energies

MDPI

Article

Enhancing Injectivity in Lithuanian Hydrocarbon Reservoirs through Wettability-Altering Surfactant Injection

Shankar Lal Dangi [1] and Mayur Pal [2,*]

1 Department of Earth Sciences, IIT Roorkee, Roorkee 247667, India; shankar.es@sric.iitr.ac.in
2 Department of Mathematical Modelling, Kaunas University of Technology-KTU, LT-51368 Kaunas, Lithuania
* Correspondence: mayur.pal@ktu.lt

Abstract: Improved and efficient recovery methods are investigated as possible candidates to arrest the production decline and to improve the injection capacity in hydrocarbon fields in Lithuania. The data show that the Cambrian reservoirs in Lithuania are mixed to oil-wet in nature, which results in poor water-flooding efficiency. Wettability alteration could help in improved water injection and, at the same time, it could help recover additional oil from the residual oil saturation zone of the reservoir. In this paper, a screening exercise is conducted to help alter reservoir wettability, improve water injection efficiency, and to improve oil recovery. Analytical and machine-learning supported methods are used for screening. Based on the screening results, dilute surfactant-based injection techniques are suggested as a potential method to improve injectivity and, thereby, recovery from the field. An initial experimental analysis targets the wettability of the rock from the field, followed by testing for wettability-altering surfactants. Based on the findings of the screening study and experimental analysis, it is recommended that we initiate a core flooding experimental program to investigate wettability changes and enhance injection and recovery from the field.

Keywords: screening; oil-wet; wettability alteration; machine learning; experimental analysis; surfactant; injection improvement; EOR

check for updates

Citation: Dangi, S.L.; Pal, M. Enhancing Injectivity in Lithuanian Hydrocarbon Reservoirs through Wettability-Altering Surfactant Injection. *Energies* **2024**, *17*, 2726. https://doi.org/10.3390/en17112726

Academic Editor: Marcin Kremieniewski

Received: 18 April 2024
Revised: 20 May 2024
Accepted: 31 May 2024
Published: 3 June 2024

Copyright: © 2024 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

The Baltic basin comprising Lithuania, Latvia, and Estonia has several hydrocarbon reservoirs in offshore and onshore settings, most of which are located in the territory of Lithuania and Latvia [1]. The Baltic basin in Estonia is too shallow to have any significant reservoirs [2]. These reservoirs are made up of both sandstone and carbonate rocks (see Figure 1, which shows the hydrocarbon accumulation sites in the Baltic region). It is estimated that there are over 50 oil and gas fields in the region, both in onshore and offshore settings. Several of these fields are currently in decline (see Figure 2). Some of these hydrocarbon reservoirs are within the Gargzdai high area, covering over ~200 sq. km. area. These reservoirs are perfect candidates for improved and enhanced oil recovery. This study is focused on one of the reservoirs within the south-western part of Lithuania in the Gargzdai area.

