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A CASE STUDY OF GAS-CONDENSATE RESERVOIR PERFORMANCE WITH GAS CYCLING

The study examines the application of dry gas injection technology (cycling process) in different depletion stages (25%, 50%, 75%, 100% of the initial reservoir pressure, and the dew point pressure) at a gas condensate field. The injection took place with varying numbers of injection wells relative to production wells (4:1, 3:1, 2:1, 1:1, and 1:2). The study assessed the impact of dry gas injection periods, ranging from 1 to 3 years, on increasing the condensate recovery factor in a real gas condensate reservoir named X. A hydrodynamic model was used and calibrated with historical data, resulting in a comprehensive approach. Compared to the traditional depletion development method, this approach led to a significant 9% rise in the condensate recovery factor. The results indicate that injection has a positive effect on enhancing the recovery factor of condensate and gas when compared to primary development methods based on depletion. As a result, these findings facilitate a rapid evaluation of the possibility of introducing similar measures in gas-condensate reservoirs in the future for reservoir systems that have a low and moderate potential for liquid hydrocarbons C₅₊. The optimised multidimensional hydrodynamic calculations, utilising geological and technological models, are crucial in determining the parameters for the technological production and injection wells.

Keywords: Gas condensate field; reservoir pressure; injection well; dry gas; recovery factor; development; gas cycling

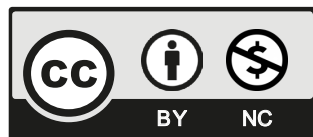
1. Introduction

One of the main challenges in developing gas condensate fields is increasing condensate recovery. As gas condensate fields are being depleted, the reservoir pressure drops below the dew point and heavier hydrocarbons (condensate) retrogradely condensate (Fig. 1). Some of which

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fall out into the liquid phase and are lost in the reservoir. This is due to the immobility of the condensate deposited in the porous rock and its inability to participate in the filtration process [1].

The effectiveness of gas and gas condensate field development depends on the extent of hydrocarbon retrieval from the reservoirs [2]. Additionally, condensate retrieval is limited to a maximum of 30-60%. Utilising the natural depletion method in domestic practices fails to yield optimal hydrocarbon recovery factors. On average, gas recovery in gas fields is limited to 85-90%, while gas condensate fields achieve 75-85% [1-2].

The substantial difference in gas and condensate recovery coefficients can be attributed to the complex geological conditions found in gas condensate fields, as well as the thermodynamic properties of gas condensate [3]. The anomalous behaviour exhibited in its two-phase region accounts for these peculiarities. The development of gas condensate fields has revealed that retrograde condensate saturation in the vicinity of wellbores is a key factor contributing to the lower productivity of production wells [4]. The accumulation of condensate in the porous productive formation within the well zone (known as a condensate plug) reduces the gas permeability of the formation and hinders the escape of the gas phase, while valuable hydrocarbon components remain in the liquid phase.

In the retrograde condensation (or retrograde evaporation) region (Fig. 1), at an isothermal pressure drop (or isobaric temperature drop), the amount of liquid or gas phase formed in the system increases up to its maximum value. Further decreasing pressure or temperature results in a decrease in the volume of the liquid or gas equilibrium phase. At a specific pressure or temperature, the liquid or gas phase disappears, and the multi-component system transitions back to a single-phase gaseous or liquid state.

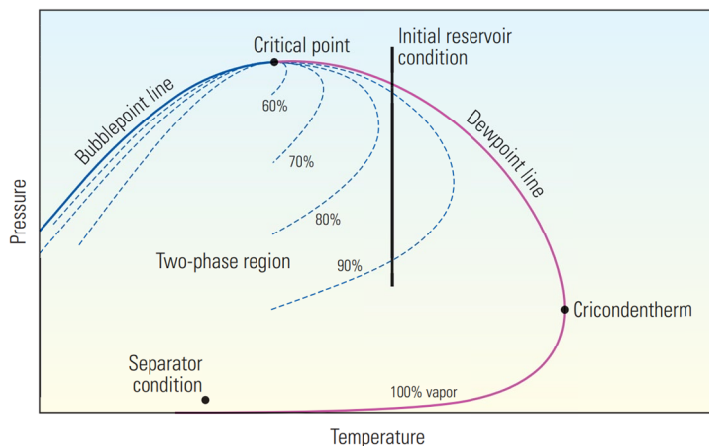


Fig. 1. Phase diagram of a typical gas-condensate system [5]

The results of laboratory, analytical, and industrial studies indicate that retrograde condensation of a hydrocarbon mixture has adverse effects on almost all technological processes used in gas and condensate production [6-7]. This results in various consequences.

Firstly, as previously mentioned, both condensate and gas recovery rates decrease as the pressure drops below the dew point.

Secondly, the permeability of the porous medium for gas decreases due to the condensation of heavy hydrocarbons, thereby causing its significant recovery reduction. The impact of hydrocarbon mixture retrograde condensation on the gas phase permeability change increases with higher initial condensate concentration and lower rock absolute permeability. The greatest decrease in gas phase permeability occurs in the vicinity of wellbores, where the porous medium saturation level with condensate is at its peak.

Thirdly, the wells' production characteristics deteriorate, and their production capacity decreases. The gas flow rate decreases due to a decrease in the phase permeability for gas caused by condensate precipitation in the formation and the loss of some of the pressure to move the moving part of the condensate.

Additionally, condensate accumulation in well plumes creates resistance to gas movement, affecting the operating conditions of the gas collection system. This results in increased pressures at wellheads and decreased gas flow rates, sometimes leading to well shutdowns. Meanwhile, the inlet pressure to the gas treatment unit decreases, reducing the efficiency of gas throttling. The gas treatment quality at low-temperature separation units worsens due to the gradual loss of the throttling effect, as well as the alteration of the initial state of the gas condensate mixture caused by the settling of heavy hydrocarbons in the reservoir.

Given the above, the global practice has necessitated the creation of specialised systems for developing fields dealing with retrograde condensation issues. By adhering to specific guidelines and methods in developing such fields, the negative impact of condensation on gas and condensate reservoir parameters can be avoided.

The primary objectives for increasing the condensate recovery factor in gas condensate fields undergoing depletion are to ensure stable production well operation and utilise reservoir pressure maintenance techniques if the gas contains more than $250 \text{ cm}^3/\text{m}^3$ of condensate and gas reserves exceed 8 billion sm^3 . Conversely, if the condensate content is less than $23 \text{ cm}^3/\text{sm}^3$, and there are gas consumers, gas reinjection is deemed unprofitable [8].

The cycling process allows efficient recovery of condensate that settles out in the reservoir [9-10]. However, this method has only been utilised in Ukrainian fields at Novotroitske (K-30 field), Kotelevske (C-5 reservoir), Timofeevskoe (FM-1), Kulychykhynske (FM-1), and Berezivske (C-5) fields.

The cycling process has been implemented at various gas condensate fields worldwide, including Kaybob, the largest field in Canada, since 1968. Additionally, it has been applied at the deep-seated Carter-Knox field in Oklahoma [11-12], the Arab D reservoir of the Dukhan field in Qatar, within the Permian-Triassic Khuff horizon [13], La Gloria in Texas [11], and Cotton Valley in Louisiana [14].

The primary concept of utilising dry gas is its capacity to vaporise condensed liquid fractions, which can be separated and reused for further injection. The study of process efficiency and injection rim size is frequently conducted on bulk core samples, PVT units, or compositional modelling [14-15].

Gerard Massona examined the effects of geological uncertainties on extra condensate output resulting from the potential introduction of the cycling process during the phase with only two appraisal wells in the field [16]. He asserts that the effectiveness of the cycling process is dependent on the heterogeneity of the deposits, and increased heterogeneity yields decreased additional condensate production.

For a significant period, there have been discussions regarding the methods employed in the geological modelling of hydrocarbon deposits and their reserve estimations [17].

The cycling process in gas condensate field development is limited by economic and technological factors. Compared to developing depletion fields, implementing the cycling process requires significant capital expenditures and gas reserve conservation for re-injection into the reservoir, resulting in delayed sales. From a technological standpoint, the cycling process is limited by the low squeeze coverage ratio. Dry gas injected into the reservoir has lower viscosity compared to the gas condensate mixture extracted from the reservoir. In heterogeneous reservoir conditions, this results in rapid breakthroughs from injection to production wells, leading to a decreased condensate recovery factor.

