics of the hydrate formation process in water-logged gas wells

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Abstract. The relevance of this research is driven by the transition of most natural gas fields to the late stage of development, which is accompanied by a significant increase in water production and creates thermodynamic conditions conducive to the emergency blockage of wellbores by gas hydrates. The aim of the study was to determine the influence of water cut and reservoir drawdown on the characteristics of the hydrate formation process in watered gas wells in order to optimise their operating conditions. To achieve this objective, a comprehensive mathematical model of the thermodynamic state of a multiphase fluid was developed and applied to a series of simulations on a model well under different reservoir drawdown values (2.5%, 5.0%, 7.5%, 10.0%, and 15.0% of the initial reservoir pressure) and water cut values (0-1,000 L/thousand m^3). The results showed that, at low reservoir drawdown (2.5% of the initial pressure) and limited water inflow, the hydrate formation risk zone is most critical and extends to depths exceeding 1,000 m. The temperature distribution along the wellbore was analysed, demonstrating that when the water cut exceeds 500 L/thousand m^3, the gas-liquid flow becomes sufficiently "hot" due to the high heat capacity of water, enabling the well to leave the hydrate formation zone without external intervention. Critical water cut values corresponding to the cessation of natural flowing conditions were determined, at which the actual wellhead temperature decreased to a minimum of 0.28°C. A graph-analytical method for constructing hydrate formation boundaries was developed, making it possible to clearly distinguish between the thermodynamic states associated with active hydrate formation and those corresponding to stable well operation. It was demonstrated that increasing reservoir drawdown leads to an increase in the critical water cut value at which hydrate formation in the production tubing ceases without external intervention.

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The practical significance of the results lies in the possibility of using the developed model by petroleum engineers and field specialists for the justified selection of hydrate-free operating modes for watered gas wells

Keywords: water cut; well operation; reservoir drawdown; hydrate formation temperature; natural gas

Introduction

Hydrate formation in water-flooded gas wells is a critically important task for ensuring uninterrupted operation of gas fields at the late stage of development. The appearance of formation or condensation water in the wellbore significantly changes the thermodynamic equilibrium of the system, creating a favourable environment for the formation of technogenic hydrate deposits. Hydrate formation in the wellbore leads to partial or complete overlap of the cross-section of the tubing (tubing) and flow rate reduction. Studying the kinetics of this process allows not only to better understand the physicochemical features of phase transitions, but also to develop effective methods for preventing hydrate deposits.

The problem of water-flooded gas wells, which is accompanied by a natural decrease in reservoir pressure and intensive waterlogging of products, which critically changes the operating conditions of gas wells, is being studied by prominent scientists. In particular, the authors R. Kondrat & L. Matiishyn (2025) noted in their work that most of the fields of Ukraine are at the final stage of development and require the implementation of new approaches to modelling well drives in conditions of significant waterlogging. Scientists draw attention to the fact that it is necessary to take into account the dynamics of reservoir energy when predicting complications in the operation of gas wells. Researchers O.A. Lukin & O.R. Kondrat (2025) in their studies concluded that uncertainty in predicting production from compacted reservoirs affects the accuracy of determining zones of possible moisture condensation. This suggests that even minor errors in predicting hydrocarbon production rates lead to critical errors in determining the actual locations of hydrate formation. Scientists F. Yin *et al*. (2026) in their studies focused on the fact that the transition of the liquid-gas system to the hydrate state significantly changes the physicochemical properties along the wellbore. The authors noted that the location of hydrate formation is critical in the drilling and exploitation of deep-water horizons.

Scientists M. Gudala *et al*. (2025) in the process of studying the Joule-Thomson effect found that when gas is injected into depleted reservoirs, the sharp expansion of the gas provokes local freezing of the formation water. The authors developed a model that confirms that even at high initial temperatures, the risk zone for hydrate formation remains in high-permeability zones due to nonlinear pressure gradients. Authors A. Qu *et al*. (2023) using the example of North Sea fields found that the most dangerous intervals of hydrate formation are localised closer to the wellhead, where the lowest ambient temperatures are observed. Scientists suggested the use of special simulators to accurately calculate the time until the pipe cross-section is completely blocked by a hydrate plug.

In the work of J. Pei *et al*. (2024) reviewed the current state of CO_2 capture technologies using the gas hydrate method as one of the promising areas of decarbonisation. The authors summarised the main mechanisms of CO_2 hydrate formation, analysed the influence of thermodynamic and kinetic promoters, as well as design and process factors that increase the efficiency of hydrate formation. They concluded that gas hydrate technology is an energy-efficient and environmentally attractive alternative to traditional CO_2 capture methods, but its industrial implementation is still limited by the problems of slow kinetics, the need for high pressure, and the complexity of scaling up processes. In the study by J. Gauteplass *et al*. (2020) focuses on the processes of gas hydrate formation during CO_2 injection into porous media and their impact on the permeability and hydrodynamics of formations. The authors analysed the conditions for the occurrence of hydrate blocking, and also proposed approaches to its prevention and restoration of filtration characteristics by controlling thermobaric conditions and flow drives. As a result, they showed that the formation of hydrates can significantly reduce the efficiency of CO_2 injection, however, with proper process control, this phenomenon can be partially controlled and taken into account in CO_2 storage and transportation technologies in geological formations.

Analysis of the above-mentioned scientific works showed that despite the in-depth study of the hydrate formation process, in the analysed works, scientists did not pay enough attention to the complex relationship between different values of the water factor and the magnitude of the depression on the formation directly for water-flooded gas wells. Most of the research results take into account static conditions of phase equilibrium, or pure "gas-water" systems without taking into account the real influence of the nature of the multiphase flow, which is typical for the late stage of development. The lack of clear patterns of how the value of the water factor and depression on the formation on the process of hydrate formation served as the basis for conducting this study. The aim of the work was to study the influence of the water factor and depression on the formation on the characteristics of the hydrate formation process in water-flooded gas wells.

