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Ivan Kuper,
Bohdan Mykhailyshyn,
Iryna Lartseva

IDENTIFICATION OF HYDRAULIC FRACTURING IMPACT FACTORS ON THE SKIN EFFECT IN THE NEAR-WELLBORE ZONE OF THE RESERVOIR

The object of this research is the clogging of the near-wellbore zone of the productive reservoir, which leads to the formation of a positive skin factor and a decrease in well productivity. The subject of the study is the impact of hydraulic fracturing on the reservoir properties of the near-wellbore zone, as well as the assessment of the effectiveness of modern numerical modeling methods for predicting well productivity and optimizing technological parameters of production stimulation operations.

The study addressed the problem of gas well productivity decline due to the deterioration of the filtration and capacitive properties of the near-wellbore zone of the formation caused by clogging, fluid accumulation, retrograde condensation and other physical and chemical processes that impede the movement of fluids to the bottomhole. The work is aimed at finding an effective stimulation method to increase well production and reduce the skin factor, as well as refining methods for forecasting production rate taking into account reservoir properties.

In the course of identifying patterns, an injection test and regression analysis, software productivity modelling, and hydraulic fracturing of the X1 well. After fracturing, a significant increase in absolute free flow rate was recorded – from 1240 to 13250 m^3/d. The numerical modelling performed before and after hydraulic fracturing allowed to optimize engineering solutions, reduce uncertainty in work planning and achieve high accuracy of the flow rate forecast. In the course of identifying patterns, the dependencies between fracture geometry, skin factor and flow rate were determined, which made it possible to quantify the effectiveness of hydraulic fracturing. A practically oriented approach to the implementation of well modelling was developed.

The obtained results can be effectively used in the design and modelling of hydraulic fracturing in practice under conditions of clogging of the near-wellbore zone, positive skin factor, and low permeability of the formation, will significantly increase well production rates and the efficiency of reservoir development with complex filtration conditions.

Keywords: *near-wellbore zone, reservoir permeability, clogging, skin, gas flow rate, stimulation, hydraulic fracturing.*

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1. Introduction

A key component of energy security, protection of national interests and successful integration of the country into international processes is the efficient operation of the fuel and energy complex of Ukraine, in particular those related to the production, storage and transportation of natural gas. Therefore, it is important to constantly increase hydrocarbon production to fully meet the energy needs of the population and production [1].

Increasing natural gas production in Ukraine can be achieved by drilling new wells and improving the efficiency of existing fields. Drilling new wells helps to expand the volume of recoverable resources, while optimizing the operation of existing wells, improving the filtration properties of the near-wellbore zone, and using modern flow stimulation technologies can increase the hydrocarbon recovery factor from existing fields [2].

Well performance largely depends on the quality of the productive formation opening, i. e. the set of activities aimed at ensuring the hydrogas-dynamic connection between the well and the productive formation. The choice of opening methods depends on the current reservoir pressure, characteristics of the productive horizon and other geological and technical conditions. Almost all wells after secondary opening require near-wellbore zone of the formation treatment to increase their productivity.

The reasons for the deterioration of the conductivity of the near-wellbore zone include mechanical, physical-lithological, physical-chemical and thermochemical contamination (clogging).

During drilling, each productive formation is exposed to drilling mud, which comes into contact with the rock around the well. Contamination with drilling mud causes deterioration of the physical and chemical properties of the rock and a decrease in well productivity, which complicates the process of fluid recovery [3].

The presence of a clay crust on the well's walls to reduce the filtration of drilling mud into the formation is very important. The absence of a clay crust (complete or partial) facilitates the formation of deep leachate penetration zones. This reduces gas flow even in areas with high porosity and gas saturation. This phenomenon was observed at the Yablunivske and Kolomatske fields in the Dnipro-Donetsk basin [4].

The effect of water on the phase permeability of the porous medium and changes in hydrodynamic conditions in the near-wellbore zone was investigated in [5]. It was found that water can cause fluid trapping, reducing the efficiency of their movement to the well, and thus reducing production.

Study [6] examined the effect of paraffin on the near-wellbore zone of a reservoir: a decrease in pressure and temperature in the reservoir promotes the precipitation of paraffins due to a decrease in their solubility in oil. The resulting paraffinic precipitates clog pores and reduce the permeability of the near-wellbore zone.

Laboratory, analytical and industrial studies [7] show that retrograde condensation contributes to the loss of condensate from the formation (losses can reach 60–87%). It also causes a sharp decrease in phase permeability for gas, especially in the near-wellbore zone, where the saturation of the porous medium with condensate is at its highest. This leads to a decrease in well production rates due to the difficulty of gas movement and loss of condensate head. As a result, well productivity deteriorates and the overall gas recovery factor decreases, and premature well shutdowns may occur due to insufficient gas flow rates for condensate removal.

Changes in thermodynamic parameters contribute to the precipitation of calcium carbonates and sulphates from mineralized formation water, which significantly reduce formation permeability. This makes it difficult to maintain reservoir pressure and reduces well productivity [8].

During the long-term operation of oil and gas reservoirs, irreversible changes in permeability occur due to changes in the stress-strain state of the reservoir during its development. To improve the accuracy of productivity forecasting and ensure optimal management of hydrocarbon reservoir development, it is necessary to take these geomechanical effects into account in models [9].

Forecasting the impact of near-wellbore clogging and determining the effectiveness of its reduction or elimination remains a constant challenge for industry professionals. The impact of near-wellbore contamination is assessed by conducting hydrodynamic well testing. Modelling of the contamination consequences is often carried out to answer the question of how it will affect well production. Therefore, the concept of skin effect is used to accurately predict and evaluate the impact of near-wellbore contamination on well productivity or injection.

The term "skin effect" should be understood as three factors that cause it: deterioration of the formation's filtration and capacitive properties, complications during operation due to deterioration of the well's technical condition and fluid accumulation in the wellbore. These factors are caused by various physical and chemical processes occurring in the formation, but the change in the state of the of the near-wellbore zone has the greatest impact. Filtration processes in the near-wellbore zone are complicated by changes in pressure, temperature, fluid saturation and rock stresses. These changes are called the skin effect. Near-wellbore contamination acts as a fitting that restricts the flow of hydrocarbons to the well and creates additional pressure losses (ΔP_{skin}). Hydrodynamic studies can be used to estimate the degree of contamination of the near-wellbore zone. If the skin factor is greater than 0, then there is contamination of the near-wellbore zone. A negative skin factor shows how much the effective radius of the well has increased after stimulation in the near-well zone.

When studying wells in low-permeability reservoirs, it was found that a high skin effect worsens the near-wellbore condition and reduces well productivity. In order to reduce the skin effect and increase oil and gas flow to low-producing wells in low-permeability formations, it is recommended to use hydraulic fracturing or acid treatment, or a combination of both [10, 11].

