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Experimental Studies of Immiscible High-Nitrogen Natural Gas WAG Injection Efficiency in Mixed-Wet Carbonate Reservoir

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Abstract: Crucial oil reservoirs are located in naturally fractured carbonate formations and are currently reaching a mature phase of production. Hence, a cost-effective enhanced oil recovery (EOR) method is needed to achieve a satisfactory recovery factor. The paper focuses on an experimental investigation of the efficiency of water alternating sour and high-nitrogen (~85% N_2) natural gas injection (WAG) in mixed-wetted carbonates that are crucial reservoir rocks for Polish oil fields. The foam-assisted water alternating gas method (FAWAG) was also tested. Both were compared with continuous water injection (CWI) and continuous gas injection (CGI). A series of coreflooding experiments were conducted within reservoir conditions (T = 126 °C, P = 270 bar) on composite cores, and each consisted of four reservoir dolomite core plugs and was saturated with the original reservoir fluids. In turn, some of the experiments were conducted on artificially fractured cores to evaluate the impact of fractures on recovery efficiency. The performance evaluation of the tested methods was carried out by comparing oil recoveries from non-fractured composite cores, as well as fractured. In the case of non-fractured cores, the WAG injection outperformed continuous gas injection (CGI) and continuous water injection (CWI). As expected, the presence of fractures significantly reduced performance of WAG, CGI and CWI injection modes. In contrast, with regard to FAWAG, deployment of foam flow in the presence of fractures remarkably enhanced oil recovery, which confirms the possibility of using the FAWAG method in situations of premature gas breakthrough. The positive results encourage us to continue the research of the potential uses of this high-nitrogen natural gas in EOR, especially in the view of the utilization of gas reservoirs with advantageous location, high reserves and reservoir energy.

Keywords: enhanced oil recovery; high-nitrogen natural gas; WAG; FAWAG; mixed-wet fractured carbonates; immiscible gas injection

1. Introduction

A key requirement of any enhanced oil recovery (EOR) process connected with fluid injection into the reservoir is to achieve a favorable mobility ratio between displacing and displaced fluid. Gas injection in EOR is associated with an unfavorable mobility factor (due to the significant difference in dynamic viscosity between the injected gas and crude oil to be displaced), which leads to destabilization of the displacement front, gas fingering and premature breakthrough of the injected fluid into production wells. Moreover, zones saturated with oil and not covered by the displacement front occur. This results in a relatively low recovery factor [1,2].

Water Alternating Gas injection (WAG) was initially introduced to enhance oil recovery in the continuous gas injection (CGI) process through improving macroscopic sweep efficiency. The technique,

which was a combination of two commonly and globally used processes known as CGI and waterflooding (WF), was first implemented in the late 1950s in a sandstone reservoir (Alberta, Canada) [3]. For that reason, the WAG process is sometimes referred to as a combined water/gas injection (CGW) [4].

The combination of the improved microscopic displacement of CGI with an improved macroscopic sweep of WF led in most cases to enhanced oil recovery, especially when compared to the gas or water injection alone. Cyclic injection of water and gas slugs allows the control of the gas mobility ratio, thus improving the efficiency of the oil displacement process [5]. The slugs of water are able to sweep oil from the bottom part of the reservoir (because of its higher density compared to gas) and to stabilize the displacing front [6]. Another important advantage besides the gas mobility control is that less gas is needed for injection, instead it is in favor of the usually cheaper water.

In 1958, Caudle and Dyes proposed a variation on WAG process involving simultaneous injection of water and gas, which is called simultaneous WAG (SWAG) [7]. Other less common variations are Hybrid WAG (HWAG or DUWAG), where a huge slug of gas is followed by a number of conventional WAG cycles [8], and Tapered WAG (TWAG), where the volume of injected gas is gradually reduced over time [9].

Initially, most of the WAG projects were located in North America, but currently, the WAG method is the most widely used solution for gas mobility reduction worldwide. It is considered that about 80% of the USA WAG field implementations were profitable [1,10]. WAG processes have also been successfully applied in the North Sea oil fields such as Snorre, Gullfaks, Ekofisk, Statfjord and Brage [11]. The review of 72 WAG field cases indicates that the average incremental recovery was around 10%, and in some cases, up to 20% of the Original Oil in Place (OOIP) [3].

The WAG performance is influenced by many factors that have been extensively studied, such as the reservoir parameters including wettability [12,13] and heterogeneity [6,14,15], the injected fluid parameters including water salinity [16,17] and gas type [18,19], the WAG parameters including the WAG ratio [20,21], the number of cycles, slug sizes [22], the timing of injection [23] and, finally, the injection rates of the gas and water phases [24]. The cyclic nature of the WAG process involves complex three phase-flow, which makes the prediction of WAG performance very difficult, and which was extensively studied by Fatemi, Sohrabi and Shahverdi [25–27].