An alternative approach to enhance the efficacy of developing gas condensate reservoirs is the implementation of the waterflooding process [18-19]. However, rock heterogeneity and fracturing can affect the efficiency of waterflooding, just like in the cycling process. Therefore, it is crucial to consider these factors when designing the process [20].

Thus, despite both positive and negative aspects, the suggested methods for boosting hydrocarbon recovery in gas condensate deposits have a high potential for practical application in Ukrainian gas condensate fields. The practice of injecting multiple components into gas condensate reservoirs to extract liquid condensate is not novel, yet still disputed. On one hand, it is appealing due to its relatively simple implementation. On the other hand, its high implementation costs and potential for gas loss in the reservoir are concerning.

2. Materials and methods

2.1. Field Geology

The prototype reservoir used for the study represents a generic reservoir in the central part of Ukraine (Fig. 2).



Fig. 2. Field location on the map of Ukraine

From a perspective of orohydrography, the deposit zone comprises a hilly plain intersected by a limited gully and ravine network. The hydrographic network is composed of small rivers,

namely Orel and Berestova, with associated tributaries. The ground slopes generally from north-east to southwest. At the watersheds, absolute elevations range from +139-+196 m, whereas in the valleys, they are up to +117 m and below.

The map in Fig. 3 displays the field's structure, which forms an asymmetric northwest fold. The dome is situated in the area surrounding well 27. The area at the base of the -3200 m isohypsis measures 4×3.5 km, and the uplift's magnitude is between 300-320 m.

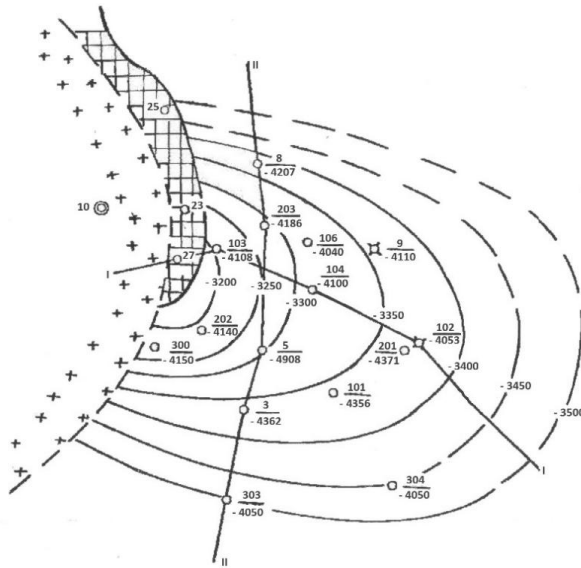


Fig. 3. The structural map of the studied field

The object of study was put into development at the end of the 20th century. Natural gas reserves amount to about 10 billion standard cubic metres and condensate approximately 6 million cubic metres. The field is characterised by a relatively uncomplicated geological structure and fairly good petrophysical properties. At the field, the porosity is in the range 0.11-0.14, the permeability is 10 mD, and the gas saturation coefficient ranges from 0.85 to 0.9. The deposits of this horizon are represented by a thickness typical for the region of 760 m. The thickness of the productive layers reaches 18-25.2 m. The deposit is massive-stratified with a single GWC (Gas-Water Contact) at the absolute depth -3885 m and is limited to the west by a salt stock [21].

2.2. Field development

During field development, the number of production wells increased gradually.

Between 1971 and 1982, a total of 17 wells were drilled at the field: 14 for exploration and 3 for production. Out of these, 7 wells (1, 3, 5, 8, 101, 102, 106) were put into development, and 10 wells (2, 4, 6, 7, 9, 10, 15, 50, 51, 52) were abandoned. Among the 10 abandoned wells, 8 were due to geological reasons and 2 (4, 9) were due to technical reasons. Between 1982 and 1987, 5 additional wells were developed, consisting of 2 production wells (103, 104) and 3

exploration wells (23, 25, 27). During the development phase in 1988, 2 wells (1, 102) were abandoned. Both wells failed during the workover due to crushed production strings and tubing. From 2000 to 2012, the company drilled 6 additional wells: 3 for production (201, 202, 203) and 3 for exploration (300, 303, 304).

As of January 1, 2012, the field was developed by 16 production wells (3, 5, 8, 23, 25, 27, 101, 103, 104, 106, 201, 202, 203, 300, 303, 304).

The field's maximum gas extraction of 448.8 million sm^3 was recorded in 1973. In the following years, the gas field underwent development with a decreasing production and a constant number of wells, totaling 7 units until 1983. Afterwards, production declined and stabilised during the period under review, attributed to the introduction of new wells and a higher exploitation rate.

TABLE 1 displays the schedule of wells connected to the development.

TABLE 1

Events in the wells operation

Date	The event	Total number of wells	Date	The event	Total number of wells
1971	Start of field development by wells 1 and 8	2	1987	+ well 104	12
1972	+ well 3	3	1988	Abandonment of wells 1 and 102 was necessary due to geological disturbance	10
1973	+ well 5	4	2001	+ well 201	11
1975	+ well 23	5	2002	+ well 202	12
1976	+ well 25	6	2004	Well 106 for workover + well 203	12
1977	+ well 27	7	2006	+ well 300	13
1978	+ well 101	8	2007	Well 106 coming out of workovers	14
1980	+ well 102	9	2008	+ well 303	15
1982	+ well 103	10	2010	+ well 304	16
1984	+ well 106	11	2011	Well 106 for workover	15

There were no complications during the operation of the wells, and no stimulation works were performed.

TABLE 1 shows the key milestones in the development history of the field. Short-term repairs, spanning several days to months, were not featured in the table but were considered and replicated in the hydrodynamic model construction process. The main indicators of the development of the study field for the last reporting period are shown in TABLE 2.

As of 01.12.2012, the field was in the stage of active development, the gas recovery factor was 64%, whereas condensate recovery 46%.

2.3. Reservoir fluids

The primary component of hydrocarbon gases in the reservoir mixture is methane, accounting for over 80-85%. The remaining components represent a maximum of 15-20%. Nitrogen,

TABLE 2

Parameters of field X development over the last 10 years

Years	Cumulative gas production, mln m^3	Cumulative condensate production, th tons	Annual gas production, mln m^3	Flow rate, th m^3/d	Reservoir pressure, MPa	Bottomhole pressure, MPa	Outlet pressure, MPa	Drawdown pressure, MPa	Number of wells, pcs.	Gas water ratio, cm^3/m^3
2002	4678	78.47	59	14.2	15.43	11.77	7.9	3.66	11	2.9
2003	4743	79.08	66	14.5	15.42	12.50	7.9	2.92	12	3.3
2004	4806	79.90	63	12.9	14.94	12.00	8.1	2.94	13	3.1
2005	4872	80.66	66	11.9	14.82	11.88	7.9	2.94	13	2.6
2006	4955	81.53	83	14.9	15.75	11.64	7.85	4.11	15	3.1
2007	5057	82.32	102	18.4	15.16	11.61	7.85	3.55	16	3.1
2008	5162	83.18	104	18.8	16.47	11.23	7.85	5.24	16	3.3
2009	5258	83.83	96	17.4	16.03	11.12	7.83	4.91	16	3.2
2010	5371	84.43	113	18.1	14.99	10.53	7.8	4.46	16	3.6
2011	5480	85.05	109	17.5	14.70	9.72	7.78	4.98	16	4.1

hydrogen, hydrogen sulfide, carbon dioxide, and inert gases (such as helium and argon) may be present as impurities in the hydrocarbon gases.

TABLE 3 shows the detailed component composition of the produced gas obtained from one of the well tests.

TABLE 3

Compositional analysis of simulated reservoir gas

Hydrocarbon component	Mole fraction, %
N_2	0.398
CO_2	2.417
C_1	79.808
C_2	10.795
C_3	3.501
IC_4	0.604
NC_4	0.614
C_{5+}	1.863

3. Geological and hydrodynamic gas-condensate field model

3.1. Geological model

The first step in developing a geological model of the field involved creating a structural map of the reservoir cap and locating producing wells. The outcomes of these actions are depicted in Fig. 4 within the PETREL software environment of Schlumberger.

