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Optimizing Oil Recovery by Low-Pressure Nitrogen Injection: An Experiment Case Study

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Abstract

Currently, most oilfields are in the final stages of development, making enhanced oil recovery (EOR) methods essential for efficient oil extraction. Among these methods, nitrogen injection has proven particularly effective. EOR encompasses advanced techniques aimed at maximizing oil extraction throughout an oilfield's productive lifespan. The process unfolds in stages: primary recovery (natural flow due to reservoir pressure), secondary recovery (water injection to maintain pressure), and tertiary recovery (methods like CO_2, nitrogen injection, and steam recovery). This study investigates linear nitrogen injection at 0.7 MPa and 1 MPa over 24 hours to determine the most efficient method for the J-Sandstone Formation in the North Karamandybas field. Results indicate nitrogen injection effectively enhances oil recovery in lower to middle-permeability sandstone reservoirs at lower pressures. Using low salinity water injection, the oil recovery factor (RF) was approximately 50-55%. The linear displacement method proved particularly successful in gravity-stable injection scenarios, achieving an average RF of 65%, compared to 51% in gravity-unstable nitrogen flooding. Combined secondary and tertiary flooding with water and nitrogen achieved an average RF of 87.32%. These results underscore nitrogen injection's potential as a viable EOR technique for enhancing oil recovery in specific geological settings, particularly at lower pressures.

Keywords: Recovery factor; Nitrogen injection; Sandstone; North Karamandybas field; Total area and linear displacement.
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1. Introduction

Enhanced oil recovery (EOR) is a common technique used to increase oil production in mature reservoirs.[1] "IOR" stands for "Improved Oil Recovery," which refers to any method used to improve the amount of oil that can be recovered, such as infill drilling and horizontal wells. "EOR" or "Enhanced Oil Recovery".[2] The process of oil recovery involves three stages: primary, secondary, and tertiary. Initially, hydrocarbons are extracted from the reservoir using the natural forces present. However, the natural pressure decreases over time and additional measures are required to bring the oil to the surface.[3] EOR involves reducing oil saturation below the Residual oil saturation (Sor) to recover oils retained due to capillary forces or high viscosity. Miscible processes, chemical floods, and steam-based methods are effective EOR methods.[4,5,6] It is estimated that the next trillion barrels of oil will have to come from reservoirs that are significantly more hostile than the ones that have provided the first 2 trillion. To unlock the remaining oil at economical rates, EOR techniques may have to be considered from the early days.[7,8] The objective of EOR varies significantly depending on the specific types of hydrocarbons being addressed.[4,9]

A substantial portion of the world's remaining oil is situated in tight formations, frequently of carbonate origin, characterized by high heterogeneity.[10] The development and management of any reservoir require careful consideration of factors such as; well placement, completion processes, and enhanced oil recovery methods.[11]

Gas is injected into the reservoir oil at the minimum miscibility pressure (MMP) or above to merge the two completely. This technique is known as miscible gas injection. When flooding by the gas is conducted below MMP, it is called immiscible gas injection. The primary conditions that affect miscibility are composition, fluid characteristics, pressure, and temperature (Fig. 1).[12] Remarkably even

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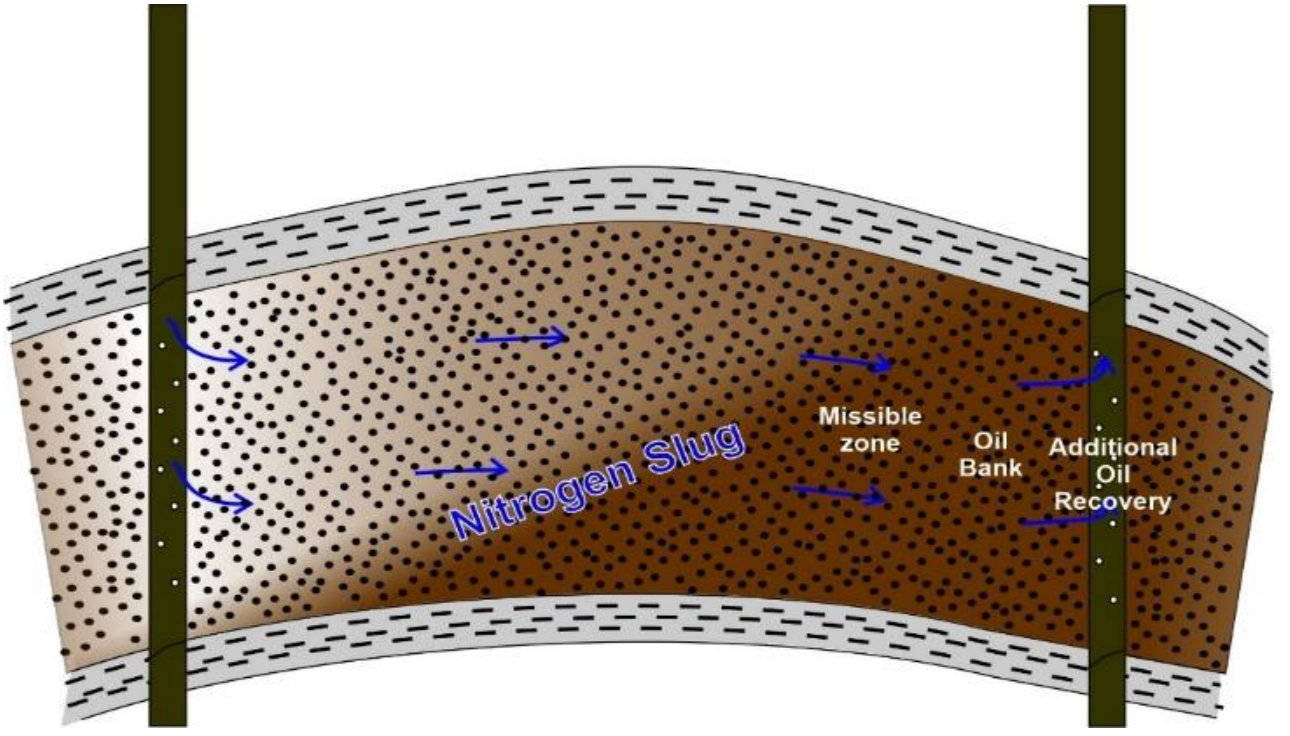


Fig. 1 Nitrogen injection in miscible displacement.

immiscible nitrogen injection has a high potential in EOR. For example, the authors of[13] studied the impact of pressure drop during immiscible nitrogen injection on oil recovery. The relationship between the oil recovery factor and injected time during nitrogen injection into 6.27 mD and 8.39 mD carbonate cores at pressure drops of 100 and 400 psi, respectively, at 70 °C was explored. The results demonstrated that a lower pressure drop leads to a higher ultimate oil recovery, attributed to delayed gas breakthrough and more consistent oil displacement. Interestingly, within a specific timeframe before gas breakthrough, a larger pressure drop correlates with higher oil recovery.