Hydraulic fracturing is one of the most effective methods of stimulating oil and gas wells, which can significantly improve hydrocarbon flow, especially in low-permeability reservoirs. It is based on creating artificial fractures in the formation by means of high-pressure fluid injection, which causes mechanical fracturing of rocks and the formation of new pathways for fluid flow. This is particularly important in low-permeability reservoirs such as shale or tight sandstones, where natural fracturing is not sufficient for economically viable production. The hydraulic fracturing process takes place in two key stages. The first step is to initiate a fracture by injecting a fluid, which is usually highly viscous and injected at high velocity. This creates an overpressure in the rock that exceeds its mechanical strength, causing fracture formation and propagation. The second stage involves filling the resulting fracture with a fracture-opening agent called a proppant. Proppants can be either naturally occurring (e. g., quartz sand) or artificial (ceramic or bauxite granules), which have high strength and the ability to keep the fractures open after the hydraulic pressure is released. The physical mechanism behind the effectiveness of hydraulic fracturing is that after the pressure is released, the fracture does not close due to the presence of propane, which acts as a supporting frame. As a result, a highly permeable channel is formed between the formation and the wellbore, which significantly reduces the resistance to hydrocarbon filtration and increases well production. This technology is widely used not only in conventional reservoirs but also in shale gas and oil production, which has become a key factor in the development of the energy sector in the US and other countries focused on unconventional hydrocarbon sources.

Modern software allows for numerical modeling of hydraulic fracturing with high accuracy and compliance with real industrial conditions [12].

The aim of the study is to identifying the factors that lead to the deterioration of reservoir properties of the formation near-wellbore zone and, accordingly, well productivity, and to develop engineering solutions aimed at increasing production, improving the efficiency of operations and reducing costs. This will allow oil and gas companies to accurately forecast the efficiency of hydraulic fracturing operations, optimize the technological parameters of hydraulic fracturing, increase the flow rates of low-productivity wells, and ensure the economically viable development of complex, low-permeability fields under conditions of near-wellbore clogging.

2. Materials and Methods

The object of research is the clogging of the near-wellbore zone of the productive reservoir, which leads to the formation of a positive skin factor and a decrease in well productivity. The use of hydraulic fracturing was investigated to increase production well productivity.

The first step was to collect data on reservoir fluid properties (PVT characteristics), well testing and well surveys. The collected data was thoroughly analyzed to determine important parameters such as permeability, skin factor and reservoir pressure.

The Saphir module from Kappa was used for regression analysis of the injection test data.

Based on the injection test parameters obtained, the well performance was forecasted using Prosper software from Petroleum Experts. In addition, a detailed sensitivity analysis was performed. The impact of reservoir permeability and skin factor on the overall well performance was assessed. As part of this analysis, let's consider scenarios for changing each of the parameters to assess their impact on performance.

Next, it is possible to compare the data obtained during the forecast, surveys, and the results of hydraulic fracturing and well testing to identify possible inconsistencies or peculiarities. This made it possible to diagnose the main reservoir properties and identify the factors that most significantly affect well performance. As a result, all stages of the work were aimed at understanding the key characteristics of the wells and improving their operation.

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3. Results and Discussion

This paper presents a flow rate forecast and analysis of the results obtained for well X1 of the study field, an injection test, regression analysis, production forecast before and after hydraulic fracturing, and analysis of the results obtained. Data on well X1 of the study field (P3ml horizon) are given in Table 1.

Table 1

Well parameters X1

Parameter	Value
Well bottomhole	1180 m
Artificial bottomhole	1239 m
Production string	140 × 168 mm (1696.82 m)
Perforation interval	Menilites
Perforation interval	1130–1145 m, 1150–1160 m
Tubing ∅73 mm	1114.1 m
Well depth to the middle of the perforation interval	1145 m
Temperature at the wellhead	19°C (292 K)
Formation temperature	39.9°C (312.9 K)
Gas density	0.709 kg/m^3
Relative density by air	0.588
Well type	Production
Expected permeability	0.05 mD
Average porosity (vertical)	11.5%
Effective height	5.6 m
Total height	15 m
Gas factor	0.80556
Expected reservoir pressure	130 atm

To refine the parameters for modulating well production and designing hydraulic fracturing, an injection test is used to obtain data on the formation's filtration and capacitance characteristics and hydraulic fracturing parameters.

During the injection test, a small amount of fluid is injected into the formation (from 1 to 50 m^3 depending on the formation characteristics), which leads to the formation of a hydraulic fracture. After the injection is stopped, the pressure in the well is monitored for several hours or days (an example of a pressure curve is shown in Fig. 1). The data obtained allows to evaluate such parameters as the efficiency of the working fluid, formation permeability, fracture closure pressure (an indicator of minimum horizontal stress and net pressure), the presence of natural fractures and formation pressure. This information is critical for the proper design of hydraulic fracturing operations and analysis of reservoir filtration and capacitance properties.

An injection test was carried out at well X1 using 3 pumping units. As a result, 10 m^3 were injected at a flow rate of 3.2 m^3/min. The injection schedule is shown in Fig. 1.

After the injection test, a regression analysis was performed in the Saphir module of the Kappa software, the results of which are shown in Fig. 2.

The following main parameters were obtained from the injection test (DFIT):

– Young's modulus (E) was 344,827 bar, which characterizes the stiffness of the rock.
– Fracture closure (G_c) – 2.43.
– Injection fluid viscosity was 1.0 cPs.
– Fracture closure pressure (P_c) was determined at 126 bar.
– Reservoir capacitance (r_p) – 0.96.
– Instantaneous injection pressure (*ISIP*) was recorded at 173 bar.
– Calculated permeability according to the analysis results was 0.05 mD.
– Calculated reservoir pressure was 130 atm.

The obtained data was used for hydraulic fracturing modelling and flow rate forecasting. The flow rate forecast was performed in Prosper software from Petroleum Experts.

The following settings were chosen for the calculations (Fig. 3). To describe the fluid, the type "Dry and Wet Gas" was selected, which indicates the gas nature of the product with a possible content of a small amount of liquid. To model the physical and chemical properties of the fluid, let's use the "Black Oil" model, which provides a simplified representation of gas and liquid through basic dependencies without complex phase transitions. This allows engineering calculations to be performed with sufficient accuracy with a limited amount of input data.

The following initial data were used for the calculation:

– Gas gravity – 0.6.
– Separator pressure – 1.01325 bar.
– Condensate gas ratio and water gas ratio is set at $5 \cdot 10^{-6}$ cm^3/cm^3, which indicates a low content of condensate and water vapor.
– Condensate density – 775 kg/m^3.
– Water mineralization – 300.000 ppm.
– Mole percent H_2S in the gas composition is absent (0%).
– Mole percent CO_2 – 0.5%.
– Mole percent N_2 – 1.15%.
– Correlation "Lee et al" was used to calculate the gas viscosity.

