International Journal of Engineering Trends and Technology
ISSN: 2231–5381 / https://doi.org/10.14445/22315381/IJETT-V72I12P122

Volume 72 Issue 12, 247-268, December 2024

Original Article

Development of Effective Production Strategies for Gas Condensate Fields based on Analysis of Operating Conditions

Annaguly Deryaev

Department of Well Drilling, Scientific Research Institute of Natural Gas of the State Concern "Turkmengas", Ashgabat, Turkmenistan.

Corresponding Author : deryaevannaguly6@gmail.com

Received: 21 August 2024 Revised: 14 November 2024 Accepted: 07 December 2024 Published: 25 December 2024

Abstract *- This study, conducted at the Altyguyi field in Southwestern Turkmenistan, aimed to study the characteristics of oil reservoirs to determine the critical parameters affecting production potential, with the subsequent possibility of optimising extraction processes. The research employed a comprehensive approach, including collecting and processing raw condensate, degassing, and removing butane in the laboratory. Critical components of gas condensate systems were calculated, and well and reservoir characteristics were assessed using the steady-state sampling method. Hydrodynamic studies provided a systematic analysis of the data. As a result of the work carried out in the field, data were obtained that are crucial for understanding the features and characteristics of the oil reservoirs. Key findings revealed that the condensate content in reservoir gas varied across different wells, with values of 69.5 g/m³ for well No. 2 (III), 95.2 g/m³ for well No. 1 (II), and 96.5 g/m³ for well No. 5 (I). Predicted condensate content was 80.5 g/m³ for layer NK_{7d} and 95.2 g/m³ for layer N_{K8}. The oil in this field has a specific gravity of 0.91 g/cm³ and a high paraffin content, negatively impacting well productivity. Expected condensate yields for layers NK_{7g} and NK_8 were 95 cm³/t and 118 cm³/t, respectively. The results highlight the importance of systematic studies, including lithology, geology, and production parameters, to enhance field assessment and optimise long-term extraction efficiency.*

Keywords *- Condensate stability, Differential isotherms, Gas lift, Initial pressure, Reservoir characteristics.*

1. Introduction

Gas condensate fields play an important role as a potential energy source for the oil and gas industry. Their development provides a significant share of the petroleum products and natural gas that are vital to meeting the energy needs of the global economy. These fields are becoming a focal point for companies in the energy sector seeking to ensure energy security and support economic growth. However, despite their great potential, gas condensate fields present complex technical and geological challenges that require in-depth analysis and specialised production strategy development [1]. The variable physical and chemical properties of gas and condensate and the geological features of the fields create conditions for instability in the production process. This requires continuous improvement of technologies and strategies to ensure efficient and safe operation. To ensure the productive exploitation of gas condensate fields, it is necessary to develop production strategies considering all aspects of their unique geological nature. This includes a thorough analysis of the fields' geological, physical-chemical, and other features and continuous improvement of production technologies in accordance with changing conditions [2]. This will ensure the sustainability of the extraction process, increase its efficiency, and contribute to minimising the environmental impact on the region. When developing production strategies for gas condensate fields, it is essential to consider field data, such as the exact parameters of formation fluids and the geomechanical properties of rocks. A study by M.A. Islam et al. [3] found that analysing these data allows for a more accurate determination of field characteristics, contributing to developing effective production strategies. The work of B. Ahmed and M. Al-Jawad [4] also confirmed the importance of considering these parameters when selecting optimal extraction methods. In the work of S. Xu et al. [5], detailed research results highlighted pore space distribution as one of the key factors affecting the production potential of deposits. However, despite the similarities and identified successes in the presented works, some challenges associated with insufficient field data and uncertainty of their parameters remain relevant and require additional research. Another key factor in developing gas condensate field production strategies affecting development efficiency is the study of the degree of influence of geological aspects [6]. In a study by A. Alizadeh et al. [7], which focused on the analysis of geological characteristics of the field, the influence of rock structure on production potential and production efficiency was revealed. At the same time, the study by S. Li et al. [8] also emphasises the importance of considering geological features when selecting optimal technologies and development strategies. The work of D. Hu et al. [9] draws attention to the need for a comprehensive analysis of geological data to accurately predict the characteristics and behaviour of fields in exploitation. Nevertheless, it is necessary to consider that several other geological factors can also significantly impact the production of gas condensate fields and require additional attention and study. This study, conducted in the Altyguyi field in Southwest Turkmenistan, focused on analysing the characteristics of oil reservoirs to identify key factors affecting their production potential. The study's main objectives were to identify optimal production strategies based on a thorough analysis of field conditions and investigate the effectiveness of various technological solutions to optimise the production processes of gas condensate fields.

2. Literature Review

Recent developments in gas condensate field production tactics have arisen as essential solutions to the distinct problems presented by these reservoirs. A notable accomplishment in the subject is the creation of differential condensation isotherms, which are crucial for precisely evaluating reservoir gas compositions. Creating these isotherms entails intricate procedures, including collecting raw condensates during the initial product separation, which is succeeded by degassing and extracting butane under-regulated laboratory circumstances. The study by M.R. Brann et al. [10] underscores the necessity of precisely determining the critical parameters of stable condensates, such as molecular weight and density, of stable condensates to construct these isotherms efficiently.

Alongside enhanced techniques, hydrodynamic modelling has experienced substantial improvements, enabling more accurate estimates of fluid flow in reservoirs. T.S.R. Pereira et al. [11] assert that optimising wellhead layouts and executing strategic operational modifications can enhance flow dynamics and production rates. Extended production tests performed across many wells indicated that modifications in wellhead fittings enhanced flow rates, highlighting the need for customised operating tactics in optimising recovery. Furthermore, the incorporation of mathematical modelling has grown progressively intricate. Recent models employ empirical data to predict characteristics like condensate losses and recovery factors, tackling issues encountered during manufacturing in settings devoid of sophisticated experimental apparatus. O. Udovchenko et al. [12] showed a link between initial reservoir pressures and condensate losses, offering critical insights for optimising production techniques tailored to individual field circumstances. This method promotes comprehension and enables the creation of focused therapies to improve recovery efficiency. K. Zhu et al. [13] notably highlight the optimisation of developmental factors by numerical simulations. Their research examines several parameters influencing the performance of condensate gas reservoirs, including well spacing, production rates, and pressure maintenance measures. Utilising sophisticated modelling methods, they establish a framework for optimising these factors to enhance recovery efficiency. Their findings indicate that meticulous control of development techniques can substantially enhance production outcomes, underscoring the significance of numerical modelling in modern gas condensate extraction methodologies.

Exploiting gas condensate deposits may necessitate implementing sophisticated technology to guarantee optimal output [14]. One such technique is the gas lift, which elevates oil and gas from wells. S. Muzaffarov's study [15] focused on analysing various hydrocarbon production systems, including gas lift, and elucidated their advantages and limits, thus enhancing the overall comprehension in this field. S. Zolghadri and M. Rahimpour [16] did a comparative investigation of several gas lift methods, including electrohydraulic and gas-hydraulic, to identify the most effective alternative for a certain sector. The research by T. Ganat et al. [17] introduced novel strategies to enhance gas lift operations, focusing on performance improvement and cost reduction. These studies are crucial for enhancing production techniques in gas condensate fields; nevertheless, more studies in this domain might further advance and refine production technology.

3. Materials and Methods

In order to fully explore the Altyguyi gas condensate field and identify important parameters of its operation, this study used an approach that included a set of techniques and technologies. The first step in the study was the collection of raw condensates. This involved the accumulation of the raw condensate for further investigation. The raw condensate was then subjected to degassing and debutanisation (removing butane) under controlled laboratory conditions. These processes were designed to remove gas components such as methane and butane, as well as butane fractions, from the raw condensate. The critical components were then calculated for all gas condensate systems. This calculation was based on values found in the separation gas and the fraction of pentanes and heavier components that boil off in the stable condensate. These parameters were determined based on stable condensate characteristics such as volume, density, and molecular weight. This research's primary recovery methods include the first extraction phase, in which natural reservoir pressure forces hydrocarbons to the surface. These approaches employ wellhead pressure control and steady-state sampling to evaluate gas dynamics and improve output without external intervention. The steady-state sampling method evaluates the gas dynamic properties of wells and reservoirs by sustaining stable operating conditions. This approach requires the well to stabilise for at least 24 hours, ensuring that wellhead pressures and flow rates attain steady-state conditions prior to data collection commencement. Throughout this period, ongoing measurements of pressure, temperature, and flow rates are conducted using sample pressure gauges, allowing for precise characterisation of the reservoir's behaviour and aiding in building differential condensation isotherms for further study. Secondary recovery methods are used when primary recovery is insufficient and focus on increasing hydrocarbon extraction using procedures like gas injection to maintain reservoir pressure and increase condensate flow.

Mathematical models and empirical data from the RUT and UGK-3 systems applied to gas condensate fields in Southwest Turkmenistan were used to estimate the recovery factor and condensate losses. A steady-state sampling method was used to characterize the wells and reservoirs in the Altyguyi field, allowing a complete understanding of the gas dynamic characteristics of the wells. The work also utilized depth gauges such as the MGN2 with pressure limits up to 800 kgf/cm² and the MSU1-100 with pressure limits up to 160 kgf/cm², as well as electronic geophysical equipment such as Granit and Sakmar to provide additional data and improve measurement accuracy.

A comprehensive approach was used to accurately measure the daily gas flow rate, including a PBS-350/64 separator. A field rig with a Demag separator DSP-0.063 and DPS-1.6 flow meters was used for more detailed analyses. Diaphragm critical gas flow meters (DICT) were used for accurate calculations. Simultaneously, wellhead pressures were recorded using sample pressure gauges. To maximise accuracy, Downhole and reservoir temperatures were measured using TP-7-type thermometers with mercury columns. Due to technical limitations, estimation of reservoir and bottomhole pressures in some wells was performed using leaky, non-deployed downhole pressure gauges.

A rig, including a PBS-350/64 mobile block separator and a DEMAG separator, was used to extract condensate and water from the production stream and determine its volume per 1 m³ of gas. The study encompassed comprehensive exploratory drilling and performance evaluation at 11 locations, concentrating on three wells (No. 1, 2, 5) that functioned under steady-state filtration conditions (Table 1). These wells were selected to encompass a spectrum of reservoir conditions, including differences in depth and pressure. The preliminary stage involved gathering raw condensate, which underwent regulated laboratory procedures like degassing and debutanisation to precisely ascertain the gas composition and compute essential metrics such as volume, density, and molecular weight. This data enabled the development of differential condensation isotherms for each well, offering insights into condensate composition and phase behaviour. Moreover, extensive hydrodynamic analyses were performed at different depths (2700 m, 3000 m, and 3500 m) and operating pressures (8.5 MPa and 15 MPa) to assess gas dynamics. Measurement instruments, including depth gauges and electronic geophysical devices, were employed to guarantee precision in recording gas flow rates and reservoir attributes. The study utilised steady-state sampling techniques and advanced analytical methods to generate a representative dataset that accurately reflects the behaviour of gas condensate systems in the Altyguyi field, thereby improving the reliability of the findings for broader applicability in similar reservoirs.

A statistical SPSS study examined the correlations between initial reservoir pressure and condensate content. The Pearson correlation coefficient was computed, demonstrating a weak negative linear association ($r=-0.134$) with a p-value greater than 0.05, signifying that this link lacks statistical significance. A linear regression analysis yielded the equation $Y=153.8-0.130X$, where Y denotes condensate concentration, and X signifies starting reservoir pressure. The regression model produced a p-value of 0.45, indicating that the predicted association between these variables is statistically insignificant. The study conducted comparative analyses of production performance at different levels of specific gas flow rates at each considered depth. For this purpose, oil production was monitored at varying specific gas flow rates and different operating pressures. The optimum specific gas flow rates were determined for each reservoir depth at the respective operating pressures based on the data obtained.

4. Results

Obtaining the component composition of reservoir gas to construct differential condensation isotherms is a complex and challenging step. This process begins with collecting raw condensates at the initial product separation stage, followed by degassing and debutanisation under controlled laboratory conditions.

The critical components for all gas condensate systems are calculated based on the values (in the separation gas) and the fraction of pentanes and heavier components boiled off in the stable condensate, which is determined from the characteristics of the stable condensate: volume (q_{st}), density (p) and molecular weight (M_{st}). The essence of this methodology is the accurate identification of reservoir gas components and key parameters to construct differential condensation isotherms. This approach plays a fundamental role in reservoir analysis and resource evaluation by providing valuable data on gas condensate characteristics (1):

$$C^{st.c.}_{5+\text{ above}} = \frac{2.404*\rho}{M} \tag{1}$$

Where: q_{st} – steady state condensate yield, g/m^3; ρ – steady-state density, g/m^3; M – molecular weight. This method was applied to calculate the molecular weight (M) (2):

$$M = 44.29\frac{\rho_{st.c.}+0.004}{1.034-\rho_{st.c.}}, \tag{2}$$

Table 1. Geological context and condensate content of selected wells in the Altyguyi gas condensate field

Well no.	Formation	Depth (m)	Initial pressure (kgf/cm²)	Temperature (°C)	Condensate content (g/m³)
1	NK8	3615-3624	496	83	95.2
2	NK7d	3512-3522	518	81	69.5
5	NK7d	3618-3624	526	84	96.5

Source: Developed by the author

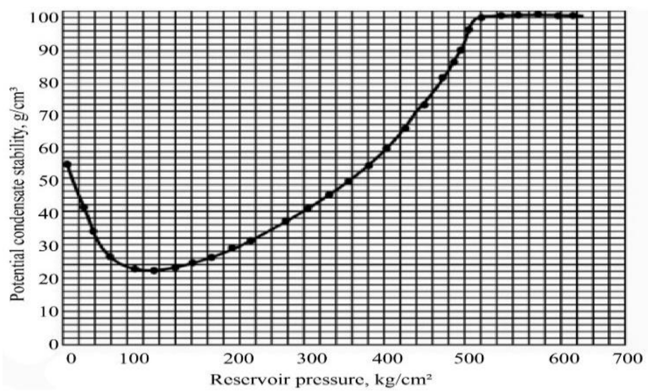

Fig.1 Graph of the differential condensation isotherm of the gas condensate system of well No. 2 (III)

Source: Developed by the author.