The WAG processes can be classified in different ways, but the most common classification is based on the miscibility of the injected gas with the reservoir oil. Gas injection within the WAG process can be conducted under immiscible (IWAG) or miscible (MWAG) conditions that are characterized by the Minimum Miscibility Pressure (MMP). Sometimes it is difficult to distinguish between miscible and immiscible process because of some uncertainties caused by the dissolving of gas to some degree into the oil (leading to mass exchange – swelling and stripping) and, more likely, it could be a "near-miscible" regime (nMWAG). The MWAG/nMWAG processes are considered to be more efficient than IWAG [18], but many studies revealed that IWAG, which is used in the case of this study, could be very effective in enhancing oil recovery [28,29]. The IWAG process is controlled by two types of mechanisms: fluid-fluid interactions leading to oil swelling and viscosity reduction, and rock-fluid interactions, including oil film flow and three-phase permeability effects [30]. Some of the experimental IWAG data show incremental recovery in the range of 14 ÷ 20% of OOIP [30].

Most of the WAG experimental studies were conducted, as in this paper, using coreflooding tests [18,19,24,31–34]. Still, a lot of important work was also done using micromodel tests [35–37].

Janssen et al. [38] studied several immiscible nitrogen injection schemes in sandstone cores saturated with n-hexadecane and found out the IWAG was superior over CGI.

Khanifar et al. [39] conducted IWAG coreflooding studies using native cores, live oil samples, synthetic brine and high CO_2 content gas. The coreflooding experiment resulted in high recovery factors (up to 74.0%), and the simulation modelling showed the potential to recover up to 7% additional oil over waterflooding.

Alkhazimi et al. [40] investigated the impact of the IWAG parameters, such as slug sizes and injection order, and injection strategy on the process performance in mixed-wed sandstones. The results revealed that the short-sized slugs of water and gas have better recovery efficiency compared with larger cycle injections.

Zhang et al. tested IWAG with CO_2, N_2 and flue gas on core plugs saturated with heavy oil [41], and CO_2 with flue gas on cores saturated with medium oil [42]. They reported recoveries of 6% OOIP for the heavy oil and up to 20% OOIP for the medium oil. However, some of the reservoir experiences indicate that in highly heterogenic and fractured carbonate formations, application of the WAG process may not be sufficient to control the mobility of the injected gas. As a remedy, chemicals are used to support the WAG process by foam generation [43,44]. This is deemed the Foam Assisted WAG (FAWAG) process. Foam flow significantly increases the effectiveness of oil displacement in the presence of the fracture system, and considerably reduces the negative impact of horizontal fractures on oil recovery [45–47].

Gas injection in EOR could be especially cost-effective when using media owned by the operator, e.g., associated petroleum gas, hydrocarbon gases from neighboring fields (also nitrogen rich) and post-process gases (e.g., acid gases from sweetening).

Since the late 60s, a number of laboratory and simulation studies has been conducted in detail concerning different issues of WAG process properties and design [18,48–50], enabling us to use it more effectively in different reservoir conditions. Most of the published laboratory WAG process studies are focused on commonly used hydrocarbon and non-hydrocarbon (especially pure CO_2 and N_2) [19,51,52] gases. Increased interest in CO_2 EOR is particularly evident in recent years because of its high effectivity as well as environmental and economic implication when combined with CCS [53]. The immiscible gas injection could be a cost-effective EOR method, especially when considering huge reserves of high-nitrogen (> 80% N_2) natural gas that are located close to the oilfields, as is the case in the Polish Lowlands. There is a lack of studies on the utilization of high-nitrogen sour gas in EOR. Therefore, this work aims to determine its effectiveness using WAG and FAWAG methods with P-T conditions related to the carbonate reservoirs of the Polish Lowlands.

2. Materials and Methods

To mimic the reservoir conditions as closely as possible while performing the coreflooding experiments, an original reservoir rock was saturated with original reservoir water and live reservoir hydrocarbon fluid. The reservoir is of a structural-lithological nature controlled mainly by the lithology, which is where porous oolitic-intraclastic dolomites are changing horizontally into a non-porous dolomites and limestones of mudstone lithofacies. Total pay zone thickness varies considerably from about 80 m to 20 m. The pay zone sediments mainly represent the toe-of-slope facies with the oolitic dolograinstones, packstones and floatstones interbedded with dolomudstones that are interpreted as grainflow deposits (turibidites, grainflows and debris flows) [54]. The sediments are characterized by high heterogeneity in petrophysical and flow properties caused by intensive diagenetic processes such as dissolution (presence of moldic or intraclastic porosity), recrystallization, secondary cementation and fracturing. Observed locally, a very high porosity (up to 35%) does not always correlate with high permeability values. Both porosity and permeability exhibit high variability, and the mean values are 14.7% and 5 mD, respectively. The natural fracture system is well developed in the reservoir and includes micro-, mezzo- and macro-scale fractures. Both horizontal and vertical fracture systems were identified in the reservoir rocks. Horizontal fractures developed as a dense micro-fracture system supported by the meso-fracture system are found throughout the entire reservoir. The occurrence of horizontal macro-fractures is more local, but they are responsible for the hydrodynamic communication of certain parts of the reservoir. In some areas, they have a fundamental input (80–90%) in the reservoir fluids transport. The Main Dolomite carbonates are sealed above and below by evaporites, creating a closed petroleum system that contains both source and reservoir rock. It caused residual

organic matter to still be present in reservoir rocks, which strongly affects reservoir parameters and leads to mixed wettability [55].