Materials and Methods

Research of the characteristics of the hydrate formation process in water-flooded gas wells were performed for the conditions of a hypothetical (model) gas well with the following data: well depth – 3,400 m, gas-saturated layer thickness – 18 m, current layer pressure – 32 MPa, layer temperature – 341 K, relative gas density – 0.6, tubing lowered to the middle of the perforation interval to a depth of 3,391 m; internal tubing diameter – 0.062 m; filtration resistance coefficients of the bottomhole zone of the layer: $A = 0.12$ MPa^2·day/thousand m^3; $B = 0.0027$ (MPa·day/thousand m^3)^2. The specified parameters (coefficients *A* and *B*) of the model well were used as a base scenario for conducting a series of calculations. These indicators remained unchanged throughout the study.

The studies studied the effect of different values of depression on the formation (2.5; 5.0; 7.5; 10.0; 15.0% of the initial pressure) and water factor values (0; 5; 10; 21; 25; 46; 50; 83; 100; 157; 188; 250; 350; 500; 800; 1,000 l/thousand m^3) on the hydrate formation temperature and wellhead temperature, as well as the depth of hydrate formation in the wellbore. To perform the calculations, the values of the bottomhole pressure were specified, which was determined through a given percentage of depression per reservoir from the initial reservoir pressure. From the equation of gas flow to the wellhead, the gas flow rate was determined for each value of bottomhole pressure using the formula R.M. Kondrat *et al*. (2023):

$$q_g = -\frac{A}{2B} + \sqrt{\left(\frac{A}{2B}\right)^2 + \frac{P_f^2 - P_{bh}^2}{B}}, \tag{1}$$

where P_f, P_{bh} – reservoir and bottomhole pressures, MPa, respectively; q_g – reservoir gas flow rate under standard conditions, thousand m^3/day; *A*, *B* – filtration resistance coefficients of the bottomhole zone of the reservoir; $A = 0.12$ MPa^2·day/thousand m^3; $B = 0.0027$ (MPa·day/thousand m^3)^2.

For each value of bottomhole pressure and gas flow rate, the pressure distribution along the working wellbore was calculated using the formula for gas movement in vertical wellbore pipes, corrected for the movement of the gas-liquid mixture in the tubing according to the method given in the work of R.M. Kondrat *et al*. (2023):

$$P(x) = \sqrt{\frac{P_{bh}^2 - \Theta \cdot {q_{mix}}^2}{e^{2S_0}}}, \tag{2}$$

where each component is calculated using the formulas:

$$S_0 = \frac{0.03415 \overline{\rho}_g \rho \cdot x}{Z_{aver} T_{aver}}; \tag{3}$$

$$\theta = 0.0133 \lambda \frac{Z_{aver}^2 T_{aver}^2}{{d_{in}}^5} \left(e^{2S_0} - 1\right); \tag{4}$$

$$q_{mix} = \frac{G_g + G_l}{\rho_g} = \frac{q_g \rho_g + q_w \rho_w}{\rho_g}; \tag{5}$$

$$\rho = \varphi + (1 - \varphi) \frac{\rho_w}{\rho_g(P)}; \tag{6}$$

$$\rho_g(P) = \frac{\rho_g P_{aver} T_{st}}{P_{at} T_{aver} Z_{aver}}; \tag{7}$$

$$\varphi \le \beta = \frac{q_g(P)}{q_g(P) + q_w}; \tag{8}$$

$$q_g(P) = \frac{q_g P_{at} T_{aver} Z_{aver}}{P_{aver} T_{st}}; \tag{9}$$

$$P_{aver} = \frac{2}{3}\left(P_{bh} + \frac{P_{(x)}^2}{P_{bh} + P_{(x)}}\right); \tag{10}$$

$$T_{aver} = \frac{T_{bh} - T_{(x)}}{ln \frac{T_{bh}}{T_{(x)}}}, \tag{11}$$

where *x* – the distance from the middle of the well perforation interval, m; Z_{aver} – the gas compressibility coefficient for P_{aver} and T_{aver}; T_{aver} – the average temperature in the wellbore, K; P_{bh}, $P_{(x)}$ – the pressure at the bottom and at a distance *x* from the wellbore, MPa; P_{aver} – the average pressure in the wellbore, MPa; G_g, G_w – the mass flow rate of gas and water, t/day; q_g, q_w, q_{mix} – the volumetric flow rate (flow rate) of gas, water and water-gas mixture, thousand m^3/day; T_{aver}, $T_{(x)}$ – the temperature at the bottom and at a distance *x* from the wellbore, K; d_{in} – the internal diameter of the tubing, cm; ρ_g, ρ_w – the density of gas and water under standard conditions, kg/m^3; $\rho_g(P)$ – gas density at average pressure and average temperature in the wellbore, kg/m^3; $\overline{\rho}_g$ – relative gas density; λ – coefficient of hydraulic resistance of the tubing; φ – actual (true) volumetric gas content (shows the actual amount of gas in the pipe at a certain moment); β – flow gas content (shows what part gas occupies in the production).

Dependence (8) describes the phenomenon of phase slippage. The water flow rate q_w can be expressed in terms of the gas flow rate q_g and the water factor F_w:

$$q_w = 10^{-6} F_w q_g, \tag{12}$$

where F_w – water factor, l/thousand m^3.

To determine the minimum required gas flow rate for removing water from the face to the surface, the dependence of the minimum required gas flow rate $q_{min,}$ obtained by R.M. Kondrat and V.S. Petryshak based on the results of statistical processing of industrial data on the operation of watered wells of one of the fields that stopped working due to water-flooded wells, which are shown in the works of R.M. Kondrat *et al*. (2023):

$$q_{min.} = 2{,}213 d_{in}^{1.94} q_l^{0.22} \sqrt{\frac{P_{bh} \rho_w}{\overline{\rho}_g Z_{bh} T_{bh}}}, \tag{13}$$

where q_w – water flow rate, m^3/day; Z_{bh} – gas compressibility coefficient for P_{bh} and T_{bh}; d_{in}, m; P_{bh}, MPa, ρ_w, kg/m^3.

