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Optimisation of the operation of a group of wells with different productive characteristics connected to a common collector

Andrii Uhrynovskyi

PhD in Technical Sciences, Associate Professor
Ivano-Frankivsk National Technical University of Oil and Gas
76019, 15 Karpatska Str., Ivano-Frankivsk, Ukraine
https://orcid.org/0000-0002-3886-9639

Lesia Moroz*

PhD in Technical Sciences, Associate Professor
Ivano-Frankivsk National Technical University of Oil and Gas
76019, 15 Karpatska Str., Ivano-Frankivsk, Ukraine
https://orcid.org/0000-0002-5183-4940

Ihor Kryskiv

Ukrainian Research Institute of Natural Gases
61010, 20 Himnaziina Naberezhna Str., Kharkiv, Ukraine
https://orcid.org/0009-0003-4534-2856

Vasyl Hutsulyak

Postgraduate Student
Ivano-Frankivsk National Technical University of Oil and Gas
76019, 15 Karpatska Str., Ivano-Frankivsk, Ukraine
https://orcid.org/0000-0003-4973-7719

Abstract. Optimisation of the operation of a group of wells connected to a single pipeline consists of the correct distribution of the pressure load between the wells, which ensures that there are no gas production losses at the group level, as well as the maximum involvement of each well in the production process. Therefore, the aim of the study was to establish the optimal technological mode of well operation, taking into account the connection of wells to a common collector with different working pressures at their mouths. This was achieved by redistributing the flow rate between wells, taking into account the gas reserves in the specific drainage volume, by installing a fitting at their mouths. The problem was solved by simultaneously solving two equations: an equation reflecting the constancy of the ratio between the well flow rate and gas reserves per unit of drainage volume, and an equation for the volumetric gas flow during adiabatic (i.e., without heat exchange with the environment) leakage through the fitting, which was described by the Saint-Venant-Wansel formula. Based on the solution of the problem and the performed calculations, it was established that three wells from the group were operated at reduced flow rates due to differences in residual specific drainage volumes, while the remaining wells exceeded the optimal gas flow rate parameters. Such a discrepancy was interpreted as evidence of inefficient utilisation of the resource potential of the field. A solution to the multi-objective problem was proposed, aimed at optimising the operating mode of a group of wells and the gas gathering network as a single integrated hydrocarbon production system. With this approach, a balance was achieved between the efficiency of hydrocarbon extraction and the uniformity of the load on the infrastructure. The outcomes of the study are expected to be useful in practice for establishing optimal technological modes of operation for wells with different production characteristics operating in a single collector

Keywords: pipeline; flow rate; fitting; pressure; gas; field; gathering system

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*Corresponding author

Introduction

Depending on the pipeline system configuration, hydrocarbon products gathering systems were classified as collector and non-collector schemes. In gas field development, it was common for products from several wells to be fed into a common pipeline (collector), through which they were transported to a gas processing plant (GPP). One of the key operational tasks in managing such a system was to maintain optimal operating conditions for wells connected to a common collector.

In their study, A.V. Uhrynovskyi *et al*. (2022) analysed approaches to organising product gathering systems at oil fields. It was concluded that creating a single universal system was impractical because of the unique geological and technical conditions characterising each field. In particular, several factors were identified that determined the specifics of the gathering system, the layout of wells, the physical and chemical properties of reservoir fluids, the level of remaining reserves, the climatic conditions of the region, the selected well operation methods, and the volume of hydrocarbon products. Thus, the necessity of an individual approach to the design of gathering systems for each specific field was emphasised.

