INVESTIGATION OF THE PRODUCTION EFFICIENCY OF A GAS-CONDENSATE FIELD UTILIZING GAS CYCLING

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Abstract. *In this study, the feasibility of applying dry gas injection technology at different pressure depletion stages in a gas-condensate reservoir was investigated. The injection process was carried out based on various ratios of injection wells to production wells (4:1, 3:1, 2:1, 1:1, and 1:2). Dry gas injection periods ranging from 1 to 3 years were studied using the Kultak gas-condensate field as a case example, with the aim of evaluating their impact on improving the condensate recovery factor. A hydrodynamic reservoir model was employed for the analysis, which was calibrated using historical production data from the field, allowing for a systematic and integrated approach. Compared to the conventional production method based solely on natural pressure depletion, the gas cycling method demonstrated a 9% increase in the condensate recovery factor. The results of the study indicate that gas injection has a significantly positive impact on enhancing the recovery efficiency of both condensate and gas when compared to traditional recovery methods. Based on the findings, this approach provides a practical and efficient solution for the rapid evaluation and implementation of enhanced recovery techniques in gas-condensate reservoirs with low to moderate C5+ liquid hydrocarbon content.*

Keywords: *Gas-condensate reservoir, injection well, dry gas, recovery factor, viscosity, gas cycling.*

Introduction

One of the main challenges in the development of gas-condensate reservoirs is improving the condensate recovery rate. During natural production from gas-condensate reservoirs, the reservoir pressure declines below the dew point, resulting in the retrograde condensation of heavier hydrocarbons (i.e., condensate) from the gas phase. A portion of this separated condensate transitions into the liquid phase and becomes trapped within the reservoir rock. This phenomenon occurs because the condensate becomes immobile within the pore spaces and is unable to participate in the filtration (flow) process. Efficient development of gas and gas-condensate reservoirs is directly dependent on the hydrocarbon recovery factor from the reservoir. Unfortunately, the recovery factor for condensate typically does not exceed 30–60%. In local practice, reservoir development is often based on natural depletion, but this approach does not provide an optimal hydrocarbon recovery rate. On average, dry gas reservoirs achieve gas recovery rates of 85–90%, whereas in gas-condensate reservoirs, this figure ranges between 65–75%. The significant discrepancy between gas and condensate recovery factors is primarily attributed to the complex geological conditions of gas-condensate reservoirs and, secondly, to the thermodynamic properties of the gas-condensate mixture. These properties are characterized by anomalous behavior observed in the two-phase region, where both gas and liquid coexist simultaneously. Studies of gas-condensate reservoirs have shown that the accumulation of retrograde condensate in the near-wellbore zone leads to reduced productivity of production wells. The buildup of condensate in the porous, productive formation around the wellbore—commonly referred to as a “condensate bank”—significantly reduces gas permeability and impedes the flow of the gas phase. As a result, valuable liquid hydrocarbon components remain trapped in the reservoir in the liquid phase. Within the retrograde condensation region, isothermal pressure decline (or isobaric temperature decline) leads to an increase in the amount of liquid or gas phase in the system up to a certain maximum. Beyond this point, any further decrease in pressure or temperature reduces the volume of the equilibrium phase. At a specific pressure or temperature, the liquid or gas phase disappears entirely, and the multicomponent system returns to a single-phase state—either purely gas or purely liquid.