Immiscible nitrogen injection has demonstrated favorable outcomes not only in trials with low permeability but also in those with high permeability. For example, increasing the pressure to 5 bar and injecting nitrogen into a 17-cm-length core with a permeability of 1.94 Darcy, after approximately 5 pore volumes of water flooding, led to a 17 % additional increase in oil recovery factor (ORF) using n-hexadecane as a representative oil model.[14]

An investigation was carried out for clastic reservoirs that have been buried at depths of over 5000 meters. The microscopic initiation mechanism of residual oil after water flooding has been identified as the key to enhancing oil recovery through gas flooding. To better understanding the occurrence states and distribution of residual oil, an experimental equipment was designed for the first time, which successfully overcame the limitations of visualization accuracy.[15]

Nitrogen is more affordable and widely available than CO_2 and natural gas, and is also non-corrosive. It is 2-3 times cheaper than CO_2 and 4-8 times than natural gas, offering the additional advantages of widespread availability and non-corrosiveness.[16] Throughout the oil production process, nitrogen can be easily separated from crude oil streams, ensuring efficient utilization with minimal expenses.[17] Due to its inert properties, nitrogen prevents swelling in clay formations, avoiding permeability damage and preserving rock stability.[18] Because of this advantages nitrogen injection, encompassing various methods like pure nitrogen injection, nitrogen foam injection, and nitrogen-water alternative injection tailored to different reservoir types, stands out as a highly effective technique for reservoir development.[19] Moreover, the combined use of nitrogen and foams is also a promising EOR method.[20] For example, in the study by[21] the authors delve into a research article detailing the pilot test of nitrogen foam flooding in Xinjiang oilfield's M unit, noting its enduring impact for up to 18 months. The positive findings encompass a substantial decline in injectors' pressure index and filling degree, enhanced fluid injection profiles, heightened oil production, reduced water cut for producers, and a moderated natural decline rate. The difference in oil recovery rate between N_2 and CO_2 flooding was significantly greater in large pores than in small ones. However, the trend of the difference in oil recovery rate between N_2 and CO_2 flooding under different pressures was almost identical in small and large pores.[22] Thus, the pore radius only had a slight effect on this variation, while the displacement pressure had a significant impact.[23] Larger pores exhibited a better oil recovery rate under CO_2 flooding compared to N_2 flooding.[24] In the study,[25] analyzes phase behavior in volatile oil systems using nitrogen and carbon dioxide in reservoir simulations. Key findings include: Customizing an EOR for accurate representation in complex systems with multiple oils and

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gases. Despite similar miscibility pressures, nitrogen and hydrocarbon gas behave differently, affecting density and viscosity. Agreement among MMP algorithms and impacts of nitrogen-CO_2 blends on MMP. Potential incremental recovery with nitrogen Water-Alternating-Gas (WAG) EOR schemes, suggesting technical feasibility. Further research is recommended to assess uncertainties and commercial viability of N_2 WAG- EOR.

This paper contributes to the existing body of knowledge by conducting extensive core displacement experiments to systematically study the enhanced oil recovery potential of nitrogen injection. The confirmed feasibility of enhanced oil recovery, coupled with an in-depth analysis of the impact of injected parameters, provides valuable insights for optimizing parameters in the development of sandstone reservoirs.

The significance of this study can be summarized by using two nitrogen core-flooding methods at low pressure to identify the best and most economical method for the Sandstone Formations.

2. Geological setting

The South Mangyshlak oil and gas region is a large area characterized by a trough. Throughout its geological development.[26] this region has experienced a prolonged and stable deflection compensated by the accumulation of thick sedimentary rock layers.[27] These conditions have been favorable for converting organic matter into bitumen and forming oil and gas accumulations.[28] The South Mangyshlak basin has three zones: the Mangyshlak uplift system, the South Mangyshlak depression, and the Karabogaz zone.[29]

The North Karamandybas field is located east of Kazakhstan close to the Uzen and Tenge oil and gas fields.[30] The stratigraphic column of the North Karamandybas Field is shown in Fig. 2. North Karamandybas oil comprises six horizons (J-II, III, VII, VIII, J-IX, and I) and eleven deposits (J-Ia, Ib, IIa, IIb, III, VIIa, VIIb, VIIIa, VIIIb, IXa, and IXb). Initially, the development of the J-VII, J-VIII, and J-IX horizons is planned as exploitation targets because the oil reserves in these horizons are larger in volume than the other horizons. J-VII Horizon - Lithologically, characterized by alternating sandstones, siltstones, and argillites.[31] The sandstone siltstones are beige-gray, weakly cemented, and fine-grained, with rare thin discontinuous layers of carbonaceous-clayey material. Based on petrographic descriptions, the structure of the sandstone siltstones is euro-micro psammitic, with a disorderly texture. The grains consist of quartz (40-45%), feldspars (25-30%) represented by plagioclase and microcline, fragments of carbonaceous shales, siliceous rocks, and biotite plates. Grain size ranges from 0.02 to 0.25 mm, with mixed cement including clayey and calcite components.

Based on granulometric analysis of samples with permeability greater than 1×10^{-3} μm^2, the reservoir rocks are predominantly composed of fine-grained sandstones and siltstones. Fig. 3 shows the percentage content of granulometric fractions and the carbonate composition of reservoir rocks. The porosity of the reservoir rocks ranges from 14 to 20.3%, permeability from 1.0 to 55×10^{-3} μm^2, clay content up to 40.8% by weight, and carbonate content from 3.7 to 9.4%.[29] Based on the geological cross-section of the J-VII, J-VIII, and J-IX horizons at the field, it appears that the perforation interval of the formations is not significantly far apart from each other within each formation (Fig. 4). The porosity of the reservoir rocks in these horizons is 19%, 18%, and 17%, respectively. In addition, the reservoir pressure is 17.68 MPa, 18.23 MPa, and 19.02 MPa, respectively, and the oil saturation is 62%, 65%, and 70%, respectively. Therefore, it is feasible to exploit these horizons simultaneously in one well, as shown in Fig. 5.[32]

J-VIII Horizon - Lithologically, the J-VIII horizon is similar to the J-VII horizon. Based on macro-description and granulometric composition, it consists of coarse- and fine-grained beige-gray siltstone with barely noticeable streaky layering, highlighted by carbonaceous material and emitting a UV odor on fresh breakage. Analysis of samples shows permeability coefficients ranging from $(1.15 \text{ to } 7.8) \times 10^{-3}$ μm^2, porosity coefficients from 0.169 to 0.19 dimensionless units, and carbonate content ranging from 2.0 to 5.7%. Petrographic descriptions indicate a polymictic siltstone collector with a coarse- fine- alevritous structure and disorderly texture.[32]

Grains sized 0.03-0.09 mm consist of quartz (35-50% of the detrital portion), feldspars (25-30%), and fragments of rocks, clayey-shale rocks, and mica sheets. The cement is clayey, hydro-mica-porous type, and calcite-based. The fractional characteristics of the reservoir rocks based on samples are shown in Fig. 6, where the fraction content with grain sizes from 0.5 to 1 mm (Fig. 6).

3. Materials and methods

3.1 Materials

The North Karamandybas crude oil was used in this study. The density and dynamic viscosity of the oil at room temperature were equal to 0.850 g/cm^3 (~35 API) and 5.08 cp, respectively. Low salinity brine with Total dissolved solids (TDS) equal to less than 1 g/L was used for core flooding (Table 1).

North Karamandybas sandstone core samples at depth

Table 1. Chemical composition of reservoir water in the North Karamandybas field.

Core No	Identifiable ingredients									
	dry impurities	HCO_3 mg/dm^3	SO_4^{-2} mg/dm^3	Cl^{-1} mg/dm^3	CO^{-2} mg/dm^3	Fe Total mg/dm^3	Ca^{+2} mg/dm^3	Mg^{+2} mg/dm^3	Na + K mg/dm^3	SiO_2 solution
1	908	237	336	156	0	11	168	32	98,4	3,3