2.1. Reservoir Fluids and Injected Media

Reservoir fluid was recombined from oil and gas separator samples. It was light (41° API) and sour crude oil. The live oil had a dynamic viscosity of 0.515 cP, and a density of 0.645 g/cm^3 at reservoir (test) conditions (P = 270 bar, T = 126 °C). The water phase used for cores saturation, as well as the injection fluid, was sampled from the same well as the hydrocarbon fluids and proved to have a pH of 7.9 and a density of 1.006 g/cm^3. Its dynamic viscosity at test conditions was 0.411 cP. A simplified composition of the formation water is tabulated in Table 1.

Table 1. Composition of formation water.

Total Salinity (g/l)	Cation (g/L)					Anion (g/l)					
	Na^+	K^+	Mg^{2+}	Ca^{2+}	NH_4^+	Cl^-	Br^-	SiO_3^{2-}	HCO_3^-	SO_4^{2-}	S^{2-}
8.932	2.03	0.462	0.062	0.389	0.259	5.265	0.037	0.013	0.177	0.147	0.505

The high-nitrogen natural gas was taken from the separator during a production test. It was characterized by a very high nitrogen content (~87%) and the presence of hydrogen sulphide (2.7%) and carbon dioxide (1.2%). Its dynamic viscosity at test conditions was 0.0273 cP. A simplified compositional analysis of the injected gas is shown in Table 2.

Table 2. Simplified composition of high-nitrogen natural gas.

Density (kg/m^3)	Component Concentration (%mol)							
	N_2	H_2S	CO_2	H_2	C_1	C_2	C_3	C_{4+}
1.2507	86.9	2.7	1.2	1.1	5.6	0.8	0.7	1

In FAWAG corefloodings, a solution of commercial grade AOS (alpha-olefin sulphonate) surfactant at a concentration of 0.5% vol. was used. The solution was based on the reservoir (separator) water described above. It was prepared directly before the coreflooding experiment and injected alternately with gas. Therefore, the generation of the foam took place in situ in a porous medium.

2.2. Rock Material

Original reservoir rock samples that represent the Upper Permian Main Dolomite formation from the Zechstein Basin in western Poland were used. The rock material came from core samples of the producing well from a depth of around 3000 m, and its selection was imposed by the availability of the proper material for further drilling out of the core plugs.

The quantitative mineral composition of the reservoir rock was established using X-ray powder diffraction (XRD) with Siroquant software for XRD Rietveld analysis. Four representative samples from the different parts of the considered cored interval were selected for XRD analysis. The analysis revealed that the mineral composition of dolomite reservoir rock was quite uniform (Table 3) and consisted of dolomite (~83%), ankerite (~16%), anhydrite (~1%) and quartz (~0.5%). An exemplary diffractogram of a tested sample is shown on Figure 1.

Table 3. Mineral composition of reservoir rock samples.

Sample	Mineral Composition [%]			
	Quartz	Dolomite	Ankerite	Anhydrite
1	0.5	83	15.6	0.9
2	0.4	80.3	16.5	2.8
3	0.3	82.4	16.5	0.8
4	0.5	83	15.6	0.9

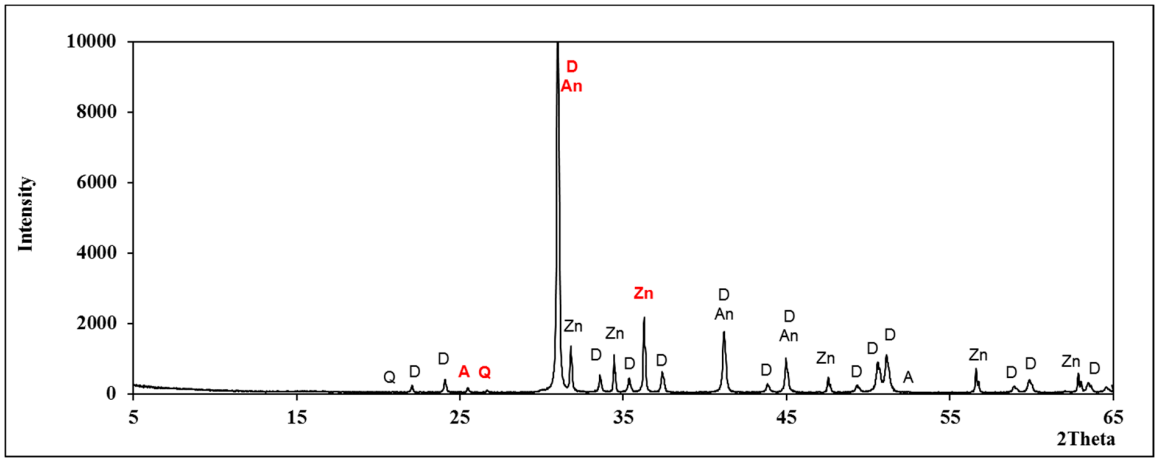


Figure 1. Exemplary diffractogram of sample 1.