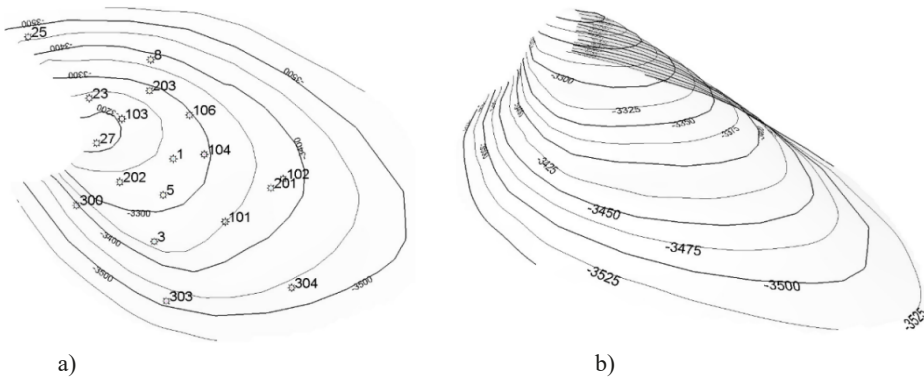


Fig. 4. The structural map of the studied field in 2D (a) and 3D (b) formats

The next step was to create a structural framework for the field model. The bottom surface of the pay zone was replicated with reference to the top surface, taking into account the average thickness of the pay zone. However, this could cause inaccuracies in the field model, so all values were adjusted to meet similarity criteria.

A cell size of 50×50 metres was deemed appropriate for the study. The reservoir was divided into seven layers of varying thicknesses between 1 and 2 metres in the vertical direction, as shown in Fig. 5

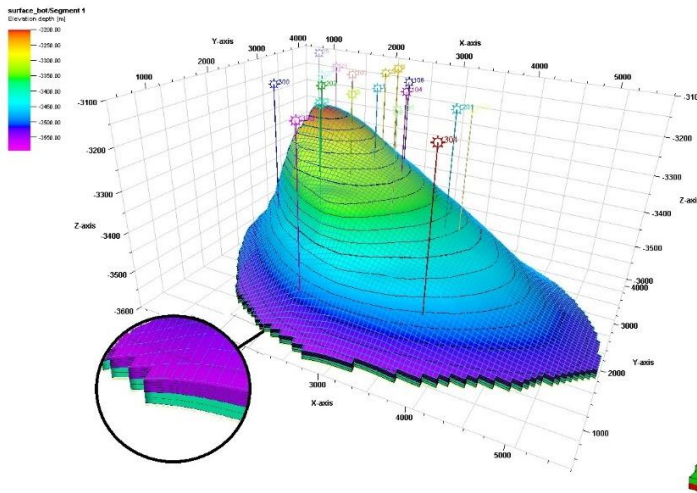


Fig. 5. 3D field grid and the division of the productive layer thickness into interlayers

3.2. Petrophysical filed X model

The petrophysical modeling was conducted without undergoing data analysis, yet the data were still automatically adjusted to conform to a normal distribution. Meeting the criteria of the

GSLIB Sequential Gaussian Simulation algorithm necessitates fulfilling the standard normal distribution prerequisite. Thus, the data were converted accordingly.

From Fig. 6, it can be observed that porosity is almost normally distributed with a spatial trend. Detecting this trend through transformation helps to model and apply the properties again to the modeling result. The trend and corresponding distribution were saved in the resulting model.

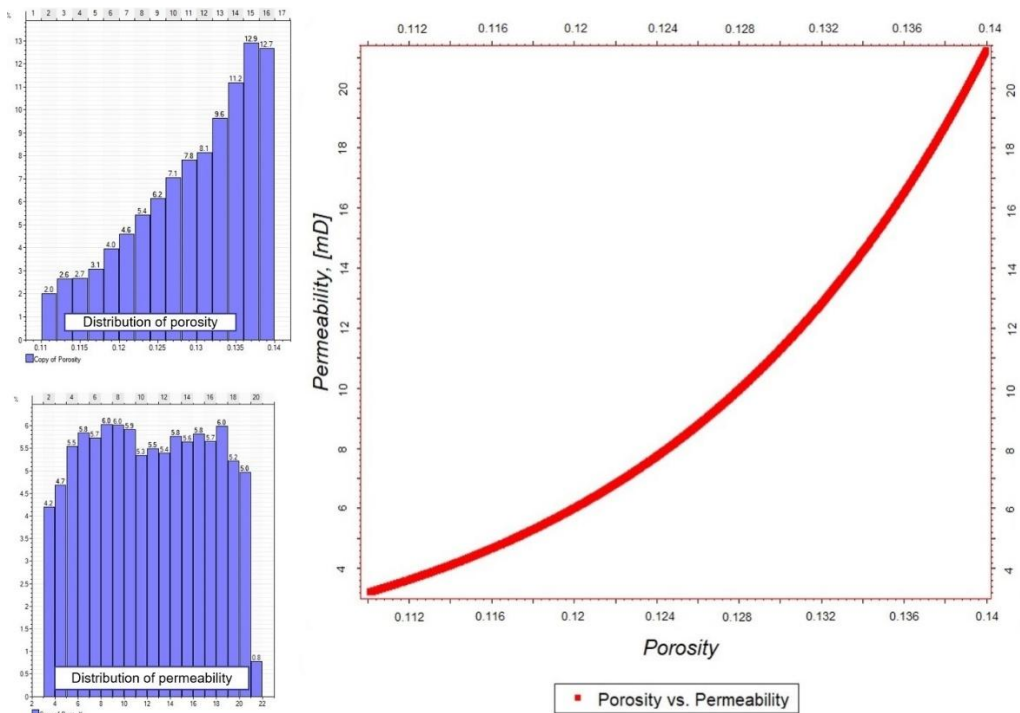


Fig. 6. Distribution the porosity and permeability randomly across the reservoir using the Gaussian method

To calculate the relative phase permeabilities, the “Make rock physics functions” module of the Petrel software complex was used. Relative permeability curves were created based on Corey correlations for sandstone formation [22].

Laboratory data on the relative phase permeabilities obtained from core samples were not available. Therefore, the module “Make rock physics functions” of the Petrel software package was used for calculations as a first approximation. The empirical dependencies characteristic of sandstone were used. The Corey correlations were used as a basis and subsequently adjusted in accordance with the petrophysical properties of the reservoir.

Fig. 7 shows the graphs of relative phase permeabilities that were used to build a hydrodynamic model of the field X.

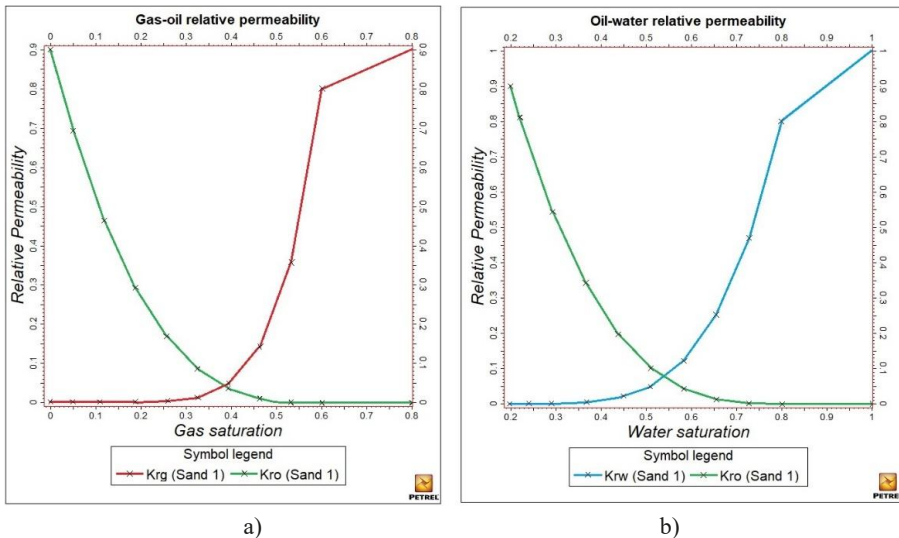


Fig. 7. Phase relative permeabilities of the water-gas-condensate systems (a) gas – condensate system, (b) condensate – water system

3.3. PVT model

To build a PVT model, first of all, it was necessary to create a component-fractional composition of the reservoir hydrocarbon system. For this, it was necessary to know the component composition of separation, degassing, debutanisation gases and the results of fractional distillation of stable condensate.