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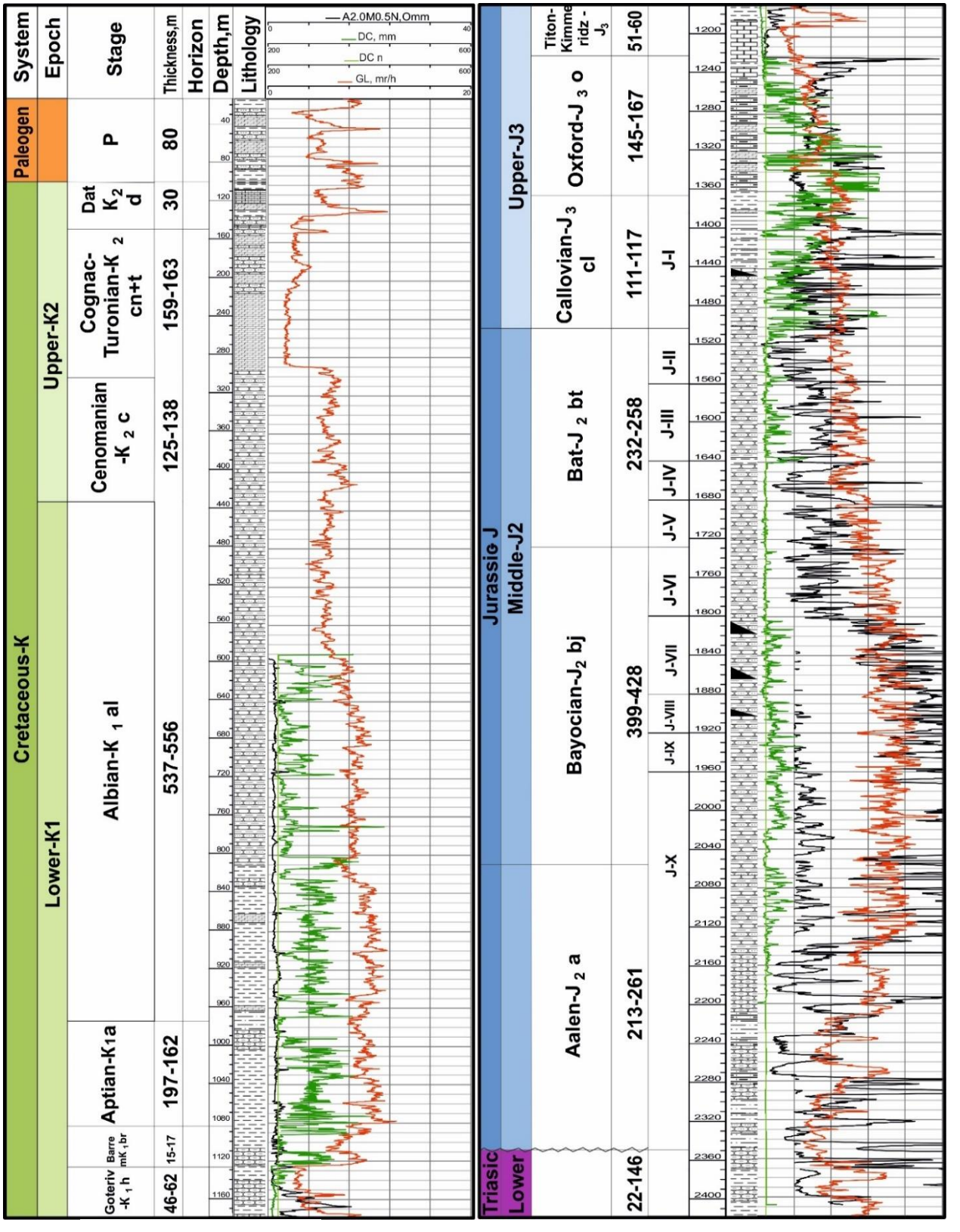


Fig. 2 Stratigraphic column of the North Karamandybas Field.

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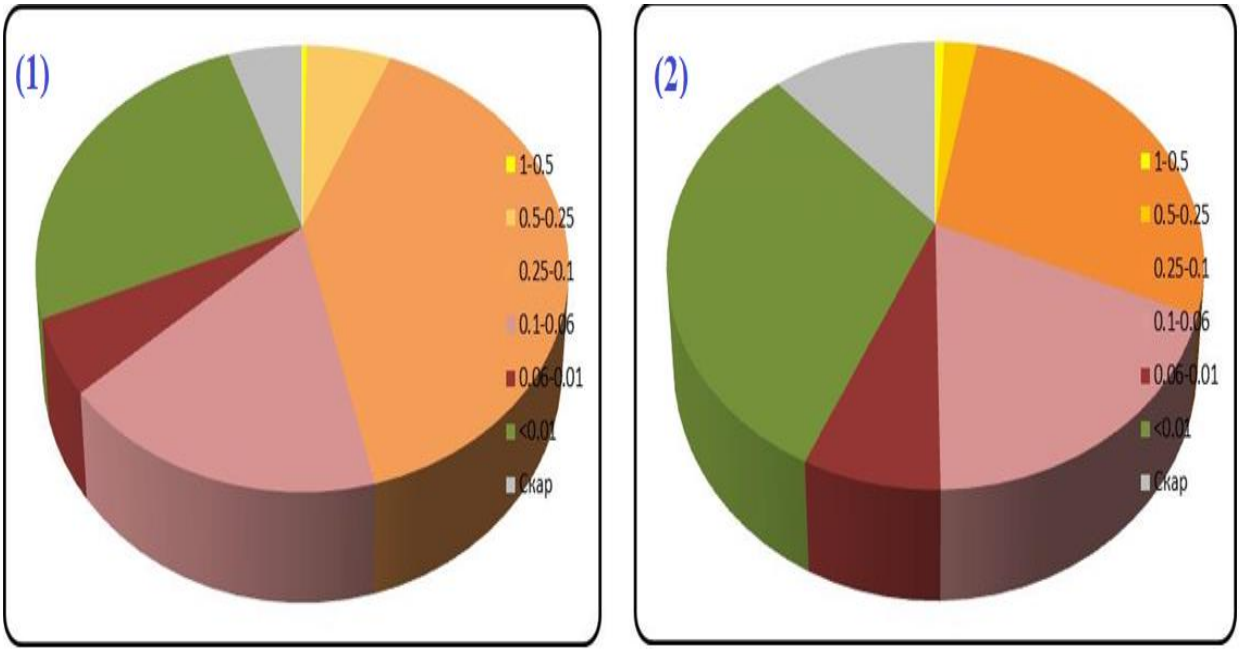


Fig. 3 Fractional compositions of reservoir, 1- non-reservoir, 2- Rocks of the J-VII horizon.