Core plugs of 2.54 cm in diameter were drilled horizontally from the whole core samples (Figure 2). As the length of a single core plug was quite short, 5.01–5.78 cm, they were put along together to make a composite core with a length of 21.21–22.30 cm. Individual core plugs were ordered with decreasing permeability in the flow direction based on criterion from Langaas [56], such that the core with the highest permeability was placed at the inlet and the core with the lowest permeability was placed at the outlet. After drilling out the core plugs, the next steps of core handling were end facing, polishing, cleaning and drying. The core plugs were cleaned of residual solids/hydrocarbons initially with the Soxhlet extraction method using toluene and methanol, and then with solvent flushing was done by direct pressure for better removal of salts precipitated from the formation brine. After cleaning, the core plugs were dried in the conventional oven at 116 °C. Most of the core plug preparation procedures were conducted following the guideline from API RP40 [57].



(**a**) (**b**) (**c**)

Figure 2. (**a**) Opened core plug with spacers; (**b**) and (**c**) assembled core plug with a centrally placed fracture supported by spacers.

After that, their parameters such as porosity, absolute permeability and pore volume were determined. Absolute permeability of the individual core plugs was measured with a DGP-100 Gas Permeameter using nitrogen gas. The volume of interconnected pores (effective porosity) was determined using an EPS HPG-100 Helium Porosimeter along with the mercury displacement test.

Based on the value of the helium pressure drop, the mercury density and the core weight in mercury as well as in air, the following core plug parameters were calculated: effective porosity, pore volume, bulk density and grain density. Six composite cores were assembled with the average porosity in the range of 23–30% and permeability of 70–80 mD. Basic parameters of composite cores used in coreflooding tests are presented in Table 4.

Table 4. Properties of composite cores.

Composite Core No.	Length [cm]	Average Porosity [%]	Average Permeability [mD]	Pore Volume [cm^3]
1	21.21	27.1	70.5	28.8
2	21.73	30.4	77.3	33.0
3	21.95	24.6	72.1	26.4
4	22.30	22.7	80.7	25.7
5	21.40	24.6	80.4	26.7
6	22.15	28.7	77.0	31.8

To estimate the impact of fracturing on displacement efficiency, some of the experiments were carried out on artificially fractured cores. Artificial fracturing was also needed for the investigation of gas mobility control by foam flow. Core plugs included in the composite cores No 2 and 3 were slabbed using a precise circular saw with a 0.4 mm thick blade. Two spacers with a thickness of 0.25 mm each were used to ensure a constant gap width and to avoid fracture closing under the given confining pressure (Figure 2).

The gap width was, therefore, maintained at 0.5 mm along the entire length of the fracture (whole composite core). Each spacer frame was cut exactly to the dimensions of the given core, and the volume of empty spaces in the spacers was precisely measured. The geometry of the fracture created throughout the composite core is shown in Figure 3.

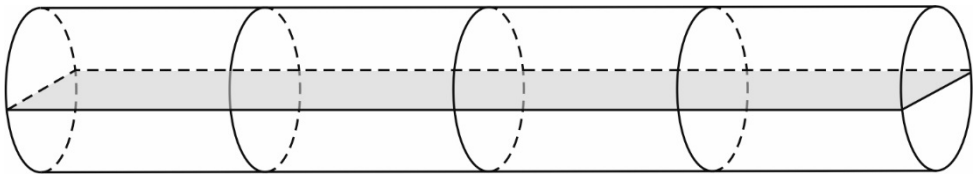


Figure 3. The geometry of the fracture in the composite core.

As a result, the changes in the pore volume of each core associated with slabbing and creation of artificial fracture were meticulously taken into account in the balance of injected and recovered fluids. The measurement of permeability before and after artificial fracturing allowed us to determine the fracture permeability. This turned out to be more than 10 times higher than the permeability of the matrix. Other composite core parameters have changed very slightly (Table 5).

Table 5. Properties of composite cores with the artificial fracture.

Properties of Fractured Core	Composite Core No			
	2		3	
	Value	Change [%]	Value	Change [%]
Permeability [mD]	752	1006	584	1142
Average effective porosity [%]	31.23	2.7	23.06	4.1
Volume of non-fractured cores set [cm^3]	106.48	2.2	108.11	2.1
Pore volume [cm^3]	33.09	0.3	24.77	1.8
Fracture volume [cm^3]	1.54		1.52	
Contribution of fracture volume in pore volume [%]	4.7		6.1	
Contribution of fracture volume in total volume [%]	1.4		4.2	

2.3. Experimental Process

A total of 10 coreflooding experiments were carried out, including four on non-fractured cores and six on fractured cores. For the comparison of the WAG process efficiency, tests with continuous gas injection–CGI (simulation of gas flooding) and continuous water injection–CWI (simulation of waterflooding) were performed. The studies were conducted at a reservoir temperature of 126 °C and a reservoir pressure of 270 bar. Under considered conditions, the high-nitrogen natural gas was immiscible with the given crude oil.