Shukhov's formula, which are given in the scientific works of R.M. Kondrat *et al*. (2023) the temperature distribution along the wellbore at each segment *x* is determined:

$$t(x) = t_f - G_{gr}\, x - \Delta t_i\, e^{-ax} + \frac{1 - e^{-ax}}{a}\left(G_{gr} - D_j \frac{P_{bh} - P_x}{x} - \frac{A}{C_{l.mix}}\right), \tag{14}$$

where
$$t_j = D_j\left(P_f - P_{bh}\right) \frac{lg\left(1 + \frac{G \cdot C_{l.mix} \cdot \tau}{\pi \cdot h \cdot c_V \cdot r_W^2}\right)}{lg \frac{R_c}{r_w}}; \tag{15}$$

$$a = \frac{2\pi\lambda_c}{G C_{l.mix} \cdot f(t)}; \tag{16}$$

$$f(t) = ln\left(1 + \sqrt{\frac{\pi \lambda_c \tau}{c_V r_w^2}}\right), \tag{17}$$

where $t(x)$ – gas temperature at a distance *x* from the middle of the perforation interval,°C; G_{gr} – geothermal gradient,°C/m; D_j – differential Joule-Thomson coefficient,°C/MPa; A – thermal equivalent of work, equal to 1/427 kcal/kg·m; Δt_j – decrease in gas temperature in the bottomhole zone of the well due to the Joule-Thomson effect, taking into account heat exchange with the environment,°C; $C_{l.mix}$ – isobaric heat capacity of the mixture at average pressure, J/kg·°C; *G* – mass flow rate of gas, kg/h; τ – total well operation time, h; C_v – volumetric heat capacity of rocks, J/m^3·°C (kcal/m^3·°C); r_w, R_c – radius of the well and supply circuit, m; λ_c – thermal conductivity of rocks, J/m·h·°C; $f(t)$ – dimensionless function of time.

By pressure values $P(x)$ determine the temperature of hydrate formation in the wellbore according to the formula given in the works of R.M. Kondrat *et al*. (2023):

$$t_p(x) = 18.47 \cdot lg(10P(x)) - B, \quad (18)$$

where P_{wh} – the pressure at the wellhead, MPa; B – coefficient, which is determined depending on the conventional density of the gas according to the known component composition of the gas (methane CH_4 = 90.0148%; ethane C_2H_6 – 5.487%; propane C_3H_8 – 1.0091%; iso-butane C_4H_{10} – 0.0925%; n-butane C_4H_{10} – 0.1712%; neo-pentane C_5H_{12} – 0.0004%; iso-pentane C_5H_{12} – 0.0406%; n-pentane C_5H_{12} – 0.0235%; Hexane C_6H_{14} + higher – 0.0499%; Nitrogen N_2 – 1.1799%; Carbon dioxide CO_2 – 1.9318%; Oxygen O_2 – 0.0001%), B = 16.835.

Results and Discussion

Table 1 shows the values of pressure and temperature distribution along the borehole of an operating gas well in the absence of water inflow into the well and at a water factor of 100 l/thousand m³ at a depression in the formation of 15.0% of the initial pressure.

Table 1. The value of the pressure and temperature distribution along the shaft of an operating gas well in the absence of water inflow into the well and at a water factor of 100 l/thousand m³ at a depression on the formation of 15.0% of the initial pressure

Depth, m	In the absence of the water factor			At a water factor of 100 l/thousand m³		
	P, MPa	*t*,°C	$T_{hydr.}$,°C	*P*, MPa	*t*,°C	$T_{hydr.}$,°C
0	18.55	17.20	25.06	17.908	22.93	24.78
-141	19.15	22.36	25.32	18.548	27.59	25.06
-391	19.76	27.35	25.57	19.193	32.07	25.34
-641	20.37	32.15	25.81	19.844	36.35	25.60
-891	20.99	36.74	26.05	20.501	40.4	25.86
-1,141	21.61	41.07	26.29	21.164	44.19	26.12
-1,391	22.24	45.12	26.52	21.835	47.71	26.37
-1,641	22.87	48.83	26.74	22.515	50.92	26.62
-1,891	23.51	52.16	26.96	23.202	53.77	26.86
-2,141	24.15	55.05	27.18	23.898	56.24	27.09
-2,391	24.81	57.43	27.39	24.604	58.28	27.33
-2,641	25.47	59.23	27.60	25.319	59.83	27.56
-2,891	26.14	60.35	27.81	26.044	60.84	27.78
-3,141	26.81	60.70	28.02	26.78	61.26	28.01

Source: developed by the authors

Figure 1 shows the distribution of the actual temperature and the temperature of hydrate formation along the wellbore in the absence of water inflow into the well and at a water factor of 100 l/thousand m³ at a depression in the formation of 15.0% of the initial pressure. Analysis of the graphical dependence allows to determine the conditions of stable operation of the well and the place of hydrate formation.