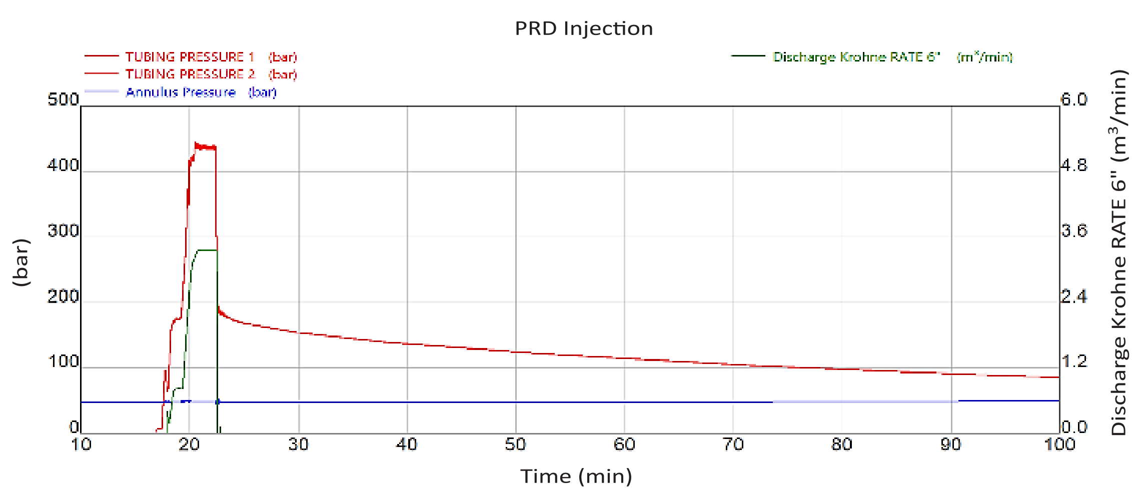

Fig. 1. Pressure and flow rate graph during injection test

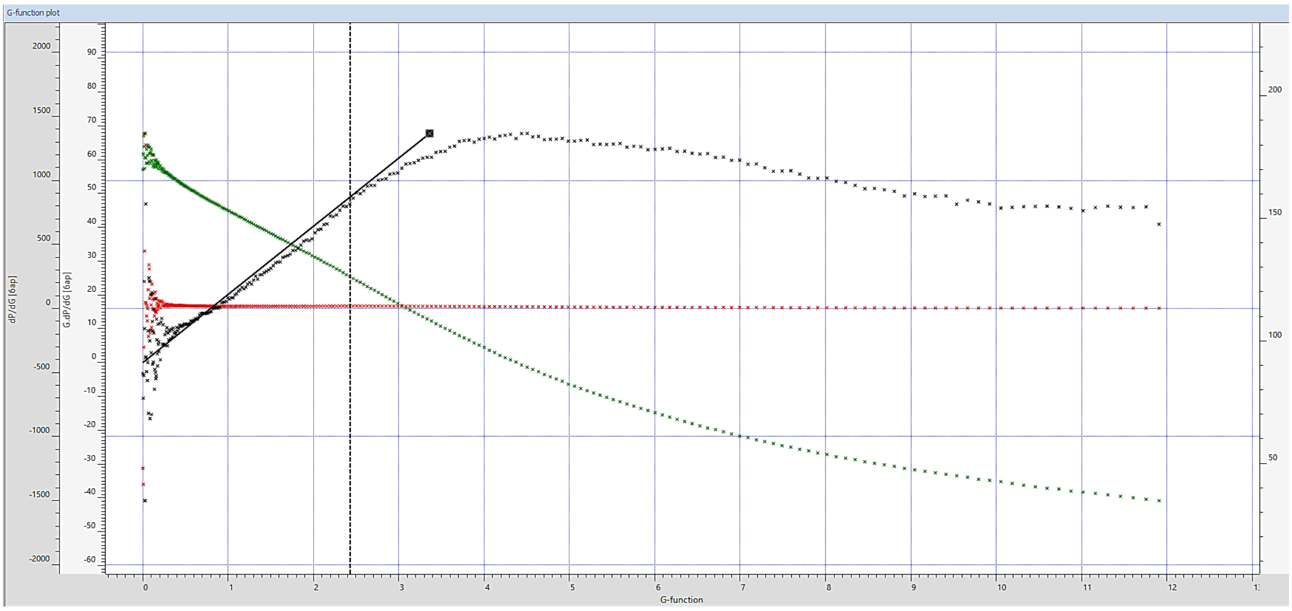

Fig. 2. Regression analysis of data after the injection test

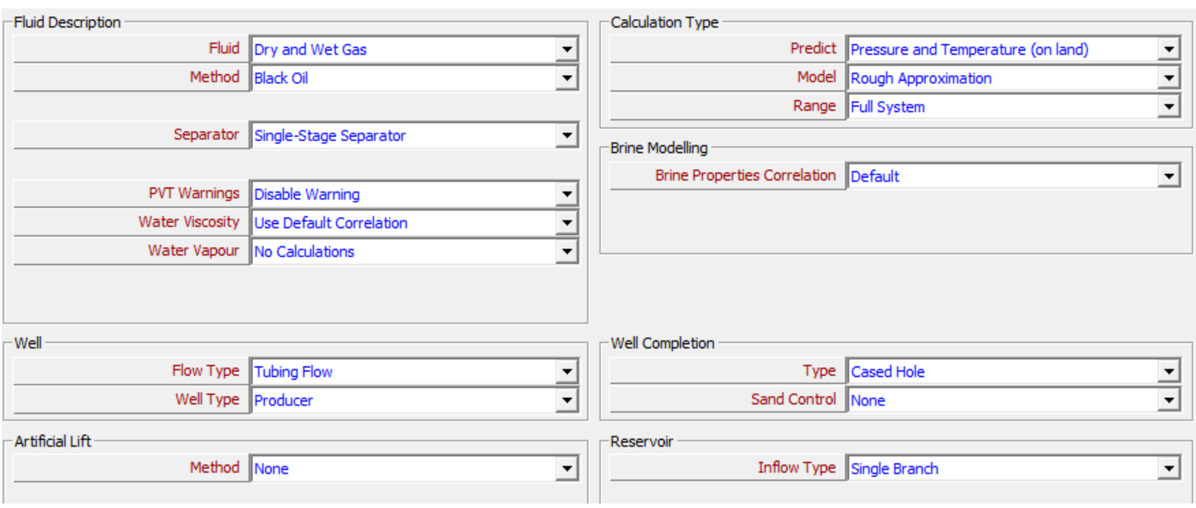

Fig. 3. Setting up the program for calculations

Next, the Jones Reservoir Model was used to forecast the flow rate before hydraulic fracturing. This is one of the classical analytical models used to describe the flow of fluids from the reservoir to the well in gas fields. The model takes into account the nonlinear effects of gas inflow, including changes in gas viscosity and compressibility with pressure, which is especially important when wells operate at low pressures. Unlike simple linear models, the Jones model allows to describe well behavior in turbulent or pseudo-formational gas inflow conditions. In its calculations, the model uses t he A and B coefficients, which determine the linear and quadratic dependence of pressure on flow rate, respectively. This makes it possible to simulate real flow curves(IPR curves), taking into account the effect of pressure degradation with increasing flow rate.