Properly prepared composite cores were placed in a rubber sleeve and then in the core holder. Protection of the tightness between the rubber sleeve and sidewalls of core plugs was maintained by a pressurized water system (Figure 4). A precise water pump was used to provide appropriate confining pressure (100 bar higher than the test pressure). The core holder and fluid bearing pressure cells were placed inside the oven, which guaranteed stable temperature conditions (±0.5 °C). The equipment set up was designed to minimize dead volume. A radial core holder can accommodate cores with a diameter of 2.54 cm and a variable length up to 25 cm. The core holder was placed horizontally. Also, the core holder has one inlet and one outlet port, and the fluid flow at the inlet was controlled through the manifold precise HTHP valves. The inlet and the outlet ports were connected to the pressure and temperature transducers to maintain control of pressure and temperature around the core holder. Produced liquids were measured using a graduated cylinder, while the produced gas was mesured using a gas meter. Initially, the cores were saturated with reservoir water until the appropriate pressure was determined and the pore volume (PV) of the set was measured. The cores were then flooded with live oil under given test pressure, with a constant flow rate q = 0.3 cm^3/min to determine irreducible water saturation and, subsequently, the hydrocarbon saturation–hydrocarbon pore volume (HCPV). Figure 4 shows a simplified schematic of the coreflooding experimental setup.

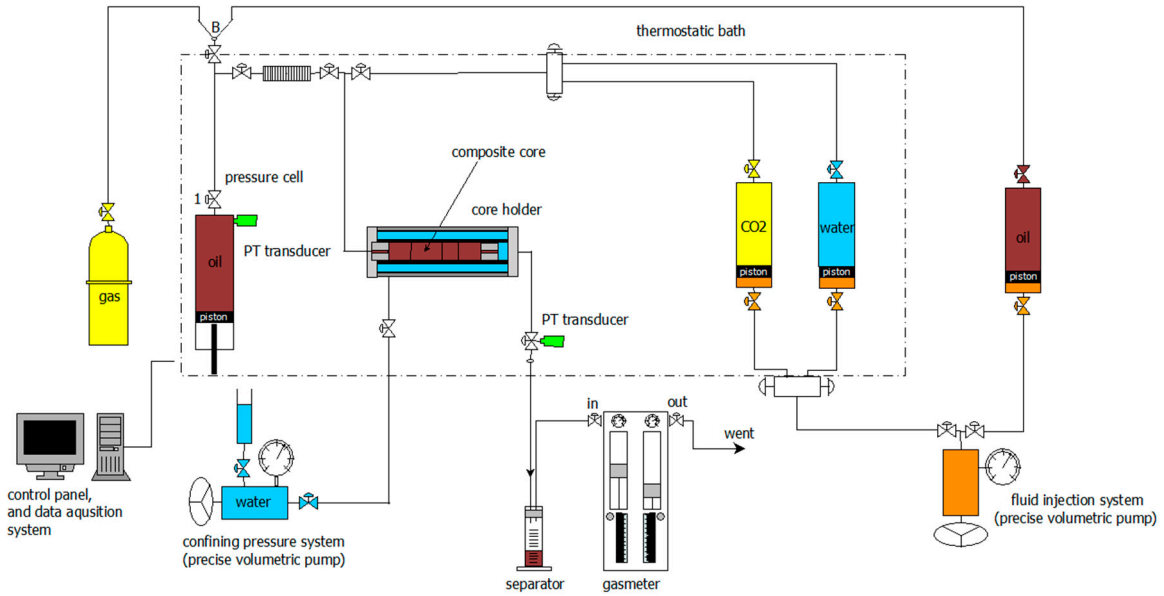


Figure 4. Simplified schematic of the experimental setup.

The total amount of injected fluids during coreflooding experiments in each case was 1.2 HCPV. The injection flow rate was fixed at 0.07 cm^3/min, which, in the core plugs, gave a velocity within the range of 2.5–3.3 cm/h. In the WAG process, injection started with the water, and the slug size was 0.2 HCPV. In the FAWAG method, the foaming agent solution was injected alternately with gas, and also with a slug size of 0.2 HCPV. Irreducible water saturation (S_{wi}) was in the range of 30.5–46.9%, and consequently, the initial oil saturation (S_{oi}) took values of 53.1–69.5. The properties of the coreflooding experiments are summarized in Table 6.

Table 6. Coreflooding experiments properties.