According to available geological and industrial data, the component composition of reservoir gas was known only for normal and iso-butane. The rest of the components are characterised as the C_{5+} fraction (TABLE 3).

In order to obtain a representative composition of reservoir gas, a PVTi software application of the Schlumberger Simulation Launcher software complex was used. Using this software, it was possible to obtain the component composition of reservoir gas up to a certain number of fractions (from 5 to 11) with known molecular weights of each of them.

Proceeding from the lack of data on differential condensation experiments, a comparison of the pressure at the beginning of condensation, which was obtained during the implementation of the differential condensation experiment, with the calculated value obtained from the equation of state for the initial critical parameters of the components were carried out.

As a result of PVTi modelling, the C_{5+} fraction was divided into 5 components, the molar fractions of which are shown in TABLE 4.

According to the results of the experiment setting, the dynamics of the potential content of C_{5+} hydrocarbons in the formation gas was calculated as a function of reservoir pressure (Fig. 8).

According to the created PVT model, the estimated dew point pressure is 35 MPa.

The phase envelope diagram of the PVTi reservoir fluid model is shown on Fig. 9.

TABLE 4

Composition of the C₅₊ fraction

FRC ₁	0.635
FRC ₂	0.786
FRC ₃	0.366
FRC ₄	0.072
FRC ₅	0.004

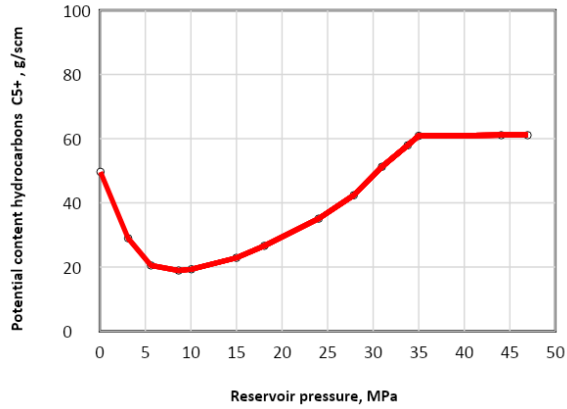


Fig. 8. Change in the content of HC C₅₊ in the gaseous phase with a decrease in pressure

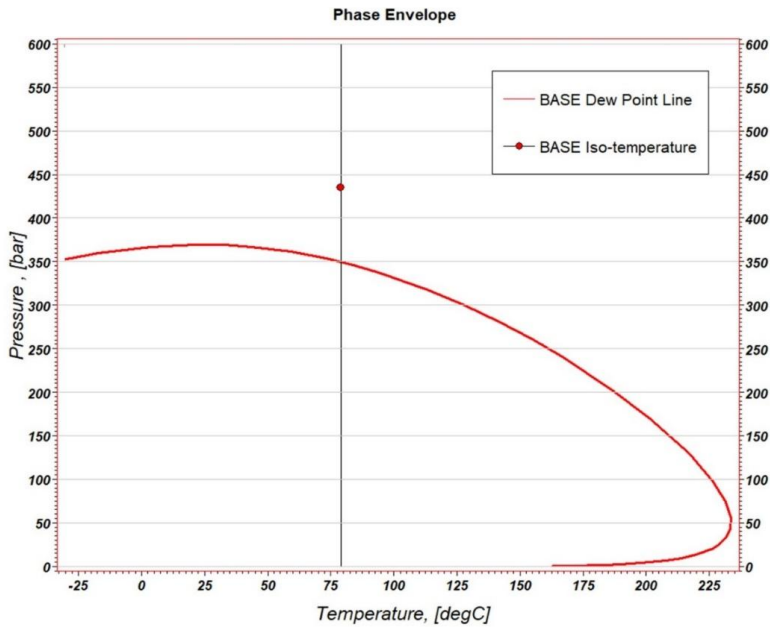


Fig. 9. Calculated phase diagram of reservoir gas-condensate system

3.4. History matching

The reservoir development history was calibrated to meet all requirements and incorporated the replication of all measures taken for the wells. Underground well equipment's technological aspects were considered, and vertical flow performance (VFP) tables were computed and formed to conform to the downhole pressures.

In global practice, a discrepancy between modelled and actual data of 5% or less is deemed acceptable. For most wells, the field adaptation results have a discrepancy of 1-3%, with a maximum deviation of 7% in wells with inadequate historical data input. Fig. 10 illustrates the primary

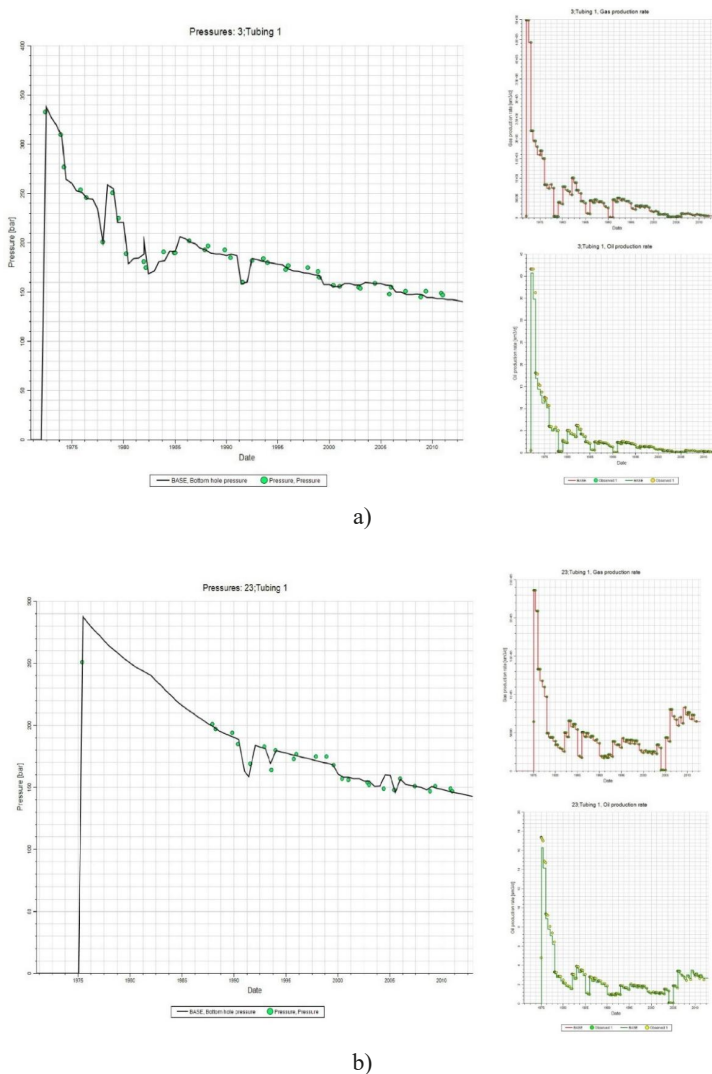


Fig. 10. Historical and calculated values of gas, condensate rates and bottom-hole pressure for the wells 3 (a); 23 (b)

indicators used for calibration, which include bottomhole pressure, gas flow rate, and condensate flow rate. Wells 3 and 23 were used as an example. Data comparison for other wells was similar.

Slight variations in downhole pressure calibration are present due to the impossibility of replicating all geological features accurately. Discrepancies between the modelled and historical values for condensate flow rate occur due to inaccuracies in the PVT model. However, all deviations remain within acceptable boundaries, and the adaptation can be considered successful.

4. Simulation and results

The simulation was conducted for two primary scenarios: the base scenario, which involved the field's normal depletion, and the investigation scenario with reservoir pressure maintenance through dry gas injection. In both scenarios, it was assumed that the deposit would be exploited for the next 30 years.

The base scenario assumes further reservoir exploitation to a normal field depletion. In the investigation scenario, a two-stage forecast of field development was implemented to increase the condensate recovery factor via reservoir pressure maintenance utilising a gas cycling process.

The following topics have been the subject of in-depth research during the course of the project:

- best moment for dry gas injection into a gas condensate reservoir;
- optimal period of reservoir pressure maintenance using the cycling process;
- placement of dry gas injection wells;
- number of injection wells.