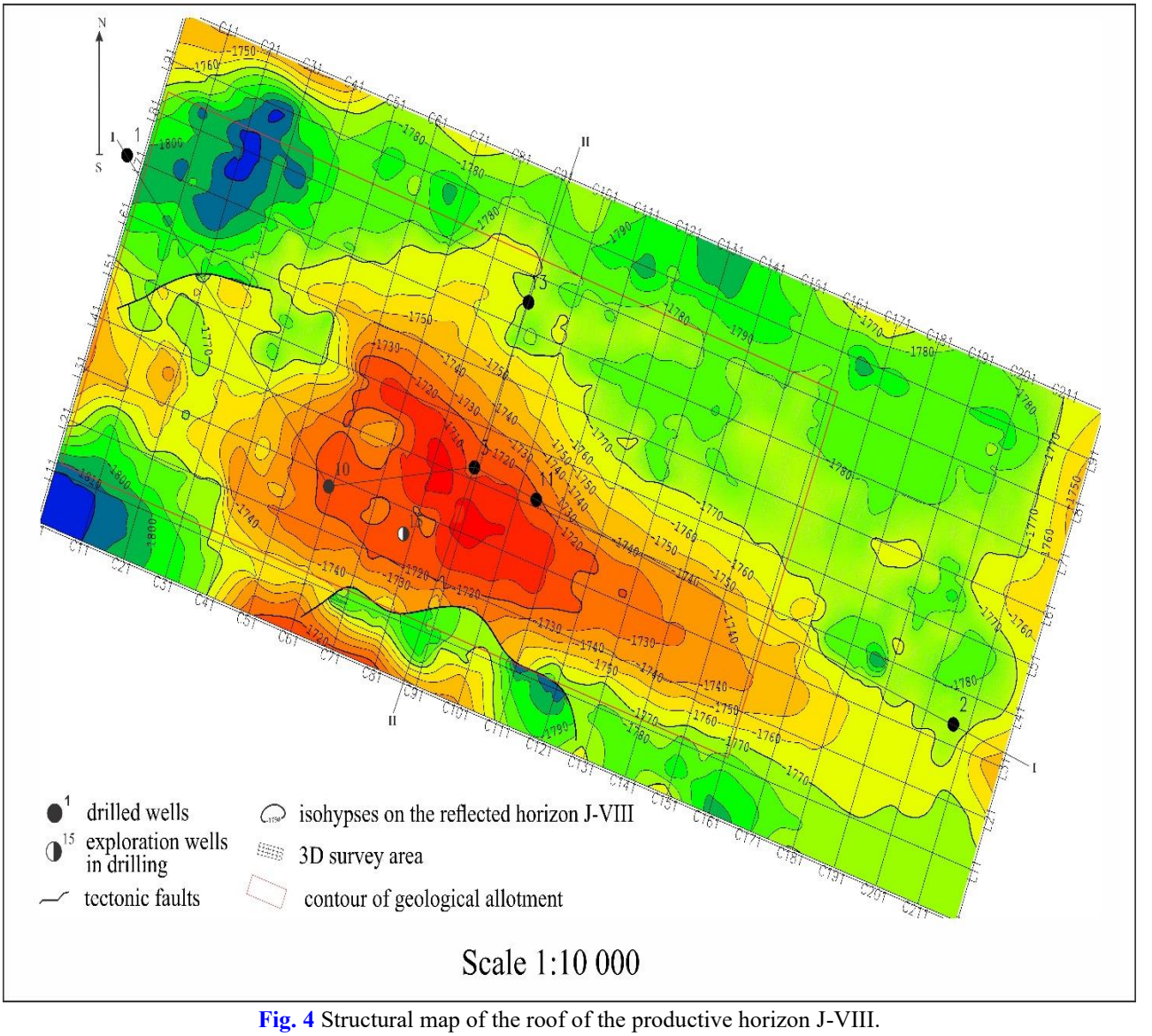


Fig. 4 Structural map of the roof of the productive horizon J-VIII.

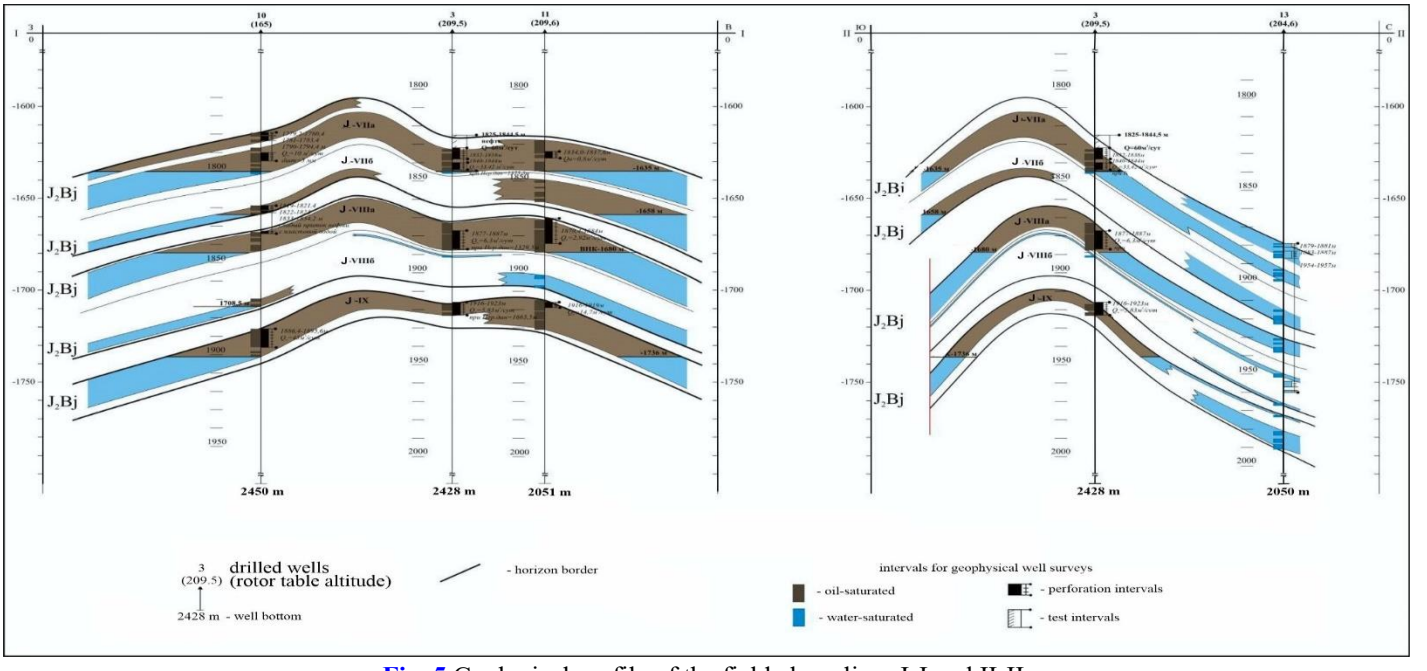


Fig. 5 Geological profile of the field along lines I-I and II-II.

2250 m were used for cored wells shown in Fig. 7. Table 2 shows the porosity and permeability of the samples determined by injecting low salinity brine.

3.2 Methods

The core flooding experiments were conducted according to the following procedure: The core sample underwent a high-pressure air cleaning process at 1 MPa to clean the pores, as shown in Fig. 8. This process effectively removed all dust and fine particles that may have accumulated in the porous cavities during core preparation. The weight of the dry sample was measured before subjecting it to a 10–12-hour aging process in an oil-filled beaker. To fully saturate core with oil, the beaker inside the closed cell was vacuumed at a pressure drop of at least 0.7 bar. After this, the saturated sample was weighed. Finally, either water or nitrogen was injected.

Table 2. The parameter of core samples.

Experiment	Core sample	Diameter, cm	Length, cm	Mass of the core sample, g	Porosity, %	Permeability, mD
Low salinity water flood	1	4	4	85.05	17.1	46
	2			91.54	16.4	42
	3			83.80	17.3	49
	4			89.01	16.8	48
	5			88.60	17.0	45
	6			85.02	17.2	48
Nitrogen injection	7	4	4	81.86	17.9	50
	8			71.8	19.5	56
	9			73.7	18.3	51
	10			73.2	18.6	53

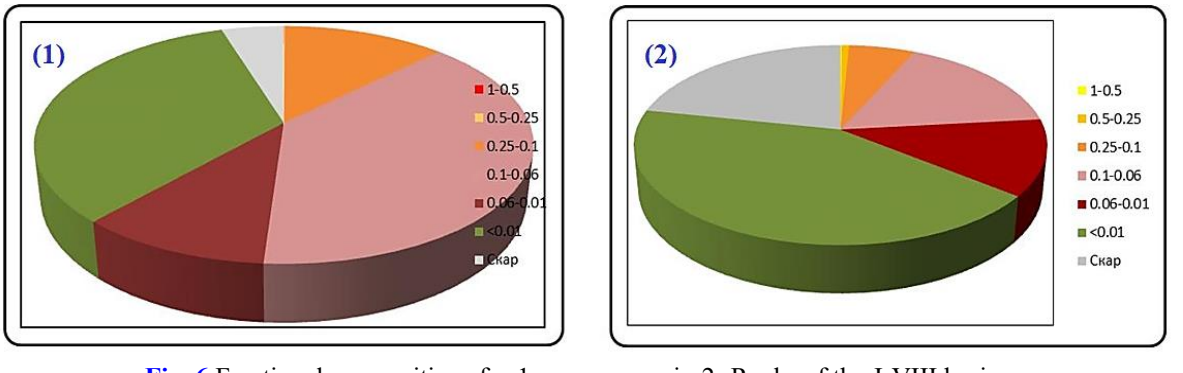


Fig. 6 Fractional compositions for 1- non-reservoir, 2- Rocks of the J-VIII horizon.