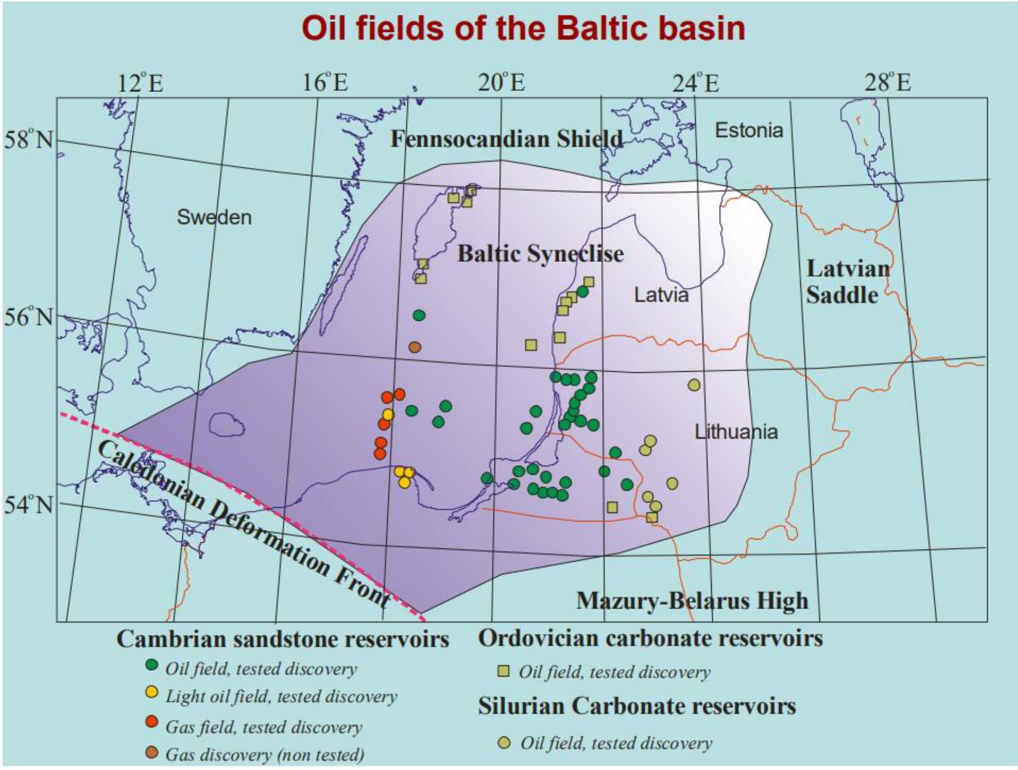

Figure 1. Figure showing the spread of regional oil fields in Baltic basin [3].

Earlier work conducted by other authors [4] estimates that the Gargzdai high structure has a very high residual oil saturation ranging between 40–60%, which makes it a large target for enhanced oil recovery. The CO_2 EOR method has already been evaluated in several fields with pilot trials showing very promising results [5–8]. The CO_2 field injection trial was conducted in the Gargzdai residual oil zone [4,9] where a total of 1000 tons of CO_2 was injected in one of the wells for a total period of 52 days. A differential pressure of 80–90 bars was used to inject the CO_2 into the reservoir. Although promising results were obtained from the initial CO_2 trial, the scale-up of CO_2 injection is currently held up due to some legal barriers related to CO_2 injection [10–13]. Therefore, it is natural to investigate other EOR methods for incremental oil recovery. To carry out the EOR evaluation and its applicability for Gargzdai oil reservoirs, we have first carried out EOR screening at two levels, first, using the EOR screening tool developed by Dicelytics Pvt. Ltd. [14], where machine-learning-based methods are used for EOR screening; and, second, using the analytical method, which is based on reservoir properties and SPE guidelines; the EOR method is selected [15–17]. Both screening exercises suggest the potential for Chemical EOR as a promising candidate for the Gargzdai reservoirs.

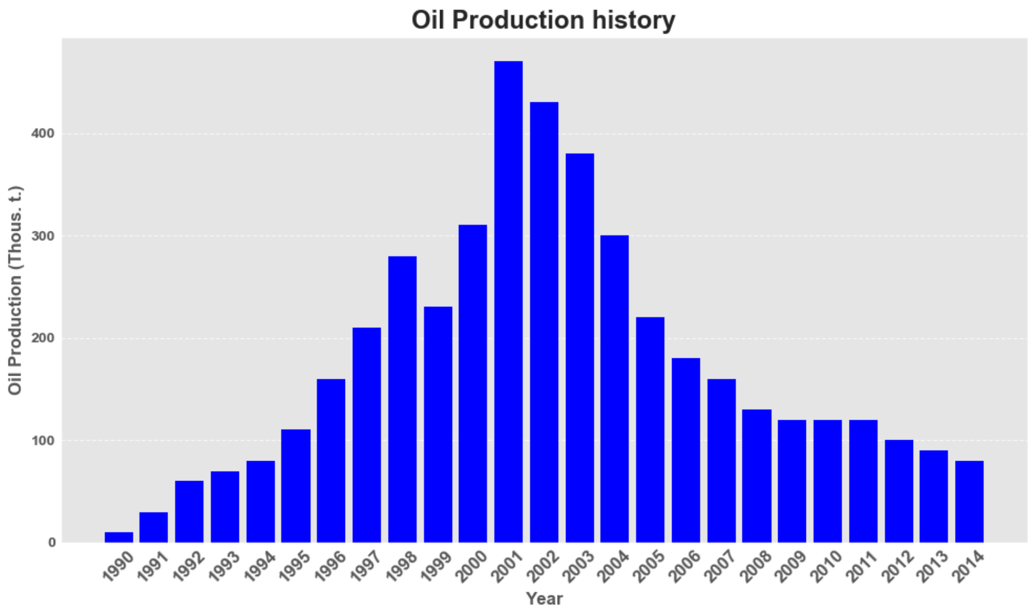

Figure 2. Figure showing production history for some of the reservoirs in Lithuania (production in thousand tons) [18].