4.1. Base scenario forecast

A base scenario has been incorporated to forecast future development parameters for reservoir energy depletion mode. In current industry practices, the forecast is grounded on continuing the field's development with the existing well stock and the parameters disclosed in the last reporting period [23-25].

Field development has been ongoing since 2012 with 16 production wells, utilising the Petrel & Eclipse software package. The wells undergo limit control monitoring using the minimum downhole pressure, which was settled individually for each well. The well shutdown control was activated when the gas flow rate fell below 500-1000 m³/day or the liquid content exceeded 100 cm³/m³ in the production output. The forecast was limited to a maximum of 30 years, starting from 2012 to 2041. TABLE 5 shows the main technological indicators at the end of the forecast period (2041).

Fig. 11 shows the dynamics of the main indicators in the development scenario of the field X in the period 1971-2041. On the left-hand side of the yellow line is the historical period (1971-2012), and to the right is the forecast (2012-2041).

The charts presented (Fig. 11) unveil a detailed overview of the gas field development with associated condensate extraction. Initially, during the intense exploitation of the reservoir, there was a sharp decline in the production rates of both gas and condensate. This decline directly correlates with a consistent decrease in reservoir pressure. As a result, when the reservoir pressure drops below the dew point, condensate starts to actively accumulate within the reservoir, as evidenced by the changing gas-to-condensate ratio.

Final indicators of field X development for BASE scenario)

Name of scenario	Base
Cumulative gas production, mln sm^3	7067.55
Gas production rate, thousand sm^3/day	125.38
Cumulative condensate production, thousand m^3	305.34
Condensate production rate, m^3/day	2.80
Final reservoir pressure, MPa	8.93
Gas recovery factor, %	77.54
Condensate recovery factor, %	50.65

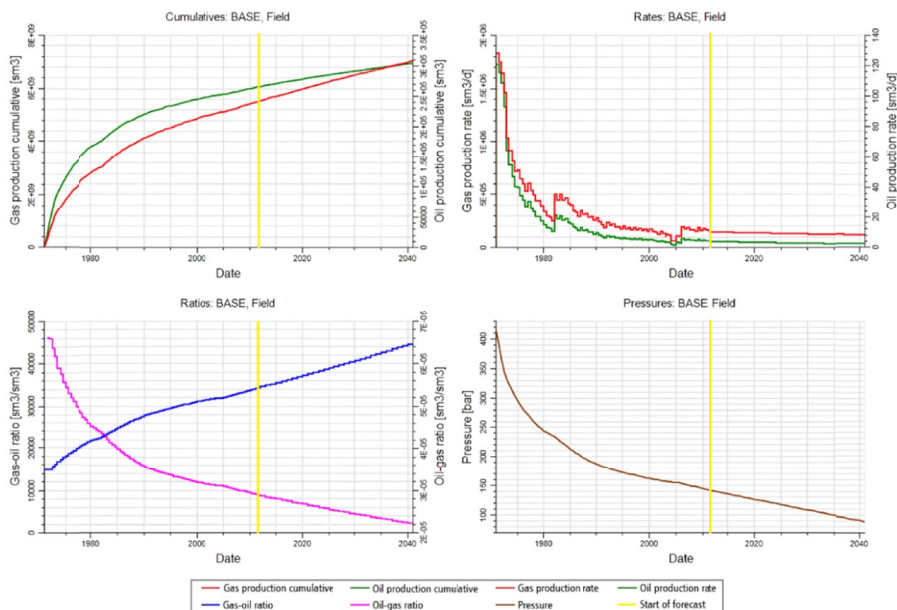


Fig. 11. Dynamics of oil/gas cumulative; oil/gas rates; reservoir pressure and oil-gas/gas-oil ratios for BASE scenario of field development

This trend is further validated when looking at the projected values from TABLE 5. By the end of 2041, the cumulative gas production is forecasted to reach 7067.55 mln sm^3 , while the cumulative condensate production is anticipated at 305.34 thousand m^3 . Such figures, alongside a final reserved pressure of 8.93 MPa, highlight the reservoir's vast potential and the challenges faced during its exploitation.

Over time, even with the introduction of new wells to compensate for the production drop, a similar trend persists, albeit with less intensity. The decline rates in production become less pronounced, and the decrease in reservoir pressure decelerates, indicating a stabilisation in the development process.

Delving deeper into Fig. 11, post the initial intensive development of gas field X, the extraction process reveals its lessened efficiency, largely attributed to the waning reservoir pressure and

growing condensate accumulation. This is predominantly evident in the near production wellbores area. Several studies [26-28] have researched this transition, noting the shift from single-phase to multiphase flow in proximity to the wellbore leading to this condensate buildup. The gas recovery factor nearing 78%, as showcased in TABLE 6, underlines the efficient gas extraction processes, while the 50.65% condensate recovery factor pinpoints challenges in condensate production.

Given these observations, it becomes imperative to strategise for the extraction process optimisation, ensuring the reservoir's long-term profitability and addressing the evident challenges in condensate production.

4.2. Investigation scenario

The use of a cycling process is proposed as a way to mitigate the negative impact of condensate deposition in the reservoir and increase condensate recovery [29]. In this scenario, the produced gas (gas-condensate mixture), after separation and drying, is injected back into the reservoir at 100% of its volume, and the condensate is sent to the processing line. In a forecast, it is not planned to attract gas from other fields for re-injection. The amount of gas produced fully satisfies the needs.

In this way, due to the planned actions, accounting for all the geological and technological parameters of the field development, it was planned to increase the amount of extracted condensate by 5-10%.

The field development forecast with dry gas cycling has a duration of 30 years, starting from the end of the reporting period on January 1st, 2012, until January 1st, 2041. The quantity of production wells persisted unaltered during the entire considered period.

The investigation scenario aimed to enhance the condensate recovery factor by injecting dry gas into the reservoir. The implementation was planned in two steps:

- Step 1. Investigation of the optimum reservoir pressure at the start of dry gas injection.
- Step 2. Investigation of the optimal number of injection wells and their localisation.

In step 1, dry gas reinjection was simulated at various stages of X field development. The studied variants 1-5 (TABLE 6) were chosen to encompass periods of reservoir pressure above, at, and below the dew point pressure. Throughout the entire injection period, a constant reservoir pressure was maintained by injecting dry gas into the reservoir to fully compensate for current hydrocarbon production. Based on the results obtained in step 1 for further investigation (step 2), the variant with the highest condensate recovery factor was selected.

Step 2 of the research was to investigate the impact of the number and location of the injection wells in the field on condensate recovery.

Four variants with different numbers of injection wells and locations were tested in this step. The findings of the research are presented upon completion of the reservoir's development.

Each variant was evaluated for 3-time intervals of dry gas injection: 1, 2, and 3 years. This decision was made to showcase both the negative and positive outcomes resulting from the actions taken. Such effects can only be observed and analysed over an extended period of field exploitation. This decision was also made to provide insight into the efficacy of the process.

The injection wells were strategically placed around the perimeter of the gas-bearing region to impact the widest possible coverage area. A general map of the location of the injection wells is shown in Fig. 12. However, it should be noted that the diagram in Fig. 13 is a general representation of all possible locations and quantities of injection wells.

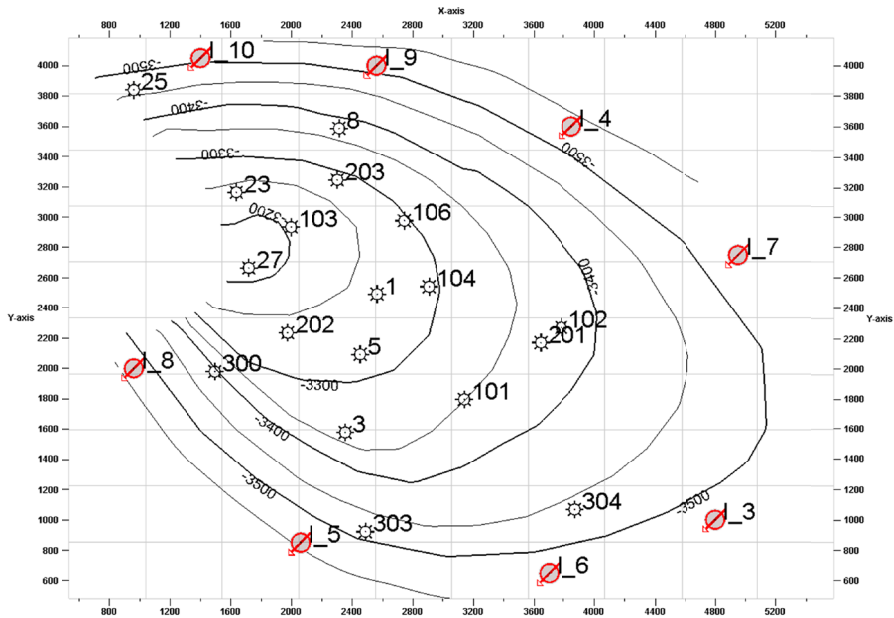


Fig. 12. Map of injection wells location in the gas bearing area

4.2.1. Investigation of the optimum reservoir pressure at the start of dry gas injection (step 1)

During the development of the field, the reservoir pressure declined from 41.2 MPa to 14.7 MPa, which is significantly lower than the dew point pressure. As this study is purely theoretical and not one of the potential development projects for field X, it is possible to make interventions during the historical period.