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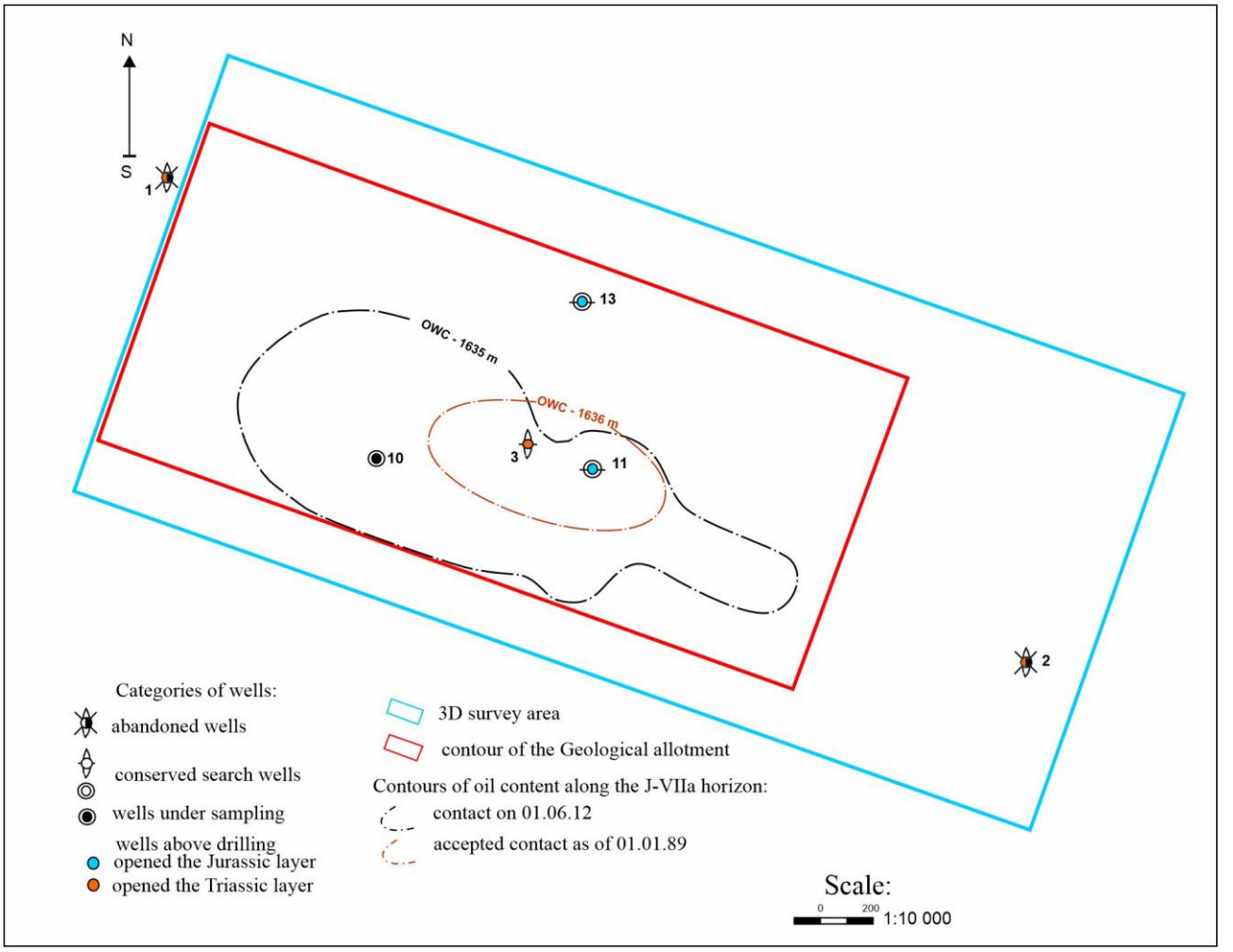
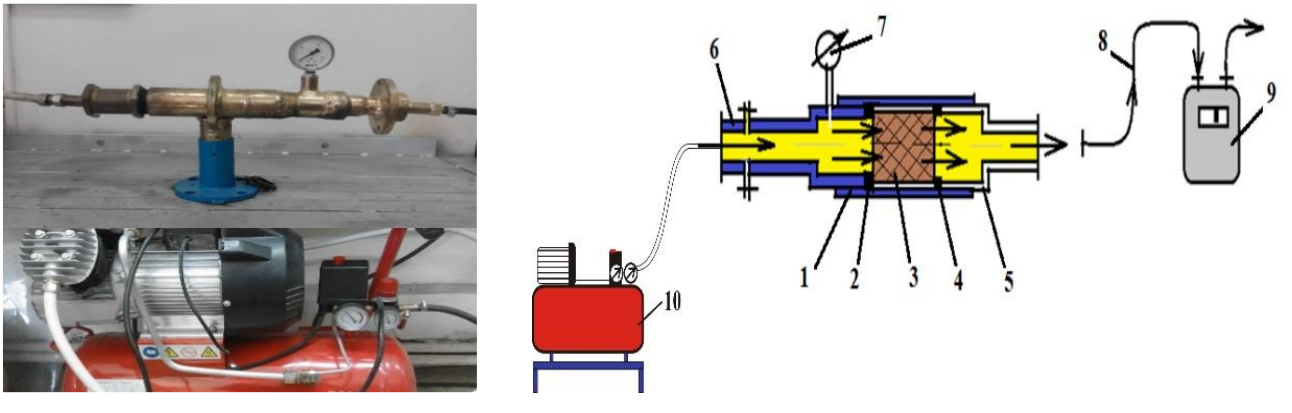


Fig. 7 Cored wells at the North Karamandybas field.

For water flooding, the core-flooding setup is shown in Fig. 9. The core was placed in a chamber (1) containing a rubber sleeve (2). The sleeve securely fixes the core inserted into the setup. Water was filled in a water tank (3) located at the top of the setup and drained down through a disconnecting valve (4) to fill the lower water tank (5). Then, using a hand pump (6), water is pushed under 1 MPa through a pipe (7) into the oil-saturated core. A pressure gauge (8) measures the high pressure created by the hand pump (1 MPa). The water injection continued until the core reached residual oil saturation (no more oil production).

Two different core-flooding setups were useable in the nitrogen injection experiments. The first setup was designed for the total area penetration of nitrogen into the core (Fig. 10).



(A) (B)

Fig. 8 Photo (A) and scheme (B) of the core cleaning device with high-pressure air: 1- horizontal cylindrical housing; 2- working chamber for installing a rubber gasket; 3- core; 4- rubber seal; 5- end fitting; 6- inlet nozzle; 7- pressure gauge; 8-tube; 9- gas flow meter; 10-air compressor.

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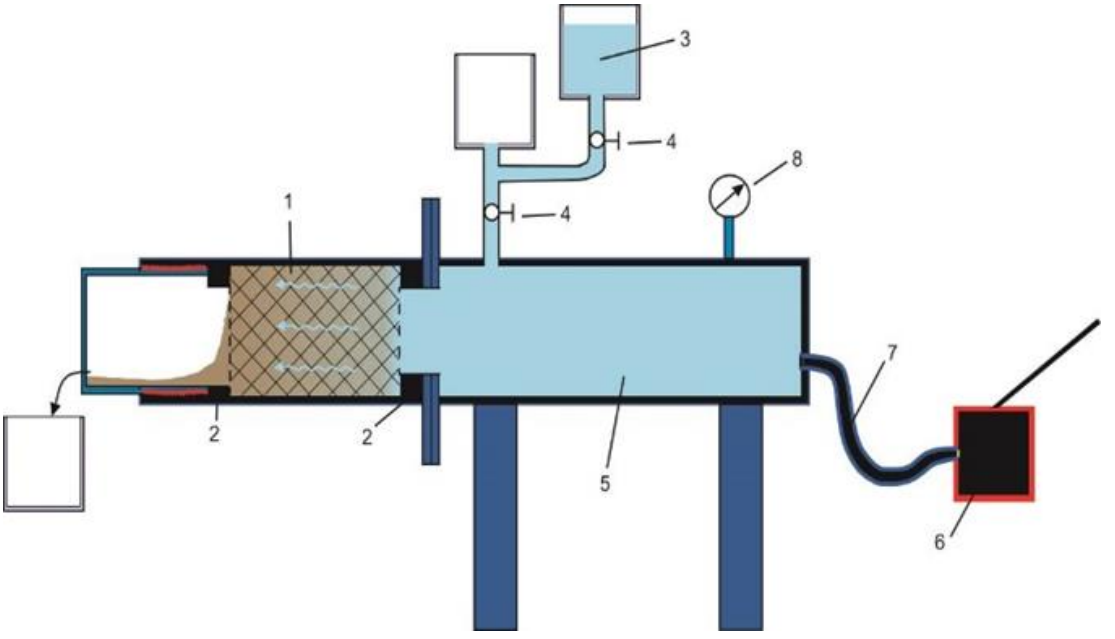


Fig. 9 Set up used for core flooding with water.