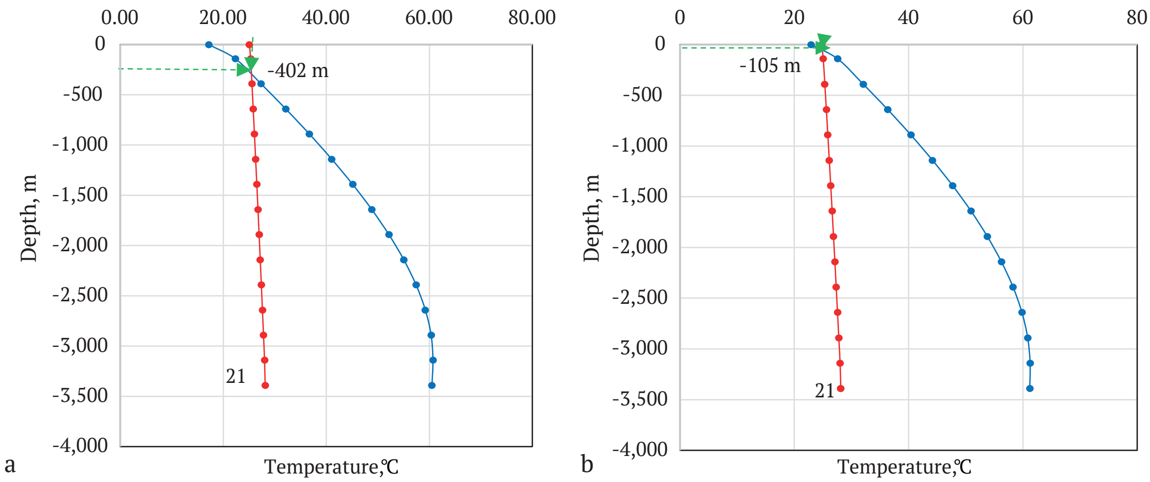

Figure 1. Distribution of actual temperature (a) and hydrate formation temperature along the wellbore (b) in the absence of water inflow into the well and at a water factor of 100 l/thousand m³ at a depression in the formation of 15.0% of the initial pressure

Note: a – actual temperature; b – hydrate formation temperature
Source: created by the authors

Analysis of the dependences of Figure 1 indicates intensive cooling of the gas during the ascent from the bottom to the wellhead (curve 1), which is due to the Joule-Thomson effect and heat exchange with colder surrounding rocks. Comparative analysis of Figure 1a and Figure 1b shows that the change in thermobaric conditions significantly affects the position of the zone of possible hydrate formation, shifting it from a depth of 402 m (Fig. 1a) to 105 m (Fig. 1b). Such a temperature distribution indicates the need to use inhibitors or thermal insulation of tubing to prevent hydrate deposition in the upper part of the wellbore. Figure 2 shows the distribution of the actual temperature at the wellhead and the equilibrium temperature of hydrate formation from the water factor at different depressions in the reservoir.

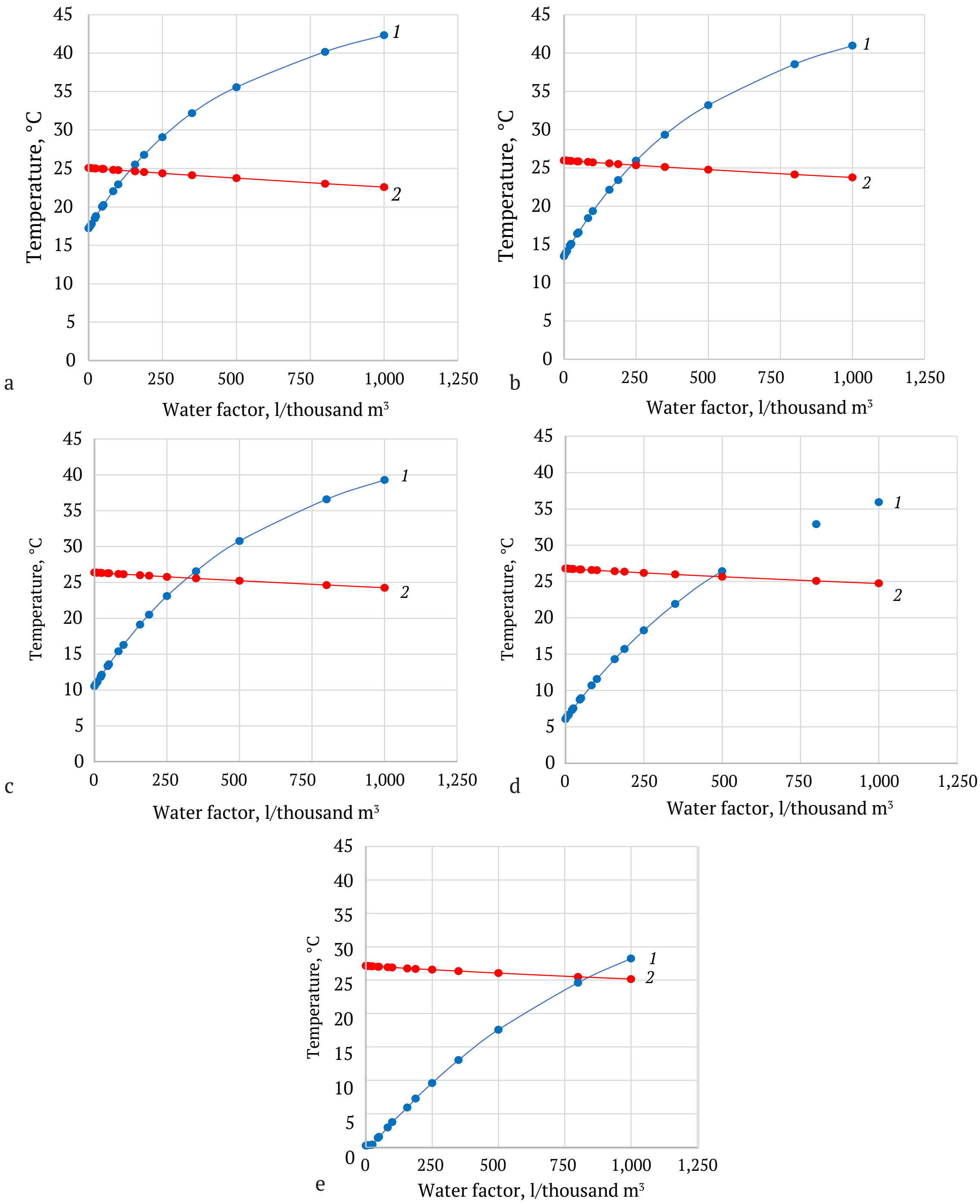

Figure 2. Distribution of the actual temperature at the wellhead and the equilibrium temperature of hydrate formation from the water factor at depression on the reservoir from the initial pressure