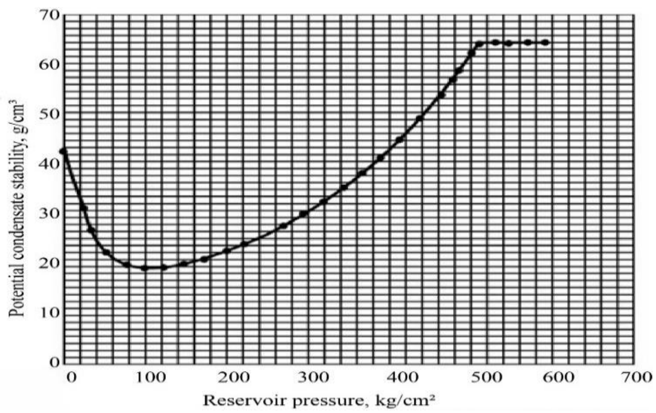

Fig.2 Graph of the differential condensation isotherm of the gas condensate system of well No. 1 (II)

Source: Developed by the author

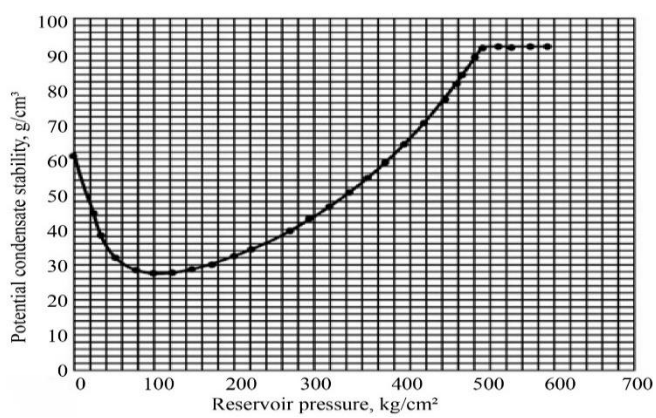

Fig.3 Graph of the differential condensation isotherm of the gas condensate system of well No. 5 (I)

Source: Developed by the author

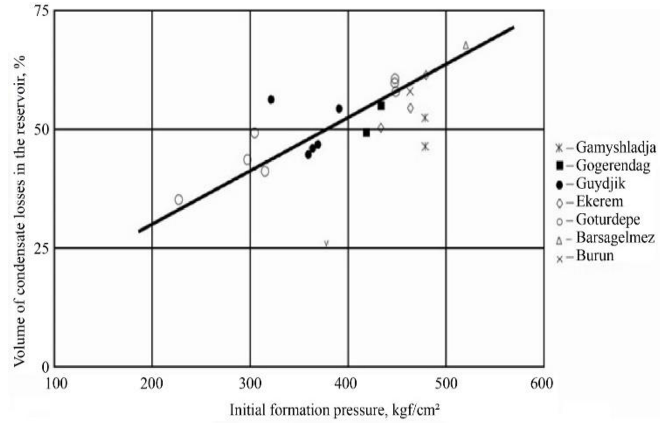

Fig. 4 Effect of initial reservoir pressure on the volume of condensate losses in formations of the South-West Turkmen oil field

Source: Developed by the author

The other components remain unchanged in the current state. Then, the formation gas composition is calculated (3, 4):

$$\mathrm{C}_4^{\mathrm{g.s}} - \mathrm{C}_{5+\mathrm{above}}^{\mathrm{st.c}} = \mathrm{CH}_4^{\mathrm{res.g.}}, \tag{3}$$

$$\mathrm{C}_{5+\mathrm{above}}^{\mathrm{g.s}} - \mathrm{C}_{5+\mathrm{above}}^{\mathrm{st.c}} = \mathrm{CH}_{5+\mathrm{above}}^{\mathrm{res.g.}}. \tag{4}$$

The use of this primary data provides an opportunity to analyse practical results. The study focuses on plots of differential condensation isotherms constructed for gas condensate systems from three different wells. It should be noted that the pressure value entirely coincides with the initial formation pressure in the well. This is not a coincidence but a fundamental observation confirmed by the study's results. This correspondence is demonstrated in the graphs shown in Figures 1-3. The constructed differential condensation isotherms provided data on the condensate content of the reservoir gas produced from the three wells. For well No. 2 (III), well No. 1 (II) and well No. 5 (I), the corresponding condensate content in 1 kg of formation gas was 69.5 g/m³ of reservoir gas was 69.5 g/m³, 95.2 g/m³ and 95.2 g/m³, 95.2 g/m³ and 96.5 g/m³ respectively. Variations in condensate content can be ascribed to differences in initial reservoir pressure, depth, and geological attributes unique to each well. For example, well No. 2 demonstrated a condensate content of 69.5 g/m³ at an initial pressure of approximately 518 kg/cm². In contrast, well No. 5 exhibited a greater content of 96.5 g/m³ at a pressure of about 526 kg/cm². These variations emphasise the impact of localised geological features and operating conditions on condensate yields, highlighting the necessity of thorough sampling procedures that include these variables to guarantee representative findings throughout the field.

These data allow the conclusion that the potential stability of condensate is expressed in g/m³. Thus, for the NK_{7d} reservoir, the predicted condensate content in 1 m³ of formation gas is estimated at 80.5 g/m³, and for the NK_8 reservoir – 95.2 g/m³. In addition, the plotted isotherms' results allow for determining the condensation onset pressure for each of the three wells. For well No. 2 (III), this pressure is approximately 518 kg/cm^2 (with a reference value of P_{res}=510 kg/cm^2). For well No. 1 (II), it is approximately 496 kg/cm^2 (P_{res}=494 kg/cm^2), and for well No. 5 (I), it is approximately 526 kg/cm^2 (P_{res}=524 kg/cm^2). The statistical analysis results demonstrate a weak negative linear relationship between initial reservoir pressure and condensate concentration, shown by a correlation coefficient of r=-0.134.

This indicates that, within the analysed dataset, elevated initial reservoir pressures correlate with somewhat reduced condensate concentration, although the association lacks sufficient strength for conclusive conclusions. The regression analysis corroborates this conclusion, yielding the equation Y=153.8-0.130X, indicating that for each unit rise in initial reservoir pressure, the condensate content diminishes by around 0.130 g/m³. Although these data indicate a possible trend, the poor association implies that additional factors may substantially affect condensate yields. Consequently, it is advisable to conduct further research utilising a more extensive dataset to examine these relationships with greater rigour and to enhance comprehension of the reservoir dynamics, as this preliminary analysis suggests that the correlation between pressure and condensate content may be complex and potentially affected by supplementary geological or operational factors. During the studies of the gas condensate deposits of the Altyguyi field, a serious problem arose – the lack of necessary experimental equipment, such as UFO and UGK-3. This made conducting analyses to estimate the recovery factor and condensate losses difficult. The missing parameters had to be determined using mathematical models and empirical data (5):

$$\sigma = 11.325 + 0.105 P_{res}^{init.}, \quad (5)$$

Where: P_{res}^{init} – reservoir pressure at the initial moment, kgf/cm^2; σ – condensate loss in the reservoir, %. This formula was obtained from the graph, depicted in coordinates $\delta = f(P_{res}^{init})$ (Figure 4). The observed trend indicates a clear relationship between increasing starting pressure and elevated condensate losses. This discovery is crucial as it underscores the necessity of regulating reservoir pressure to reduce losses during extraction. Nevertheless, dependence on mathematical models stemming from equipment constraints prompts enquiries over the precision of these forecasts. Additional confirmation by direct measurement would bolster confidence in these results. It should be noted that the discovery of this relationship resulted from extensive research conducted with the RUT and UGK-3 systems in the gas condensate fields of Southwest Turkmenistan. Depth plays a key role in the relationship between condensate losses in the reservoir, recovery factor, and initial pressure in the NK_{7d} and NK_8 formations. Surprisingly, these parameters are almost the same for both reservoirs, about 65.6% and 0.344 kg/cm², respectively. Their close depth and initial pressures explain this. The steady-state sampling method was used to accurately determine the gas dynamic characteristics of wells and reservoirs in the Altyguyi field [18]. Optimisation of the wells included strategic changes in the wellhead fittings' diameter, significantly impacting the flow dynamics. Extended production tests were conducted to gain a complete understanding of their behaviours. The oil and gas wells were operated non-stop for at least 24 hours, while the gas condensate wells went through different regimes lasting between 5 and 24 hours.

The start of measurements was carefully synchronised with full stabilisation of wellhead pressures (P_{buf} and P_{annul}). The data were collected using depth gauges, mainly MGN2 (up to 800 kgf/cm²) or MSU1-100 (up to 160 kgf/cm²), as well as electronic geophysical equipment to increase accuracy and obtain additional data (Granit, Sakmar). A comprehensive approach was used to measure the daily gas flow rate accurately. The measurement stages started with the use of a PBS-350/64 separator (50 mm measuring aperture). A field installation with a Demag separator and flow meters DSP-0.063 and DPS-1.6 was used for more detailed analyses. DICT was used for accurate calculations. Wellhead pressures (P_{buf} and P_{annul}) were recorded simultaneously using MO-type sample pressure gauges. Downhole and reservoir temperatures were measured using TP-7-type thermometers with mercury columns for maximum accuracy. In some situations, technical limitations prevented the wells from being fully sealed to an accurate reservoir pressure. The reservoir pressure had to be determined experimentally.

In order to obtain a complete picture of the wells and their behaviour, steady-state filtration conditions were established in the bottomhole zone of the reservoir, and periodic regime changes occurred. Comprehensive hydrodynamic studies were performed at 17 separate sites, including 16 wells, and the procedure was repeated 22 times. During the studies, daily flow rates were measured in 6 wells (No. 12, 19, 107, 108, 111, and 112). Formation and bottomhole pressure were measured in four wells once each (No. 7, 21, 105, and 107). For oil wells No. 2 and No. 7, the pressure recovery curve was used to normalise the fluid flow rate. After analysing the data obtained, Horner's methodology determined the hydraulic conductivity coefficient and formation permeability. The results of this study are presented in Table 2. The oil in the Altyguyi field stands out for its specific gravity of 0.910 g/cm³, which is higher than that of other oil fields in the region of Turkmenistan. However, its significant paraffin content is an important problem. When the temperature drops during production, the paraffin solidifies, decreasing the pipe's internal diameter and increasing downhole pressure [19, 20]. These factors negatively affect the daily oil flow rate and make determining the well's productivity factor difficult. To ensure the accuracy of measurements and data collection, it is necessary to clean the inner walls of the tubing from such deposits before carrying out studies [21, 22]. The initial values of reservoir pressure and temperature of the oil reservoir HK_9 were determined from measurements at the No. 7 well connection and are 643 kgf/cm² and 87°C, respectively. The pressure recovery curve plots are clearly shown in Figures 5 and 6. Table 2 illustrates notable discrepancies in hydraulic conductivity and permeability across wells, which are essential indications of flow dynamics within the reservoir. Significantly, well-performing parameters, including flow rates and filter resistance coefficients, offer insights into operational efficiency and possible output bottlenecks. The absence of complete data for certain wells constrains thorough study. Hence, further studies are required to comprehend these dynamics properly. Standard techniques and equipment used in oil reservoir evaluation were applied to fully explore a gas condensate field and identify parameters such as condensate content per 1 m³ of gas.

The challenge was to adapt these techniques to the unique needs of gas condensate fields to provide a more detailed understanding of reservoir characteristics and system dynamics. Due to technical limitations, formation and bottomhole pressures in some wells were estimated using leaky, undeployed depth gauges and the barometric formula (6):

$$P_{b-h.} = P_{b(annul)} * e^{S}, \tag{6}$$

A specialised unit was used to extract condensate and water from the product stream and determine its volume per 1 m³ of gas. It included DEMAG and PBS-350/64 separators. Extensive exploratory drilling and performance testing of gas condensate wells were carried out at 11 sites. Particular attention was paid to the parameters of five wells operating in steady filtration regimes (No. 2, 5, 102, 1, and 20). Three (No. 1, 2, and 101) underwent four comprehensive studies in transient filtration regimes, with a special bias on pressure recovery curves [23]. An example of such studies is the pressure recovery curve for well No. 101, shown in Figure 7.