The Jones Reservoir Model was used to select flow parameters to evaluate the well's performance prior to hydraulic fracturing. Initial data included a reservoir pressure of 130 bar, formation temperature of 39°C, water gas ratio of 5 cm^3/cm^3 and condensate gas ratio of 10 cm^3/cm^3. The reservoir permeability was 0.05 mD and the thickness of the productive interval was 5.6 m.

According to the modelling results, the absolute open flow (AOF) was determined to be 1238.7 m^3/d (Fig. 4, *a*), and the skin effect was equal to 1. This indicates that the well had a rather limited productivity before fracturing, and its potential was significantly lower than the desired production level, which justifies the need for hydraulic fracturing to improve the flow rate.

Next, the hydraulic fracturing model was used to forecast and analyze the sensitivity of the flow rate to changes in parameters. Based on the modelling results, the AOF was determined at 13250 m^3/d (Fig. 4, *b*).

After that, hydraulic fracturing was carried out.

According to the results of hydraulic fracturing (P3ml), the created fracture (Fig. 5) reached a length of 40.188 m, almost completely fixed by propane (40.187 m). The average height of the fracture was 42.166 m, with a fixed height in the productive interval of 14.927 m. The maximum width of the fracture in the perforation zone was 1.9655 cm, with an average fixed width in the well and productive zone of approximately 0.586 cm. The propane concentration per fracture area reached 11.128 kg/m^2 at the end of injection and 11.412 kg/m^2 at closure. The conductivity of the fracture in the productive zone at closure was 1069.2 mD · m, which provides a dimensionless conductivity of 5, and the average permeability of the fracture was 183.93 D. The ratio of the fixed fracture was 0.60208, and the time to close the fracture after injection was 16.59 minutes. In general, the parameters obtained indicate the successful creation of an effective channel for the inflow of reservoir fluids.

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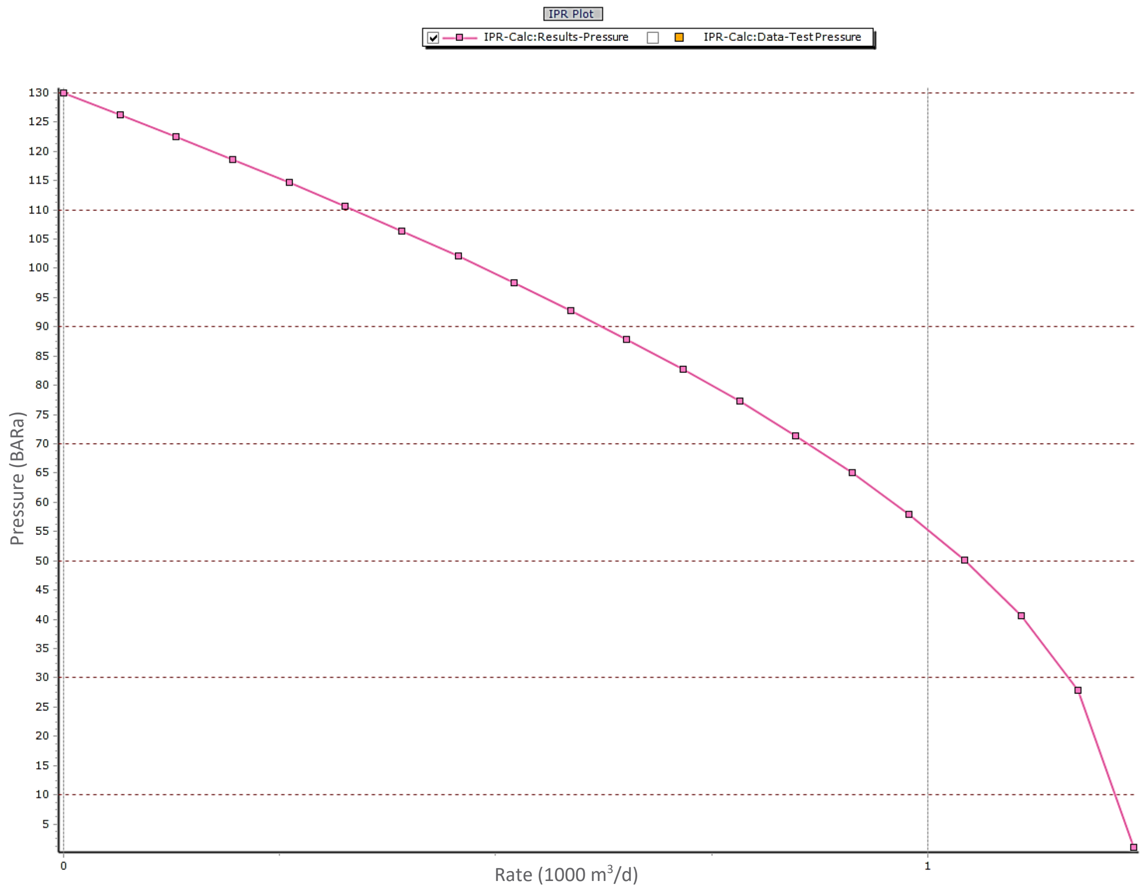
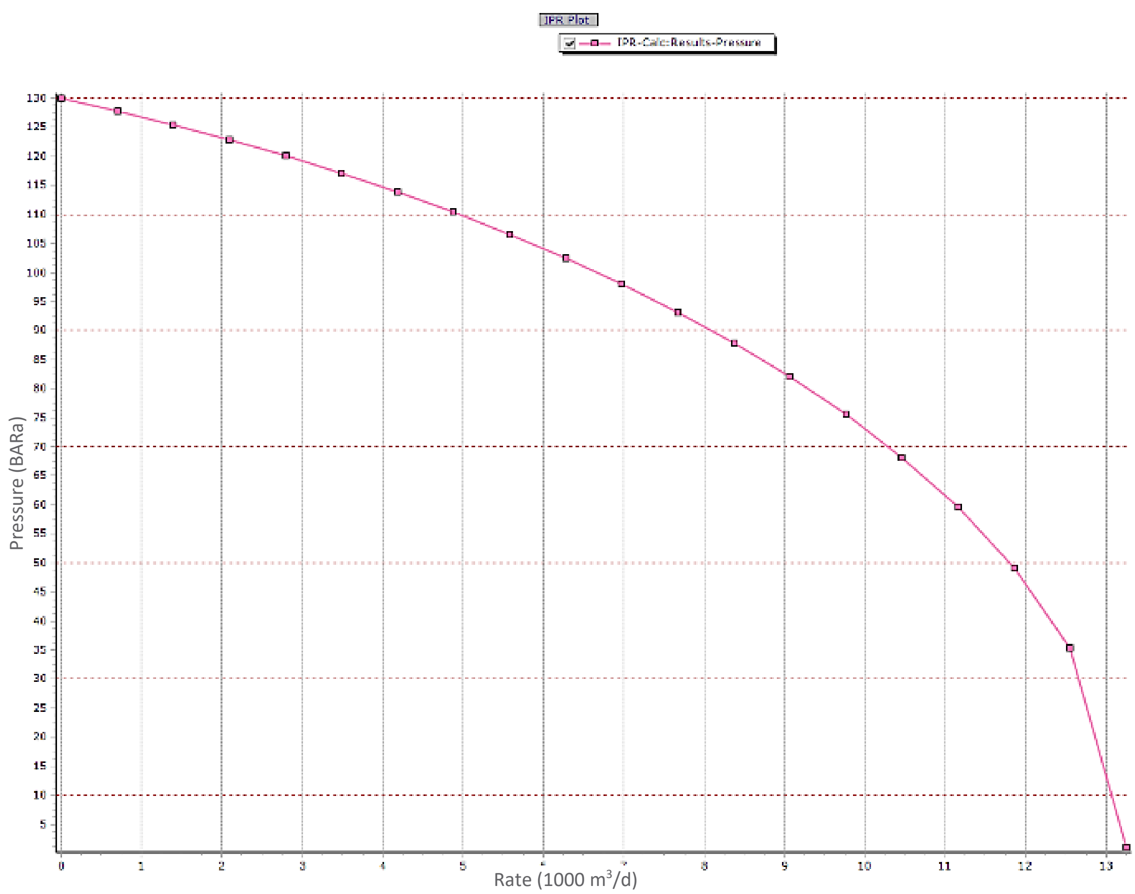