The oil-saturated core sample was placed inside the container and subjected to nitrogen pressure. Nitrogen enters into the chamber with the oil-saturated core sample inside. Nitrogen was injected linearly into a container that contained the core sample and then closed for a day. During the 24 hours, the nitrogen penetrated in all directions entered the core, and displaced the oil from it. Subsequently, the displaced oil inside a beaker at the outlet was collectible and weighed after 24 hours at 0.7 MPa. The second core flooding setup included the linear displacement of oil by nitrogen at one MPa (Fig. 8). As a result, the nitrogen acted like a piston and displaced the oil on the other side. However, the setup included nitrogen injection at a constant pressure until the limit of residual oil saturation and did not include a gas flow meter.

The primary difference between the two setups - total area and linear displacement - lies for nitrogen used. In the first setup, nitrogen is continuously supplied to maintain the pressure, resulting in higher consumption. In contrast, the second setup injects nitrogen only once until the container is filled, reducing the overall nitrogen consumption.

4. Results and discussion

4.1 Low salinity water flooding

Figure 11 displays the outcomes of saturating the cores with oil and water flooding. As the water-flooding tests were carried out at a consistent pressure drop of (1) MPa, the pressure gradient during the oil displacement process equated to 25 MPa/m, which proves to be sufficiently high for displacing all the mobile oil from the cores. As Fig. 11 shows, the oil recovery factor by low salinity water was equal to ~50-55 %.

Fractures with high permeability surrounded by lower permeability cores (Tables 2) Fig. 11 for core numbers 2 and 5) result in lower recovery factor compared to non-fractured

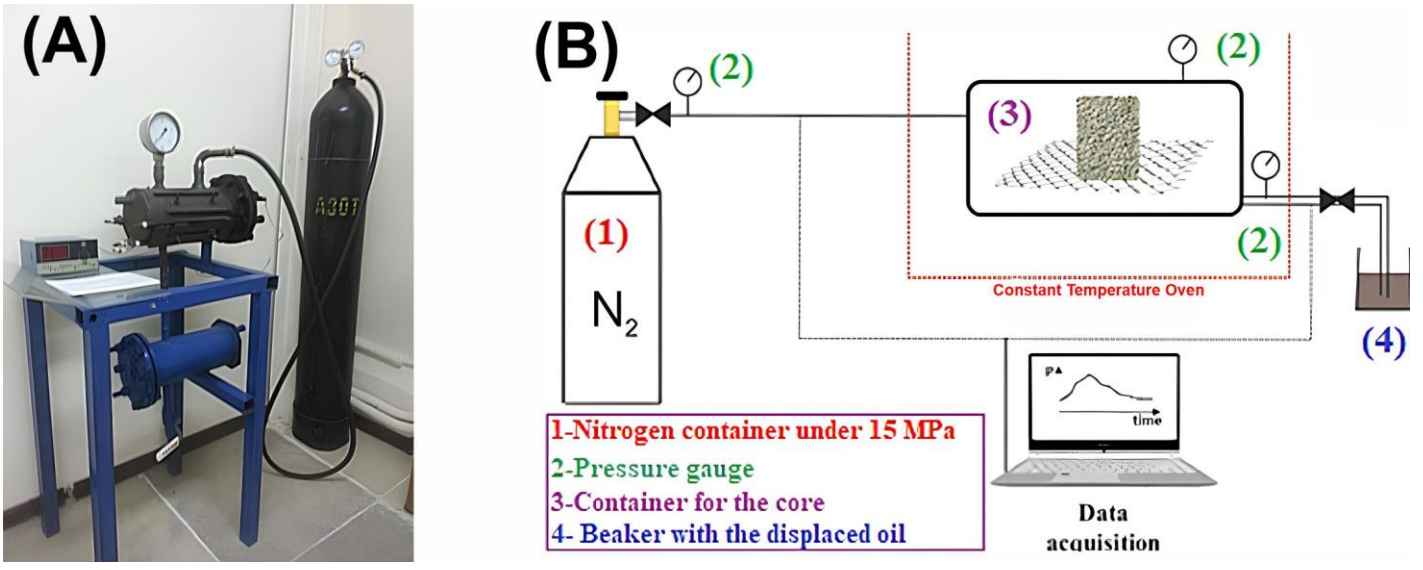


Fig. 10 Photo (A) and scheme (B) of core flooding set-up used for nitrogen injection.

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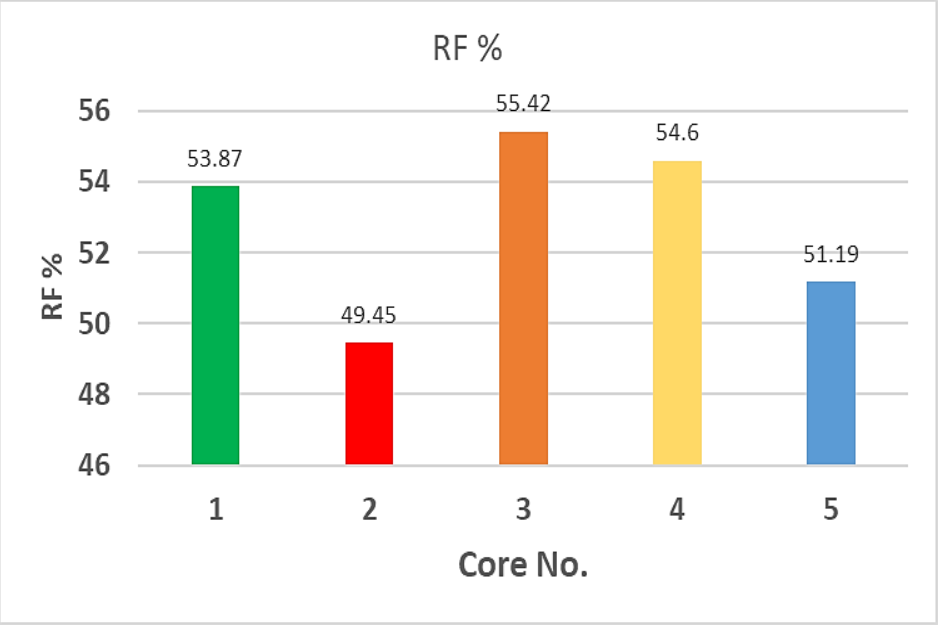


Fig. 11 Recovery factor % after water injection.

cores. The experiment with core floods at reservoir conditions must be conducted for more representative results. It should be noted that seawater dilution is a common practice in sandstone low-salinity water injection, which requires reducing the salinity to the optimum value according to the reservoir water salinity.

4.2 Nitrogen injection

Figure 12 represents the results of nitrogen injection at (1) MPa into the core samples (6, 7, 8, 9, and 10). As evident, in the majority of the experiments, the oil recovery factor with nitrogen was higher in the case of linear displacement.

The comparison between Fig. 11 and Fig. 12 indicates that the maximum oil recovery factor attained with low salinity water is 55.42%. Conversely, the maximum oil recovery factor achieved with nitrogen is 65%. However, the average of oil recovery factors calculated from five experiments were 52.9% and 55.6% for water flooding and nitrogen injection experiments, respectively (Fig. 13). According to the findings, low injection pressure led to a higher ultimate recovery. This is because it delayed the gas breakthrough and facilitated a uniform horizontal displacement of oil within the matrix towards the outlet during the injection period.