Table 2. Results of hydrodynamic studies

Well number	Plast	Interval between perforations (m)	Rebar diameter (m)	Coefficient		
				Volume (kg/cm²)	Hydraulic conductivity (sP)	Permeability (mD)
Studies in order						
1(I)	NK_9	3670-3680	5	-	-	-
			6	-	-	-
			8	-	-	-
			-	0.1807	4.4	14.52
			Repeated studies			
			6	-	-	-
			5	-	-	-
			4.8	-	-	-
			5.6	-	-	-
			6.4	0.264	6.43	21.2
2(I)	NK_9	3608-3618	4	-	-	-
			5	-	-	-
			6	0.9043	10.1 on PRC	34.34 on PRC
3(I)	NK_9	3732-3738	4			
			5			
			6	0.171	4.2	23.1
4	NK_9	3728-3740	4.8			
			5.6			
			6.4	1.1107	27.1	74.53
7(II)	NK_9	3746-3750	4	-	-	-
			4.8	-	-	-
			3.1	0.8493	22.03 on PRC	93.4 on PRC
10(I)	NK_9	3653-3662	6.3	-	-	-
			8	-	-	-
			4.8	0.4914	12	44
106(I)	NK_9	3783-3792	4	-	-	-
			5	-	-	-
			6	1.3552	33	-

Source: developed by the author.

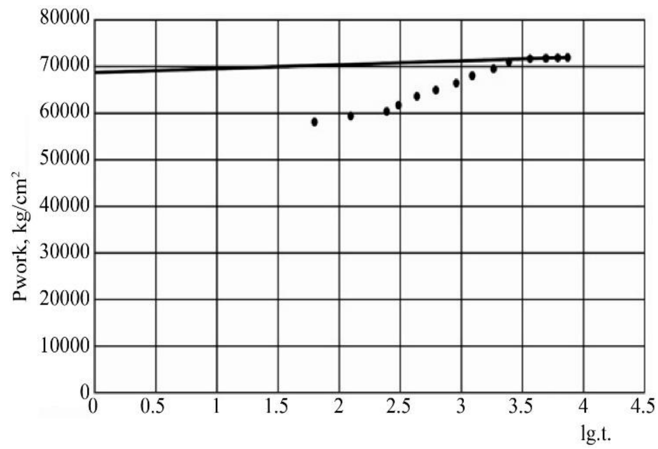

Fig. 5 Downhole pressure recovery curve versus reservoir pressure (well No. 2)

Source: Developed by the author

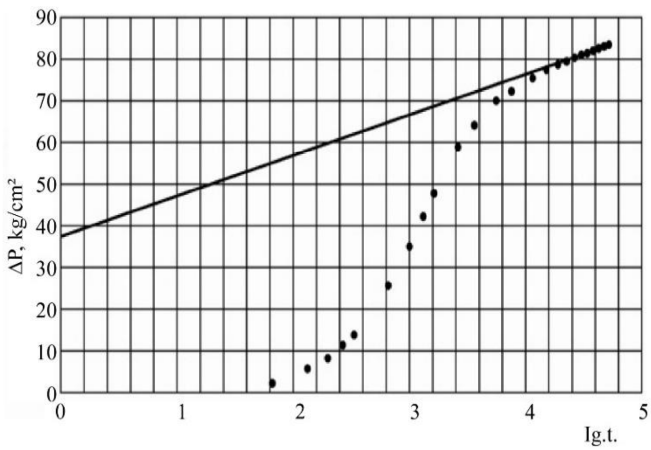

Fig.6 Bottomhole pressure recovery curve vs. formation pressure (well No. 7)

Source: Developed by the author

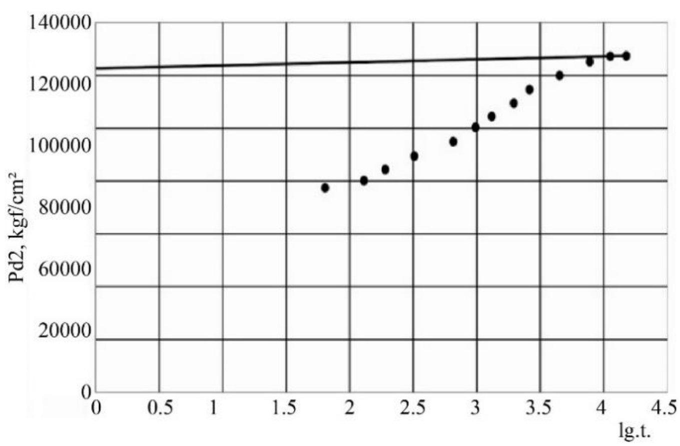

Fig.7 Downhole pressure recovery curve versus reservoir pressure for production well No. 101

Source: Developed by the author

Figures 5-7 are crucial for comprehending reservoir dynamics under diverse operational settings. The graphs illustrate the rate at which pressure equilibrates following production operations, which is essential for evaluating well performance and strategising future extraction methods. The recurring patterns shown in these data indicate that analogous geological conditions prevail throughout these wells, reinforcing the concept of geological continuity between neighbouring reservoirs (NK7d and NK8). Discrepancies in recovery rates may indicate underlying problems, such as paraffin accumulation or other operational difficulties that need additional examination.

To accurately estimate initial reservoir pressure and reservoir temperature, it is recommended to use standardized values of 517 kgf/cm² for pressure and 87 °C for temperature. NK_{7d}. These conclusions are based on analyses of data from two wells – well site II of well No. 2 and well site I of well No. 5. The reservoir location NK_{7d} and NK_8 wells, separated by only 30 m, suggest similar reservoir pressure and temperature conditions. Accordingly, values of P=517 kgf/cm² and T=87°C are established for both reservoirs based on the principle of geological continuity and the observed correlation between them. Subsequent studies include comprehensive work to determine condensate parameters and to study the thermodynamic characteristics of both wells and reservoirs for reservoirs. The study of gas condensate wells and reservoirs involved evaluation using three different filtration methods. The system analysis considered hydrogas-dynamic data using the two-term formula (7):

$$P^2_{res.} = P^2_{b-h} = aQ_2 + b * Q^2_2, \tag{7}$$

Where: P_{res} and P_{b-h} – formation and bottomhole pressure values, kgf/cm; Q_g – separation gas flow rate, thousand m^3/day. Table 3 contains the results of gas dynamic studies and a quantitative assessment of the gas-condensate factor — the amount of condensate released from 1 m^3 of formation gas. Table 3 delineates the specific features of gas condensate acquired during field experiments, encompassing condensate outflow volumes and molecular weights across several operational modes. The fluctuation in condensate yield (e.g., from 64.6 cm³/m³ to over 241 cm³/m³) highlights the impact of operational factors on production results. This table is essential for assessing reservoir performance, although it also reveals discrepancies that may result from differing operational circumstances or measuring methods. The value of formation fluid flow rate, denoted by $Q_{res.fl}$ is defined as (8):

$$Q_{res.fl.} = Q_{s.g.} + \frac{Q^{sat}_{c.} + G_{eqv.}}{10^3}, \tag{8}$$

Where: $Q_{res.fl}$ – formation mixture, thousand m^3/day; $Q_{s.g}$ – separated gas flow rate, thousand m^3/day; $Q^{sat}_{c.}$ – saturated condensate flow rate, m^3/day; G_{eqv} – gas equivalent. The gas equivalent is calculated as (9):

$$G_{eqv.} = 23342 * \rho / M, \tag{9}$$

Table 3. Gas condensate characteristics obtained during field tests

No. of wells	Plast	Interval between perforations, (m)	Diameter of reinforcement (mm)	Operating modes (hour)	Condensate outlet (cm^3/m^3)		Molecular weight of condensate
1(II)	NK_8	3615-3624	13	24	241.8	180.9	-
			11	16	156.9	119.3	-
			-	-	-	-	152.6
			7	8	115.1	89.1	-
			8.5	24	11.6	9.7	-
			7	16	14.1	12.1	-
			5	16	16.6	13.2	-
1(I+II)	NK_8+ NK_9	3513-3523 3680-3690	-	-	-	-	151
			10	24	Productive OCH		-
			8	18			-
			6	16			-
			-	-			-
			6	24	Productive OCH		-
			8	22			-
			10	20			-
2(III)	NK_{7d}	3512-3522	8	24	64.6	56.2	-
			-	-	-	-	-
			12	24	-	60.5	159
			8	22	-	29.6	-
			10	18	-	46.3	-
2(III)	NK_{7d}	3512-3522	6.5	24	107.5	93.4	-
			8	18	97.2	81.6	-
			9	15	99.8	86.2	-
			-	-	-	-	159
			9.5	22	14.3	13.1	-
			8	17	12.9	12	-
			6	15	23.4	21.5	-
			-	-	-	-	-
5(I)	NK_{7d}	3618-3624	10	20	111.8	102.8	-
			8	21	118.6	104.4	-
			6	15	113.1	101.8	-
			-	-	-	-	144.5
			9.5	20	10.6	8.7	-
			8	21	12.8	10.5	-
			6	15	16.2	13.2	-
			-	-	-	-	153.5
			8	24	50.9	43.8	-
			-	-	-	-	149
			12	24	-	51.4	
			8	21	-	46.9	
			10	16	-	46.3	
101	NK 8	3564-3566	12	24	-	-	-
			10	24	-	-	-
			8	16	-	-	-
20 (III)	NK 8	3950-3958	-	-	-	-	-
			9.5	22	-	-	-
			8	17	-	-	-
			6	15	-	-	-
			-	-	-	-	-

Source: Developed by the author

Where ρ and M are the density and molecular weight of fraction C_{5+b}. Thus (10):

$$M = \frac{44.29(\rho_{c.}^{st}+0.004)}{(1.034-\rho_{c.}^{st})}, \tag{10}$$

Where: $\rho_{c.}^{st}$ – the density of stable condensate. Tables 4-6 provide an overview of key parameters related to both reservoir and well properties. These data were obtained from gas dynamic studies as well as observations of stable condensate formation at the facilities. Expected condensate yields of 95 cm/t^3 and 118 cm/t^3 were determined for the NK_{7g} and NK_8 formations. However, a significant and accelerated decline in reservoir pressure was observed despite the relatively short period of gas condensate reservoir operation.

It is also worth considering well No. 2, which was brought on stream in 2018 with an initial reservoir pressure of 470 kgf/cm². The formation pressure decreased rapidly throughout the year, reaching only 350 kgf/cm² by 2019 and further decreasing to 230 kgf/cm² by 2021. A similar situation is observed in well No. 1 of the reservoir NK_8.

This will, also commissioned in 2018 with a reservoir pressure value of 435 kgf/cm², experienced a significant decline, and by 2021 measurements indicate a pressure drop to 220 kgf/cm². The poor results obtained in the study can be attributed to the lack of a suitable product separation regime. The gas condensate field in Turkmenistan is characterised by various reservoirs, including oil, gas, and their mixtures.

Table 4. Calculations based on gas condensate quality studies

No. of well	Plast	Reservoir pressure (kgf/cm^2)	Reservoir temperature (°C)	Stable condensate production (cm^3/m^3)
1(II)	NK_8	495	83	118
		451	88	11.3
1(I+II)	NK_8+NK_9	451	92	-
		309	89	-
2(III)	NK_{7D}	510	81	86.2
		490	87	12
		471	82	56.2
		270	81	60.5
5(I)	NK_{7D}	524	84	103
		487	90	8.7
		426	82	43.8
		274	84	51.4
20	NK_8	401	95	4.1
		337	88	97.2
101	NK_8	359	79	86.5

Source: Developed by the author

Table 5. Gas condensate characteristics of wells and formations

No. of wells	Plast	Filtration resistance coefficient		Flow rate of completely free gas (thousands of m^3/day)	Gas conductivity coefficient (m/sP)	Filtration coefficient (mD)
		a	b			
1(II)	NK_8	57.7	0.38	732.3	7.87	26.2
		137.6	0.243	677	3.4	11.2
1(I+II)	NK_8 +NK_9	86.1	0.411	713	5.37	8.1
		11	0.423	460.7	41.7	65.9
2(III)	NK_{7d}	92.5	0.1	1205.5	4.73	14.2
		37.9	0.112	1304.3	12.1	36.3
		-	-	-	-	-
		67.8	0.0123	921.2	6.6	20
5(I)	NK_{7d}	187.8	0.194	800.4	2.42	12.1
		80.6	0.112	1145.7	5.81	29.6
		-	-	-	-	-
		92.3	0.0145	726.2	4.89	25.1
20	NK_8	-	-	-	-	-
		135.1	0.785	302.3	3.5	12.9
101	NK_8	85.1	0.336	511.5	5.4	78.8

Source: Developed by the author.