According to O. Stanley *et al*. (2021), the operation of wells in heterogeneous reservoir conditions was accompanied by several technical problems. They emphasised that differences in reservoir properties caused significant differences in pressures of wells and flow rates, even when wells were located close to each other, which significantly complicated the effective operation of the gathering system. It was noted by the authors that considerable heterogeneity of reservoir rocks could lead to major differences in wellhead pressure and production rate even among wells situated within a short distance of each other. It was established that connecting such wells to a common pipeline led to a redistribution in the system: wells with high pressure could suppress low-pressure ones, limiting their productivity to a minimum level. It was also emphasised that well productivity was closely dependent on wellhead pressure; therefore, a change in the operating mode of one well could significantly affect the performance of other wells within the system. In the study by I.W. Purnomosidi *et al*. (2024), effective methods for regulating the operation of gas wells were explored. It was pointed out that one of the main ways to control well productivity was to control the pressure at the wellhead or the inlet of the tubing shoe. The most common practical method was the creation of backpressure at the wellhead using a fitting. The use of downhole fittings had not become widespread due to difficulties associated with their installation and maintenance. A key aspect of the study was the observation that adjusting the cross-sectional area of the choke opening allowed for precise regulation of the well flow rate according to reservoir conditions.

In the works of T.M. Nesterenko *et al*. (2021) and S. Bekov *et al*. (2024), the process of achieving a stable technological operating mode of wells after adjusting fitting parameters was analysed. It was noted that after adjusting the passage area of the fitting, the well had to operate in the set mode for a certain period until stabilisation was achieved. This stable mode was characterised by constant flow rate, bottomhole and annular pressures. It was emphasised that the technological operating mode was established taking into account a set of limiting factors and determined the operating conditions under which the maximum possible gas flow rate was achieved without damaging the integrity of the formation or technical equipment.

The study by L.V. Moroz *et al*. (2023) was devoted to analysing the formation of the technological mode of gas well operation at industrial enterprises. It was noted that such modes were developed quarterly by the geological service of the enterprise and approved by the chief geologist and chief engineer of the gas production department. Special attention was given to determining the optimal operating conditions, which required the identification of the leading factor or group of factors most influencing production efficiency. It was highlighted that the rational design of a technological regime requires taking into account a wide range of parameters: well construction, the stability of gas-bearing formations to destruction, geological structure (multi-layered, heterogeneous, sequence of formations), physical and chemical characteristics of gas (water and condensate content), features of the operating scheme (group placement of wells, connection to a header), as well as the presence of complications such as salt deposits.

In the studies by Q. Zhang *et al*. (2022), J. Wu *et al*. (2022), and M.S. Al-Kadem *et al*. (2024), designed solutions used to implement the specified operating mode of wells were reviewed. It was stated that the most common means of control are fittings of various designs – both straight and angular, as well as fittings such as throttle washers. The latter received special attention due to their simplicity, reliability, and efficiency. An orifice-type choke consisted of a metallic disc with a hole of a specified diameter, installed at the wellhead in place of the sealing ring between two flanged joints. In the works of B. Tan *et al*. (2024) and J. Wu *et al.* (2022) presented an innovative technical solution to improve the efficiency of well pressure control, a choke equipped with an electronically controlled control system with an electric drive. It was noted that the introduction of such a system made it possible to significantly improve the accuracy of pressure control and reduce the response time to changes in operating conditions. The electronic control made it possible to remotely adjust the throttle parameters in real time, providing continuous pressure monitoring and rapid system adjustment. This approach also significantly improved personnel safety, as it eliminated the need for manual intervention at the well site.

Although numerous studies were devoted to various approaches for organising production gathering systems in oil and gas fields, a clear methodology for selecting throttle washers for wells with different performance characteristics connected to a common collector was not found in the current scientific literature. This gap indicated the need for further research and development aimed at optimising well operation regulation under heterogeneous conditions, which was essential for enhancing production efficiency and operational reliability. The aim of this study was to determine the optimal well operation mode, taking into account their connection to a common collector at different wellhead pressures.