Test No	Composite Core No	Method of Injection	Artificial Fracture	Injected Fluid	WAG Ratio	S_{wi} [%]	S_{oi} [%]	TWI [1] [HCPV]	TGI [2] [HCPV]
1	1	CWI	no	Water	1:0	46.9	53.1	1.2	0
2	4	CGI	no	Gas	0:1	39.6	60.4	0	1.2
3	6	WAG	no	Water/Gas	1:1	30.8	69.2	0.6	0.6
4	5	WAG	no	Water/Gas	1:2	30.5	69.5	0.4	0.8
5	3	WAG	yes	Water/Gas	1:1	38.1	61.9	0.6	0.6
6	2	WAG	yes	Water/Gas	1:2	30.8	69.2	0.4	0.8
7	3	CGI	yes	Gas	1:0	42.5	57.5	1.2	0
8	2	CWI	yes	Water	0:1	32.1	67.9	0	1.2
9	3	FAWAG	yes	FAS[3]/Gas	1:1	41.6	58.4	0.6	0.6
10	3	FAWAG	yes	FAS[3]/Gas	1:2	37.8	62.2	0.4	0.8

[1] TWI–total water (solution) injected. [2] TGI–total gas injected. [3] FAS–foaming agent solution.

3. Results

The objective of the coreflooding experiments was to determine:

- the effectivity of high-nitrogen sour gas WAG injection in mixed-wet carbonates compared to CGI and CWI;
- the impact of artificial fracture on recovery efficiency;
- the possibility of foam flow utilization for gas mobility control in the presence of fractures.

The results showed wide variations (19–72%) in recovery factors (RF) between different variants of injection and, as expected, a significant impact of the artificial fracture for oil recovery. To compare relative merits of gas injection, the Utilization Factor was used. It is defined as the volume of gas injected under standard condition to produce a barrel of oil:

$$UF = \frac{V_{Gas}\ (MSCF)}{Q_{Oil}\ (Bbl)}. \quad (1)$$

The lowest gas utilization factors are observed in WAG injections with a WAG ratio of 1:1, and the highest are yielded by the CGI. There is strong discrepancy in UF values between the same experiments conducted in fractured and non-fractured cores, but the exact trend with the highest UF for CGI and lowest for WAG 1:1 is observed. In fractured cores, foam assisted WAG yielded almost the same UF, but resulted in a significantly higher RF. Results of the conducted coreflooding experiments are shown in Figure 5 and discussed below.

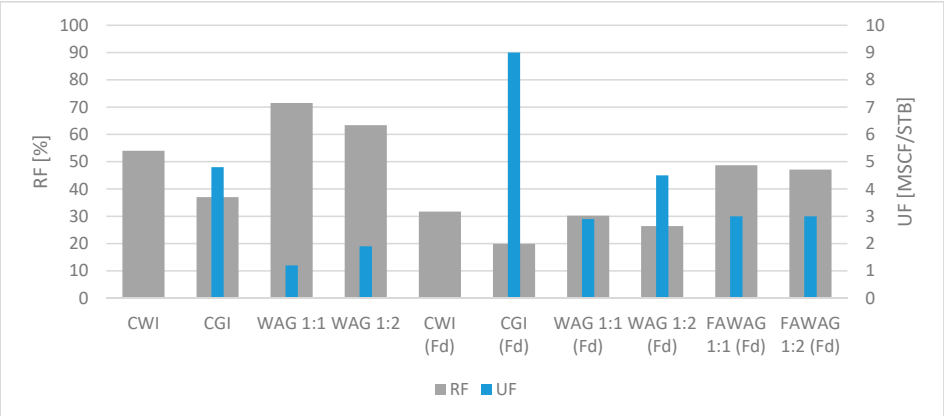


Figure 5. Comparison of Recovery Factor (RF) and gas Utilization Factor (UF) for all coreflooding experiments conducted in non-fractured as well as fractured (Fd) cores.

3.1. Non-Fractured Cores

The application of WAG injection in non-fractured cores without artificial fracture gave the best results, with the recovery factor (RF) in the range of 63–72%. The WAG process was much more effective than CGI (RF higher by 35 percentage points) and CWI (RF higher by 18 points). Four variants of the WAG process were tested, differing in the volume of injected fluids (WAG ratio) and experimental pressure. The best efficiency is observed for WAG ratio 1:1, where equal volumes of water and gas were injected in each cycle. The efficiency of WAG with an increased volume of gas in relation to water (WAG ratio 1:2) and at a lower pressure was slightly reduced (RF lower by 9%), but it was still better than continuous gas and water injection (Figure 5). A comparison of the effectiveness of different injection methods on non-fractured cores expressed in total RF is presented in Figure 6.