Accordingly, five variants were chosen to implement the start of the cycling process based on the average reservoir pressure expressed as part of its initial value. TABLE 6 summarises the key information.

TABLE 6

Gas cycling variants

Variant	Reservoir pressure at the start of dry gas injection, MPa	Data of start injection	Gas injection cumulative, mln sm^3		
			Period of dry gas injection		
			1 year	2 years	3 years
1	41.2 ($1 P_{in}^*$)	01.01.1971	653.76	1226.33	1583.28
2	35 (P_{dew}^{**})	01.01.1972	571.99	928.85	1209.35
3	31 ($0.75 P_{in}$)	06.01.1974	279.97	532.03	741.06
4	20 ($0.5 P_{in}$)	06.01.1989	116.11	229.14	328.66
5	10 ($0.25 P_{in}$)	01.01.2038	43.71	87.51	131.31

P_{in}^* – initial reservoir pressure, P_{dew}^{**} – dew point pressure

As can be seen from TABLE 6, different amounts of dry gas were injected for variants 1-5. This is due to the fact that at the early stages of field development, the flow rates of productive wells were high, so all the produced gas was reinjected back into the reservoir after drying.

Considering the various stages of field development and corresponding reservoir pressures, the number of injection and production wells also varied. To ensure a consistent approach, it was decided that each injection well would require two production wells. The number of wells increased gradually with decreasing reservoir pressure. At 10 MPa ($0.25 P_{init}$), the maximum number of injection wells was eight, whereas the number of production wells was sixteen. The location of the injection wells is shown in Fig. 12.

Fig. 13 displays the dynamics of reservoir pressure across all variants. The figure distinctly illustrates the pressure profiles resulting from the maintenance of reservoir pressure through dry gas injection over a period of one year.

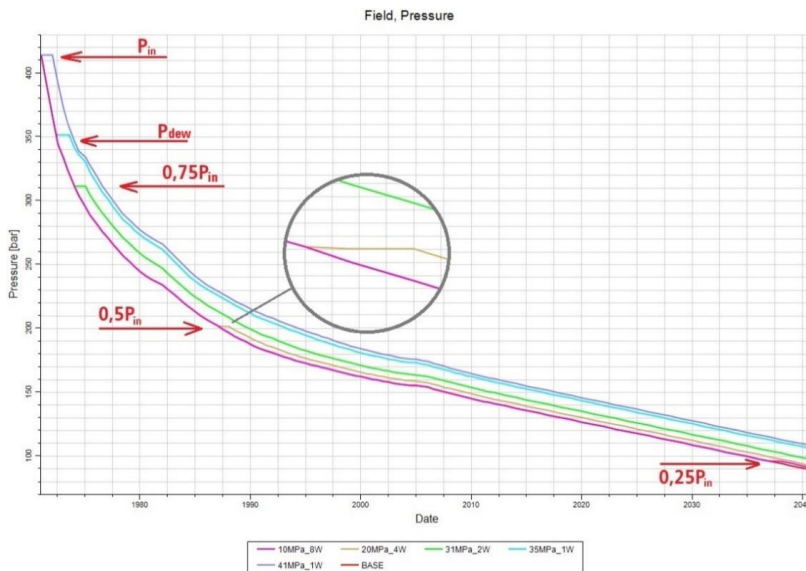


Fig. 13. Reservoir pressure dynamics for all variants of dry gas injection lasting 1 year

Assessing the effect of injection on the final reservoir pressure, the most effective reservoir pressure maintenance effect is obtained when the gas cycling starts at the early stage of field development when the reservoir pressure is above dew point pressure.

Fig. 14 shows the final condensate recovery factors for the studied variants and a base scenario (red horizontal line).

Analysis of the investigated variants (Fig. 15) shows that, at an injection pressure of 35 MPa (dew point pressure), the condensate recovery factor is 54.83% for a 1-year injection period, which is 4.18% higher than the base scenario. Similarly, at an injection pressure of 31 MPa, the recovery factor is 52.18 % for a 1-year period, which is 1.53% higher than the base scenario. For a 2-year injection period, the recovery factor is 56.34% at 35 MPa, i.e., 5.69% higher than the base scenario, and 53.17% at 31 MPa, i.e., 2.52% higher than the base scenario. For a 3-year

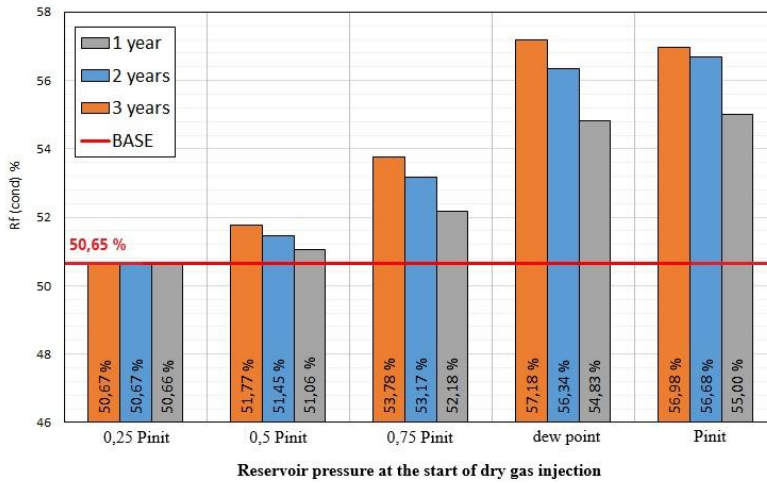


Fig. 14. Condensate recovery factors for variants 1-5 at different periods of dry gas injection

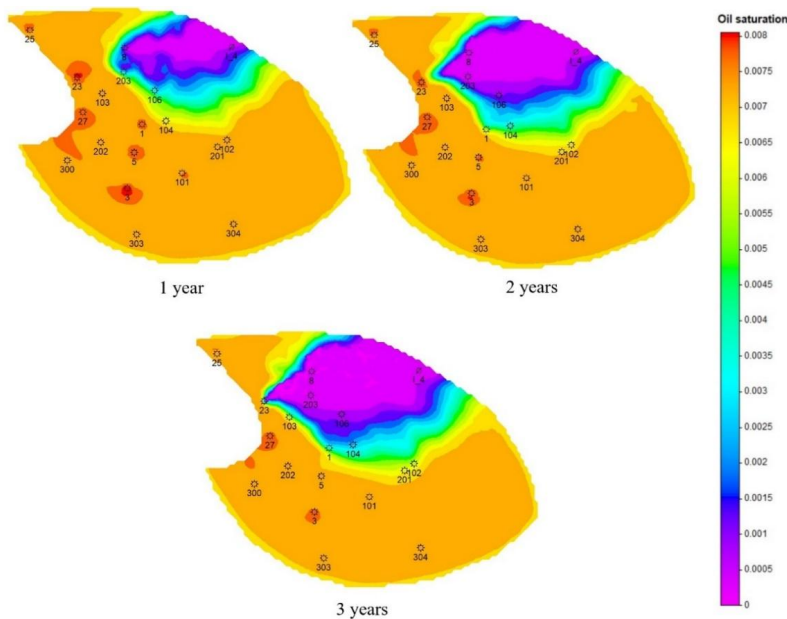


Fig. 15. Condensate saturation at the end field production after 1, 2 and 3 years of dry gas injection in variant 2

injection period, the recovery factor is 57.18% at 35 MPa, i.e., 6.53% higher than the base scenario, and 53.78% at 31 MPa, i.e., 3.13% higher than the base scenario.