Materials and Methods

The material used in this study was data on the operation of gas wells operating with wellhead throttle washers and sharing a common gas gathering collector. Optimisation of a group of wells connected by a single pipeline was based on the correct balancing of the pressure load between them, which avoided a decrease in overall gas production and ensured efficient operation of each well. To meet these requirements, a constant ratio between the well flow rate and the gas reserves per unit volume of the drainage area had to be maintained, specifically:

$$\frac{q(1)}{\alpha \times \Omega_1} = \frac{q(2)}{\alpha \times \Omega_2} = \ \dots \ = \frac{q(i)}{\alpha \times \Omega_i} = \text{const}, \qquad (1)$$

where $q(i)$ is the flow rate of the i-th well, m^3/d; $\alpha \times \Omega_i$ is the gas-saturated drainage volume of the i-th well, m^3. According to the Saint-Venant-Wanzel formula, the volumetric gas flow rate during adiabatic (without heat exchange with the environment) movement through an opening (fitting, throttle washer) could be found by the formula:

$$q_g = \mu \times \omega_o \times \sqrt{2 \times R} \times \frac{P_1 \times T_o}{P_o} \times$$
$$\times \sqrt{\frac{1}{T_1 \times M_g} \times \frac{k}{k-1} \times \left[\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}} - \left(\frac{P_2}{P_1}\right)^{\frac{k+1}{k}}\right]}, \qquad (2)$$

where q_g is the volumetric gas flow rate under normal conditions, m^3/s; P_o, T_o are the pressure and temperature under standard conditions, Pa and K; ω_0 is the leakage rate, m/s; P_1, T_1 are the pressure and temperature at the inlet of the fitting, Pa and K; P_2 is the pressure after the fitting, Pa; μ – is the flow coefficient for the lemniscate nozzle $\mu = 0.95$ - 0.98 increases with the Reynolds number and slightly decreases with P_1/P_2; k is the adiabatic coefficient, which changes little with temperature and molecular weight of the gas, so for practical calculations it can be taken with sufficient accuracy as $k = 1.25$; $R = 8{,}314.3$ J/(kg·K) is the standard gas constant; M_g is the molar mass of a gas, kg/mol. The application of this formula is limited by the critical pressure ratio:

$$\left(\frac{P_2}{P_1}\right)_{kr} = \frac{2}{(k+1)^{k/(k-1)}}. \qquad (3)$$

This is a condition where the flow velocity reaches the speed of sound and the gas flow rate is maximum, i.e. formula (2) is applicable under the condition $\left(\frac{P_2}{P_1}\right) > \left(\frac{P_2}{P_1}\right)_{kr}$. If $\left(\frac{P_2}{P_1}\right) \le \left(\frac{P_2}{P_1}\right)_{kr}$ then in formula (2) $\left(\frac{P_2}{P_1}\right)$ must be replaced with $\left(\frac{P_2}{P_1}\right)_{kr}$, i.e. take $\left(\frac{P_2}{P_1}\right) = \left(\frac{P_2}{P_1}\right)_{kr}$, then the maximum gas flow rate is:

$$q_g = \mu \times \omega_o \times \sqrt{2 \times R} \times \frac{P_1 \times T_o}{P_o} \times$$
$$\times \sqrt{\frac{1}{T_1 \times M_g} \times k \times \left(\frac{2}{k+1}\right)^{(k+1)/(k-1)}}. \qquad (4)$$

To determine the diameter of the throttle washer, formulas (2) and (4) should be written in the following form:

$$d = \sqrt{\frac{4 \times q_g \times P_o}{\pi \times \mu \times P_1 \times T_o \times \sqrt{2 \times R} \times \sqrt{\frac{1}{T_1 \times M_g} \times \frac{k}{k-1} \times \left[\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}} - \left(\frac{P_2}{P_1}\right)^{\frac{k+1}{k}}\right]}}}; \qquad (5)$$

$$d = \sqrt{\frac{4 \times q_g \times P_o}{\pi \times \mu \times P_1 \times T_o \times \sqrt{R} \times \sqrt{\frac{1}{T_1 \times M_g} \times k \times \left[\frac{2}{k+1}\right]^{\frac{k+1}{k-1}}}}}. \qquad (6)$$