Note: depression on the layer 15% (a); 10% (b); 7.5% (c); 5.0% (d); 2.5% (e)

Source: created by the authors

The point of intersection (Fig. 2) between the actual temperature and the hydrate formation temperature lines is a critical technological indicator. To the left of the point, thermodynamic conditions favour the formation of hydrates, since the flow temperature is lower than the hydrate formation temperature. An increase in the water factor leads to an increase in the actual temperature, which gradually brings the system into a safe zone (to the right of the intersection point). With an increase in the water factor, the actual flow temperature increases rapidly, which is explained by the high heat capacity of water compared to gas. The hydrate formation temperature (curve 2) tends to decrease slightly with an increase in the amount of water in the flow. Analysis of the dependencies of Figure 2 shows that with a decrease in depression from 15 to 2.5 % of the initial pressure, the actual gas temperature at the mouth decreases significantly. With a decrease in depression, the zone of the hydrate-free drive shifts towards higher values of the water factor. This means that at low depressions, the well requires a significantly larger amount of formation water to "self-heat" the flow above the hydrate formation point. Table 2 shows the values of the depth of hydrate formation in tubing depending on the water factor at different values of depression in the reservoir.

Table 2. The value of the depth of hydrate formation in tubing depending on the water factor at different values of depression per reservoir

No. n/n	Water factor, l/thousand m³	Hydrate depth, m				
		15% P_{in}	10% P_{in}	7.5% P_{in}	5.0% P_{in}	2.5% P_{in}
1	0	402	593	718	900	1,158
2	5	382	564	705	881	1,142
3	10	363	555	670	869	1,129
4	21	334	525	651	841	1,110
5	25	306	497	645	832	1,102
6	46	258	453	612	794	1,071
7	50	239	440	593	784	1,066
8	83	133	382	507	727	995
9	100	105	325	469	689	965
10	157	15-20	191	354	545	899
11	188		105	249	506	842
12	250		15-20	143	392	755
13	350			15-20	191	611
14	500				15-20	392
15	800					15-20
16	1,000					

Source: created by the authors

The results of the studies (Table 2) reflect the general dynamics of the depth of hydrate formation in the tubing depending on the water factor. However, the analysis of the studies showed that when a certain critical value of the water factor is reached, stable operation of the well is stopped ($q_g < q_{min}$). At low depressions in the formation (for example, 2.5 % of the initial pressure), such a state occurs already at minimum values of the water factor, which predicts a rapid cessation of natural gushing due to self-extinguishing of the well. Taking this into account, further studies of the pressure and temperature distribution in the wellbore were carried out taking into account the prospective transition to mechanised methods of well operation (gas lift, plunger lift). Thus, the obtained results of studies on the depth of hydrate formation depending on water factors are the basis for designing hydrate formation prevention systems (for example, determining the location / points of injection of hydrate formation inhibitors) already at the stage of well operation using mechanised methods. Figure 3 shows the dependence of the depth of hydrate formation in tubing on the water factor at different values of depression on the reservoir, which make it possible to assess the hydrate formation zones in which well operation becomes impossible without constant supply of hydrate formation inhibitors.

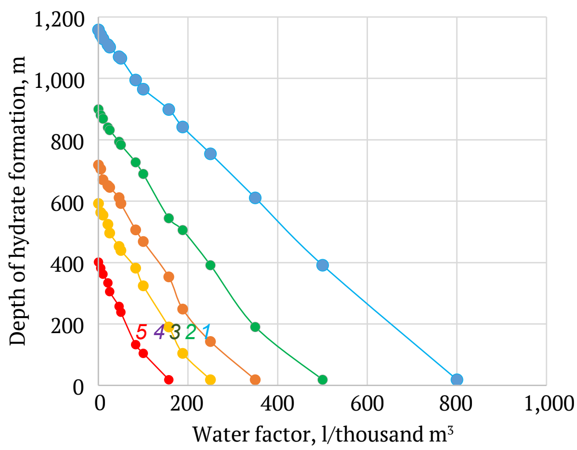

Figure 3. Dependences of the depth of hydrate formation in tubing on the water factor at different values of depression on the reservoir

Note: 1 – 2.5% 2 – 5.0%; 3 – 7.5%; 4 – 10.0%; 5 – 15%

Source: created by the authors

According to the results of the conducted studies, it was established that at low values of the water factor ($F_w < 25$ l/thousand m³) the zone of potential hydrate formation is the deepest and reaches over 1,000 m. All this is explained by the low heat capacity of pure gas: during the lifting of well products, the flow is intensively cooled through Joule-Thomson, therefore the curve of the actual temperature intersects the curve of the hydrate formation temperature at significant depths. With an increase in the water factor (over 100 l/thousand m^3) the reverse process is observed. The high heat capacity of water stabilises the flow temperature, "pushing" the hydrate formation zone to the wellhead. Analysis of the dependencies of Figure 3 shows that with an increase in the water factor, the depth of hydrate formation decreases. That is, with a large amount of water, hydrates begin to form much higher in the wellbore (closer to the wellhead). For example, with a depression of 5.0% of the initial pressure and the absence of water inflow into the well, an increase in the water factor to 500 l/thousand m^3 "raises" the hydrate formation zone from 900 to 15-20 m. An increase in the depression per reservoir leads to a significant decrease in the depth of the hydrate formation zone. This is explained by a change in the temperature mode and thermodynamic equilibrium in the tubing string. At minimum depression (2.5% of the initial pressure), the risk zone of hydrate formation is the deepest (reaches 1,158 m). At maximum depression (15% of the initial pressure), hydrates are formed only in the upper part of the well, and at high water factors (more than 188 l/thousand m^3) the conditions for their formation in the tubing are completely absent. For most operating modes, the upper part of the wellbore is critical (depths up to 400-600 m). At high water content (more than 800 l/thousand m^3), the risk of hydrate formation is shifted directly to the surface (depth about 15-20 m), which creates a threat of hydrate formation in wellhead equipment and plumes.