A review of existing data from the Gargzdai oil zone suggests that some of the reservoirs are in oil-wet to mixed-wet conditions [19]. Wettability plays a crucial role in oil recovery, where oil-wet formations impede water imbibition, leading to a diminished sweep efficiency and early water breakthrough. In such scenarios, oil tends to strongly adhere to the rock surface, retained within the matrix by capillarity [20–22]. During water flooding, successful oil displacement relies on water imbibition into the rock matrix, but, in oil-wet conditions, this process is hindered, preventing the efficient displacement of oil from tight pores [22,23]. Consequently, injected water primarily flows through larger pores or fractured networks, bypassing the oil in the matrix. This phenomenon exacerbates issues like poor sweep efficiency and premature water breakthrough.

Over 60% of global oil reserves are located in oil-wet reservoirs [24]. Despite this abundance, the oil recovery factor from such reservoirs remains notably low, with primary and secondary recovery methods typically retrieving only about one-third of the original oil in place (OOIP), leaving approximately two-thirds trapped as residual oil [24]. This inefficiency stems from various factors inherent to oil-wet reservoirs, including heterogeneous rock properties such as porosity and permeability, as well as variable wettability across the reservoir, collectively posing significant challenges to secondary oil recovery methods like water flooding [24–26].

Numerous laboratory studies have demonstrated that altering the rock surface wettability towards a more water-wet state can substantially improve oil recovery during water flooding. This phenomenon is attributed to the creation of positive capillary pressure under water-wet conditions, facilitating water imbibition into tight rock pores [22,23,27–29]. The inclusion of wettability-altering surfactants further enhances water imbibition into low-permeability matrices and promotes water spreading on carbonate rock surfaces, effectively releasing trapped oil and, thereby, augmenting cumulative oil recovery.

Cationic surfactants are proposed to form ion pairs with adsorbed organic carboxylates from crude oil, inducing the release of the adsorbed organic material from the surface and, thereby, altering wettability towards a more water-wet state [30–34]. Consequently, water gradually infiltrates the matrix structure, driven by capillary forces, while oil is expelled from the core. Anionic surfactants, particularly ethoxylated sulfonates with a high number of EO groups, have been investigated for their ability to displace oil through non-uniform brine imbibition [31]. The suggested mechanism involves the formation of a surfactant bilayer through a hydrophobic interaction with the surface, with the hydrophilic head groups creating a small water zone between the oil and the hydrophobic surface, generating a weak capillary force driving brine imbibition. Anionic surfactants tend to adsorb onto rock surfaces, especially carbonate reservoirs, due to the positive zeta potential from carbonate mineral ionization to Ca^{2+} ions [22]. To mitigate surfactant adsorption, the combination of anionic surfactants with sodium carbonate has been proposed [22]. This combination alters wettability and reduces the oil–brine interfacial tension to ultralow values ($<10^{-2}$ mN/m), primarily facilitating buoyancy or gravity drainage for oil recovery. However, the reduced reliance on capillary forces for oil displacement may necessitate the inclusion of mobility control agents to mobilize oil through the reservoir [27,35].

Nonionic surfactants are extensively studied for their role as wettability-altering agents, contributing to enhanced oil recovery efforts [27,36–39]. Field trials have also been conducted using nonionic surfactants, for wettability altering surfactants, showing promising results [40–42]. Nonionic surfactants induce wettability alteration by solubilizing adsorbed hydrophobic material on carbonate surfaces into the aqueous solution via micellar action. In this hypothesis, the hydrophobic material is oil which would be dislodged due to the surfactant into the flowing brine and would be suspended due to the surfactant lowering the IFT. A favorable surfactant formulation and lower surfactant adsorption are critical to the economic success of any surfactant injection project [25]. Nonionic surfactants offer advantages over anionic ones, including brine compatibility, improved phase behavior, low adsorption on carbonate rock, and enhancing oil recovery via capillary-pressure-driven expulsion from tight matrix pores, eliminating the need for mobility control agents [27,39]. This paper discusses selecting the appropriate surfactant and conducting various laboratory experiments to assess its efficacy. Based on the findings of EOR screening and given the data suggesting the oil-wet nature of the rock, wettability-altering surfactants are used for carrying out experiments on the reservoir rock.

This paper is organized as follows: The introduction to EOR is presented first, followed by the field data description which is used in this study. The EOR screening results are presented in Section 3. The initial surfactant screening experiments are presented in Section 4. Section 5 discusses the impact of wettability alteration on water injection improvement. The conclusions are presented in Section 6.

2. Field Data

The field data used for the analytical screening are shown in Table 1. The data correspond to one of the depleted hydrocarbon fields, which is a Cambrian reservoir located in the Baltic basin at a depth of around 2 km. The field has been in production since early 1990 and has been water-flooded for pressure maintenance since 2000s [43]. The production forecast shows a declining production as shown in Figure 3. The water flood has provided initial production support, and, now, production is declining year after year. The reservoir makes a perfect candidate for improved and enhanced oil recovery.