a



b

Fig. 4. Well flow rate forecasting: *a* – before hydraulic fracturing; *b* – after hydraulic fracturing

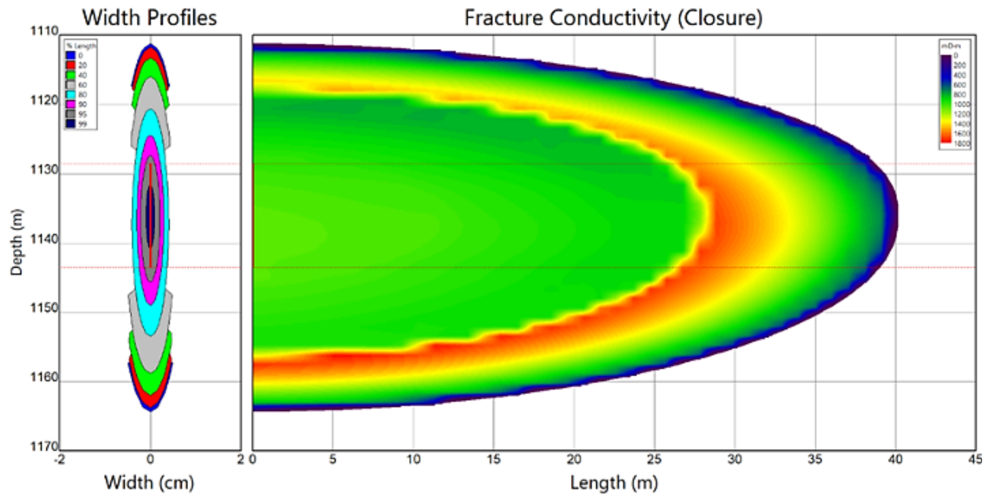


Fig. 5. Obtained fracture parameters

The flow rate was forecasted for the lengths: case 1 – 5 m, case 2 – 10 m, case 3 – 20 m, case 4 – 30 m, case 5 – 40 m, case 6 – 50 m, case 7 – 60 m. The dependence of the flow rate change on the fracture length is shown in Fig. 6.

After the hydraulic fracturing, the well was developed and tested on the fittings (Fig. 7). The study was conducted on 60 mm tubing in 3 modes.

The results obtained for wellhead pressure were converted to bottomhole pressure and black dots were plotted on the IRP curve (Fig. 8). The correctness of the calculations was confirmed by measuring the flow rates at the connectors, which coincided with the forecast. The sensitivity analysis of wellhead pressures was also performed.

Comparison of the inflow (IPR – inflow performance relationship) and lift (VLP – vertical lift performance) curves shown in Fig. 9, allows for a full analysis of the well operation and determination of the equilibrium points of the formation-well-surface equipment system. During the modelling, several variants of IPR curves were built according to different theoretical approaches. The intersection of the IPR and VLP curves allowed to identify the points of the operating flow rate and the corresponding values of the bottomhole pressure. As can be seen from the graph, depending on changes in operating conditions or lifting system parameters, the intersection point can shift significantly, which demonstrates the sensitivity of the system to hydraulic resistance. All the curves were built using actual measurement data and used as a basis for model calibration.