The diameter of the throttle washer was determined using formula (6), which ensures critical gas flow at a given gas flow rate q_g. After solving equations (1), (5), and (6) collectively, the required diameter of the throttle washer for each well was determined. The amount of residual drained gas reserves from the total volume of reserves in the wells was found using formula (7):

$$\Delta = \frac{Q_{inres}}{\Sigma Q_{res}} \times 100\%. \qquad (7)$$

The gas flow rate for production optimisation was determined as the product of the total gas flow rate by wells and the value of the remaining drained gas reserves of the total reserves volume for each well:

$$q_2 = q_t \times \Delta. \qquad (8)$$

Results and Discussion

A group of six wells connected to a single pipeline was examined. Figure 1 shows a graph of the gas flow rate of each well as a function of the change in working pressure at the wellhead. The total gas flow rate of these wells was limited by the consumer and amounts to 34.35 thousand m^3/d. Under these conditions, the pressure in the reservoir is 20 atm, and at the inlet to the gas processing plant (GPP), the gas flow was throttled to a pressure of 5 atm.

The graphical dependence of the gas flow rate of six wells on the working pressure at the wellhead is shown in Figure 1. The horizontal axis shows the working pressure (P_w) in the range from 4 to 24 atm, and the vertical axis shows the corresponding gas flow rate (1,000 m^3/day). Each line corresponds to a separate well (well 1-well 6) and is approximated by a second or fourth-degree polynomial, which allows for accurate reflection of the change in productivity depending on pressure. Analysis of the graph shows a nonlinear dependence of flow rate on pressure at the wellhead. The most productive well is No. 2, whose flow rate at low-pressure values exceeds 20 thousand m^3/day. Conversely, well No. 6 shows the lowest production level, less than 2 thousand m^3/day under the same conditions.

This difference was caused by geological and technical features of the corresponding drainage intervals. The dependencies were an important basis for further optimisation of the gas collection system, as they allowed assessing the impact of changes in wellhead pressure on the intensity of each well and the group as a whole. Table 1 shows the gas flow rates of the wells at a reservoir pressure of 20 atm, the initial drained gas reserves and the accumulated production for each well. Well No. 6 has the lowest gas flow rate – 1.52 thousand m³/day, which is only 4.4% of the total flow rate of the six wells. To ensure an even load between wells, according to formula (1), a constant ratio between the well flow rate and the volume of gas per unit of drained space should be maintained.