Table 6. Characteristics of stable condensate

No. of well	Plast	Interval between perforations, (m)	Diameter of reinforcement (mm)	Amount of condensate from 1 m^3 of formation gas, (cm^3/m^3)		Speed at which the mixture enters the barrel (m/s)
				Intense	Stable	
1(II)	NK_8	3615-3624	10	157	118	4.95
			9.5	12	10	4.5
			10	Petroleum is a type of light hydrocarbon. The specific gravity of this substance is 0.8455 g/cm^3. The calculations were performed on gas because of the large gas factor		
			6			
2(III)	NK_{7d}	3512-3522	8	97	82	4.1
			8	13	12	4.3
			8	65	56	3.5
			10	-	60.5	4
5(I)	NK_{7d}	3618-3624	8	119	105	4.1
			8	13	11	4
			8	51	44	3.8
			10	-	46	4
20	NK_8	3950-3959	8	-	4	-
			12	-	55	4
101	NK_8	3564-3566	10	-	83	4

Source: Developed by the author

The lack of a plan to maintain pressure in the reservoir may lead to its decrease during operation [24, 25]. In this context, the gas lift method can effectively solve this problem. It provides production stability and flexibility in managing reservoir conditions, which makes it the preferred choice to ensure continuous field operation. Choosing the right production methods is key in Turkmenistan's gas condensate fields, which are rich in reservoir diversity. The effectiveness of gas lift in wells depends on many factors, including system parameters, working fluid pressure, and reservoir properties [26, 27]. Particular attention should be paid to fluid lift height, especially in the western region of Turkmenistan, which has unique conditions that further influence production dynamics. The western region of Turkmenistan is a unique environment with many challenges affecting fluid lift efficiency.

High lift heights require a customised approach to overcome long-distance challenges. Low flow rates require optimised strategies to maintain efficiency. Gradual increases in the water content of produced fluids add to the complexity, emphasising the need for adaptive methods to deal with changing properties [28-30]. Understanding the relationship between system parameters, agent pressure, reservoir properties, and the challenges of high lift heights, low flow rates, and variable fluid composition is important to success in this region. Developing a fluid lift strategy considering these characteristics is essential to optimise processes and ensure sustained success in this challenging environment. Using gas lift operations in Turkmenistan's fields represents a practical approach for continuous and intermittent fluid lifting systems. The optimal solution for maximum productivity is continuous gas lift wells with flow rates greater than 30 tonnes/day. For wells with lower flow rates, less than 30 tonnes/day, it is preferable to use periodic gas lifts. When studying the geological and operational characteristics of the field, it was found that the productive formations include alternating oil and gas reservoirs separated by thick, impermeable strata. Many gas reservoirs cover a larger area than the oil reservoirs [31, 32]. This geological configuration creates an opportunity to apply dual completion techniques to produce oil and gas from a single well. It is also worth considering the introduction of downhole gas lift technology, an efficient method of operation that does not require significant capital investment. This approach can further improve the efficiency and productivity of the field. When selecting a wellbore configuration, achieving acceptable production rates with a low gas factor and minimal water and sand yields is important for efficient production. The combination of dual completion methods and downhole gas lift can optimise production using the geological characteristics of the field.

Also, reservoir conditions and field operation peculiarities should be considered when selecting the well operation mode. It is also of paramount importance to ensure the productive production of hydrocarbons and the regular operation of flowing wells. Some common causes of failures are wax build-up, sand plugs, corrosion of fittings, and other factors. Various methods are used to restore well operation, such as introducing a liquid pump to remove sand plugs. Prompt diagnosis of the causes and targeted measures can ensure efficient and uninterrupted well operation, a key element in reservoir management and production optimization. The detection of a sudden drop in pressure in the annular zone of a well often indicates a blockage downhole, jeopardising continuous hydrocarbon production. If water is detected in the well, pressure must be restored immediately using techniques such as reducing the diameter of fittings to prevent water ingress. Solutions may also include running the well without fittings or flooding the wellbore with oil. When a drop in buffer pressure accompanies an increase in well flow rate, it may indicate nozzle corrosion problems caused by abrasive sand particles [33, 34]. In such situations, the fountain jet should be promptly diverted to another outlet and the damaged nozzle replaced. In cases where standard methods fail, the well is suspended for comprehensive workover operations. The well is returned to service when these activities are completed, ensuring reliable and efficient production. The successful operation of flowing wells depends on effectively managing paraffin deposits in lift pipes. Paraffin typically accumulates in the upper sections of the pipes, which are 400-1000 m from the wellhead, especially in cold weather.

Operational measures such as reducing pulsation and adjusting the gas factor combat this problem. If this does not help, mechanical, thermal, or chemical cleaning is used. An important well maintenance procedure that avoids shut down operations is wax pipe cleaning. This involves the use of pigs to remove deposits. Another method is also the application of heat. Lifting pipes are heated with steam or hot oil to melt the paraffin, which is then carried out by the oil flow [35, 36]. The solvent method utilises the properties of the condensate to dissolve the deposits. Each method is selected individually depending on well conditions and paraffin problems [37]. Gas lift operations, in turn, can encounter several typical problems that include sand ingress, plugging, and wax deposition. Operational methods are used to control the flow of fluids into the well [38] to combat sand deposition. This minimises sand settling and ensures smooth operation. “Cartridge sand plugs” can cause a sudden increase in gas pressure in the well, preventing the gas mixture from rising to the surface. In such cases, gas is sent directly into the lift pipes to break the plug. If this fails, pipe removal is resorted to.

The development of gas condensate resources in western Turkmenistan focuses on improving gas lifting, given changes in reservoir pressure and the vulnerability of reservoirs to flooding. The new approach involves ascending pipe columns with drilling chambers and gas lift valves above the packer and inside the production string. This avoids the negative impact of injected gas on the flow of fluids into the well. To optimise gas lift well operations, studies are planned using special techniques to determine the most efficient flow rates. This approach ensures that gas lift operations are tailored to specific field conditions and provide optimal performance. The gas distribution system should be equipped with modern control and metering technologies to improve gas lift performance while reducing the volume of injected gas. These measures aim to ensure the stability and performance of the gas lift system by adapting to the field's unique characteristics. Also, as the life of gas condensate fields grows, gas-lift wells are expected to increase. The transition to a mechanised method becomes more favourable as the use of well blowouts decreases, requiring careful planning and adaptation. The working gas injection depth ranges from 1400 to 3000 m in the current operating mode, carried out through specialised holes or perforators. This approach meets the operational requirements of gas lift wells, ensuring efficient gas delivery to the required depth. Estimating well performance and development parameters is based on gas condensate reservoirs, particularly in areas with no oil rims. It is important to recognise that this assessment involves a degree of uncertainty that can affect the accuracy of the results. Among the main causes of uncertainty are the following:

- Assessing the level of activity following legal constraints in the fields is a complex task requiring prediction of the potential impact on drainage patterns;
- Insufficient number of reservoir pressure measurements leads to incomplete information on the dynamics of pressure changes with time, especially at different levels in the reservoir;
- The lack of sufficient data to determine key filtration parameters (denoted as A and B) creates serious obstacles to obtaining average values of these parameters in the development zones;
- The lack of empirical data to estimate condensate recovery rates limits the ability to predict production levels accurately.

This complex nature of forecasting in gas condensate fields emphasizes the need for systematic analysis and consideration of multiple variables. Addressing this challenge requires continuous data collection, analysis, interpretation, and adaptation of field management strategies to meet changing conditions. To improve the efficiency of gas condensate field management, a specific methodological approach is used to optimize the use of available reservoir pressure measurement data. This approach involves a structured process aimed at increasing the accuracy and reliability of predictions (11):

$$\overline{P}_{res.} = f(\overline{Q}_{g.}), \tag{11}$$

Where: $\overline{P}_{res.}$ – the ratio of the current reservoir pressure value to its initial value; $(\overline{Q}_{g.})$ – the ratio of total gas production to total recoverable reserves. When analysing gas reserves in the initial stage of gas condensate field development, the gas recovery factor estimated at 0.85 was used. The experience of gas condensate field development in Western Turkmenistan shows that operational work in these fields leads to changes in reservoir dynamics. Temporary changes in the pressure balance in the reservoir contribute to the formation of edge and bottom waters. The calculations used differential condensate isotherms at reservoir conditions, which were processed and transformed into polynomial equations. Initial calculations performed in the lower reservoir include forecasting annual and cumulative gas production and determining average gas well production rates (denoted as q_1) for future developments, particularly in the context of considering an independent grid well development strategy. The sequence of calculations is as follows:

- Annual and cumulative gas production for the lower reservoir is estimated, and the average gas well production rate (q_1), which provides a basis for future possible development using an independent well grid. The reservoir pressure fluctuations in the lower reservoir can be calculated from the production data (Q_1) (12):

$$P_{res.init.1} = P_{res.init.}f(\overline{Q}_{g.1}). \quad (12)$$

- The calculation of the bottomhole pressure, denoted as P_{b1} is carried out using the filtration coefficients A_1 and $B_1$and known values such as gas flow rate (q_1) and formation pressure (P_1) (13):

$$P_{b1} = \sqrt{P_1^2 P - (A_1 q_1 + B_1 q_1^2)}. \quad (13)$$

- Accurate determination of wellhead pressure is critical in subsurface fluid production (14-19):

$$P_2 = e^{-after}\sqrt{P_1^2 - 1.377\lambda_1 \frac{Z_{av.1}^2 T_{av.1}^2}{\rho_1 d_{int.1}^5} Q^2 mix_{-1}(e^{2after} - 1)}, \quad (14)$$

$$S_0 = 0.03415 \frac{\overline{\rho}\rho L}{Z_{av}T_{av}} : \rho = \varphi + (1 - \varphi)\frac{\rho_{liq.}}{\rho_{g.op.}}, \quad (15)$$

$$\rho_{g.op.} = \frac{\rho_g P_{av.} T_{st.}}{P_{at.} T_{av.}} : \varphi \leq \beta = \frac{Q_{liq.}}{(Q_{g.op.} Q_{liq.})}, \quad (16)$$

$$Q_{g.op.} = \frac{Q_g P_{at.} T_{av.}}{P_{av.} T_{st.}} : Q_{mix} = \frac{G_g + G_{liq}}{(\rho_{g.})}, \quad (17)$$

$$G_g = Q_g \rho_g; \overline{\rho} = \frac{\rho_g}{\rho_{air}}; T_{st} = 293°K, \quad (18)$$

$$\theta = 1.377\lambda \frac{Z_{av.}^2 T_{av.}^2}{d^5}(e^{2S} - 1), \quad (19)$$

where: ρ_g, ρ_{air}, ρ_{liq} – densities of gas, air and liquid, kg/m^3; $\rho_{g.op.}$, $Q_{g.op}$ – density and gas flow rate in the wellbore under typical operating conditions, kg/m^3 and thousands of m^3/day; G_{liq}, G_g– flow of liquids and gases in large volumes, tonnes/day; Q_{mix}, Q_{liq}, Q_g – flow rate of the gas-liquid mixture, liquid and gas, at P_{at} and T_{st}, thousand m^3/day. To accurately determine the volume content of gas in a well, it is common to use experimental measurements by comparing the actual gas volume (V_t) to the volume of the wellbore. However, such measurements can be difficult and impractical. In cases where direct measurements are not possible, the gas content (β) can be estimated using the formula presented below. It is important to note that β is usually greater than the actual volumetric gas content (φ) in the well. Substituting β for φ can lead to an underestimation of bottomhole pressure, especially if the difference between the fluid content of the well and the gas release is significant. In addition, the hydraulic resistance coefficient is of great importance in the flow characteristics of the well [39]. Ideally, this coefficient should be obtained from a complete study of the well in different operating modes. In the absence of such studies, it is common to use assumed values of λ such as λ_t=0.025 for tubing and λ_p=0.0815 for the packer. These circumstances emphasise the importance of accurate measurements and assumptions in analysing well performance, especially in complex flow dynamics and variable parameters in oil and gas production. All parameters, includingZ_{av}, $\rho_{g.op}$, $Q_{g.op}$, β and others that depend on the mean reservoir pressure (P_{av}) are calculated using an iterative method known as successive approximations. This approach is essential for predicting and analysing gas factors and oil and gas reserves in complex reservoirs, often with intricate drainage patterns. Gas factor forecasting and estimation of oil and gas reserves in productive reservoirs of fields can present significant challenges. Their dynamics are affected by various complex factors, including changes in the types of energy involved in the oil displacement process from the well production zone [40-42]. In order to address these complexities, the research used experience in constructing similar reservoirs in other areas, such as the lower red. To better understand reservoir dynamics and pressure changes over time, especially in cumulative gas production, the corresponding graphs shown in Figures 8 and 9 were plotted. Assessing the economic feasibility of field development options involves analysing several key indicators, such as capital investment and operating costs. This analysis considers the projected technological parameters and development options [43]. Based on these data, informed decisions are made to select the most optimal strategies that not only maximise production but also meet the economic objectives and sustainability of the industry.

Technological standards and economic criteria adequately assess the financial impact of new well drilling and field development. This assessment includes calculations of drilling and infrastructure capital expenditures and operating costs. New wells and their infrastructure require long-term capital investment to ensure the growth and stability of the field [44, 45]. Operating costs associated with oil, gas, and condensate production are projected, considering depreciation, depletion, and exploration expenses. Many factors, including geological features, climatic conditions, the composition of produced fluids, and the technical reliability of equipment, are considered when selecting methods of mechanised oil recovery at the Altyguyi field. The results of laboratory studies, which determine the effectiveness and reliability of various approaches to extracting oil from complex formations, play a crucial role. Ejector pumps in the Altyguyi field are inappropriate for several reasons. An important factor is the significant depth of the pay zone, which is beyond the operating range of ejector pumps. Such pumps require large well depths, which makes them ineffective for fields with shallower depths. In addition, ejector pumps need a high gas content in the fluid to operate, which is not the case in the Altyguyi field.