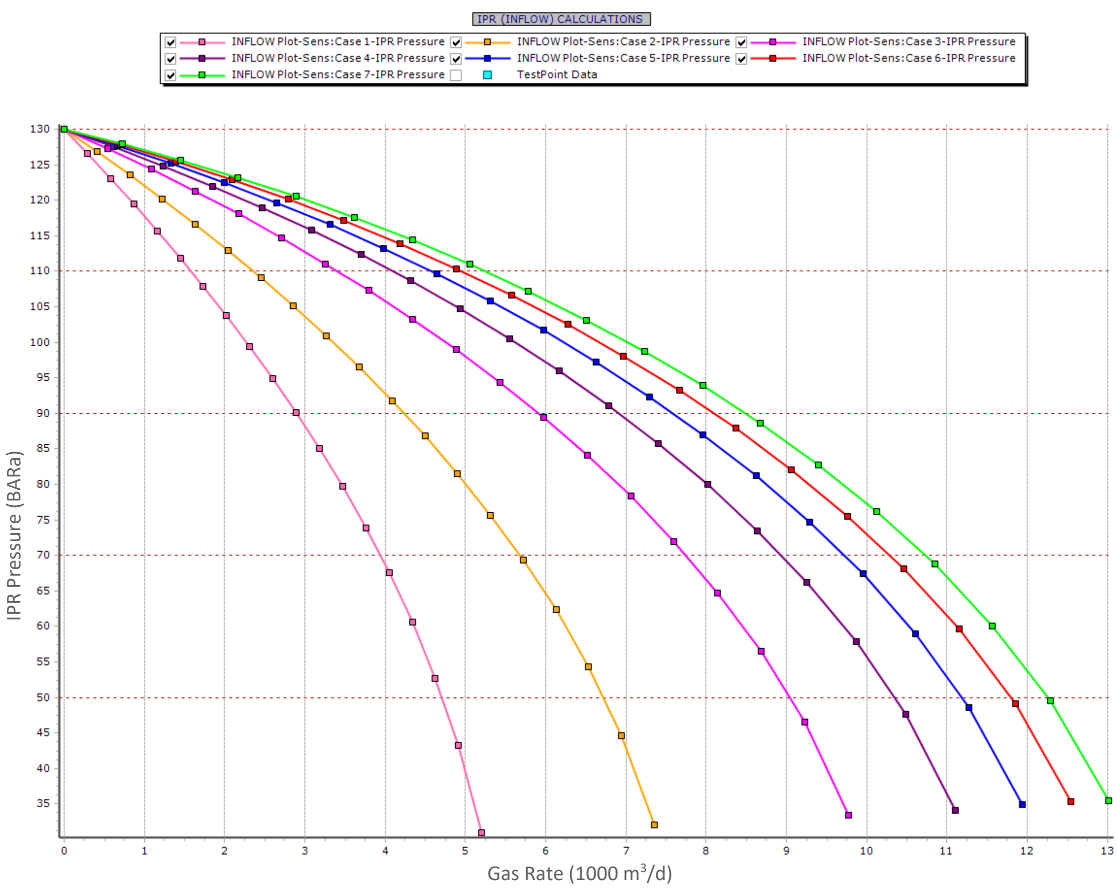


Fig. 6. Flow rate value depending on the length of fractures

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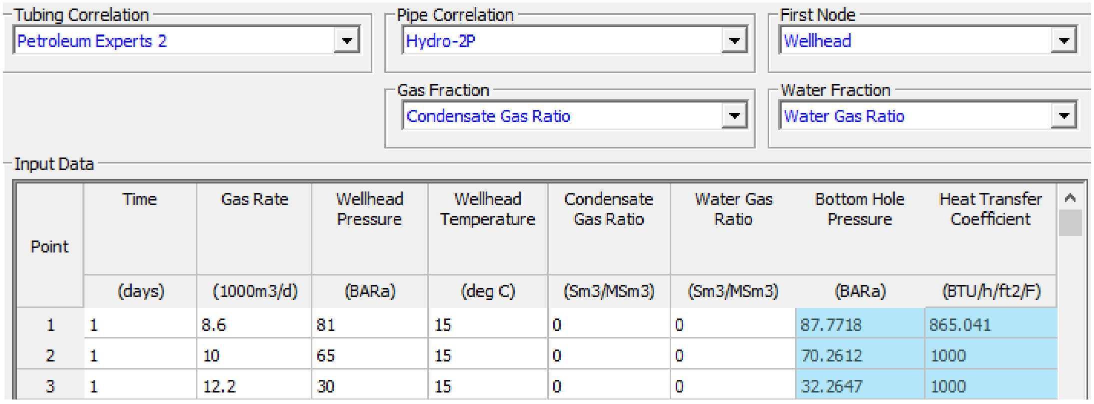

Tubing Correlation: Petroleum Experts 2
Pipe Correlation: Hydro-2P
First Node: Wellhead
Gas Fraction: Condensate Gas Ratio
Water Fraction: Water Gas Ratio

Input Data

Point	Time (days)	Gas Rate (1000m3/d)	Wellhead Pressure (BARa)	Wellhead Temperature (deg C)	Condensate Gas Ratio (Sm3/MSm3)	Water Gas Ratio (Sm3/MSm3)	Bottom Hole Pressure (BARa)	Heat Transfer Coefficient (BTU/h/ft2/F)
1	1	8.6	81	15	0	0	87.7718	865.041
2	1	10	65	15	0	0	70.2612	1000
3	1	12.2	30	15	0	0	32.2647	1000

Fig. 7. Well testing data

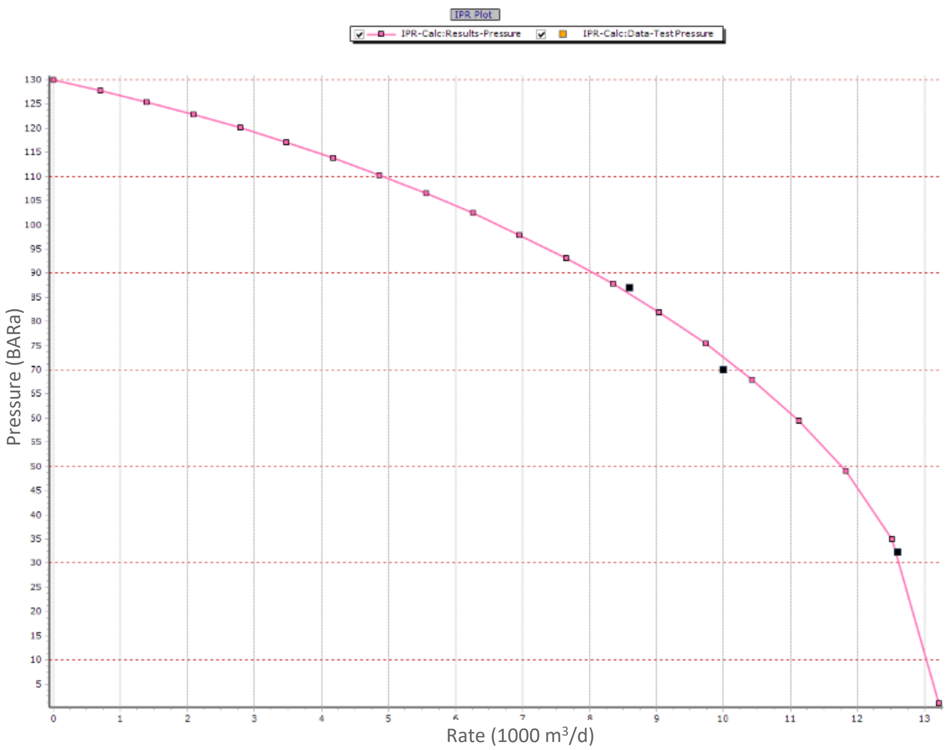

Fig. 8. Test data on fittings and IRP

An analysis of reservoir productivity was also conducted using various theoretical models (Fig. 10), in particular using IPR (inflow performance relationship), based on the approaches of Darcy, Vogel, Fetkovich, Brown, and modified versions of these models were used. To assess the reliability of the obtained productivity curves, a comparison was made with empirical data from field tests. As a result of the analysis, the best fit to the experimental data was shown by models adjusted by the Gray and Petroleum Experts methods. In particular, the modified Gray model provided the most accurate match with the real test results in the entire flow range, which indicates its high adequacy in the specific conditions of this reservoir. Petroleum Experts Model also demonstrated good correlation, especially in the mid-range of flow rates, allowing it to be considered a reliable tool for engineering calculations.