The results of the research allow to predict the intervals of possible hydrate deposition for specific well operating modes. This is the basis for choosing an effective technology for preventing hydrate formation, in particular, determining the required dose of inhibitors or establishing the optimal thermal mode of well operation by choosing the appropriate depression in the formation. Figure 4 shows the dependence of the maximum water factor on the depression in the formation at the moment of cessation of hydrate formation in the tubing.

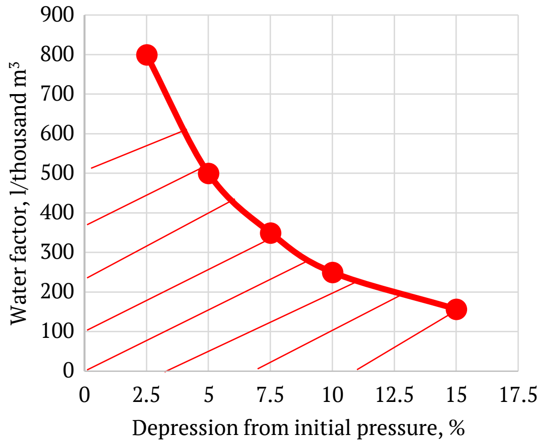

Figure 4. Dependence of the maximum water factor on the depression in the reservoir at the moment of cessation of hydrate formation in the tubing

Source: created by the authors

The analysis of the research results (Fig. 4) was based on finding the intersection points of the curves of the distribution of the actual temperature and the equilibrium temperature of hydrate formation along the wellbore for different values of depression per reservoir. With an increase in depression per reservoir, the critical value of the water factor, at which the formation of hydrates in the tubing stops, decreases rapidly. The area located to the left and below the red line in Figure 4 corresponds to the thermodynamic conditions under which active formation of hydrates occurs. This is a zone that combines high water content and low values of depression per reservoir, which leads to the rapid accumulation of hydrate deposits, which can cause complete overlap of the cross-section of the tubing. The area located to the right and above the red line determines the well operating conditions under which hydrates do not form. For a specific assessment of the well operating conditions at the time of cessation of natural gushing, the calculation of key technological indicators was carried out depending on the values of depression per reservoir. The results of the studies are presented in Table 3.

Table 3. Values of water factor, gas flow rate, minimum required gas flow rate, wellhead pressure, wellhead temperature and hydrate formation temperature for different values of depression in the formation at the time of cessation of natural well flow

Depression from initial pressure, %	Water factor, l/thousand m^3	Gas flow rate, thousand m^3/day	Minimum required gas flow rate, thousand m^3/day	Throat pressure, MPa	Temperature of wellhead,°C	Hydration temperature,°C
2.5	5	116.4	116.4	24.01	0.28	27,131
5	21	171.4	171.4	22,827	7.31	26,725
7.5	46	212.8	212.8	21,587	13.34	26,277
10	83	247.1	247.1	20.26	18.44	25,769
15	188	302.9	302.9	17,373	26.78	24,535

Source: created by the authors

Figure 5 shows the dependence of the water factor, wellhead pressure, wellhead temperature, and hydrate formation temperature on the depression in the reservoir at the moment of cessation of natural well flow.

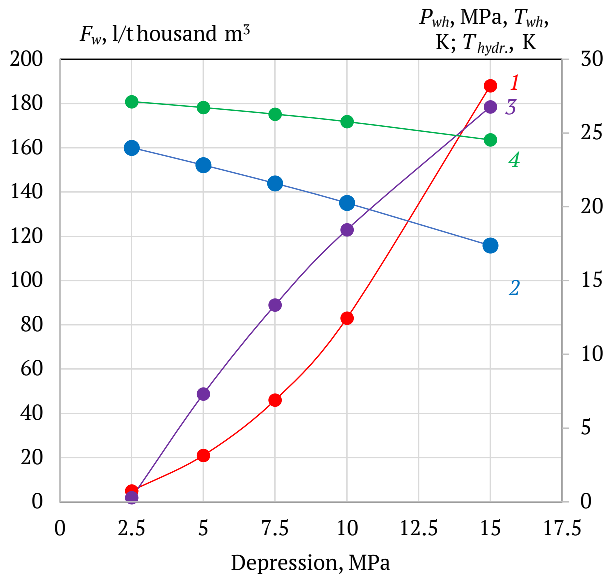

Figure 5. Dependence of water factor (1), wellhead pressure (2), wellhead temperature (3) and hydrate formation temperature (4) on the depression in the reservoir at the time of cessation of natural well flow

Source: created by the authors

Analysis of the research results at the time of cessation of natural well gushing shows that with a decrease in depression from 15% to 2.5% of the initial pressure, a sharp decrease in the actual wellhead temperature is observed (from 26.78 to 0.28°C). At the same time, the hydrate formation temperature increases from 24.535 to 27.131°C. This indicates that at low depressions, the actual gas-liquid flow temperature becomes significantly lower than the hydrate formation temperature and the hydrate formation process is inevitable without external intervention. A decrease in depression leads to an increase in wellhead pressure (from 17.373 to 24.01 MPa), which additionally contributes to the stability of hydrates at higher temperatures. The water factor, at which natural well gushing is still possible, significantly decreases with a decrease in depression. Thus, with a depression of 15% of the initial pressure, the well can deliver up to 188 l/thousand m³ of liquid, and with a depression of 2.5% of the initial pressure, this figure is only 5 l/thousand m³.