The research indicates that the reservoir pressure at the start of dry gas injection into the gas-condensate field impacts the technological parameters of field development. The achieved

results show that dry gas injection at a reservoir pressure above the dew point pressure yields the highest condensate recovery.

Condensate pore saturation maps were produced for variant 2, where dry gas injection began at the dew point pressure and lasted 1, 2 and 3 years accordingly. Fig. 15 illustrates the situation at the end of field production in the year 2041.

As depicted in Fig. 15, extending the dry gas injection period results in a faster breakthrough to the producing wells. After one year of gas recycling, a minor dry gas breakthrough is observed in wells 8 and 203. By the end of the second year, the drainage area for these wells, including well 106, becomes fully saturated, and dry gas starts infiltrating well 23. With an injection period of three years, a more widespread breakthrough is noticeable in over half of the entire set of producing wells.

Consequently, wells experiencing the dry gas breakthrough start to produce less and less condensate and more the injected dry gas intended to maintain reservoir pressure.

A comparable pattern is noticed concerning the condensate recovery factor (Fig. 14). The most pronounced growth in this factor, relative to the baseline scenario, is seen for one year of dry gas injection and reservoir pressure at or above the dew point. Over two years of maintaining reservoir pressure, the condensate recovery factor does increase, but not in direct proportion to the injection period. For instance, a 100% extension of the injection period (2 years) gives the growth in the recovery factor only +16-21% compared to one year of dry gas injection. And when the injection period is extended by 200% (3 years), the increase is +18-26% compared to one year. In terms of intervention efficiency, the best results were achieved for one year of injection; however, the highest recovery factors were undoubtedly achieved over three years of dry gas injection.

This highlights the significance of another variable in developing projects with a reservoir pressure maintenance system using the cycling process – the placement and quantity of injection wells. The insights and collective analysis of these results highlight patterns for the issue under investigation, which can be utilised not just for this specific reservoir but for the development of any gas-condensate reservoir.

4.2.2. Investigation of the optimal number and injection wells localisation (step 2)

The initial phase of the study (step 1) demonstrated positive outcomes towards elevating the condensate recovery, highlighting the effectiveness of developing gas condensate fields through dry gas cycling. The optimal outcomes were achieved for the variant where the introduction of dry gas was initiated at the reservoir pressure of the dew point (35 MPa). However, several concerns arose during the research that requires clarification, specifically regarding the placement and quantity of injection wells.

Step 2 is essentially a modified version of variant 2 from step 1, in which the reservoir pressure is maintained at the dew point level by adding more injection wells.

To evaluate the effect on the ultimate condensate recovery factor, an additional four variants differing in the number (2, 4, 6 and 8) and location of dry gas injection wells were selected. In each considered variant, the amount of produced and injected gas was equal.

All injection wells were located on the gas-bearing contour, as demonstrated in Fig. 12. Specific information about the wells, including their names and respective flow rates are shown in TABLE 7.

TABLE 7

Basic information about dry gas injection wells

Variant	Number of injections well	Each well injection rate, $\text{th sm}^3/\text{day}$
1	2 (I_9; I_4)	826.1
2	4 (I_9; I_4; I_3; I_6)	413.1
3	6 (I_9; I_4; I_3; I_6; I_10; I_8)	275.4
4	8 (I_9; I_4; I_3; I_6; I_10; I_8; I_5; I_7)	206.5

As indicated in TABLE 7, the combined flow rates for all wells in each variant are equivalent. The objective of step 2 is to sustain the reservoir pressure by delivering an equivalent volume of dry gas through a varied number of injection wells that are located at different positions in the gas-bearing zone.

Fig. 16 displays the final condensate recovery factor values for the four studied variants in step 2. The red line represents the results of pre-optimal variant 2 ($P_{dew} = 35$ MPa) from step 1, where only a single injection well was used for dry gas injection.

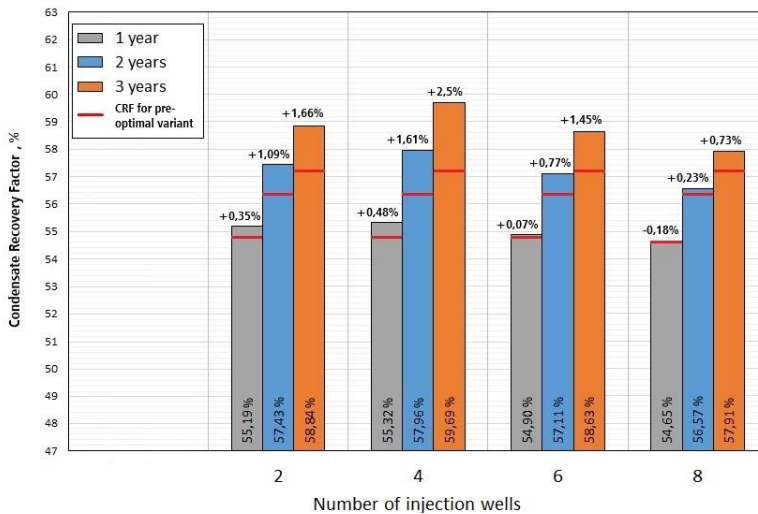


Fig. 16. Dependence of final condensate recovery factors on the number of injection wells during various injection periods

The analysis of dependences variants on Step 2 (Fig. 16) shows that the hydrocarbon recovery factor increases reaching a maximum value for the 4 dry gas injection wells, and then begins to decrease with an increasing number of injection wells.

Variant 2 (TABLE 7), which employs dry gas injection through four injection wells, yielded the highest results for all injection periods studied. Specifically, with an injection period of one year, the condensate recovery for variant 2 was 55.32%, representing a 4.67% improvement over the base scenario and a 0.48% improvement over the pre-optimal variant 2 ($P_{dew} = 35$ MPa) of step 1. Over three years of dry gas injection, the condensate recovery was 59.69%, which is 9.04% higher than the base scenario and 2.51% higher than the pre-optimal variant of step 1.

For variant 4, 8 injection wells were used to inject dry gas. In the case where dry gas injection lasted only one year, the condensate recovery factor is 54.65%, which is 0.18% lower than the pre-optimal variant 2 from Step 1.

Fig. 17 shows the condensate saturation at the end of the field development forecast for variants 1-4 of step 2 and a one-year dry gas injection period.

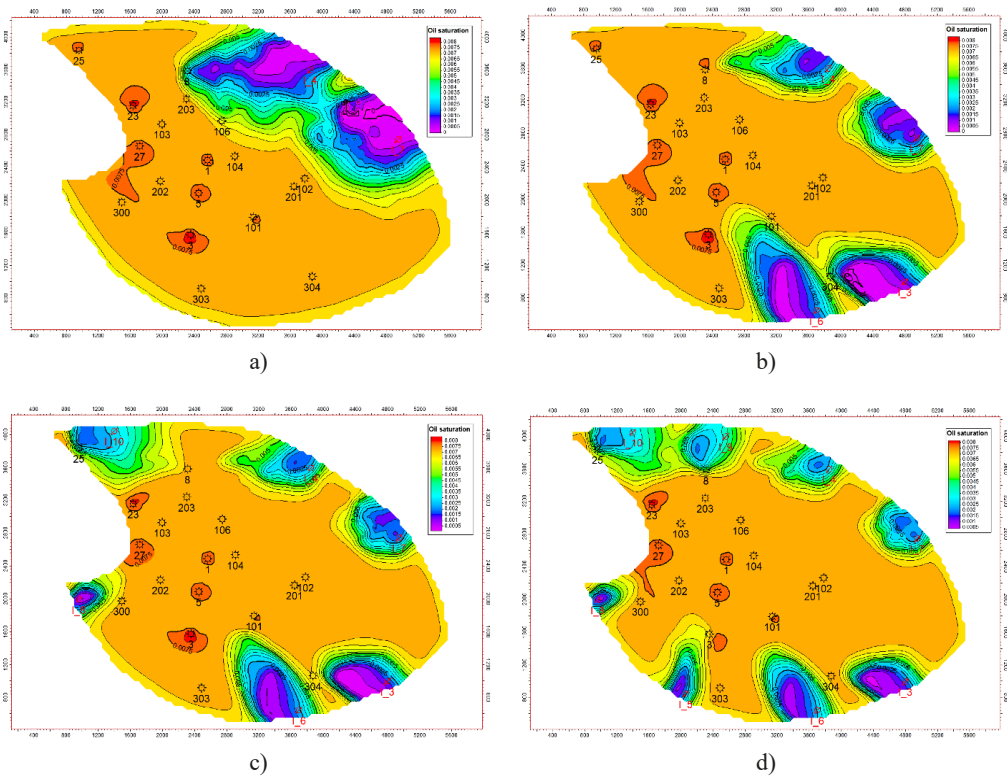


Fig. 17. Condensate saturation at the end of field development forecast (01.01.2041) for different number of injection wells. a) 2 injection wells; b) 4 injection wells; c) 6 injection wells; d) 8 injection wells