After hydraulic fracturing and wellhead testing, a pressure falloff test (PFT) was performed to refine reservoir pressure, permeability, and skin factor parameters. Analysis of the falloff curve indicated that the skin factor decreased to – 3 following the fracturing treatment. The reservoir pressure was recorded at 128 atm, and the permeability was estimated at 0.0149 mD.

In the study [13], the productivity of existing wells in Libya is analyzed based on pressure build-up test data, using Kappa Saphir and Prosper software to calculate the productivity index followed by sensitivity analysis. However, the modelling of the hydraulic fracturing process and the influence of fracture parameters on well flow rate are not addressed, as the authors focus solely on interpreting existing well test data and evaluating well productivity. In contrast, our study explores these aspects comprehensively: numerical modelling of hydraulic fracturing is conducted, taking into account fracture geometry, skin factor, and conductivity, with the model further calibrated using actual data from well X1 to predict production gains after fracturing.

In the work [14], the author discusses the challenges of hydraulic fracturing modelling – from selecting fracture geometry to refining constitutive relationships. He criticizes the overreliance on theoretical models and emphasizes the necessity of field-based calibration. In this study, exactly such an approach was applied: the model was calibrated using real data from well X1, which represents a key advantage compared to many purely theoretical works.

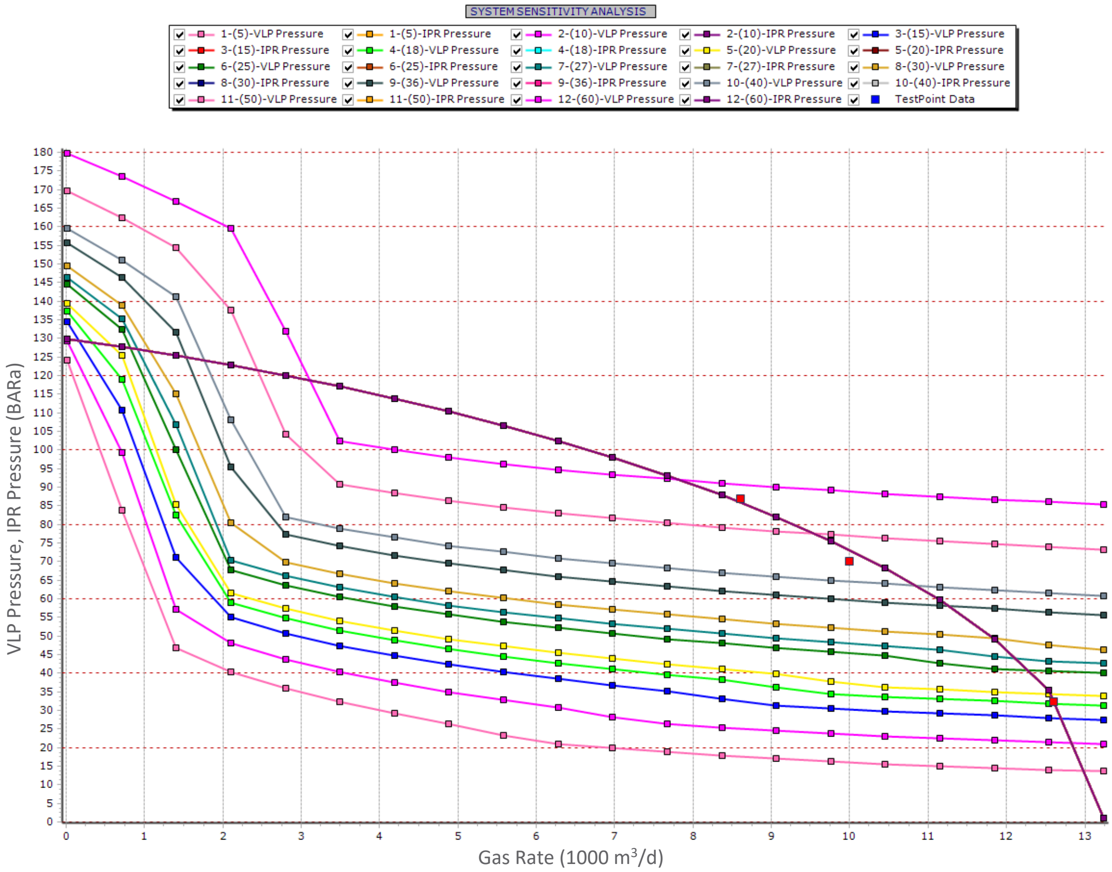

Fig. 9. IRP and VLP data

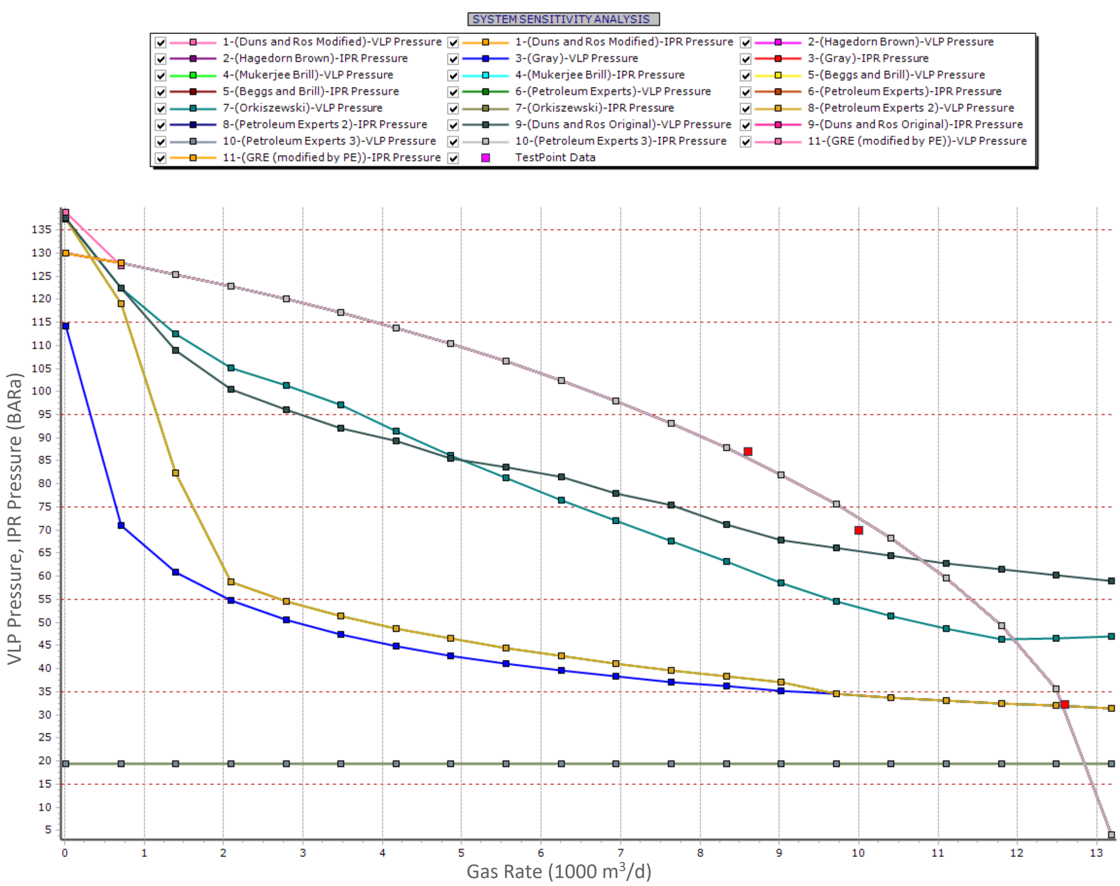

Fig. 10. Test data on fittings and IRP

The study [15] proposes an automated approach for analyzing hydraulic fracturing and well-test data, explaining how it generates well performance models and analyzes diagnostic fracture injection test (DFIT) data using numerical algorithms and machine learning. This method enables rapid construction of IPR/VLP curves, basic diagnostics, and fracture parameter estimation through standard curve-matching algorithms. It is effective for automated processing and inter-well comparison, but relies primarily on analytical estimations, which may deviate from actual field results. In contrast, our study identified key factors influencing well flow rate using Prosper software. This allowed to accurately reproduce the effects of fracturing geometry and reduce the skin factor, which ultimately led to a significant increase in production after fracturing.

The practical significance of the study lies in the potential application of the obtained results in the oil and gas industry to enhance the efficiency of producing wells. The use of modern stimulation technologies not only increases production rates but also improves the economic viability of field development while minimizing the environmental impact.

The practical application of the study results is clearly demonstrated by the achieved economic and operational efficiency following hydraulic fracturing. After the fracturing treatment, the well's production rate increased from 1,240 to 13,250 m^3/day, which, at a market price of 300 USD per 1,000 m^3, yields a gross daily revenue of 3,975 USD or 119,250 USD per month. Considering Ukraine's taxation framework – including a royalty rate of 12%, corporate income tax of 18%, and a 1% military levy – the net monthly profit is approximately 85,000 USD. With the hydraulic fracturing operation costing 100,000 USD, the payback period is estimated at around 36 days. This confirms the economic viability of hydraulic fracturing even under high initial investment conditions. However, to fully assess the project's efficiency, future research should also consider costs related to well preparation, post-fracturing well clean-up, and other associated expenditures that affect the overall profitability and investment return timeline.