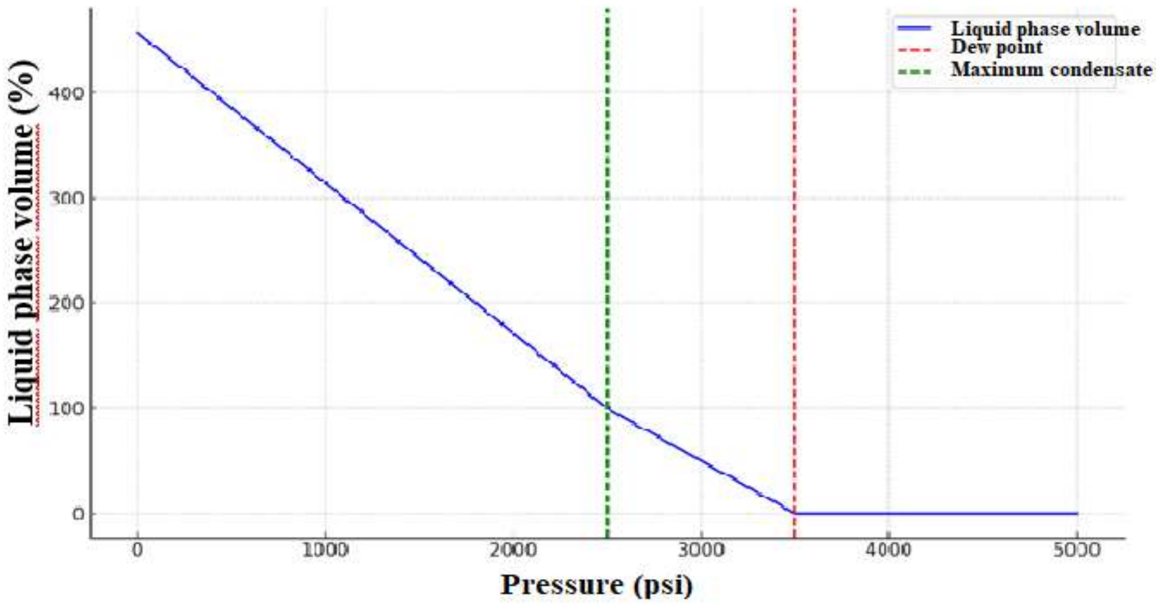

Figure 1. Typical phase diagram of a gas-condensate system.

Laboratory, analytical, and industrial research results indicate that retrograde condensation of hydrocarbon mixtures has a negative impact on nearly all technological processes used in the extraction of gas and condensate. This leads to several adverse consequences. Firstly, when the pressure drops below the dew point, the recovery rates of both condensate and gas decrease. Secondly, as a result of the condensation of heavy hydrocarbons, the permeability of the porous medium to gas is reduced, which significantly decreases the efficiency of gas production. This effect becomes more pronounced when the initial condensate concentration is high and the absolute permeability of the reservoir rock is low. The greatest reduction in gas phase permeability is observed in the near-wellbore zones, as these regions exhibit the highest levels of condensate saturation within the porous medium. Thirdly, the production performance of wells deteriorates, and their production capacity declines. The extracted gas flow rate decreases due to a reduction in gas-phase relative permeability caused by condensate dropout within the reservoir. Additionally, a portion of the reservoir pressure is lost in displacing the mobile fraction of the condensate. Furthermore, the accumulation of condensate around the wellbore axis creates resistance to gas flow, which negatively affects the operational regime of the gas gathering system. As a result:

- **Wellhead pressure increases,**
- **Gas flow rate decreases,**
- **In some cases, it may lead to well shutdown.**

In global practice, the need has arisen to develop specialized systems for the exploitation of fields facing retrograde condensation issues. The primary objectives for increasing the condensate recovery factor in gas-condensate fields are to ensure the stable operation of wells and to apply reservoir pressure maintenance technologies, particularly when the gas contains more than 250 cm^3/m^3 of condensate and reserves exceed 8 billion m^3. Conversely, if the condensate content is less than 23 cm^3/m^3 and gas consumers are available, gas reinjection is considered uneconomical. The cycling process allows for the efficient recovery of condensate that has accumulated within the reservoir. However, this method has so far only been applied in Ukraine at the Novotroitske (K-30 field), Kotelevske (C-5 reserve), and Timofeevske (FM-1) fields. The cycling process has also been used in various gas-condensate fields around the world, including the large Kaybob field in Canada since 1968. It has also been implemented at the La Gloria field in Texas and the Cotton Valley field in Louisiana. The key concept behind the use of dry gas is its ability to vaporize condensed liquid fractions, which can then be separated and reused for further injection. For a long time, discussions have continued around methods for geological modeling and reserve estimation of hydrocarbon accumulations. In the development of gas-condensate fields, the cycling process is constrained by economic and technological factors. Compared to traditional depletion-based production methods, implementation of the cycling process requires significant capital investment and the storage of gas for reinjection. From a technological standpoint, the cycling process is limited by a low sweep efficiency. The injected dry gas has a lower viscosity than the original gas-condensate mixture in the reservoir.