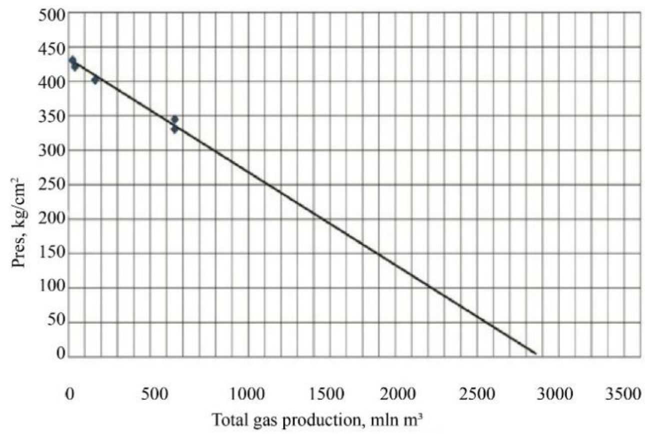

Fig. 8 Change in reservoir pressure as a result of cumulative gas production in the reservoir NK$_8$

Source: Developed by the author

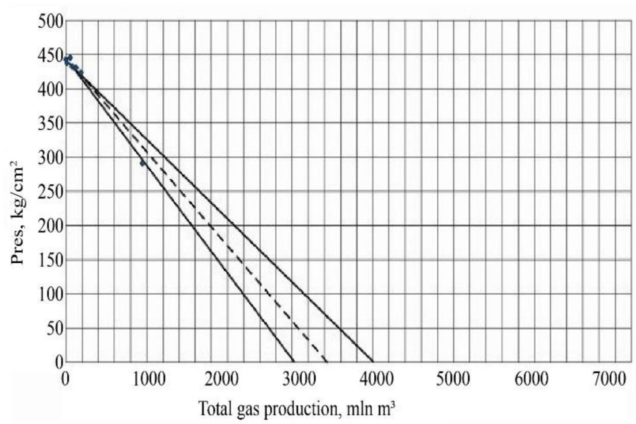

Fig. 9 Change in reservoir pressure as a result of cumulative gas production in the reservoir NK$_{7d}$

Source: Developed by the author

These limitations make alternative methods more preferable and efficient for oil production in this field. The use of Electric Submersible Pumps (ESPs) in the Altyguyi field is impractical due to its deep well depths ranging from 3600 to 3700 m. ESPs are typically designed to operate at depths of up to 1600 m, making them impractical for this field. An additional limitation is the high gas content of the pumped fluid, which is contrary to the ESP's optimum operating conditions of minimal gas in the fluid. The predicted flow rate at the Altyguyi field is well below the minimum capacity of ESPs, making them impractical in this context. Given these limitations and the incompatibility with the field's unique characteristics, using ESPs becomes impractical. The use of the Insertion Rod Pumping Unit (IRDP) in the Altyguyi field is also limited by several factors. The IRDP, despite its well design and available equipment, is effective in wells up to 2300 m deep, wildly when pumping from shallow formations. However, its application is limited by a high gas factor, significant well depth, and small wellbore deviation [46-48]. Today's standard pumps, including thrust-type lift pumps and vertical rod pumps, can theoretically lift fluid from depths up to 3500 m. However, as depths increase, operational reliability issues arise with pump tubing and rods, making field infrastructure more challenging to maintain and repair. In Turkmenistan, the practical application of IRDP units is usually limited to depths of up to 2300 m. Actual production from such depths rarely exceeds 5.3 m³/day, indicating the influence of various unfavourable factors on injection efficiency. Hydraulic piston pumps with automated units are reliable for operating directional and deep wells [49, 50]. Their efficiency is demonstrated in wells deeper than 4000 m, providing high productivity even at depths of about 3000 m with flow rates of up to 100 m³/day.

The compact dimensions of the pumps allow their use in wells with different production casing diameters from 117.7 to 155.3 mm [51]. Among the offered hydraulic piston pump models are the IHP 25-150-25, IHP 40-25-20, and IHP 100-200-18, which are ideal for pumping formation fluids from wells using hydraulic piston pumps of the discharged type. These pumps effectively solve specific operational problems in such wells. Introducing Hydraulic Piston Pumps (HPPs) in the Altyguyi field is seen as a potential solution to address specific operational challenges. However, at the current stage, the use of these units is not included in the immediate development plans. The introduction of HPPs will require thorough analysis and preparation, including the selection of optimal process flow diagrams, considering the specifics of the field. Energy, technical and economic aspects must also be thoroughly investigated to make informed decisions on the most efficient method of operation. It is planned to postpone the introduction of the HPP to a later stage of field development, when the wells are expected to have a high-water content of over 90% and a transition to more efficient oil production methods, including the use of hydraulic piston pumps, is required. The specific timing and conditions for introducing the HPP will be determined as the field develops and the characteristics of the field are better understood.

Submersible Screw Electric Pumps (SSEP) is an innovative solution for the efficient recovery of high-viscosity reservoir fluids from oil wells in the Altyguyi field. These units are designed to accommodate wells characterised by low production rates and significant gas presence and are dominated by high-viscosity oil in reservoir conditions. SSEP units are designed to operate with formation fluids within specific parameters, including a maximum temperature of 70°C, viscosity in the range of 1-10 m/s, mechanical impurities content not exceeding 0.8 g/l and free gas concentration at the pump inlet not exceeding 50%. Compliance with these parameters is essential to ensure the reliability and longevity of SSEP plants [52-54]. German-made screw electric pumps of NTZ-240.DT16 types are being actively introduced in the fields of Turkmenistan. These pumps have a potential flow rate of 15 to 30 m³/day and can be run to depths of up to 1900 m. However, practical use has revealed limitations, such as a preference for vertical wells and reduced reliability and efficiency in curved wells.Considering the limitations, the optimum solution is to use electric screw pumps in vertical, shallow wells with a dynamic level of at least 1700 m. The temperature of the pumped formation fluid should not exceed 70°C, and the free gas content at the pump inlet should not exceed 50%. The gas lift is also an integral oil recovery technology in the Altyguyi field. However, it is important to consider many factors affecting its operation, such as equipment features, working fluid pressure, and reservoir characteristics.

High lift heights, average production rates, and increased water content of produced fluids over time characterise the Altyguyi field. Gas lift can be applied continuously or periodically, depending on well production rates. The continuous method is recommended for higher flow rate wells to improve production efficiency, while the intermittent approach is better suited for low flow rate wells. Analysis of Altyguyi geological and field data allows for optimising the choice of completion methods and the use of the downhole gas lift. For the successful implementation of gas lift in the Altyguyi field, it is important to carefully determine the parameters of operations, including length, diameter, and gas flow rate of lift pipes. This will maximise the use of gas lift technology to recover oil from the wells. M pipes with parameters such as a 62 mm bore diameter demonstrate high flexibility and practicality, especially in the field. Adaptable to technical and mechanical factors, they provide a wide range of options for efficient production. Figure 10 shows that a comprehensive fluid lift system is also a priority. Such a system should allow for both intermittent and continuous lifting of fluids from wells and will maximise adaptability to different field conditions.

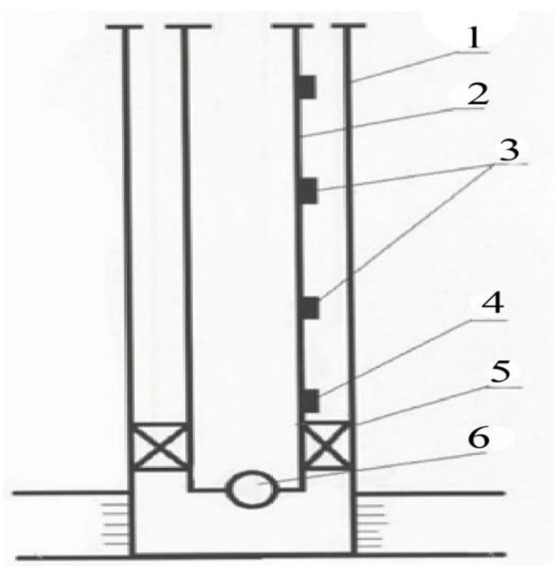

Fig. 10 Gas lift diagram

Note: 1 – Production pipes; 2 – Lifting pipes; 3 – Initiation valves; 4 – Production valve; 5 – Packer; 6 – Check valve.
Source: Developed by the author

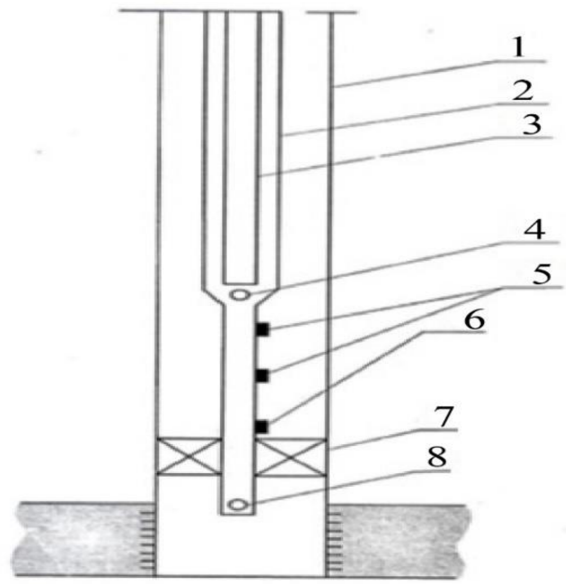

Fig. 11 Schematic diagram of the stepped gas lift

Note: 1 – Operational column; 2 – Intermediate column; 3 – Upper lift section; 4, 8 – Check valves; 5 – Initiation valves; 6 – Operational valve; 7 – Packer.
Source: Developed by the author

This configuration appears to be the most optimal for wells where the depth of gas intake is limited to values up to 3000 m. However, an alternative lift configuration is required for deeper wells, where depths reach 4000 m or even greater, as illustrated in Figure 11. In the context of gas lift operations in the Altyguyi field, M tubing demonstrates the flexibility required to meet various operational challenges. However, a particular field site's unique well characteristics and production requirements should determine the appropriate lift configuration. To maximize fluid recovery efficiency, it is important to sink the lift tubes to the maximum depth to minimize bottomhole pressure (20):

$$\mathrm{L} = \mathrm{H} - (20{:}\,30), \tag{20}$$

Where: H – the distance between the pores of the upper filter, m. Determination of the optimum specific gas flow rate for continuous lift in the downhole system plays an important role in ensuring the efficiency of oil production. This calculation is based on equation (21):

$$\mathrm{R} = \frac{0.388[\mathrm{Lpg} - (\mathrm{P_1} - \mathrm{P_2})]}{\mathrm{d}^{0.5}(\mathrm{P_1} - \mathrm{P_2})\mathrm{Lg}\frac{\mathrm{P_1}}{\mathrm{P_2}}}, \tag{21}$$

where: P_1 – operation under load, Pa (operating pressure is 8.5, 10, and 12 MPa); P_2 – minimum wellhead pressure under typical operating conditions, it is taken equal to P_2=1.2*10^6; 1.5*10^6 MPa; ρ – density of oil, remains constant and is 861 kg/m^3; g – the force of gravity (9.81 m/sec^2); d – diameter of lifting pipe, m; L – height to which the liquid rises, m. When calculating the gas injection rate, the gas solubility must be taken into account (22):

$$R_{inj.} = R_{req} - \left[G_0 - \alpha\left(\frac{P_1+P_2}{2}\right)\right]\left(1 - \frac{n_w}{100}\right), \quad (22)$$

Where: G_0 – gas factor (in case of oil), m^3/t; α – coefficient of gas solubility in oil, α = 0.4031 m^3/t; n_w – water content in the product, %. Studying the optimal specific flow rate of injected gas at different reservoir depths allowed us to identify key parameters for improving oil production efficiency. The 2700 m, 3000 m, and 3500 m depths at working pressures of 8.5 and 15 MPa were considered, where the optimum values were 200, 300 and 500 m³/t, respectively.

For the depth range of 3000-3500 m with operating pressures of 10 and 15 MPa, the optimum specific flow rates from 150 to 400 m³/t were established. Considering the operating characteristics of the Altyguyi field, the most effective approach is to use a customized strategy with a single-row interchangeable chamber design. This approach includes a strategically located packer and checks valve at the bottom of the oil column, specifically adapted for intermittent gas lift use, as illustrated in Figure 12.

The configuration of the annular space between tubing and casing as a special replacement chamber in the Altyguyi field was based on the desire to optimize the gas lift process, considering its unique conditions. A single-row substitution chamber with a packer and check valve aims to improve production efficiency and accuracy, fully meeting the Altyguyi field's requirements.