With increasing depression on the formation, the maximum value of the water factor increases at the moment of cessation of natural well gushing. Thus, the obtained results confirm that the transition to modes with low depression on the formation is accompanied not only by a deterioration in the conditions for liquid removal to the surface, but also by a rapid entry into the zone of active hydrate formation due to significant cooling of the gas flow in the well. This requires comprehensive measures for thermal insulation of the tubing or constant supply of hydrate formation inhibitors to the annulus. To prevent hydrate formation, the most effective is to maintain a high depression. If the well is forced to operate at low depressions, it is necessary to ensure the supply of hydrate formation inhibitors to the gas-liquid flow. The obtained results of modelling the formation of hydrates in the wellbore of watered gas wells confirm the complex relationship between depression on the formation and the water factor. Scientific research by J.G. Delgado-Linares *et al.* (2022) are devoted to systems containing carbon dioxide CO_2. The authors' conclusions regarding the mechanisms of particle aggregation are of fundamental importance for explaining the obtained dependencies. Scientists prove that the risk of hydrate formation depends on the viscosity of the extracted product, which increases significantly with an increase in the water factor. The results obtained indicate that at high water factors the hydrate formation zone shifts to the wellhead not only due to the thermodynamics of the processes, but also due to an increase in the viscosity of the extracted mixture.

The results of the obtained studies are also confirmed in the studies of M.O. Kehinde (2018). The authors focus their attention on the implementation of thermal intensification methods, which lead to the saturation of the production fluid with aggressive components (CO_2, H_2, oxygen). These fluids, under condensation conditions, cause intensive liquid corrosion and erosive wear of equipment due to the formation of iron sulfides. The obtained studies on the analysis of depression on the reservoir complement this theory. Phase instability and moisture condensation are determining factors of complications both in the wellbore and in the places of collection of production products. However, if in the studies the author considers the presence of hot water vapor as a negative factor, then in the results obtained for watered gas wells, the high heat capacity of formation water and the rational depression mode for the formation are used as a useful tool for preventing hydrate formation.

The results of the obtained studies are also confirmed in the studies of L.F. Dalla *et al.* (2026). The authors focus their attention on predicting hydrates during well shutdown or start-up using transient multiphase flow simulators. Taking into account such factors as the viscosity of the hydrate suspension and hydrate washout processes allows for highly accurate reproduction of the system behaviour in complex dynamic scenarios. The obtained studies on the depth of hydrate formation complement this theory, as they focus on the method of choosing the optimal depression in the reservoir, which ensures stable fluid removal and eliminates the conditions for hydrate formation. Static calculations based on reservoir parameters are insufficient, since the real risk of hydrate formation is determined by the hydraulic parameters in transient modes.

The results of the obtained studies, which are related to thermodynamic processes in water-filled wells, demonstrate the critical role of heat balance in preventing phase transitions. A similar approach to thermal mode control is noted in the work of researchers K. Ito *et al.* (2024). Although the object of their analysis is the extraction of methane from natural hydrate deposits of the sea shelf, the physical laws of the processes have deep parallels with the obtained studies. The results of the obtained studies on the temperature modes of watered wells are also confirmed in the studies of V. Indina *et al*. (2024). The authors focus their attention on the fact that the Joule-Thomson effect directly depends on the reservoir permeability k and the initial pressure P_{in}, which leads to the formation of hydrates when the working fluid temperature is higher than the equilibrium temperature of hydrate formation. The results of the obtained studies are compared with the scientific results of J. Ye *et al*. (2023), where the authors investigated the Joule-Thomson effect during CO_2 injection. Although the object of the research itself is different in the authors' scientific achievements, the physics of the process is identical – that is, a sharp expansion of the gas leads to intense cooling. The obtained studies confirm the authors' conclusions that at low reservoir pressures (in conditions of depleted reservoirs) this effect becomes dominant.

Researcher Z. Zhang *et al*. (2021) in their studies argued that the detection of the place of hydrate formation should be based on the transition from static thermodynamic regions to dynamic hydraulic indicators. The results obtained indicate that the static calculation according to reservoir conditions is not entirely sufficient. The results obtained for a depression in the reservoir of 2.5% of the initial pressure (Fig. 3) demonstrate that it is the dynamics of pressure reduction and gas cooling in the tubing that determines the real depth of hydrate formation, which can reach more than 1,000 m, which significantly exceeds the predictions based on average statistical indicators. Research by L. Wang & A.Y. Sun (2020) on the adhesion of hydrates on the walls of pipes indicates that the roughness of the tubing accelerates the growth of deposits. The obtained studies on the analysis of the depth of hydrate formation complement this theory, that at low values of the water factor, when the risk zone of hydrate formation covers more than 1,000 m of the wellbore, the surface area for potential crystal adhesion is maximum. All this contributes to the creation of prerequisites, which creates prerequisites for the gradual narrowing of the passage cross-section of the pipes.

The results of the research are closely intertwined with the scientific developments of D. Biberg *et al*. (2025). The authors focus their attention on the formation of significant liquid plugs that occur at low gas flow rates. These complications disrupt the operation of production collection systems. The results obtained indicate that the implementation of an integral wave instability indicator allows for fairly rapid prediction of the moments of occurrence and cessation of fluid flow pulsations. The results of studies on the analysis of depression per reservoir complement this theory. The transition to a mode with low depression per reservoir creates prerequisites for the accumulation of fluid in the upper part of the wellbore. The authors' scientific studies focus on assessing the risks of pulsations in pipelines. The results of the above studies show the dynamics of pressure reduction and gas cooling in tubing to determine the real depth of hydrate formation. Research by X. Sui *et al*. (2023) are directed to the fact that the supply of a significant amount of ethylene glycol to combat hydrates significantly reduces the solubility of salts and contributes to the formation of salt deposits. The methodology for selecting the optimal depression in the formation, which was obtained in the studies, is more rational in this context, since it allows using the so-called natural "self-heating" of the fluid flow due to the heat capacity of the formation water, which minimises the need for chemical reagents.