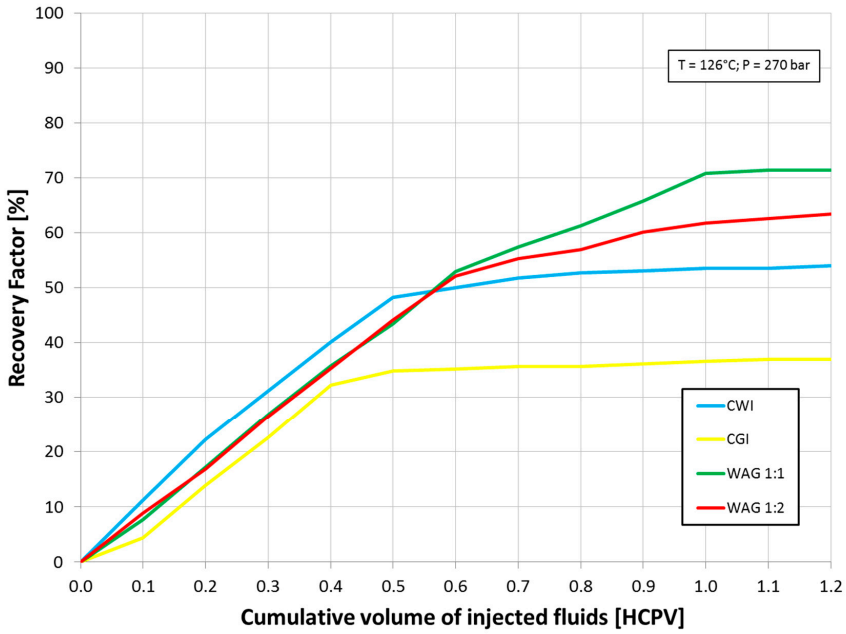


Figure 6. The efficiency of oil recovery using different methods of injection for non-fractured cores.

3.2. Fractured Cores

The presence of the artificial fracture, resulting in the development of a dual permeability system, significantly influenced the effectiveness of oil displacement. A considerable decrease in efficiency was observed for the WAG injection, as well as for the CGI and CWI processes. Continuous gas injection (CGI) showed the lowest recovery efficiency (about 20% of RF). The efficiency of the WAG process was slightly higher (by 6–10 percentage points) than the continuous gas injection. Herein, using a larger amount of gas in relation to the water had an unfavorable effect on recovery efficiency. The efficiency of oil recovery for continuous water injection in fractured cores was found to be comparable to the WAG process, which is in opposition to the results obtained from non-fractured cores (Figure 5). As can be seen in these experiments, oil recovery efficiency decreases with the increasing amount of injected gas in relation to the injected water. The flow of injected gas, due to its higher mobility, concentrates in high permeability zones (artificial fracture) resulting in poorer oil displacement efficiency in the rock matrix (Figure 7).

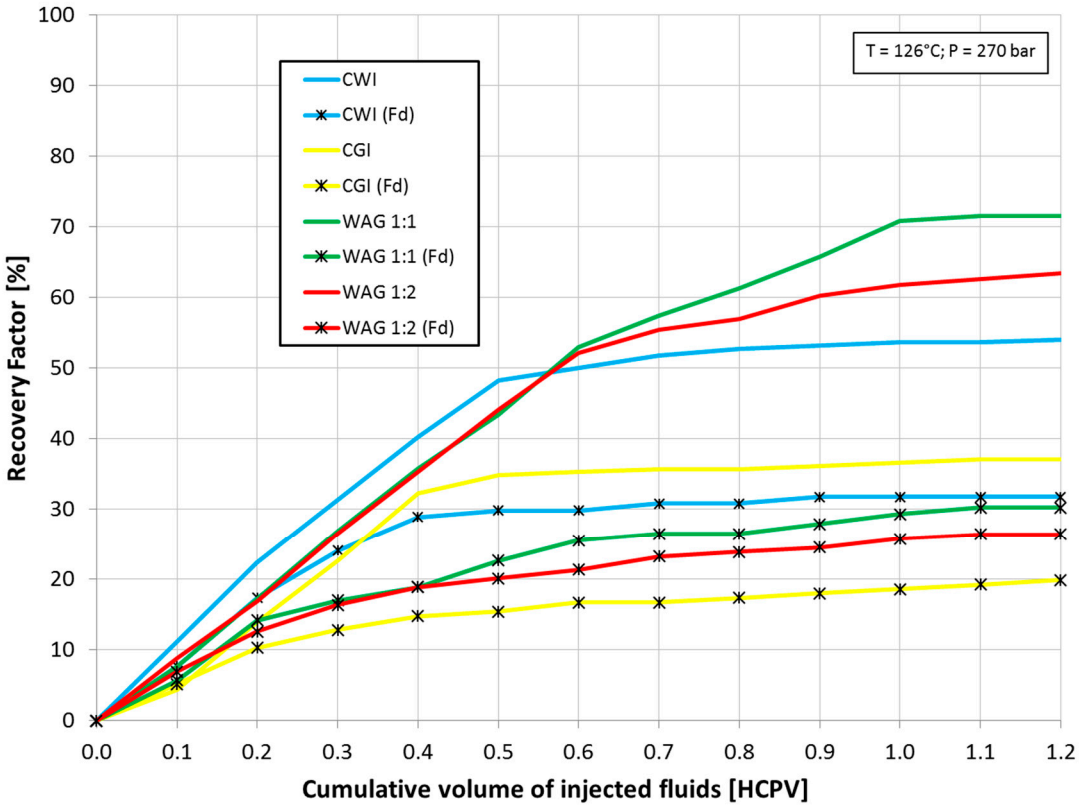


Figure 7. Comparison of oil recovery efficiency in non-fractured and fractured (Fd) cores.