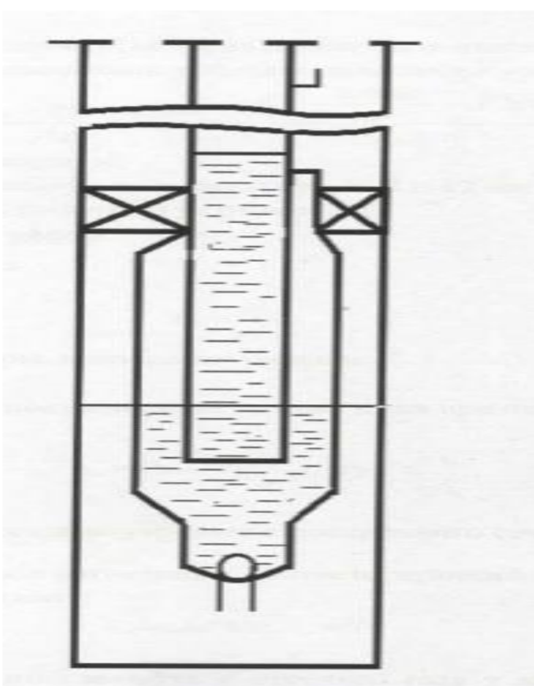

Fig.12 Schematic diagram of a lift with a replaceable chamber for intermittent lifting of liquid

Source: Developed by the author

This design has proven practical for field conditions, efficiently executing periodic gas lift operations. The packer and check valve facilitate controlled gas flow, which improves lifting efficiency. Integrating initiation valves into the tubing represents a strategic alternative to improve gas lift operations in the Altyguyi field. This innovative approach reduces injected gas pressure and facilitates fluid removal from the wellbore. The lower valve, known as a functioning valve, performs the dual function of a shut-off device and specific gas flow rate control.

A functioning valve in gas lift operations plays a key role in controlling gas flow and limiting the consumption of certain gases. This dual function improves gas injection control and optimizes the gas lift system. Start-up valves placed at the top of the tubing string provide precise control of the gas injection process, improving efficiency and overall system optimisation. Integrating these valves ensures efficient fluid removal from the well, helping to improve productivity in the Altyguyi field and building operational success. The operating pressure of the injected gas is calculated as (23):

$$P_{work} = \frac{h\gamma_{oil}}{10} - P_{pip} + P_{w.h}. \quad (23)$$

The maximum height of the liquid column to be lifted into the lift pipes at maximum working pressure is defined as (24):

$$h = \frac{(P_{work} - P_{pip} - P_{w.h})^{10}}{\gamma_{oil}} = \frac{\left(P_{work} - \frac{0.0064L}{d^{0.5}} - P_{w.h}\right)^{10}}{\gamma_{oil}}, \quad (24)$$

Where: L – length of the lift, m; d – inner diameter of the lift pipe, equal to d=62 mm (2.5”); P_{work}, $P_{w.h.}$ – working and wellhead pressures, at; γ_{oil} – oil density. In this case, the length of the chamber (25):

$$l_c = \frac{d^2}{d_{1c}^2}, \quad (25)$$

Where: d_c – 4” is assumed to be the diameter of the chamber. The amount of fluid lifted per cycle at the ideal gas injection rate is equal to (26):

$$q_{cyc.} = \left(h\frac{0.5\sqrt[3]{L^2}}{d^{0.5}\gamma}\right)f\gamma, \quad (26)$$

Where: d = 0.003 m – the internal cross-sectional area of 2.5-inch pipes. During the injection period, the gas flow rate will be minimal (27):

$$V_0 = 1.1d^2\sqrt[3]{L^2}. \quad (27)$$

For intermittent gas lift with gas shut-off in the chamber, the amount of gas required for one cycle can be calculated as (28):

$$V_c = f(L + h - l_c)\frac{P_{work}}{p_o}. \quad (28)$$

The duration of the gas injection time is equal to (29):

$$T_1 = \frac{60V_c}{P_o}. \quad (29)$$

Total cycle duration (30):

$$T = \frac{q_{cyc.}1440V}{Q}, \tag{30}$$

Where: Q – liquid flow rate, tonnes/day. Duration of the fluid accumulation period (31):

$$T_2 = T - T_1. \tag{31}$$

Number of cycles performed daily (32):

$$n = \frac{1440}{T}. \tag{32}$$

Gas consumption per 1 tonne of liquid (33):

$$R_0 = \frac{V_c}{q_{cyc.}}. \tag{33}$$

The design parameters presented in Table 7 are key to the design of gas lift systems, defining the basic parameters for creating efficient lift operations. Particular attention is paid to determining lift depth, as this directly affects the placement and functionality of the valves in the system. Correct strategic valve placement ensures optimal gas injection and lift efficiency. The design of a gas lift system must follow industry standards and consider the unique characteristics of reservoir fluids. This includes fluid composition and behaviour under different conditions. It is also important to account for the variable flow rates of each well, which requires flexibility in system design. Proper design of the gas lift system, considering the parameters from Table 7, is a critical element in optimising production from gas lift operations.

Valve placement, combined with an understanding of lift depth and flow rate, allows for fine-tuning of gas injection in each well, which improves production efficiency and ensures stable, well operations at the Altyguyi field. Bellows valves such as G-38, G-38R, G-25, and G-25R are recommended for gas lift systems and typically installed in well chamber pockets. Proper selection and placement are important in controlling the gas lift process and ensuring efficient system operation. A comprehensive evaluation is required for every significant oil field, including exploratory drilling, geological studies, geophysical surveys, and laboratory analyses.This evaluation identifies the critical parameters and characteristics of the field, which are necessary to understand its geological and hydrogeological characteristics fully. Among the key aspects that are important to define are:

- A lithological and stratigraphic section that includes the definition of formations, their lithological characteristics, and the presence of oil- and gas-saturated formations, as well as the presence of impermeable areas;
- It is necessary to identify gas-oil-bearing contacts at different points in the field and analyse their shape and size;
- Calculate the total, effective, and oil-gas saturated thickness of productive sediments and identify changes in these thicknesses within oil-bearing zones;
- Study the type, mineral composition, porosity, permeability, and other characteristics of rocks in productive formations;
- Describe the properties of cover rocks, including their material composition, porosity, permeability, and other important parameters;
- Determine initial oil and gas saturation levels in reservoir rocks, taking into account changes in the field;
- Record initial values of formation pressure and temperature for all productive formations;
- Assess hydrogeological conditions and take into account geocryological features in permafrost zones;
- Study saturation pressure, gas concentration, density, viscosity, and other parameters of reservoir oil;
- Estimate parameters such as density, viscosity, molecular weight, and other properties under standard conditions;
- Investigate the component composition, density, compressibility, and content of various components in gas and condensate;
- Study the physicochemical parameters of produced water, such as density, viscosity, and ion content;
- Define oil, gas, and water flow rates at different bottomhole pressures and well productivity factors;
- Determine the hydrophilicity or hydrophobicity of the rock and the saturation of bound water;
- Identify the correlation between these parameters in reservoir rocks, taking into account water saturation;
- Study thermal conductivity, heat capacity, and other thermal parameters of rocks.

The research on the Altyguyi gas condensate field has substantial practical relevance for optimising hydrocarbon extraction and improving reservoir management tactics. The study utilises advanced methodologies, including the construction of differential condensation isotherms, to offer vital insights into the component composition of reservoir gas, which is crucial for accurately forecasting condensate yields and comprehending phase behaviour under different pressure conditions.

The study underscores the need to quantify essential factors such as volume, density, and molecular weight to accurately assess gas dynamics, thereby enhancing decision-making in production methods. Using empirical data and mathematical modelling to predict recovery factors and condensate losses facilitates customised strategies that may be adjusted to particular reservoir conditions.

This thorough study enhances production efficiency while addressing problems like paraffin deposition and pressure recovery, improving operational performance in gas condensate fields. The results may be immediately utilised in analogous domains, strengthening their significance in improving comprehensive resource management and extraction methodologies throughout the sector.

Table 7. Calculation of gas lift parameters

L,m	d, m	P_{pip}, MPa	P_{work}, MPa	$P_{w.h.}$, MPa	h, m	1_c, m	q_{cyc}, tonnes
2500	62	1.01	8.4	1.5	695	271.7	1.62
3000	62	1.21	10	1.5	898	350.7	2.12
3000	62	1.42	12	1.5	1115	435.7	2.66
V_0, m/h^3	**Vc, m^3**	**T_1, min**	**T, min**	**n_{cyc}, cycle**	**Q, tonnes/day**	**R_o, m/t^3**	**V, m/day**
1266	884	41.89	116.6	12.35	20	546	10920
1430	1064	44.65	152.6	9.4	20	501	10022
1584	1504	57	191.5	7.52	20	565	11314

Source: Developed by the author

A risk analysis of the Altyguyi gas condensate field research identifies many possible uncertainties in the gathered data and the consequences of fluctuations in geological and operational variables. Measurement inaccuracies may stem from instrument calibration errors or operator handling, resulting in pressure, temperature, and flow rate readings discrepancies. Thus, regular maintenance and calibration of equipment such as depth gauges and separators are crucial to mitigate this risk. Moreover, geological variability, including heterogeneity in rock properties and variations in reservoir pressure and temperature, can profoundly influence gas dynamics and condensate yields. Therefore, ongoing monitoring and comprehensive geological characterisation are essential for a deeper understanding of these effects. Environmental risks linked to gas extraction must be evaluated to adhere to rules and mitigate consequences, highlighting the necessity of a proactive risk management system that preserves the integrity of the study findings while resolving any ambiguities. Choosing optimal gas condensate well operation methods is increasingly important in modern geological and technical aspects. In order to achieve optimal well performance, complex geological conditions and hydrodynamic features must be considered. Process optimisation, including measures to recover condensate and water from the downhole, plays an important role in ensuring the economic viability of the overall project. This process must also consider the need to minimise environmental impact and preserve the integrity of the geological formations. Balancing between maximising the production of valuable fluids, such as gas and condensate, and minimising negative impacts on the reservoir is a key aspect of successful gas condensate well operations. This integrated approach, focused on efficiency and sustainability, is the basis for sustainable field development and long-term field viability.

5. Discussion

Gas condensate field production research plays an important role in developing effective production strategies, helping to improve production efficiency and ensure long-term production sustainability. It helps to optimise the choice of production technologies and methods and to predict field behaviour during operation, which helps to develop production strategies to maximise hydrocarbon production and optimise operational processes. It is also worth noting that this can help increase the production volumes of gas condensate fields and ensure the economic efficiency of projects. By analysing operating conditions and identifying optimal production technologies, companies can significantly reduce production costs and increase their competitiveness in the market. Moreover, research in this area can reduce the environmental impact of production on the environment, contributing to a more sustainable and environmentally friendly industry development.

However, despite the significance of these studies, several difficulties must be faced in this field. One of these problems is the lack of understanding of the geological processes occurring within reservoir formations, which makes it difficult to accurately predict their behaviour during production [55-58]. Moreover, extraction methods and technologies are still not perfectly adapted to the characteristics of gas condensate fields, which creates additional challenges in developing optimal extraction strategies. This requires continuous research and innovation to overcome these challenges and ensure sustainable and efficient gas condensate production. Studies at the Altyguyi field have provided important data on the condensate content of the reservoir gas. Analyses of wells No. 2 (III), No. 1 (II), and No. 5 (I) showed that the corresponding values were 69.5 g/m³, 95.2 g/m³, and 96.5 g/m³, respectively.

These figures are key to predicting condensate stability in different gas reservoirs. For example, for reservoir NK7d, the predicted condensate content in 1 m³ of reservoir gas is estimated to be 80.5 g/m³, and for reservoir NK8, it is estimated to be 95.2 g/m³. In a study by Y. Tang et al. [59], the authors also found a significant effect on phase state change during multi-cycle condensate injection and production, which is important in determining effective production strategies. However, compared to this study's results, the mentioned work left some aspects ambiguous, indicating the need for an in-depth study to obtain a more complete understanding of the production processes of gas condensate fields. The data obtained from the Altyguyi field reveals its current state in more detail, providing important information for its future exploitation and optimisation of production processes. Cheng et al. [60] analysed the relationship between initial reservoir pressure and condensate losses in the Southwest Turkmenistan gas condensate fields. These studies have led to the development of mathematical models predicting recovery factors based on empirical data, which have proven effective in optimizing production strategies by correlating well performance with reservoir characteristics. This methodology is similar to those applied in the Altyguyi study, highlighting a consistent approach across different fields in Turkmenistan. Research conducted in the Permian Basin by Cheng et al. [61] has demonstrated successful gas injection techniques that enhanced recovery rates in gas condensate reservoirs.

This aligns with the secondary recovery methods explored in the Altyguyi field, illustrating how advanced techniques can be tailored to specific reservoir conditions to improve overall recovery rates. In this study, condensation onset pressure measurements were taken for three wells in the field. The results of the analyses showed that this value was approximately 518 kg/cm² for Well No. 2 (III), approximately 496 kg/cm² for Well No. 1 (II) and approximately 526 kg/cm² for Well No. 5 (I), in the study of A. Li et al. [62], in turn, simulated the phase characteristics of the reservoir gas-condensate mixture of the Tegermen group of fields, which allowed more accurate prediction of reservoir behaviour under different production conditions. P. Panja et al. [63] also investigated the effect of temperature and pressure on the phase diagrams of gas condensate systems, which added new knowledge in production management in gas condensate fields.