Table 1. Field data used for EOR screening.

Field Name/Location	Gargzdai Reservoir (Western Lithuania)
Geological basin	Baltic basin
Formation name	Cambrian
Discovery year	1960–1970
Type of rock (sandstone/carbonate/shale)	Sandstone
Rock heterogeneity info	Very heterogeneous (0.01–100 md)
Mineral composition	95% or more quartz
Clay content (% of clay in rock)	3–7, some placed up to 20
Average porosity, %	1–12

Table 1. *Cont.*

Field Name/Location	Gargzdai Reservoir (Western Lithuania)
Average permeability, md	0.01–100
Depth, m	1975–1992.5
Reservoir area (acres)	200 sq. km—total 8 reservoirs
Average pay thickness, m	70–80 m
Reservoir temperature, °C	85
Original reservoir pressure, psi	2750
Injection well bottom hole pressure, psi	3000
Initial oil and water saturation ratios	30–56% residual oil saturation
Average connate water saturation, %	~20
Current oil cut, %	High water cut up to 90–95
Secondary recovery, %	27% (with water flood)
Start year of water flooding/injection	21+ years
Current average daily injection rate per well (Water) bbls/day	500
Number of producing wells	11 wells
Number of injection wells	4
Oil production from entire field, bbl/day	~200 (from 4 wells—around 60 bb/day)
Well configuration—horizontal/vertical	Vertical
Well spacing per well, meters	300–1000
Current average daily injection rate per well (Water), m^3/day	500 (~3200 bbls per day)
Reservoir Mechanism	
Primary producing mechanism	Water flooding
Current injection rate, m^3/day	500
Average wellhead injection pressure and BHP, bars	250–350 (depending on wells)
Water Properties	
Density of original connate/formation water, kg/m^3	1127
Salinity/total dissolved solids: Original formation water, wt %	20
Oil Properties	
API	43.4
Viscosity at reservoir temperature, cp	0.63–0.8 (in situ), 1.44 (dead oil)
Other information	
Reservoir pressure, bars	220
Wettability	Oil-wet
Initial water saturation, %	26
Recovery factor, %	27
Well spacing, ha/well	98
Average reservoir thickness, m	9.15

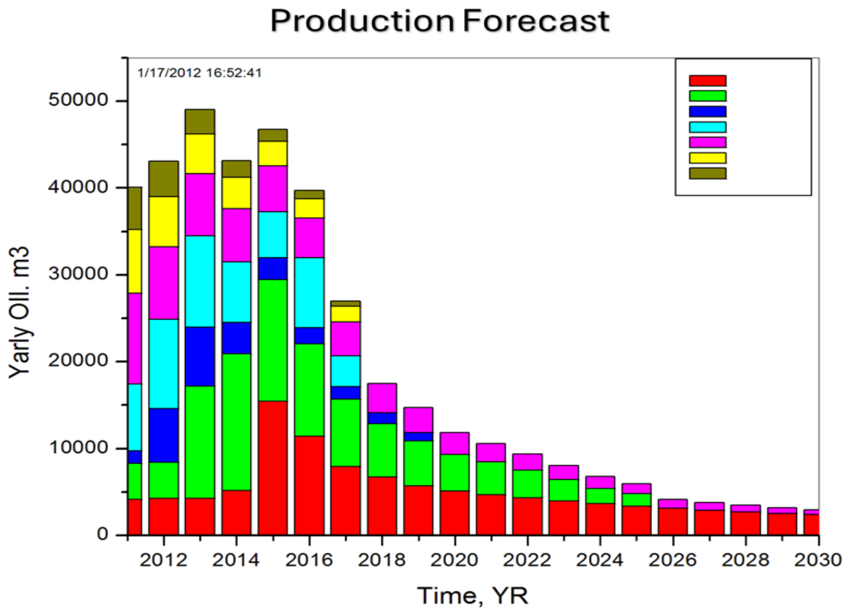

Figure 3. Declining production forecast of the oil field under investigation for injection improvement and EOR; different colors show production contribution from different reservoirs within the field; names of field are hidden due to data confidentiality.