The results are attributed to the migration of dry gas in the formation and the placement of injection wells in relation to productive ones. When considering variant 1, two injection wells are utilised (Fig. 17a), which exhibit a significant flow of dry gas injection rate (TABLE 7). Consequently, a substantial quantity of dry gas does not disperse throughout the reservoir, but instead travels throughout higher dry gas permeability areas towards regions of lower reservoir pressure and enters the bottomholes of productive wells. Due to the insufficient dry gas coverage area, the condensate within the reservoir is not entirely displaced, and the injected dry gas is almost fully recovered. Variant 4 involves injecting dry gas through 8 injection wells (Fig. 17d), but this does not provide a significant dry gas coverage area. Consequently, the condensate from the displaced formation mixture settles midway to the production wells and remains in non-developed areas.

Variant 2 is the optimal choice, as it involves injecting dry gas through four injection wells (refer to Fig. 17b). This is because the coverage zones do not overlap with the production well's drainage zones. As a result, the maximum condensate recovery factor is achieved.

The achieved results demonstrate that the field depletion recovery is highly impacted not only by the number of injection wells but also their placement. These parameters carry significant weight due to the complex geological structure of real fields. Even a substantial number of wells can yield poor outcomes in certain geological circumstances.

5. Summary

The primary objective of this study was to enhance the recovery coefficient of condensate from gas condensate reservoirs by employing an approach of re-injecting dry gas into the X field.

It was observed that the development of gas condensate fields often comes with a series of intricate technical and technological challenges. A holistic approach, backed by an in-depth analysis of both domestic and international literature, provided valuable insights into these challenges, revealing the major hurdles in gas condensate field development and highlighting potential avenues for optimisation.

The robustness of the study was further fortified by the formulation of a hydrodynamic model for the X field. This model was instrumental in facilitating the analysis of two primary developmental scenarios: a foundational scenario focused on standard field depletion and an innovative scenario emphasising pressure support via dry gas re-injection.

Throughout the project's duration, the following subjects underwent detailed investigation:

- Optimal timing for dry gas injection into a gas-condensate reservoir;
- The ideal timeframe for maintaining reservoir pressure through the cycling process;
- Strategic positioning of dry gas injection wells;
- Determination of the appropriate number of injection wells.

Various structural maps, charts, and tables were instrumental in providing a comprehensive analysis of the matters at hand.

In the 30-year forecast for further reservoir development, a condensate recovery coefficient of 50.65% was achieved through normal depletion.

The investigation scenario was orchestrated to bolster the condensate recovery factor via dry gas injection into the reservoir. This approach was bifurcated into two phases:

- Step 1. Ascertain the optimal reservoir pressure at the initiation of dry gas injection.
- Step 2. Investigation of the optimal number of injection wells and their localisation.

The fruition of the first step of research showcased promising outcomes. The most exemplary results from the examined scenarios were derived when dry gas was injected at a reservoir dew point pressure of 35 MPa. With this approach and a prolonged injection duration of 3 years, a peak condensate recovery coefficient of 57.18% was achieved, marking an increase of 6.53% compared to the base scenario. A slightly lower increment was observed for 1 year of maintaining reservoir pressure, showing a 4.18% enhancement against the base scenario. Throughout the research phase, distinct patterns associated with dry gas breakthrough to production wells were discerned. This necessitated the execution of step 2 to corroborate these findings.

Subsequent refinements during the second phase accentuated the preservation of reservoir pressure at the dew point, complemented by the addition of further injection wells positioned

variably along the gas-bearing contour. Scenario 2, leveraging four injection wells, markedly surpassed its counterparts. The zenith value was noted at 3 years of maintaining reservoir pressure at 59.7%, overshadowing both the baseline and the pre-optimal scenario. By aggregating all the data, a clear cause-and-effect relationship was discerned. A nearly 58% condensate recovery coefficient was achieved over 2 years of pressure maintenance, a figure marginally lower but curtailing the cycling process duration by a third, deeming it optimal.

Generally, for both steps, the growth trend of the condensate recovery coefficient for 3 years exhibited a declining nature, attributed to dry gas migration within the reservoir. The outcomes were significantly influenced by the geological makeup of the deposit, its geometric dimensions, and the distance between the injection and production wells, given that these parameters predominantly determine the rate of dry gas breakthrough to the injection wells.

One must not negate another pivotal parameter when cultivating gas-condensate fields using the cycling process: the rate of dry gas injection. This parameter holds paramount significance. However, in this study's ambit, scenarios where the reservoir pressure was sustained uniformly, abetted by an injection rate of 1:1, were solely scrutinised. Modulating the injection rate not only impacts the reservoir pressure dynamics but also incurs considerable alterations in the PVT properties of the reservoir fluid. Consequently, this parameter remained outside this study's purview.

In summation, this research underscores the salient influence of parameters like the inception pressure of injection, injection longevity, and the count and spatial positioning of injection wells on dry gas infusion into gas-condensate fields. The research lucidly propounds that the tactical allocation and the quantity of injection wells, accounting for the intricate geological framework of fields, are indispensable for maximising condensate retrieval.

6. Conclusions

This research into the X field's gas condensate recovery underscores the critical role of dry gas re-injection in enhancing recovery efficiency. The key takeaways include:

1. Optimization of Injection Strategy: The findings stress the need for meticulous planning in the injection strategy. Factors such as the timing of injection initiation, the duration of pressure maintenance, and the strategic placement and number of injection wells are crucial for maximising recovery.

2. Significant Recovery Enhancement: The investigation into the optimal timing for commencing dry gas injection revealed that the most advantageous results were achieved when injections were carried out at a reservoir pressure exceeding the dew point. This strategy led to an enhancement of the condensate recovery factor by up to 6%. Prolonging the injection period to three years yielded a further increase in this factor, though the rate of increase was more subdued compared to a one-year injection period. Efforts to augment the condensate recovery factor through the addition of new injection wells also showed beneficial outcomes, leading to an additional 3% increase in the recovery factor relative to the total recoverable condensate reserves. Therefore, this comprehensive approach resulted in an overall increment of up to 9% in the condensate recovery factor, a substantial improvement in terms of resource recovery efficiency.

3. Influence of Reservoir Characteristics: The success of dry gas re-injection strategies is heavily influenced by the geological characteristics of the reservoir and the arrangement of injection and production wells.

These factors directly impacted the dynamics of dry gas migration and, as a result, the effectiveness of the recovery process.

4. Balancing Injection Parameters: The study highlighted the importance of each parameter in developing gas condensate fields with reservoir pressure maintenance through dry gas re-injection. Minor changes in any parameter could lead to either an increase or decrease in hydrocarbon production. Therefore, achieving an ideal balance among these parameters is crucial. This equilibrium can be reached through numerical modelling, allowing for the selection of the optimal option among all possible variable combinations.

5. Strategic Recommendations for Industrial Practice in Developing Gas Condensate Fields: The research demonstrated the importance and necessity of a strategic approach to the placement of both productive and injection wells in gas-bearing areas. This strategy should be tailored to the field's unique geological framework to optimise condensate recovery.

In essence, this study provides valuable insights for enhancing condensate recovery in gas condensate fields through dry gas re-injection. It underscores the importance of an integrated approach that considers both geological factors and operational parameters to achieve the most effective recovery outcomes.

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Conflicts of interests

The authors declare no conflict of interest.

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