Nevertheless, the study's results on the Altyguyi field, in contrast to the modelling of phase characteristics and the influence of temperature and pressure on phase diagrams carried out by the mentioned works, presented specific results based on measurements made on a specific field. These data provide a more accurate representation of the real conditions in the field, which allows for optimising production processes and ensuring efficient exploitation of gas condensate resources. One of the important results of this study was also the determination of the condensate recovery factor, which for the NK7d and NK8 formations was about 65.6%, and the initial pressure was 0.344 kg/cm². These parameters are almost identical for both reservoirs due to their close depth and initial pressures. Also, the steady-state sampling method allowed for a full understanding of the gas dynamic characteristics of the reservoir and wells in the Altyguyi field, providing opportunities for gas condensate exploration. The study by A. Zhang et al. [64], which aimed to analyse the behaviour of phases and displacement mechanisms during gas injection into a gas condensate reservoir, also showed that displacement processes can vary greatly depending on a particular field's geological and physicochemical characteristics. X. Yingjie et al. [65] focused on analysing the effect of different production modes on the recovery efficiency of gas-condensate mixtures and confirmed the importance of using modern technologies and methods to improve well productivity and reduce production costs. The results of the mentioned works expanded the understanding of the relationship between the physical and chemical features of the field and the processes of extraction of gas condensate resources. Confirmation of the significance of certain approaches and methods provides new prospects for optimising production at the Altyguyi field, which in turn contributes to improving the efficiency and sustainability of gas condensate production. The calculations of the expected values of condensate yield performed during this study showed that for the formations NK7g and NK8, the expected values are 95 cm³/t and 118 cm³/t, respectively.

At the same time, despite the predictions, there was a significant and accelerated decline in reservoir pressure even with a relatively short period of operation of the gas condensate reservoir. The study highlights the need for an individual approach to selecting and optimising production methods in the western region of Turkmenistan, where unique conditions such as high elevations and low flow rates apply. At the same time, a study by A. Abad et al. [66] on the investigation of machine learning algorithms for predicting gas flow rate in gas condensate fields represented an important step in the direction of modern methods of production process management, confirming the effectiveness of using such technologies.

The work of R. Al Dhaif et al. [67] also notes the significance of new machine learning technologies in monitoring and production management in gas condensate fields. The use of modern approaches presented in the mentioned works could complement this study in the Altyguyi field, opening opportunities for improving the efficiency and accuracy of production processes and increasing the stability of the field operation. The results of the detailed gas lift system parameter studies conducted in this study showed that adherence to industry standards and consideration of the unique characteristics of reservoir fluids play an important role in optimising production.

Among the key factors emphasised was the system design's flexibility to account for each well's variable flow rate. Valve location and bellows valve selection were highlighted as important in ensuring an efficient gas lift system. In the paper by S. Matkivskyi and L. Khaidarova [68], the authors studied the influence of gas lift system parameters on the gas condensate mixture extraction, which expanded the understanding of managing this process effectively. At the same time, the work of T. Muther et al. [69] presented innovative methods and technologies for optimising extraction processes, opening new perspectives for increasing productivity and reducing extraction costs in gas condensate fields. However, unlike the mentioned works, the results of this study highlighted in detail the different characteristics and their impact on gas lift efficiency. Also, this study paid attention to traditional methods and new innovative approaches, which gave a new perspective on optimising gas lift processes and increasing productivity in gas condensate fields. In ensuring sustainable and efficient operation of gas condensate fields, the importance of all such studies cannot be overestimated. Detailed studies of gas lift system parameters, the development of new technologies and methods, and the constant striving to optimise production processes are key elements in ensuring ongoing production operations and the sustainable development of the industry as a whole. These studies help reduce costs, increase efficiency, and reduce negative environmental impact, thus contributing to a more efficient and sustainable utilisation of gas condensate resources. The current study employed a steady-state sampling technique, permitting wells to stabilise for a minimum of 24 hours before data collection, providing more precise assessments of initial reservoir pressures and condensate yields. This differs from conventional approaches that frequently neglect stabilisation, resulting in less dependable results. The research utilised sophisticated instrumentation, including PBS-350/64 separators and electronic geophysical equipment (Granit, Sakmar), improving measurement accuracy and enabling comprehensive evaluation of gas dynamics.

The development of differential condensation isotherms from raw condensate analysis yielded an enhanced understanding of the gas condensate system's behaviour, a vital element sometimes overlooked in current research. Moreover, the amalgamation of empirical data with mathematical modelling enabled precise calculation of recovery factors and condensate losses, mitigating problems presented by inadequate experimental apparatus. These methodological advancements facilitated a more refined comprehension of reservoir features and system dynamics, providing critical insights for optimising production methods in gas condensate fields. Further study on gas condensate reservoirs, especially regarding the Altyguyi field, may substantially augment comprehension of reservoir dynamics and refine extraction techniques. An interesting research option is the integration of modern data-collecting techniques, including real-time monitoring systems utilising Internet of Things technology. These systems can deliver continuous data on pressure, temperature, and flow rates, enabling more precise modelling of reservoir behaviour and proactive control of production plans. Furthermore, employing machine learning techniques to examine historical data may reveal trends that enhance forecast models for condensate behaviour across different operational situations.

6. Conclusion

As a result of the extended study of gas condensate deposits, significant data were obtained that reveal the characteristics and features of oil reservoirs in the Altyguyi field. Differential condensation isotherms allowed estimating condensate content in formation gas for three wells: for well No. 2 (III) – 69.5 g/m³, for well No. 1 (II) – 95.2 g/m³, and well No. 5 (I) – 96.5 g/m³. The predicted condensate content in 1 m³ of reservoir gas for reservoir HK7d is estimated at 80.5 g/m³, and for reservoir HK8, 95.2 g/m³. The study also showed that the oil in the Altyguyi field has a specific gravity of 0.91 g/cm³ and contains a significant amount of paraffin, which reduces well productivity. For the strata HK7g and HK8, the expected condensate yields were 95 cm³/t and 118 cm³/t. The most notable decrease in reservoir pressure is observed in wells No. 2 and No. 1: from initial values of 470 kgf/cm² and 435 kgf/cm², it decreased to 230 kgf/cm² and 220 kgf/cm² by 2021.

A gas lift is the most effective to ensure stable production at gas condensate fields, especially for wells with flow rates of more than 30 tonnes/day. The study found that a comprehensive assessment is required to fully understand oil fields, including the lithological section, gas-oil-water-bearing contacts, rock characteristics, production parameters, and physical and chemical properties of produced water. This approach aims to identify critical parameters that affect the field's production potential. This can provide an opportunity to optimise production processes and improve project economics, ensuring production sustainability throughout the life of the field. It should be noted that this study was conducted in the Altyguyi field, and the results may not be generalisable to other geological contexts.

In addition, it should be recognised that mining conditions and field characteristics may change over time, requiring ongoing monitoring and additional studies to confirm the results obtained. More in-depth analyses of the impact of different technological solutions on production efficiency are recommended for further research in this area. It is also important to investigate the impact of changing conditions on field operations to optimise production strategies and maximise resource efficiency.

References

[1] Serhii Ovetskyi, and Yaroslav Yakymechko, "Study of Capillary Injection of Chemicals into Productive Formations to Increase Well Production," *Prospecting and Development of Oil and Gas Fields*, vol. 23, no. 3, pp. 15-23, 2023. [Google Scholar] [Publisher Link]

[2] Denys Panevnyk, "Study of Hydraulic Characteristics of Jet Device for Preventing Emissions of Low-Pressure Petroleum Gas," *Ecological Safety and Balanced Use of Resources*, vol. 14, no. 1, pp. 43-53, 2023. [Google Scholar] [Publisher Link]

[3] Md Aminul Islam et al., "Three-Dimensional Structural and Petrophysical Modeling for Reservoir Characterization of the Mangahewa formation, Pohokura Gas-Condensate Field, Taranaki Basin, New Zealand," *Natural Resources Research*, vol. 30, pp. 371-394, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[4] Barzan I. Ahmed, and Mohammed S. Al-Jawad, "Geomechanical Modelling and Two-Way Coupling Simulation for Carbonate Gas Reservoir," *Journal of Petroleum Exploration and Production Technology*, vol. 10, no. 8, pp. 3619-3648, 2020. [CrossRef] [Google Scholar] [Publisher Link]

[5] Shang Xu et al., "Shale Pore Structure Characteristics of The High and Low Productivity Wells, Jiaoshiba Shale Gas Field, Sichuan Basin, China: Dominated by Lithofacies or Preservation Condition?," *Marine and Petroleum Geology*, vol. 114, 2020. [CrossRef] [Google Scholar] [Publisher Link]

[6] Rymgali Kamarov et al., "Setting the Volume and Location of The Gas Collectors of Abandoned Coal Mines," *Naukovyi Visnyk Natsionalnoho Hirnychoho Universytetu*, vol. 2018, no. 2, pp. 5-11, 2018. [Google Scholar] [Publisher Link]

[7] Akif Alizadeh et al., "Oil and Gas Content of the Productive Series and Analysis of Geological-Prospecting Efficiency," *Pliocene Hydrocarbon Sedimentary Series of Azerbaijan*, pp. 315-320, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[8] Shi-zhen Li et al., "Distribution Characteristics, Exploration and Development, Geological Theories Research Progress and Exploration Directions of Shale Gas in China," *China Geology*, vol. 5, no. 1, pp. 110-135, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[9] Dongfeng Hu et al., "Discovery of Carbonate Source Rock Gas Reservoir and Its Petroleum Geological Implications: A Case Study of The Gas Reservoir in The First Member of Middle Permian Maokou Formation in The Fuling Area, Sichuan Basin," *Natural Gas Industry B*, vol. 8, no. 1, pp. 13-23, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[10] Michelle R. Brann et al., "Differential Condensation of Methane Isotopologues Leading to Isotopic Enrichment under Non-equilibrium Gas-Surface Collision Conditions," *The Journal of Physical Chemistry A*, vol. 125, no. 42, pp. 9405-9413, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[11] Tatiane Souza Rodrigues Pereira et al., "Hydrodynamic Modeling for Flow and Velocity Estimation from an Arduino Ultrasonic Sensor" *Hydrology*, vol. 11, no. 2, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[12] Olksii Udovchenko, Jacek Blicharski, and Liliia Matiishyn, "A Case Study of Gas-Condensate Reservoir Performance with Gas Cycling," *Archives of Mining Sciences*, vol. 69, no. 1, pp. 25-49, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[13] Kai Zhu, Lingjie Gao, and Fengrui Sun, "Numerical Simulation Study on Optimization of Development Parameters of Condensate Gas Reservoirs," *Processes*, vol. 12, no. 10, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[14] E. S. Oringojin, and Gulnaz J. Moldabayeva, "Foundations of Chemical Recovery of Metals from Leaching Solutions Through Electrical Action," *International Journal of Chemical Sciences*, vol. 10, no. 2, pp. 751-767, 2012. [Google Scholar] [Publisher Link]

[15] Samir Muzaffarov, "*Comparative Analysis of Effectiveness in Implementation of Natural Drive and Artificial Lift Methods for Hydrocarbon Production*," Master Thesis, Khazar University, 2022. [Google Scholar] [Publisher Link]

[16] Sara Zolghadri, and Mohammad Reza Rahimpour, "Natural Gas from Oil Production: Gas-Lift Technologies," *Advances in Natural Gas: Formation, Processing, and Applications Volume: 1: Natural Gas Formation and Extraction*, pp. 169-187, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[17] Tarek A. Ganat et al., "Develop Optimum Gas Lift Methods to Improve Gas Lift Efficiency Using Gas Lift Pack-Off, Deep Gas Lift, And Deep Lift Set," *International Journal of Advanced Research in Engineering and Technology*, vol. 11, no. 11, pp. 1096-1114, 2020. [Google Scholar] [Publisher Link]

[18] Yang Yang et al., "A New Model Simulating the Development of Gas Condensate Reservoirs," *Energy Geoscience*, vol. 5, no. 1, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[19] Galyna Puchkovska et al., "About the Nature of Phase Transition in Pure N-Paraffin Crystals," *Journal of Molecular Structure*, vol. 704, no. 1-3, pp. 119-123, 2004. [CrossRef] [Google Scholar] [Publisher Link]

[20] Jamilyam Ismailova et al., "Development and Application of Fluid Characterization Algorithms to Obtain an Accurate Description of a PVT Model for Kazakhstani Oil," *Eastern-European Journal of Enterprise Technologies*, vol. 5, no. 6 (125), pp. 6-20, 2023. [CrossRef] [Google Scholar] [Publisher Link]

[21] Mariia D. Serediuk, "Peculiarities of The Operation of The Oil Pipeline in The Process of Its Cleaning from Paraffin Deposition," *Journal of Achievements in Materials and Manufacturing Engineering*, vol. 106, no. 2, pp. 77-85, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[22] Dmytro Tymkiv et al., "Forced Oscillations of An Oil Pipeline at An Overhead Crossing During Sequential Pumping of Various Oil Products," *Prospecting and Development of Oil and Gas Fields*, vol. 24, no. 1, pp. 32-43, 2024. [CrossRef] [Publisher Link]

[23] Dongyan Fan et al., "Well Production Forecasting Based on ARIMA-LSTM Model Considering Manual Operations," *Energy*, vol. 220, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[24] Yunpeng Shan et al., "Origin and Characteristics of The Crude Oils and Condensates in The Callovian-Oxfordian Carbonate Reservoirs of The Amu Darya Right Bank Block, Turkmenistan," *Lithosphere*, vol. 1, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[25] Lei Wang et al., "Effect of Pore Size Distribution on Phase Behavior of Sour Gas and Hydrocarbon Mixtures in Tight Oil Reservoirs," *Paper Presented at the SPE Annual Caspian Technical Conference*, Virtual, 2020. [CrossRef] [Google Scholar] [Publisher Link]