The modeling was carried out based on two main scenarios:

- **Base scenario** – development of the field under conditions of natural (primary) reservoir pressure depletion;
- **Research scenario** – maintaining reservoir pressure through dry gas injection.

In both scenarios, the development of the field over the next 30 years was taken into consideration.

The base scenario envisages the step-by-step production of reserves through natural pressure depletion. In contrast, the research scenario includes a two-stage field development forecast based on gas recycling technology, aimed at increasing the condensate recovery factor by maintaining reservoir pressure.

Within the framework of the project, the following topics were studied in depth based on scientific research:

- Determining the most appropriate timing for the introduction of dry gas injection into the gas-condensate reservoir;
- Identifying the optimal duration for maintaining reservoir pressure using recycling gas flow;
- Developing a strategy for the placement of dry gas injection wells;
- Assessing the required number of injection wells.

Forecast Based on the Base Scenario

The base scenario was developed to predict future development parameters based on the natural energy depletion regime of the reservoir. In current industrial practice, such forecasts typically rely on data reported during the most recent reporting period of field development, using the existing stock of wells. Since 2012, the development of the field has been carried out through 16 production wells. For each well, a minimum bottomhole pressure was individually specified, and the wells operated under strict boundary control conditions. When gas flow from a well dropped below 500–1000 m^3/day or the liquid content exceeded 100 ml/m^3, an automatic shut-in mechanism was activated. The forecast period is limited to a maximum of 20 years, covering the time frame from 2012 to 2031.

According to the base scenario, final development indicators. **Table 1**.

Name of scenario	Base
Cumulative gas production, mln sm3	7067.55
Gas production rate, thousand sm3/day	125.38
Cumulative condensate production, thousand m3	305.34
Condensate production rate, m3/day	2.80
Final reservoir pressure, MPa	8.93
Gas recovery factor, %	77.54
Condensate recovery factor, %	50.65

Table 1 presents the projected key technological indicators by the year 2031. In the initial stage, when the reservoir was being actively exploited, a sharp decline in gas and condensate production levels was observed. This decline is directly linked to the steady decrease in reservoir pressure. As a result, when the reservoir pressure drops below the dew point, condensate begins to actively separate within the reservoir, which is evident through changes in the gas-to-condensate ratio. Numerous scientific studies have examined this transitional phase and have focused on the accumulation of condensate in the near-wellbore zone as a result of the transition from single-phase to multiphase flow.

Gas cycling variants Table 2.

Variant	**Reservoir pressure at the start of dry gas injection, MPa**	**Data of start injection**	**1 year**	**2 year**	**3 year**
1	35.2 (1 P_{in}^{*})	01.01.2012	653.76	1226.33	1583.28
2	29 (P_{dew}^{**})	01.01.2014	571.99	928.85	1209.35
3	25 (0.75 P_{in})	06.01.2020	279.97	532.03	741.06
4	17 (0.5 P_{in})	06.01.2023	116.11	229.14	328.66
5	10 (0.25 P_{in})	01.01.2028	43.71	87.51	131.31

*Pin** – initial reservoir pressure, *Pdew*** – dew point pressure

As presented in Table 2, the gas recovery factor reaches approximately 78%, indicating efficient gas production. However, the condensate recovery factor is 50.65%, which points to existing challenges in condensate extraction. To mitigate the negative effects of condensate dropout and increase the condensate recovery level, the gas cycling process has been proposed. In this scenario, the produced gas (a gas-condensate mixture), after being separated and dried, is 100% reinjected back into the reservoir, while the condensate is directed to the processing facilities.