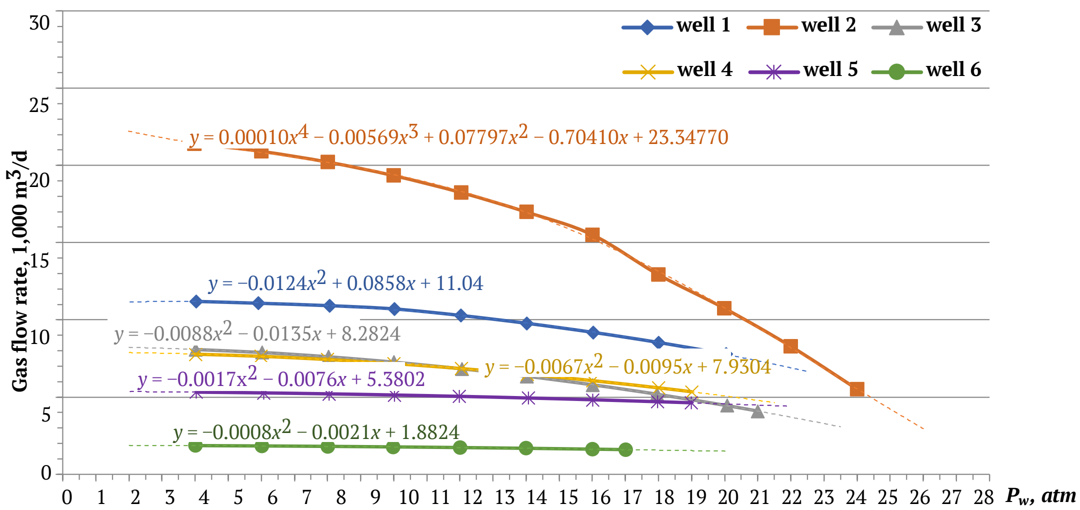

Figure 1. The influence of working pressure at the wellhead on gas flow rate

Source: created by the authors

Table 1. Operating parameters of wells operating in a common pipeline

Well	Gas flow rate (q_1), thousand m³/d	Initial drained gas reserves (Q_{res}), million m³	Accumulated gas production (Q_{pr}), million m³	Pressure in the collector (P_{col}), atm
1	7.80	88.6	27.6	20
2	10.93	107.6	69.1	
3	4.49	82.5	46.9	
4	5.06	32.0	5.5	
5	4.55	32.5	7.3	
6	1.52	48.1	28.9	
Total	34.35	$\sum Q_{res} = 391.3$	$\sum Q_{pr} = 185.2$	

Source: made by the authors

Table 2 presents the results of calculating the well flow rate after optimising gas production, taking into account the amount of residual drained gas reserves from the total volume of reserves in the wells. Analytical results of gas flow distribution between six wells are presented to achieve optimal operating mode with limited total productivity. Optimisation involves ensuring the proportional distribution of production by the residual drained gas reserves of each well.

Table 2. Results of gas flow rate calculations for production optimisation

Well	Residual drained gas reserves (Q_{res}), million m³	Residual drained gas reserves as a percentage of total reserves in wells Δ, %	Gas flow rate for production optimisation (q_2), thousand m³/d	q_1 - q_2,thousand m³/d
1	61.0	29.6	10.17	-2.37
2	38.5	20.7	7.11	3.82
3	35.6	19.3	6.63	-2.14
4	26.5	12.9	4.41	0.65
5	25.2	12.2	4.20	0.35
6	19.2	5.3	1.82	-0.30
Total	$\sum Q_{res} = 206.1$	100	34.35	

Source: made by the authors

Column 2 shows the value of residual drained gas reserves (Q_{res}, million m³. The largest volumes of residual reserves are observed in well No. 1 (61.0 million m³), and the smallest in well No. 6 (19.2 million m³). Column 3 shows the share of each well in the total remaining reserves (%), which varies from 29.6% to 5.3%. Column 4 shows the optimal gas flow rate (q_2), thousand m³/d, calculated according to the proportional model that takes into account the remaining reserves. According to the calculations, wells No. 2, No. 4, No. 5 demonstrate positive values of flow rate increase

($q_2 > q_1$), while wells No. 1, No. 3, No. 6 shows the need to reduce production ($q_2 < q_1$), which is recorded in column 5 as the difference between the current and optimised flow rates ($q_1 - q_2$). The calculated data indicate that it is possible to increase the efficiency of the entire group of wells by redistributing well flow rates, which avoids hydraulic squeezing of low-flow wells and ensures uniform hydrocarbon production.

Table 2 shows that there was a redistribution of well gas flow rates, taking into account the residual drained gas reserves. The results of the calculations show that wells No. 1, No. 3 and No. 6 should have higher operating gas flow rates by 2.37 thousand m^3/d, 2.14 thousand m^3/d and 0.30 thousand m^3/d, respectively. At the same time, the operating flow rates of wells No. 2, No. 4 and No. 5 should decrease by 3.82 thousand m^3/d, 0.65 thousand m^3/d and 0.35 thousand m^3/d, respectively. To distribute the gas flow rate between the wells according to Table 2, it was necessary to install choke washers with the appropriate bore diameter at the wellheads, which reduced the pressure in the collector. Table 3 shows the results of calculations of the operating parameters of six wells combined into one group to achieve the optimal production mode.