[26] Alexander Anisimov et al., "Development and Implementation of Automatic Conversion of Steam-Gas Power Unit from Compound Cycle Mode to Steam-Power Mode Without Shutdown of the Unit," *Power Technology and Engineering*, vol. 51, no. 5, pp. 568-573, 2018. [CrossRef] [Google Scholar] [Publisher Link]

[27] Yury Borisov et al., “Structural Transformations Occurring in Flame-Sprayed Ni60Nb40 Alloy Coatings During Heating in The Presence of Oxygen,” *Soviet Powder Metallurgy and Metal Ceramics*, vol. 26, no. 12, pp. 966-970, 1987. [CrossRef] [Google Scholar] [Publisher Link]
[28] Akper A. Feyzullayev, “Sedimentary-Condensation Model of Formation of Hydrocarbon Fields in The South Caspian Basin,” *Izvestiya, Atmospheric and Oceanic Physics*, vol. 57, no. 10, pp. 1349-1366, 2021. [CrossRef] [Google Scholar] [Publisher Link]
[29] Vasile-Mircea Cristea et al., “Prediction of Oil Sorption Capacity on Carbonized Mixtures of Shungite Using Artificial Neural Networks,” *Processes*, vol. 11, no. 2, pp. 518, 2023. [CrossRef] [Google Scholar] [Publisher Link]
[30] Yury Borisov et al., “Structure and Some Physical Properties of Plasma-Sprayed Coatings of The Nickel Boride Ni3B,” *Soviet Powder Metallurgy and Metal Ceramics*, vol. 25, no. 12, pp. 966-969, 1986. [CrossRef] [Google Scholar] [Publisher Link]
[31] Olga Bliznjuk et al., “Determination of Rational Conditions for Oil Extraction from Oil Hydration Waste,” *Eastern-European Journal of Enterprise Technologies*, vol. 1, no. 6-115, pp. 17-23, 2022. [CrossRef] [Google Scholar] [Publisher Link]
[32] Volodymyr Korzhik et al., “Structural Transformations in Fe-B-C-Si Alloys Vitrified by the Gasothermal Coating Process,” *Russian Metallurgy Metally*, no. 2, pp. 165-168, 1989. [Google Scholar]
[33] Gafar Ismayilov, Elman Iskenderov, and Fidan Ismayilova, “Problems of Hydrodynamic Corrosion in Multiphase Pipelines,” *Protection of Metals and Physical Chemistry of Surfaces*, vol. 57, no. 1, pp. 147-152, 2021. [CrossRef] [Google Scholar] [Publisher Link]
[34] Yevgeny Sanchugov, Anatoly Koval, and Sergey Belikov, “Some Peculiarities of Alloying of Nickel Superalloys Resistant to High-Temperature Corrosion,” *Paper presented at the CORROSION 2012*, Salt Lake City, Utah, vol. 4, pp. 3435-3438, 2012. [Google Scholar] [Publisher Link]
[35] Viktor Trokhaniak, and Valery Gorobets, “Heat Transfer and Gas Dynamics Numerical Modelling of Compact Pipe Bundles of New Design,” *Machinery and Energetics*, vol. 14, no. 3, pp. 79-89, 2023. [CrossRef] [Google Scholar] [Publisher Link]
[36] Oleksandr Spivak et al., “Influence of Geometric Characteristics of The French on Heat Transfer Heat Exchange Surface,” *Modern Technologies, Materials and Structures in Construction*, vol. 21, no. 1, pp. 154-160, 2024. [CrossRef] [Publisher Link]
[37] Festus Mayowa Adebiyi, “Paraffin Wax Precipitation/Deposition and Mitigating Measures in Oil and Gas Industry: A Review,” *Petroleum Science and Technology*, vol. 38, no. 21, pp. 962-971, 2020. [CrossRef] [Google Scholar] [Publisher Link]
[38] Yury Borisov et al., “Structural Characteristics of Flame-Sprayed Fe-Ni-B Alloy Coatings,” *Soviet Powder Metallurgy and Metal Ceramics*, vol. 26, no. 11, pp. 885-888, 1987. [CrossRef] [Google Scholar] [Publisher Link]
[39] Yi Yang et al., “Flow Mechanism of Production Decline During Natural Depletion After Hydraulic Fracturing of Horizontal Wells in Tight Oil Reservoirs,” *Petroleum Science and Technology*, vol. 40, no. 4, pp. 383-400, 2022. [CrossRef] [Google Scholar] [Publisher Link]
[40] Gang Hui et al., “Machine Learning-Based Production Forecast for Shale Gas in Unconventional Reservoirs Via Integration of Geological and Operational Factors,” *Journal of Natural Gas Science and Engineering*, vol. 94, 2021. [CrossRef] [Google Scholar] [Publisher Link]
[41] Clemente Capasso et al., “Data Analytics for Performance Modelling of Photovoltaic Systems in the Internet of Energy Scenario,” *In 2021 IEEE 15th International Conference on Compatibility, Power Electronics and Power Engineering, CPE-POWERENG 2021*, Florence, Italy, 2021. [CrossRef] [Google Scholar] [Publisher Link]
[42] Irina Bandura et al., “Optimisation of Energy Solutions: Alternative Energy, Reactive Power Compensation, and Energy Efficiency Management,” *Machinery & Energetics*, vol. 14, no. 4, pp. 121-130, 2023. [CrossRef] [Google Scholar] [Publisher Link]
[43] Mu Longxin et al., “Technological Progress and Development Directions of Petrochina Overseas Oil and Gas Field Production,” *Petroleum Exploration and Development*, vol. 47, no. 1, pp. 124-133, 2020. [CrossRef] [Google Scholar] [Publisher Link]
[44] Batyr Orazbayev et al., “A Systematic Approach to the Model Development of Reactors and Reforming Furnaces with Fuzziness and Optimization of Operating Modes,” *IEEE Access*, vol. 11, pp. 74980-74996, 2023. [CrossRef] [Google Scholar] [Publisher Link]
[45] Volodymyr N. Korzhik, “Theoretical Analysis of The Conditions Required for Rendering Metallic Alloys Amorphous During Gas-Thermal Spraying. III. Transformations in the Amorphous Layer During the Growth Process of The Coating,” *Soviet Powder Metallurgy and Metal Ceramics*, vol. 31, no. 11, pp. 943-948, 1992. [CrossRef] [Google Scholar] [Publisher Link]
[46] Jean Laherrère, Charles A.S. Hall, and Roger Bentley, “How Much Oil Remains for The World to Produce? Comparing Assessment Methods, And Separating Fact from Fiction,” *Current Research in Environmental Sustainability*, vol. 4, 2022. [CrossRef] [Google Scholar] [Publisher Link]
[47] Vyacheslav A. Chuzlov et al., “Calculation of The Optimal Blending Component Ratio by Using Mathematical Modeling Method,” *Petroleum Science and Technology*, vol. 37, no. 10, pp. 1170-1175, 2019. [CrossRef] [Google Scholar] [Publisher Link]
[48] R. Deepak Selvakumar, Jian Wu, and Ahmed K. Alkaabi, “Electrohydrodynamic Acceleration of Charging Process in A Latent Heat Thermal Energy Storage Module,” *Applied Thermal Engineering*, vol. 242, 2024. [CrossRef] [Google Scholar] [Publisher Link]
[49] Elman K. Iskandarov, Fidan B. Ismayilova, and Zivar I. Farzalizade, “Oil Leaks Diagnosis in Pipelines Based on Artificial Neuron Technologies,” *12th World Conference “Intelligent System for Industrial Automation” (WCIS-2022)*, Springer, Cham, vol. 912, pp. 313-323, 2024. [CrossRef] [Google Scholar] [Publisher Link]
[50] R. Deepak Selvakumar et al., “Role of Dielectric Force and Solid Extraction in Electrohydrodynamic Flow Assisted Melting,” *Journal of Energy Storage*, vol. 73, 2023. [CrossRef] [Google Scholar] [Publisher Link]
[51] Gábor Takács, “A Critical Analysis of Power Conditions in Sucker-Rod Pumping Systems,” *Journal of Petroleum Science and Engineering*, vol. 210, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[52] Clemens Langbauer et al., "Hydraulic Concentric Tubular Pumping System Simulation and Testing," *Journal of Petroleum & Environmental Biotechnology*, vol. 11, no. 5, pp. 1-15, 2021. [Google Scholar] [Publisher Link]

[53] Volodymyr N. Korzhik, "Theoretical Analysis of The Conditions Required for Rendering Metallic Alloys Amorphous During Gas-Thermal Spraying. II. Phase Formation During Solification of The Sprayed Material," *Soviet Powder Metallurgy and Metal Ceramics*, vol. 31, no. 10, pp. 826-830, 1992. [CrossRef] [Google Scholar] [Publisher Link]

[54] Emilia D. Ivanchina et al., "Mathematical Modeling of The Process Catalytic Isomerization of Light Naphtha," *Petroleum and Coal*, vol. 61, no. 2, pp. 413-417, 2019. [Google Scholar] [Publisher Link]

[55] Zhong-xian Hao, Shi-jia Zhu, and Er-Yang Ming, "System Optimization of Submersible Electric Progressing Cavity Pump: Design and Field Application of PCP specially used for Submersible Motor," *Proceedings of the International Field Exploration and Development Conference 2022*, Springer, Singapore, pp. 3010-3017, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[56] Darkhan Artykbaev et al., "Seismic Resistance of Loess Soils," *10th International Annual Conference "Industrial Technologies and Engineering" (ICITE 2023)*, vol. 474, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[57] Karmenova Markhaba et al., "Identification and Characterisation of Earthquake Clusters from Seismic Historical Data," *Indonesian Journal of Electrical Engineering and Computer Science*, vol. 36, no. 3, pp. 1594-1604, 2024. [CrossRef] [Publisher Link]

[58] Volodymyr N. Korzhik, "Theoretical Analysis of Amorphization Conditions for Metallic Alloys Under Gas-Thermal Spraying. III. Transformations in the Amorphized Alloy Under Building-Up of Coatings," *Powder Metallurgy*, no. 11, pp. 47-52, 1992. [Google Scholar]

[59] Yong Tang et al., "Change of Phase State During Multi-Cycle Injection and Production Process of Condensate Gas Reservoir Based Underground Gas Storage," *Petroleum Exploration and Development*, vol. 48, no. 2, pp. 395-406, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[60] Youyou Cheng et al., "Links of Hydrogen Sulfide Content with Fluid Components and Physical Properties of Carbonate Gas Reservoirs: A Case Study of the Right Bank of Amu Darya, Turkmenistan," *Frontiers in Earth Science*, vol. 10, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[61] Youyou Cheng et al., "Water Producing Mechanisms of Carbonate Reservoirs Gas Wells: A Case Study of The Right Bank Field of Amu Darya, Turkmenistan," *Petroleum Exploration and Development*, vol. 44, no, 1, pp. 89-96, 2017. [CrossRef] [Google Scholar] [Publisher Link]

[62] Aleksandr Li et al., "Phase Characteristics Modeling of Reservoir Gas-Condensate Mixture of Tegermen Group of Fields," *5th International Conference on Energetics, Civil and Agricultural Engineering (ICECAE 2024)*, vol. 497, 2024. [CrossRef] [Google Scholar] [Publisher Link]

[63] Palash Panja, Raul Velasco, and Milind Deo, "Understanding and Modeling of Gas-Condensate Flow in Porous Media," *Advances in Geo-Energy Research*, vol. 4, no. 2, pp. 173-186, 2020. [CrossRef] [Google Scholar] [Publisher Link]

[64] Angang Zhang, Zifei Fan, and Lun Zhao, "An Investigation on Phase Behaviors and Displacement Mechanisms of Gas Injection in Gas Condensate Reservoir," *Fuel*, vol. 268, 2020. [CrossRef] [Google Scholar] [Publisher Link]

[65] X.U. Yingjie et al., "Research on Potential Productivity Exploitation in The Middle and Late Stage of Condensate Gas Reservoir with Water in Anyue Formation," *Drilling & Production Technology*, vol. 46, no. 1, 2023. [Google Scholar]

[66] Abouzar Rajabi Behesht Abad et al., "Robust Hybrid Machine Learning Algorithms for Gas Flow Rates Prediction Through Wellhead Chokes in Gas Condensate Fields," *Fuel*, vol. 308, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[67] Redha Al Dhaif, Ahmed Farid Ibrahim, and Salaheldin Elkatatny, "Prediction of Surface Oil Rates for Volatile Oil and Gas Condensate Reservoirs Using Artificial Intelligence Techniques," *Journal of Energy Resources Technology*, vol. 144, no. 3, 2022. [CrossRef] [Google Scholar] [Publisher Link]

[68] Serhii Matkivskyi, and Liliia Khaidarova, "Increasing the Productivity of Gas Wells in Conditions of High-Water Factors," *Paper presented at the SPE Eastern Europe Subsurface Conference*, Kyiv, Ukraine, 2021. [CrossRef] [Google Scholar] [Publisher Link]

[69] Temoor Muther et al., "Unconventional Hydrocarbon Resources: Geological Statistics, Petrophysical Characterization, And Field Development Strategies," *Journal of Petroleum Exploration and Production Technology*, vol. 12, no. 6, pp. 1463-1488, 2022. [CrossRef] [Google Scholar] [Publisher Link]