3.3. Foam Assisted WAG (FAWAG) Flooding

Application of the foam flow (FAWAG), which allows us to unify the flow velocity in the fracture and the rock matrix, provided considerably better results than the WAG, CGW and CGI methods (Figure 5). FAWAG injection was found to be the most efficient method among the experiments carried out on fractured composite cores. This had a 48% of total oil recovery factor and this FAWAG recovery factor is 18–22 percentage points higher than that obtained by conventional WAG, 18 points higher than by CWI and about 29 points higher than by CGI (Figure 8). In the FAWAG injection, doubling the volume of the injected gas in relation to the foaming agent solution (when comparing FAWAG 1:1 and 1:2) did not decrease the efficiency of oil displacement, which indicates the high effectiveness of low foam amounts in stabilizing the flow in the porous medium. In other words, the same effect can be achieved using a much smaller amount of the foaming agent. Therefore, determination of the injection parameters (FAWAG ratio, slug size) and selection of appropriate foaming agent and its concentration seems to be crucial for the economics of the injection project.

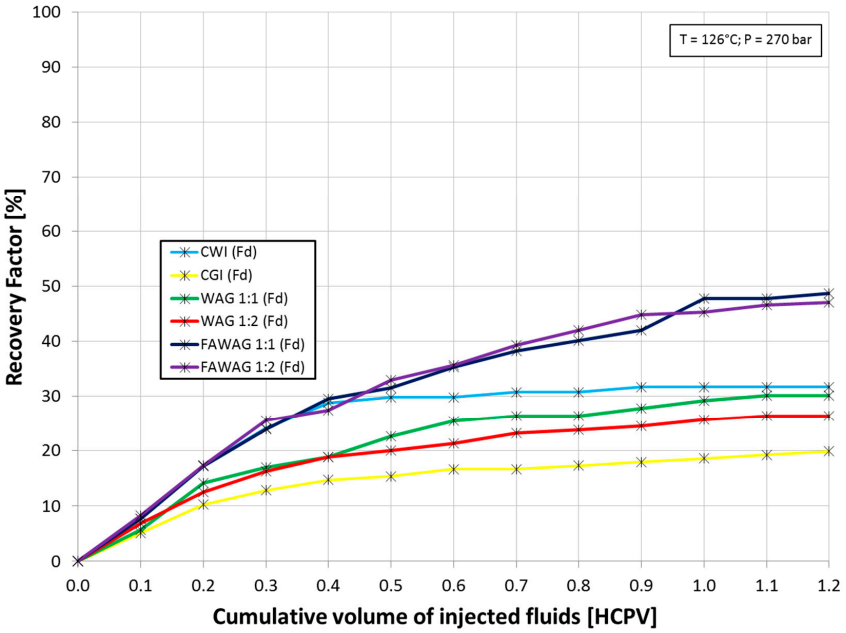


Figure 8. The efficiency of oil recovery using different methods of injection in fractured cores.

4. Conclusions

A coreflooding test performed on non-fractured cores revealed the high efficiency of the water alternating high-nitrogen natural gas (high-nitrogen WAG) process. Here, the oil recovery factor was in the range of 63–72%. The WAG ratio of 1:1, where an equal volume of water and gas was injected, showed the highest efficiency. The efficiency of the high-nitrogen WAG process with a doubled gas/water ratio was slightly lower (RF lower by about 9 percentage points), but still was better than continuous gas or water injection.

Introduction of the horizontal fracture in the composite core dramatically changes the efficiency of the injection processes. In such cases, oil recovery effectiveness of the high-nitrogen WAG method was found to be similar to continuous water injection. In contrast, continuous gas injection was characterized by a very poor recovery factor, which indicates that gas flow is concentrated mostly in the high permeability zone (fracture).

The results obtained for foam-assisted water alternating high-nitrogen natural gas (high-nitrogen FAWAG) showed that the application of foam flow allows unifying flow velocity in the fracture and rock matrix. This leads to significantly higher oil recovery efficiency. The high-nitrogen FAWAG injection was the most effective among the injection methods tested on the fractured model of the reservoir, and demonstrated a 48% recovery factor. Positive results of FAWAG coreflooding studies indicate that the implementation of high-nitrogen natural gas injection in fractured reservoir conditions could be performed using foam flow.

The introduction of the artificial fracture radically changed the state of affairs and allowed an understanding of the effectiveness of EOR methods in the conditions of a fracture system. However, it should be born in mind that the laboratory scale fractured reservoir model is based on a far-reaching simplification, where the artificial fracture is made in the central part, along with the direction of the injected media flow, and is supported in a fixed dimension along its entire length. Thus, the considered case is highly unfavorable for implementing an enhanced oil recovery process. It is recommended to use naturally fractured rock samples in future tests.

The testing of different high-nitrogen WAG/FAWAG variants in laboratory-scale allowed for preliminary evaluation and determination of oil recovery efficiency in given reservoir conditions. Positive results obtained in small-scale coreflooding experiments encourage us to proceed further with reservoir scale dynamic simulations, taking into account the detailed geological structure of the

reservoir and the technical parameters of the process (location and number of injectors and producers, production and injection rates, etc.).

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