Table 3. Gas flow rate for production optimisation and required choke plate diameters

Well	Gas flow rate for production optimisation (q_2), thousand m^3/d	Working pressure at the wellhead for production optimisation, atm	Choke plate diameter, mm	Collector pressure for production optimisation, atm
1	10.17	12.52	6.043	5
2	7.11	23.03	3.726	
3	6.63	12.95	4.798	
4	4.41	22.23	2.986	
5	4.20	24.25	2.790	
6	1.82	7.50	3.989	
Total	34.35	-	-	-

Source: made by the authors

The main controlled parameters are: the target gas flow rate of each well (q_2), the operating pressure at the wellhead, the optimal diameter of the choke washer, and the pressure in the reservoir, which is the same for the entire group and amounts to 5 atm. The value of the gas flow rate for optimisation (q_2) ranges from 1.82 to 10.17 thousand m^3/d. The highest flow rate is provided for well No. 1, which requires the largest choke washer diameter – 6.043 mm at a wellhead pressure of 12.52 atm. At the same time, the lowest flow rate corresponds to well No. 6 (1.82 thousand m^3/d), which requires a choke washer with a diameter of 3.989 mm at the lowest wellhead pressure of 7.5 atm. The operating wellhead pressure varies depending on the well characteristics and is adjusted to ensure the required reservoir pressure at the agreed production rate. For example, for well No. 2 with a production rate of 7.11 thousand m^3/d, the corresponding wellhead pressure is 23.03 atm, which requires the installation of a washer with a diameter of 3.726 mm. The working pressure at the wellhead for optimising production in the presence of a choke washer can be found from Figure 1 with a known gas flow rate q_2.

The most common variant of the technological process of gathering products from wells is a collector scheme, in which the flow from several wells is combined into one pipeline and transported to the GPP. Pressure regulators or wellhead chokes were often installed to maintain the required pressure at the bottom hole or wellhead and ensure a given oil and gas production rate. In the study of H.S. Barjouei *et al*. (2021), the peculiarities of well operation in the presence of a two-phase filtration flow were analysed. The impact of phase (gas-liquid) interaction on the hydrodynamic parameters of operation, and changes in flow rate, pressure, and production recovery efficiency under such conditions, were examined. The obtained results allowed for a better understanding of the specifics of well behaviour in a two-phase filtration mode and could be used to improve models for forecasting and optimising well operations. The calculations were performed under the conditions specific to the Sorush oil field, taking into account the flow of a gas-liquid mixture. When evaluating these studies in the context of parameters influencing well performance, such as wellbore diameter, wellhead pressure, fluid specific gravity, and the gas-liquid phase distribution ratio, it should be noted that the effect of gas pressure behind the wellbore was not considered. Furthermore, it was observed that the main flow mode of the gas-liquid mixture through the fitting was critical.

In the works of MS. Dabiri *et al*. (2024) and T. Visawameteekul *et al*. (2024), the necessity of installing a wellhead fitting to control the technological mode of well operation and prevent such complications as the formation of a bottomhole cone and destruction of the bottomhole zone of the formation was described. The importance of the wellhead choke in regulating flow rate and optimising production for the entire collection network was also noted. The model was developed using multivariate regression and an optimisation algorithm. Data for the study were collected from 21 wells in seven fields in the Niger Delta region. The developed model investigated gas flow through the wellhead and the effect of the diameter of the wellhead and gas density on well productivity. Although the developed model involved a significant amount of data from 21 wells and provided accurate verification of values, it did not take into account the mutual influence of wells connected to a common pipeline.

In the study by Q. Zhang *et al*. (2022), the technical characteristics of the wellhead fitting were shown to play a critical role in optimising well production parameters. A hydrodynamic model was constructed based on the actual layout of the prefabricated reservoir to simulate the flow process. The distribution of the flow field and the pressure drop under various operating conditions were recorded. The findings demonstrated that pressure losses in the collector occurred both as a result of changing inlet conditions and due to variations in flow structure. It was noted that the study focused on comparing different types of throttling devices. The authors concluded that, under identical opening conditions, the pressure drop associated with a wedge-type throttle was lower than that observed with a flat-type throttle.