The modelling, flow rate forecasting, and hydraulic fracturing performance evaluation in this study are based solely on data from a single well (X1) within a specific field characterized by distinct geological and technical conditions, particularly low reservoir permeability (0.05 mD) and a positive skin factor. This limits the possibility of direct transfer of the obtained results to other fields with different parameters, including higher permeability, the presence of natural fractures or other types of fluids. As a result, the obtained outcomes may be less representative for reservoirs with different petrophysical properties or in the absence of complete input parameters. Moreover, the accuracy of the modeling results is highly dependent on the quality of the input data, including reservoir characteristics, fracture parameters, and fluid properties, which introduces the risk of errors in forecasts due to incorrect interpretations or simplifications.

Prospects for further research and application include expanding the dataset of investigated wells to create a statistically reliable database that will serve as a foundation for developing advanced mathematical models of fluid inflow prediction, incorporating complex hydrodynamic and geomechanical processes. The obtained results should also be tested at other sites with similar geological and physical characteristics, particularly in fields with complicated filtration conditions. Future studies should aim to improve geomechanical modeling under varying lithological scenarios, optimize hydraulic fracturing parameters based on the degree of near-wellbore clogging, and develop typical engineering scenarios tailored to different categories of hydrocarbon reservoirs.

4. Conclusions

The study found that that hydraulic fracturing is an effective method of eliminating the negative impact of the positive skin factor and significantly increases the productivity of gas wells in low-permeability reservoirs. In particular, as a result of modelling and fracturing at well X1, the absolute free flow rate of the well increased from 1240 to 13250 m^3/d, which indicates a tenfold improvement in gas flow conditions. The results are attributed to the creation of a highly permeable channel in the formation due to a f crack over 40 m long, about 2 cm wide and with a conductivity of over 1000 mD · m, stabilized by propane. This allowed reducing the hydraulic resistance in the near-wellbore zone and compensating for pressure losses caused by clogging and other physical and chemical processes.

The analysis confirmed that hydraulic fracturing parameters have a critical impact on the level of production stimulation, and their correct selection can significantly increase the efficiency of well operations. The introduction of modern methods of modelling and analyzing processes in the near-wellbore zone allows for more accurate forecasting of well productivity and optimization of production processes, reducing technological and economic risks.

Thus, the results of the study can be used as a theoretical and practical basis for the development of new technological solutions in the field of modelling and planning of hydraulic fracturing operations, which will help to increase hydrocarbon production.

Conflict of interest

The authors declare that they have no conflict of interest regarding this research, including financial, personal, authorship, or other, that could influence the research and its results presented in this article.

Financing

The research was conducted without financial support.

Data availability

The manuscript has no associated data.

Use of artificial intelligence

The authors confirm that they did not use artificial intelligence technologies when creating the presented work.

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Ivan Kuper, *PhD, Associate Professor, Department of Petroleum Production, Ivano-Frankivsk National Technical University of Oil and Gas, Ivano-Frankivsk, Ukraine, ORCID: https://orcid.org/0000-0003-1058-1382*

Bohdan Mykhailyshyn, *PhD Student, Department of Petroleum Production, Ivano-Frankivsk National Technical University of Oil and Gas, Ivano-Frankivsk, Ukraine, ORCID: https://orcid.org/0009-0007-6383-2735*

✉***Iryna Lartseva,*** *PhD, Associate Professor, Department of Oil and Gas Engineering and Technology, National University "Yuri Kondratyuk Poltava Polytechnic", Poltava, Ukraine, e-mail: lartsevairyna@gmail.com, ORCID: https://orcid.org/0000-0003-0133-5956*

✉*Corresponding author*