The results of the obtained studies are also confirmed in the studies of A. Abdullah *et al*. (2026). The authors in their scientific works focus their attention on low temperatures in combination with high pressure, which creates conditions for the formation of hydrates in anisotropic conditions of the annulus. The obtained research results indicate that the injection of diesel fuel through flexible pipes instead of expensive chemical reagents provides effective destruction of hydrate-paraffin formations without the risk of damage to the formation. The obtained studies on the analysis of depression in the formation and determination of the real depth of hydrate formation confirm these statements. Temperature modes in the wellbore are of crucial importance. The authors propose to solve the problem of hydrate formation by periodic artificial thermal exposure and injection of heated petroleum products from the surface, and the results obtained for water-filled wells focus on optimising the hydrodynamics of fluid production.

In their research A.G. Aregbe & A.I. Fadeyi (2021) provide important context on methods for increasing hydrate dissociation and stabilising gas production. Scientists note that one of the main methods for producing gas from hydrates is depression, thermodynamic influence and the supply of hydrate formation inhibitors. All this is fully correlated with the methodology, where depression on the formation is considered as one of the key factors determining the depth of hydrate formation in the wellbore (Fig. 3). However, if the authors analyse depression on the formation as a method for destroying hydrates in the formation, then the results of the research substantiate its optimal values to prevent their formation during the lifting of production. In their research, scientists also point out the risk of hydrate reformation during cooling of the produced gas, which requires more precise control of temperature and pressure. The obtained research results (Table 3) quantitatively confirm this statement that at low depressions in the reservoir, the actual temperature at the wellhead decreases, which makes the process of repeated hydrate formation inevitable without external intervention. Thus, the research results indicate the need for comprehensive monitoring of thermobaric parameters along the entire path of fluid movement. Summing up, the results of the research performed, it can be concluded that they are not only consistent with global trends in the oil and gas industry, but also offer specific solutions for depleted fields.

Conclusions

The results of the performed studies indicate that the process of hydrate formation in water-flooded gas wells clearly depends on the value of the depression on the formation and the water factor. Studies performed for different values of the depression on the formation (2.5; 5.0; 7.5; 10.0;

15.0% of the initial pressure) and the water factor (0; 5; 10; 21; 25; 46; 50; 83; 100; 157; 188; 250; 350; 500; 800; 1,000 l/thousand m^3), made it possible to estimate the thermal effect of the liquid phase on the total energy of the flow of production products in the tubing. The key aspect of the methodology was the determination of the depths of hydrate formation for different values of the depression on the formation and the water factor. For practical identification of well operation modes, a graphical analytical construction of hydrate formation boundaries was used, which allowed dividing the thermodynamic states of the system into a stable zone and a zone at risk of hydrate formation.

It was established that at a depression on the formation of 2.5% of the initial pressure, the most critical is the operation of the well at low values of the water factor (up to 26 l/thousand m^3), where the risk zone of hydrate formation covers more than 1,000 m of the wellbore. As a result of the performed studies, it was established that when the water factor reaches a value of more than 500 l/thousand m^3, the gas-liquid flow of the produced products becomes "hot" enough to independently exit the zone of hydrate formation even at low depressions on the formation. It was quantitatively estimated that an increase in the depression on the formation contributes to an increase in the critical value of the water factor, at which the formation of hydrates in the tubing stops. The dependence of the maximum water factor on the depression on the formation at the moment of the cessation of the formation of hydrates in the tubing allows to clearly delimit the thermodynamic conditions into the zone of active hydrate formation and the zone of stable operation of the wells.

The proposed method allows predicting the intervals of hydrate formation and justifying the operating modes of wells that ensure their hydrate-free operation. The prospects for further scientific research lie in the detailing of the developed model by taking into account the influence of formation water mineralisation on the thermobaric parameters of hydrate formation. A separate direction is the study of the kinetics of adhesion of hydrate particles to the inner wall of the tubing in the presence of salt deposits, which will allow specifying the time until the pipe cross-section is completely blocked. Also relevant is the modelling of the influence of thermally insulated lift columns on the expansion of the limits of hydrate-free operation of wells with low formation pressures.

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Conflict of Interest

None.

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Дослідження характеристик процесу гідратоутворення в обводнених газових свердловинах

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Анотація. Актуальність наукових досліджень зумовлена переходом більшості родовищ природних газів на пізню стадію розробки, що супроводжується значним обводненням видобувної продукції та створює термодинамічні передумови для аварійного перекриття стовбурів свердловин газовими гідратами. Метою роботи було встановлення впливу значень водного фактора та депресії на пласт на характеристики процесу гідратоутворення в обводнених газових свердловинах для оптимізації їхніх технологічних режимів. Для вирішення поставлених завдань розроблено комплексну математичну модель термодинамічного стану багатофазного флюїду, за допомогою якої виконано серію досліджень на модельній свердловині за різних значень депресії на пласт (2,5; 5,0; 7,5; 10,0; 15,0 % від початкового тиску) та водного фактора (0-1 000 л/тис.м^3). Встановлено, що за низьких значень депресії на пласт (2,5 % від початкового тиску) та незначного припливу води зона ризику утворення гідратів є найбільш критичною і сягає глибини понад 1 000 м. Виконано температурний розподіл по стовбуру свердловини та доведено, що при досягненні водного фактора більше 500 л/тис.м^3 газорідинний потік стає достатньо «гарячим» завдяки високій теплоємності води, що дозволяє свердловині самостійно вийти із зони гідратоутворення. Визначено критичні значення водного фактора на момент припинення природного фонтанування, за яких фактична гирлова температура знижується до мінімальних значень 0,28 °C. Розроблено графоаналітичну методику побудови меж гідратоутворення, яка дозволяє чітко розмежувати термодинамічні стани системи на зону активного гідратоутворення та зону стабільної роботи свердловини. Продемонстровано, що збільшення депресії на пласт сприяє зростанню критичного значення водного фактора, за якого припиняється утворення гідратів у насосно-компресорних трубах без зовнішнього втручання. Практична цінність результатів полягала у можливості використання розробленої моделі інженерно-технічними фахівцями нафтогазової галузі для обґрунтованого вибору безгідратних режимів експлуатації обводнених свердловин

Ключові слова: водний фактор; експлуатація; депресія на пласт; температура гідратоутворення; газ