The forecast does not include bringing in gas from other fields for reinjection — the volume of produced gas fully meets the reinjection requirements. Thus, based on geological and technological parameters, this development plan aims to increase condensate recovery by 5–10%. The reservoir development forecast based on dry gas cycling spans a 30-year period —

from January 1, 2012, to January 1, 2031. During this period, the number of production wells remains unchanged. This research scenario is implemented by injecting dry gas into the reservoir with the goal of enhancing the condensate recovery factor.

The implementation of the plan consists of two stages:

Stage 1. A study to determine the optimal reservoir pressure for initiating dry gas injection;

Stage 2. A study to identify the optimal number and placement of injection wells.

In **Stage 1**, a model of the dry gas reinjection process was developed for different phases of the Kultak field development. Variants 1–5, presented in Table 2, were selected and encompass scenarios where the reservoir pressure is above, equal to, or below the dew point. Throughout the entire injection process, the strategy involves maintaining a constant reservoir pressure by injecting dry gas to fully compensate for the produced hydrocarbons.

Based on the results of Stage 1, the variant with the highest condensate recovery factor was selected for Stage 2.

In **Stage 2**, the objective of the study was to determine how the number and placement of injection wells affect condensate recovery. Four different configurations with varying numbers and locations of wells were tested. The study results were presented after the simulated field development was completed. For each configuration, dry gas injection was carried out over durations of 1, 2, and 3 years. This approach allowed the identification of both the positive and negative impacts of the implemented measures and enabled the evaluation of the long-term effectiveness of the process under extended exploitation conditions.

The injection wells were strategically located along the gas-bearing reservoir boundary to achieve maximum coverage. A general schematic of the injection well layout is provided in **Figure 2**.