The results indicate that the recovery factor obtained from experiment 2 is generally more than experiment 1 (Fig. 14). That is likely due to a more stable nitrogen front formed over a continuous flooding pressure at constant value behind the oil bank. RF will be a significant factor in the EOR using the total displacement method, even if it requires less nitrogen. The balance between the economic impact and time must be noticeable according to the current oil prices, based on the fact that increasing the injection rate will not always result in a higher recovery factor; there is an optimal injection rate for nitrogen injection.

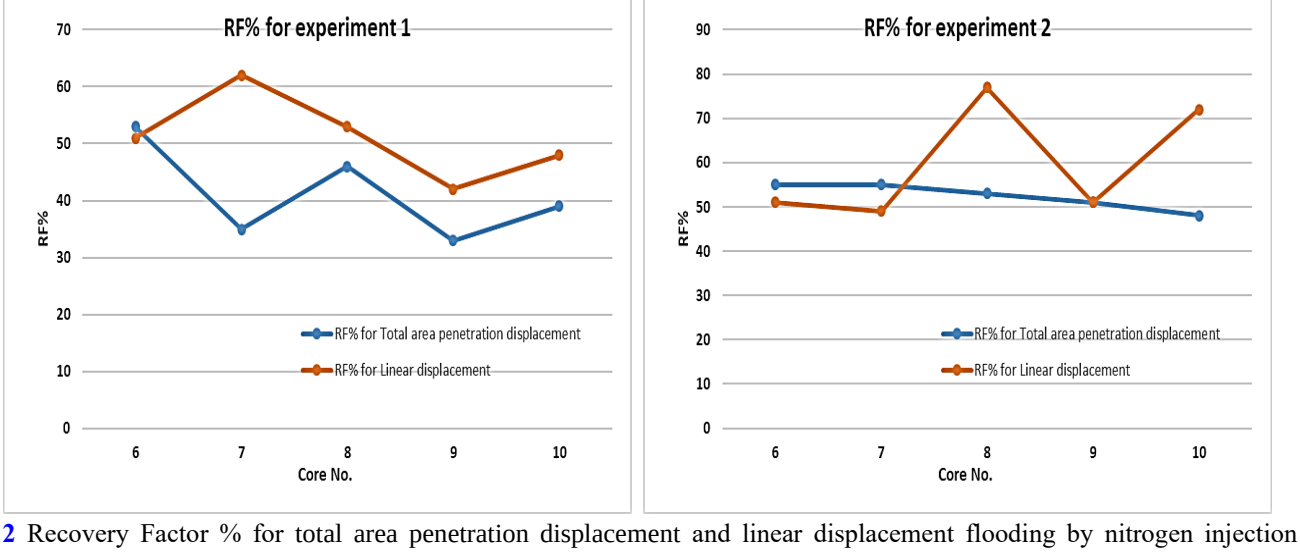


Fig. 12 Recovery Factor % for total area penetration displacement and linear displacement flooding by nitrogen injection for experiments 1 and 2.

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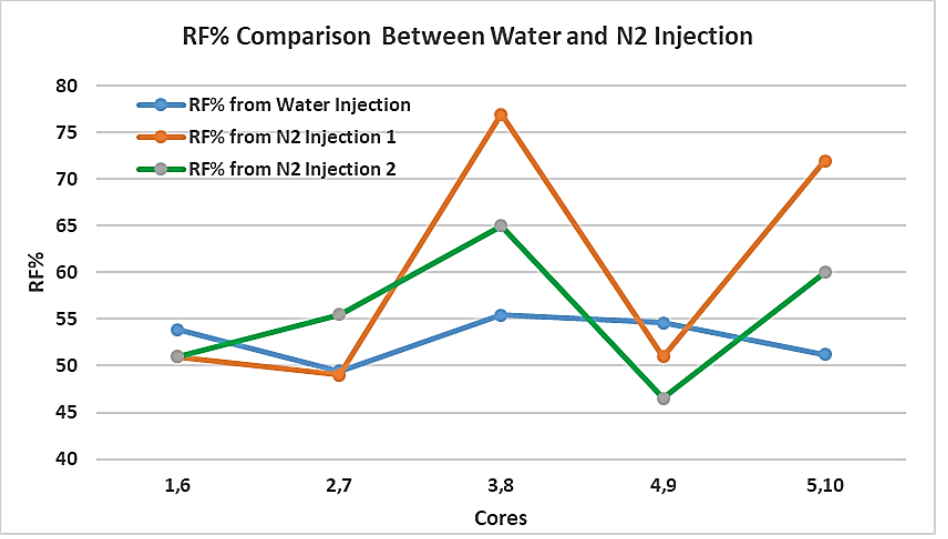


Fig. 13 RF% Comparison between Water and N_2 Injection for all experiments.

The technique used for injecting nitrogen can have a significant impact on oil recovery. The linear displacement method has proven to be the most effective approach for injecting nitrogen in a gravity-stable mode, where nitrogen acts like a piston. On the other hand, nitrogen flooding in a gravity-unstable mode, where there is total area penetration, is less effective than the linear displacement method.

4.3 Total recovery factor by water and nitrogen injection

Firstly, Nitrogen was injected into the cores used for secondary recovery by water injection (Fig. 12), and then the cores (1, 2, 3, 4, and 5) were set up for nitrogen injection. The results indicate that the recovery factor that resulted from the linear displacement is more than the total area penetration displacement core flooding. The total average recovery factor for all five cores is 87.32% (Fig. 15).

4.4 Recovery factor's comparison between water and nitrogen injection

The experiment aimed to compare water and nitrogen injection methods to determine the more effective one. Overall, nitrogen injection proved to be superior, particularly in terms of linear displacement, which resulted in a higher recovery factor (Fig. 16).

In Fig. 16, it can be observed that the recovery factor of the total area penetration displacement method displays both upside and downside variations. The experiment's setup is responsible for this phenomenon, as the nitrogen was kept in the holder for 24 hours.

Using N_2 for secondary recovery is more effective than water injection for the sandstone Formations. That may be due to the water fingering phenomena between water injected and oil, which occur by the water pressure, pore geometry, and

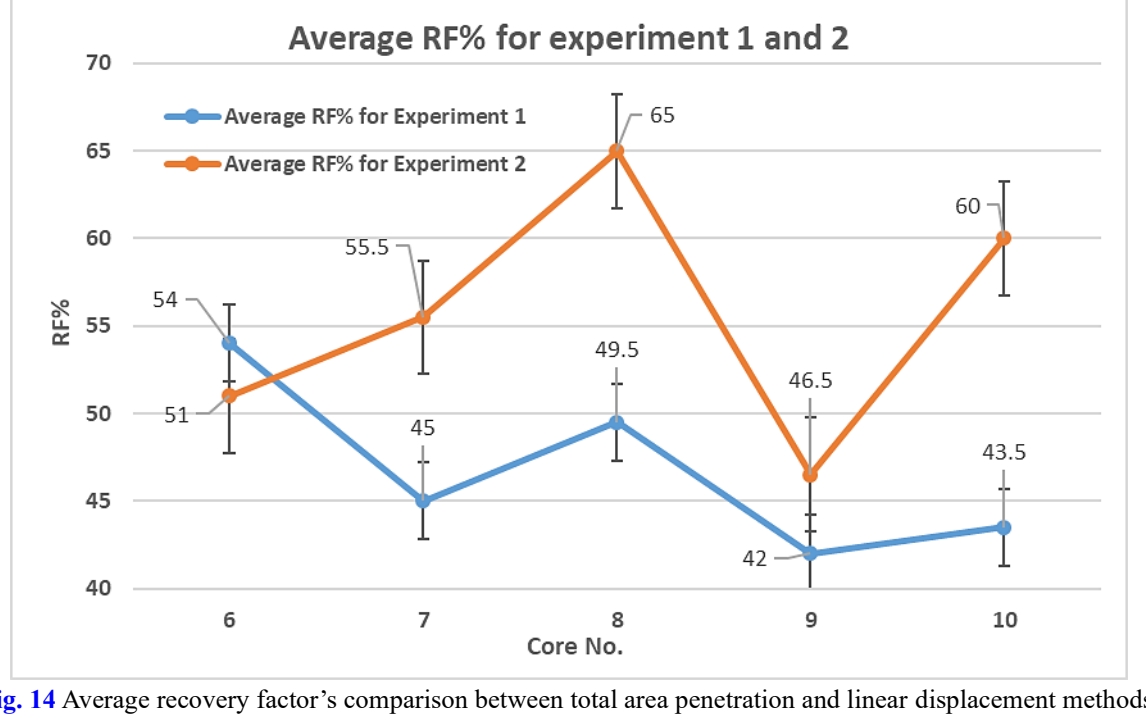


Fig. 14 Average recovery factor's comparison between total area penetration and linear displacement methods.