In the research conducted by S.K. Joshua *et al*. (2020), the optimisation of well operations was examined through variations in choke size, adjustment stages, and replacement frequency. The results indicated that a greater pressure differential at the wellhead fitting during the initial production phase resulted in a higher initial gas production rate. It was found that smaller wellhead fittings were more favourable than larger ones in terms of gas transport efficiency, with a choke diameter of 3 mm identified, through numerical modelling, as optimal. The issues related to the calculation of choke washers and pressure regulation were explored in the works of M. Bennis *et al*. (2020) and Q. Zhang *et al*. (2022). Although these studies focused on the analysis of pressure drops across throttling devices using computational methods, primary attention was given to the degree of choke opening and the hydrodynamic behaviour of the flow field.

In the work of I. Baselt & A. Malcherek (2022), a modernised form of the Saint-Venant-Wansel theoretical relationship for determining the gas flow rate from a system's flow element was presented. The studies conducted by Y.A. Rilwan & G.C. Nmegbu (2022), as well as by A.H. Al Salmi *et al*. (2023), addressed the role of flow control elements, particularly fittings and throttle washers, in gas well operations. It was established that the primary limiting components governing gas flow through wellhead equipment were the fitting and throttle washer. The choke was identified as a critical element designed to regulate the velocity of gas or liquid flow within limits acceptable for preserving the integrity of the productive formation. This regulation helped prevent the development of water or condensate cones, thereby reducing the risk of premature water breakthrough in the well. Furthermore, wellhead chokes were recognised as key tools in reservoir management, as they allowed for the control of individual well flow rates and the generation of the required pressure within the gathering collector, thereby enabling more efficient and balanced field operation.

The study of gas flow control was recognised as one of the critical tasks in the selection and installation of throttling devices in gas pipeline systems. In this context, X. Gu *et al*. (2024), and S. Kongkiatpaiboon & S. Apisaksirikul (2025) improved the design of valve sleeves to enhance the regulation of axial gas flow. Following these design improvements, eight numerical simulations were carried out at varying orifice sizes to analyse changes in the velocity field, pressure distribution, and aerodynamic noise within the flow channel for both design configurations. A comparative analysis of the two valve designs was also presented, focusing on their respective flow field structures and noise characteristics. The modelling results demonstrated that a properly increased orifice diameter in the throttling device could significantly improve the performance of the axial gas flow control valve, with noise levels reduced to below 100 dB at medium and small orifices.

Optimisation of the operation of a group of wells connected to a common collector was addressed through the rational distribution of pressure loads, with the aim of minimising production losses at the system level and maximising the individual potential of each well. The study was undertaken to determine the optimal technological modes for well operation, taking into account varying wellhead pressure values in a shared pipeline configuration. To address this objective, an approach was employed based on the simultaneous solution of two equations: the first describing the constancy of the ratio between well production rate and gas reserves per unit volume of the drainage area; the second characterising gas flow through the fitting under adiabatic conditions, following the Saint-Venant-Wansel formula. The results indicated that three wells within the group were operated at suboptimal flow rates due to limited residual drainage volumes, while others exceeded optimal output levels, highlighting a systemic imbalance in the distribution of load across the well network.

Conclusions

Based on the study, a method for solving a multi-objective problem aimed at the comprehensive optimisation of both the technological regime of individual wells and the operation of the gas gathering system as a whole was proposed. The application of this approach allowed not only for efficient hydrocarbon extraction but also for the balancing of the load on infrastructure elements, which is especially important for maintaining long-term field productivity. In this paper, a solution was presented for the operation of a group of wells with differing performance characteristics connected to a common gas pipeline. To evenly distribute the load among the wells, a system of equations was considered, one of which described the constancy of the ratio between the well production rate and gas reserves in the specific drainage volume, while the other, the Saint-Venant-Wantzel equation, characterised the gas flow through the flow element.