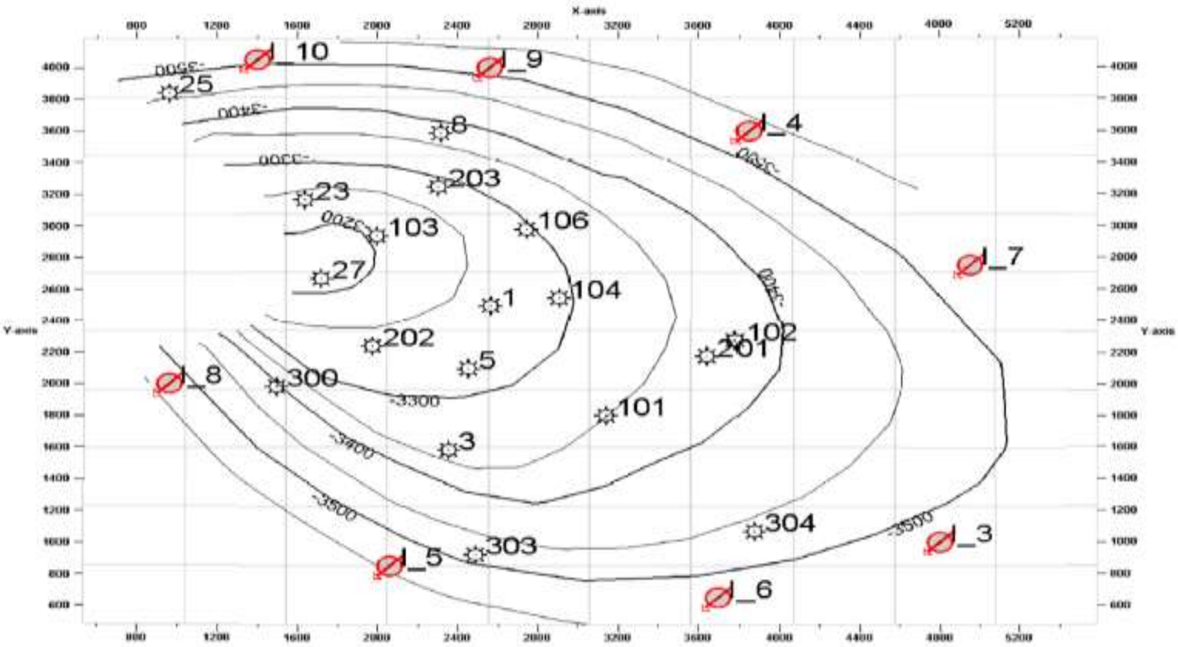

Figure 2. Map of Injection Well Placement in the Gas-Bearing Area

However, the diagram in Figure 3 represents a schematic overview that provides a general understanding of all possible injection well placements and quantities.

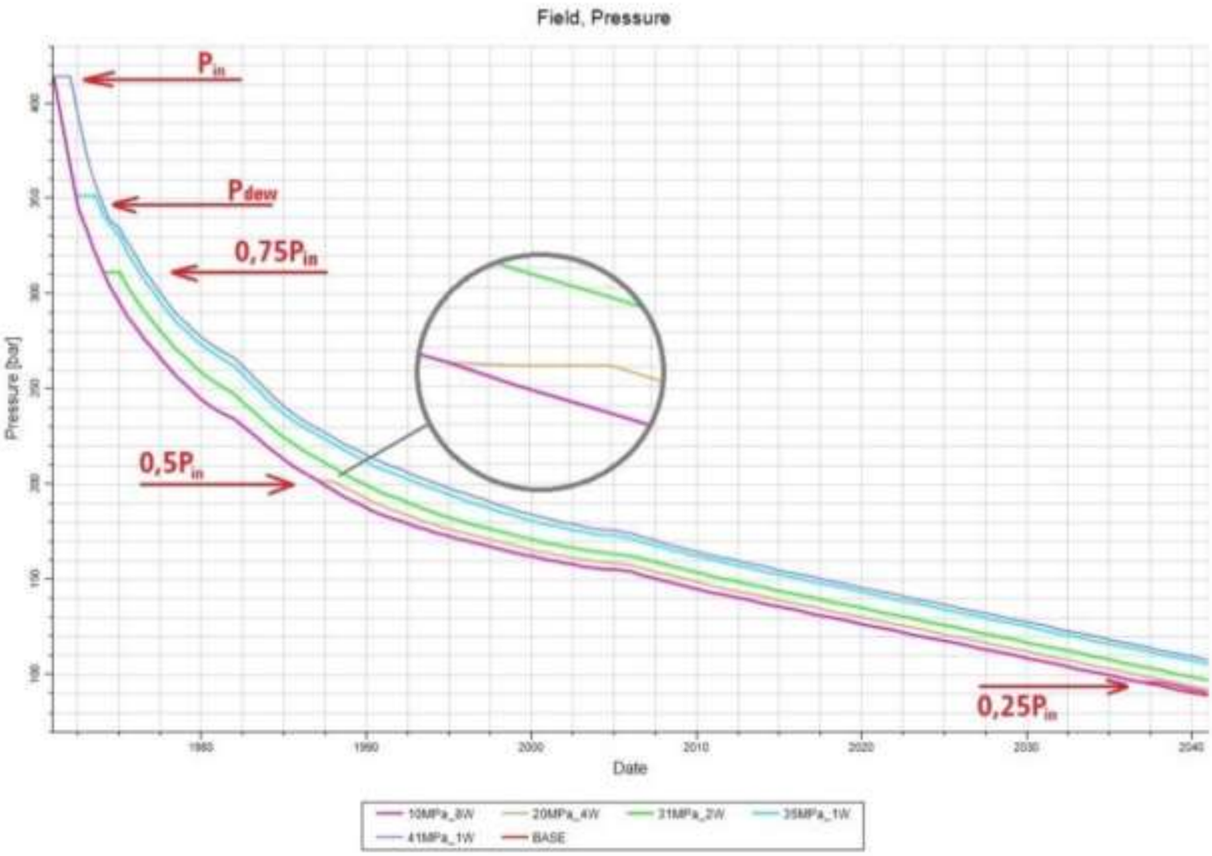

Figure 3. Reservoir pressure dynamics for all scenarios of dry gas injection over a period of 1 year.