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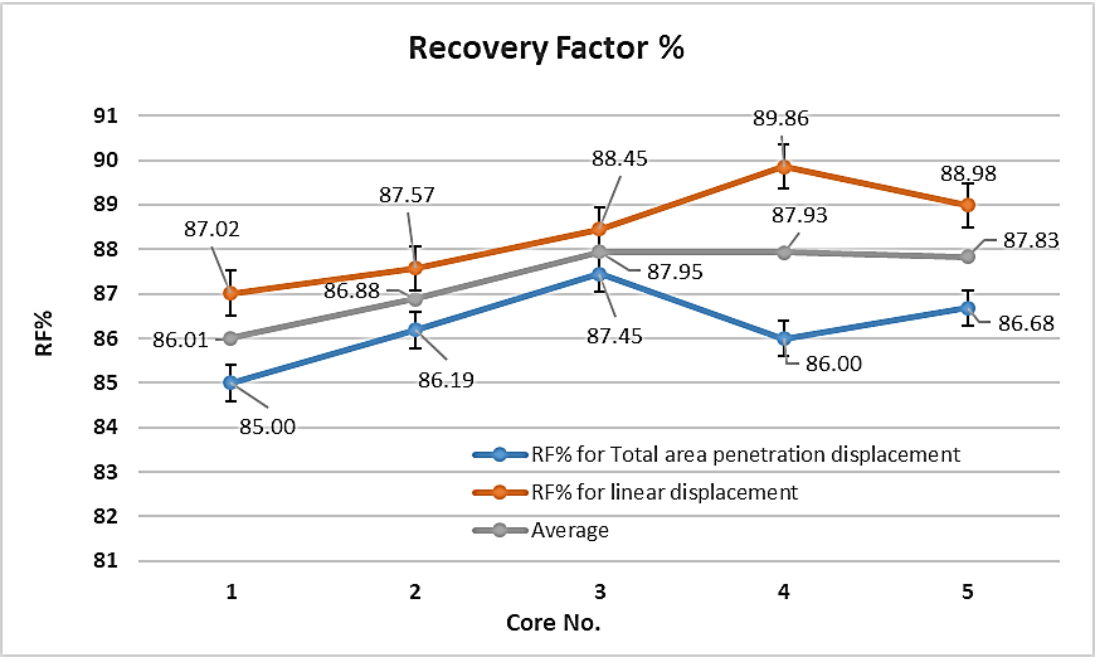


Fig. 15 Total Recovery Factor % for cores after secondary and enhanced oil recovery.

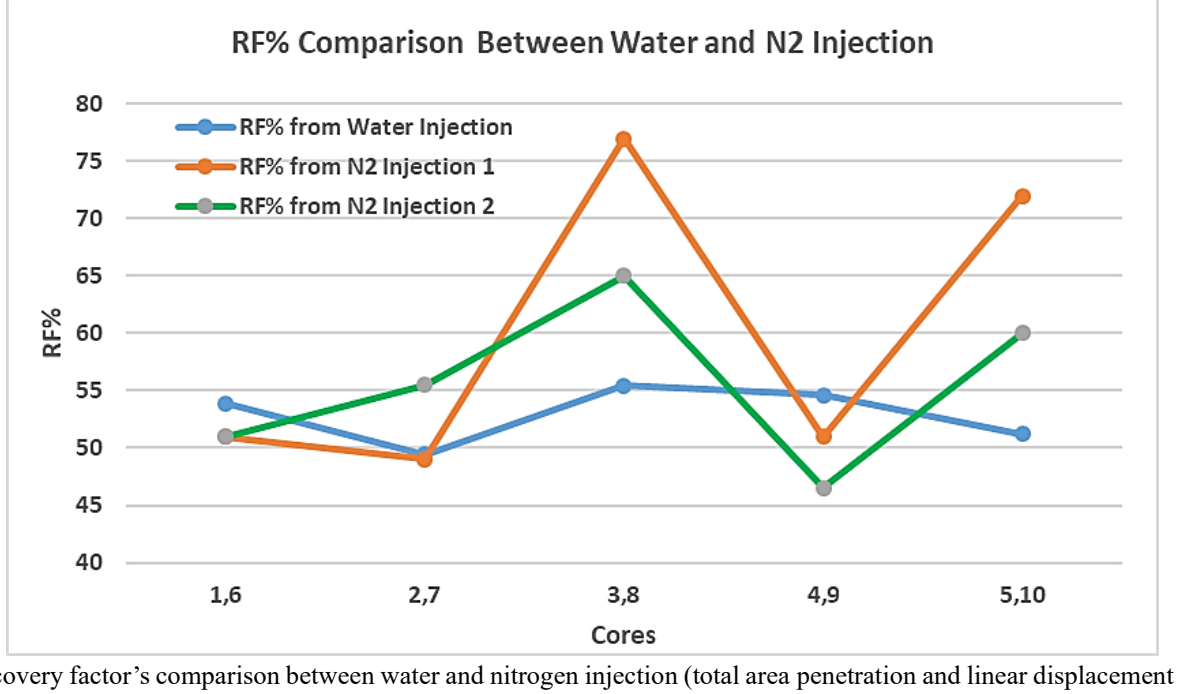


Fig. 16 Recovery factor's comparison between water and nitrogen injection (total area penetration and linear displacement methods).

water injection delay time.

5. Conclusions

1. This study conclusively proves that the injection of gas into a lower to middle-permeability sandstone reservoir is an effective method for recovering more oil at a significantly lower injection pressure.
2. The oil recovery factor by low salinity water injection was equal to ~50-55 %.
3. There is not always an improvement in recovery factor when increasing the injection rate, as there is an optimum rate for nitrogen injection.
4. N_2-gas flooding can successfully recover a large percentage of the oil in place; far more than would be recovered by either primary production or water flooding.
5. The linear displacement method is most successful for gravity-stable injection (Average RF% reach of 65%). Nitrogen flooding in gravity-unstable mode is less effective than linear displacement (at a maximum of 51%).
6. The average RF for both secondary and tertiary flooding by water and nitrogen is 87.32% for both total area penetration and linear displacement.

Future developments in oil production, including nitrogen injection, are enhancing the industry. Recent results confirm its effectiveness in low to medium permeability sandstone formations, improving oil recovery under reduced pressure.

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Optimal injection rates are important because N_2 gas flooding outperforms conventional methods. Water and nitrogen flooding provide an average recovery rate of 87.32%, demonstrating their potential for the future.

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Conflict of Interest
There is no conflict of interest.

Supporting Information
Not applicable.

Abbreviations
°C degree Celsius
CO_2 Carbon dioxide
EOR Enhanced oil recovery
g gram
IOR Improved oil recovery
mD Millidarcy
MMP Minimum Miscibility Pressure
MPa Mega Pascal
N_2 Nitrogen
OIP Oil in Place
ORF Oil Recovery Factor
RF Recovery Factor
WAG Water-Alternating-Gas

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