By establishing the correct technological mode of well operation, wellhead pressures were adjusted according to the collector pressure, and the flow rate of each well was optimised without losses in total gas production for the group as a whole. The calculations demonstrated that, depending on the residual specific drainage volumes, three wells in the group were operated with insufficient gas flow rates: No. 1 – 7.8 thousand m^3/day (10.17 thousand m^3/day was required for optimal production), No. 3 – 4.49

thousand m³/day (6.63 thousand m³/day was required), and No. 6 – 1.52 thousand m³/day (1.82 thousand m³/day was required). The remaining wells demonstrated higher gas flow rates compared to the optimisation targets: No. 2 – 10.93 thousand m³/day (7.11 thousand m³/day was required), No. 4 – 5.06 thousand m³/day (4.41 thousand m³/day was required), and No. 5 – 4.55 thousand m³/day (4.2 thousand m³/day was required). Further research should be directed towards the study of well groups operating within a single gas pipeline that experience operational issues such as fluid accumulation at the bottom hole and bottom hole formation damage. These complications are most typical for gas and gas condensate wells and increasingly require novel approaches for their mitigation. The results obtained in this study can be applied in practice to establish efficient operating regimes for wells with different performance characteristics connected to a common collector.

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Conflict of Interest

None.

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Оптимізація роботи групи свердловин із різними продуктивними характеристиками підключених у спільний колектор

Андрій Угриновський

Кандидат технічних наук, доцент
Івано-Франківський національний технічний університет нафти і газу
76019, вул. Карпатська, 15, м. Івано-Франківськ, Україна
https://orcid.org/0000-0002-3886-9639

Леся Мороз

Кандидат технічних наук, доцент
Івано-Франківський національний технічний університет нафти і газу
76019, вул. Карпатська, 15, м. Івано-Франківськ, Україна
https://orcid.org/0000-0002-5183-4940

Ігор Криськів

Український науково-дослідний інститут природних газів
61010, вул. Гімназійна набережна, 20, м. Харків, Україна
https://orcid.org/0009-0003-4534-2856

Василь Гуцуляк

Аспірант
Івано-Франківський національний технічний університет нафти і газу
76019, вул. Карпатська, 15, м. Івано-Франківськ, Україна
https://orcid.org/0000-0003-4973-7719

Анотація. Оптимізація експлуатації групи свердловин, підключених до одного трубопроводу, полягає у правильному розподілі напірного навантаження між свердловинами, що забезпечує відсутність втрат газовидобутку на рівні групи, а також максимальне залучення кожної свердловини до процесу видобутку. Тому метою дослідження було встановити оптимальний технологічний режим експлуатації свердловин, що враховує підключення свердловин у загальний колектор із різними робочими тисками на їх гирлі. Це можливо шляхом перерозподілу дебіту між свердловинами враховуючи запаси газу в питомому об'ємі дренування за рахунок встановлення на їх гирлі штуцера. Розв'язання задачі було досягнуто шляхом одночасного вирішення двох рівнянь: рівняння, що відображає сталість співвідношення між дебітом свердловини та запасами газу в одиниці об'єму дренування, і рівняння для об'ємної витрати газу під час адіабатного (тобто без теплообміну з навколишнім середовищем) протікання через штуцер, яке описувалось формулою Сен-Вена-Ванцеля. На основі розв'язання задачі та проведених обчислень встановлено, що три свердловини з групи експлуатувалися з заниженими дебітами, що зумовлено різницею у залишкових питомих об'ємах дренування, тоді як решта свердловин перевищували оптимальні параметри дебіту газу. Така невідповідність свідчить про нераціональне використання ресурсного потенціалу родовища. Запропоновано варіант розв'язання багатоцільової задачі, спрямований на оптимізацію технологічного режиму експлуатації групи свердловин та газозбірної мережі як єдиної інтегрованої системи видобування вуглеводнів. Реалізація даного підходу дозволяє досягти балансу між ефективністю відбору вуглеводнів і рівномірністю навантаження на інфраструктуру. Одержані результати дослідження будуть корисні на практиці для встановлення оптимальних технологічних режимів експлуатації свердловин із різними продуктивними характеристиками, які працюють в один колектор

Ключові слова: трубопровід; дебіт; штуцер; тиск; газ; родовище; система збору