The initial phase of the study demonstrated positive results in enhancing condensate recovery and confirmed the effectiveness of developing gas condensate fields through dry gas recycling. The optimal results were achieved in the scenario where dry gas injection commenced at the dew point pressure (35 MPa). However, during the research, several questions arose regarding the number and placement of injection wells, which require further clarification. To assess the impact of these factors on the final condensate recovery factor, four additional scenarios were selected, differing in the number (2, 4, 6, and 8) and spatial arrangement of the dry gas injection wells. All injection wells are located along the gas-bearing contour, as illustrated in Figure 2.

Key information regarding the dry gas injection wells.

Variant	**Number of injections well**	**Each well injection rate, th sm3/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

The objective is to maintain reservoir pressure by delivering an equal volume of dry gas through injection wells of varying numbers and locations within the gas-bearing area.

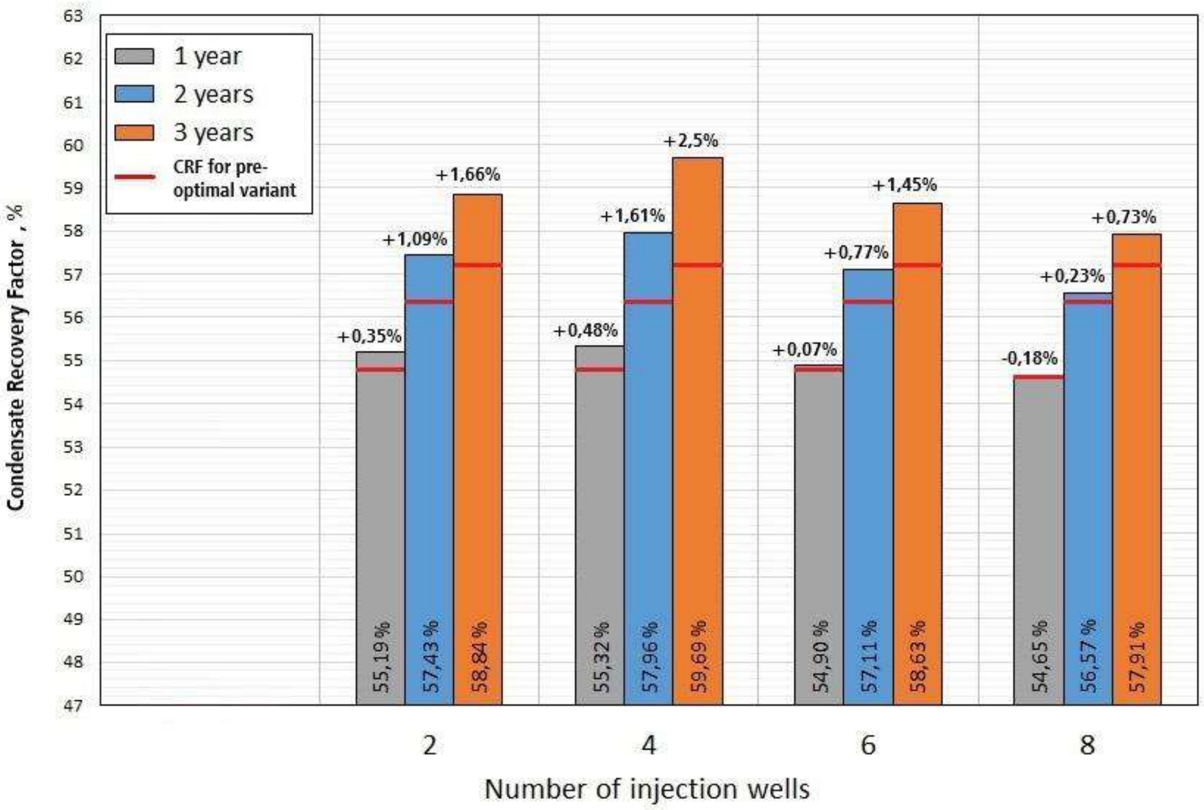

Figure 4. Relationship between the final condensate recovery factor and the number of injection wells for different injection durations.

Figure 4 presents the final condensate recovery factor values for the four studied scenarios. The red line represents the results of Scenario 2 from Step 1, previously considered optimal, where dry gas injection was performed through a single well at the dew point pressure of 35 MPa. The results can be explained by the migration of dry gas within the reservoir and the relative positioning of injection wells to production wells. A large volume of dry gas does not spread evenly across the entire reservoir but instead moves from high dry gas permeability zones to areas with lower reservoir pressure, reaching the bottom sections of production wells. Due to insufficient areal coverage by the injected dry gas, the reservoir condensate is not fully displaced, and the injected dry gas is nearly entirely recovered. The findings indicate that reducing reservoir reserves is significantly influenced not only by the number of injection wells but also by their spatial distribution. These parameters are critically important due to the complex geological structures of actual reservoirs. Even a large number of wells can yield poor results under certain geological conditions.

Conclusion.

The development of gas condensate fields is often accompanied by complex technical and technological challenges. A comprehensive approach based on an in-depth analysis of both domestic and international literature has provided valuable insights into these issues, identifying the key obstacles in the development of gas condensate fields and suggesting possible directions for optimization.

The research scenario focused on enhancing the condensate recovery factor by applying dry gas injection into the reservoir. This approach was divided into two phases:

Step 1: Determining the optimal reservoir pressure at which to initiate dry gas injection.
Step 2: Investigating the number and placement of injection wells.

The first phase of the study yielded promising results. Among the scenarios analyzed, the best outcomes were observed when dry gas injection was carried out in a reservoir with a dew point pressure of 35 MPa. This approach, combined with a three-year injection period, resulted in a maximum condensate recovery factor of 57.18%, representing a 6.53% increase compared to the base scenario. When reservoir pressure was maintained for only one year, a smaller increase of 4.18% was observed. During the study, specific patterns related to the rapid migration of dry gas toward production wells were identified, which led to the implementation of Step 2 to validate these findings. The second phase of the study introduced additional improvements, including maintaining the dew point pressure and adding supplementary injection wells strategically placed along the gas-bearing contour. Scenario 2, which involved the use of four injection wells, significantly outperformed the others. When pressure was maintained for a period of three years, the maximum condensate recovery factor reached 59.7%, surpassing both the base case and the previously identified optimal scenario. An analysis of all the gathered data revealed a clear cause-and-effect relationship: maintaining pressure for two years resulted in an approximate condensate recovery factor of 58%. Although slightly lower, this option was considered optimal as it allowed for a one-third reduction in the duration of the cyclic process. Another critical parameter that should not be overlooked in the development of gas-condensate fields through cyclic processes is the **dry gas injection rate**. This parameter plays a vital role. However, in this study, only scenarios in which reservoir pressure was held constant and the injection rate maintained at a 1:1 ratio were analyzed. Varying the injection rate not only influences the pressure dynamics of the reservoir but can also significantly alter the PVT properties of the reservoir fluids. For this reason, injection rate analysis was considered beyond the scope of the current study. In conclusion, this study emphasizes the substantial impact of parameters such as the timing of injection pressure initiation, injection duration, as well as the number and placement of injection wells in the application of dry gas injection in gas-condensate fields. The findings clearly demonstrate that in fields with complex geological structures, achieving maximum condensate recovery requires strategically positioning the injection wells and selecting an appropriate number of them.

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