3. Enhanced Oil Recovery Screening

Enhanced oil recovery (EOR) is a crucial method implemented subsequent to primary hydrocarbon extraction, designed to maximize the retrieval of the remaining hydrocarbons through secondary (e.g., water or gas flooding) and tertiary recovery mechanisms. Various EOR techniques encompass solvent-based, chemical, and thermal methods, each possessing distinct advantages and limitations. Figure 4 illustrates the classification of enhanced oil recovery screening methods based on SPE guidelines [17]. In the methodology flowchart, Figure 4 illustrates our approach and methodology, detailing the sequential steps and processes we undertake throughout our research. Typically, EOR strategies are deployed towards the latter stages of field development, as depicted in Figure 5. The initial phase of assessing EOR potential in a field entails EOR screening, traditionally relying on analytical methodologies outlined by the Society of Petroleum Engineers (SPE) [6,15,17]. However, there is a burgeoning interest in leveraging machine-learning techniques for EOR screening [44–49]. This section elucidates the outcomes derived from both traditional analytical screening methods and machine-learning approaches applied to field data.

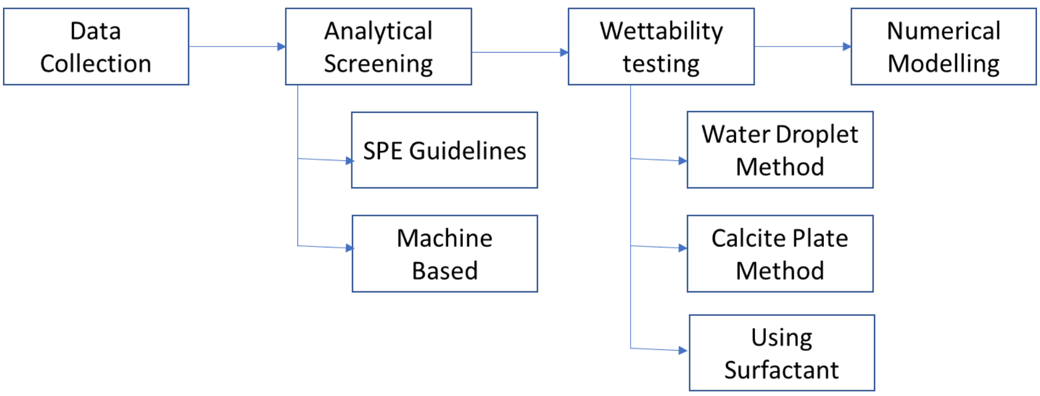

Figure 4. Methodology flowchart.

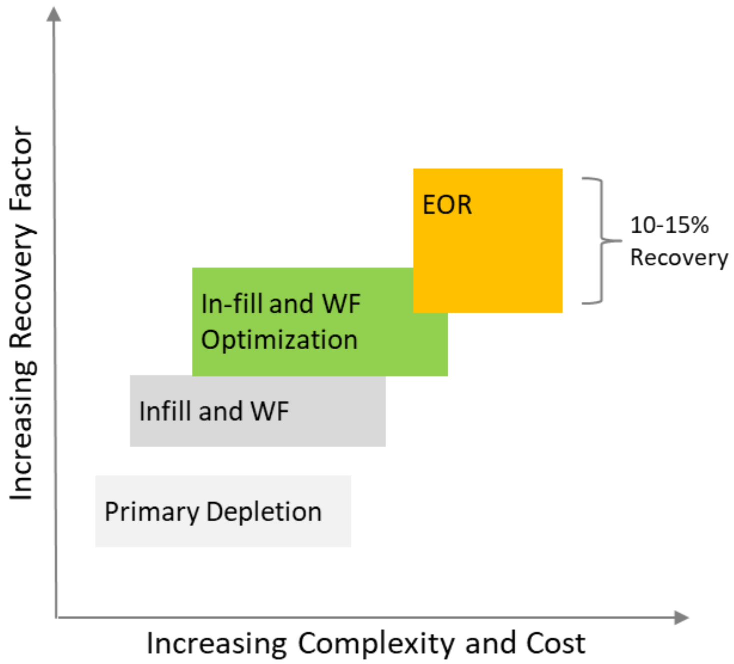

Figure 5. EOR recovery mechanizing.

3.1. *Analytical Screening Using SPE Guidelines*

Analytical EOR screening for a depleted oil field is conducted using an in-house Excel-based tool developed from the SPE guidelines [15–17]. Additionally, several SPE publications provide comprehensive screening criteria and guidelines for evaluating the feasibility of EOR projects under various technical and economic considerations, including factors like oil prices and technological advancements [50]. These guidelines offer valuable insights and methodologies for assessing EOR projects across different scenarios.

According to the SPE guidelines [16], the temperature requirement for in situ flooding is above 37 °C, with an API gravity of 10 to 27, while the field under study has a temperature of around 85 °C and an API gravity of 43.4, making in situ flooding unsuitable and prohibitively expensive. Similarly, steam flooding is recommended for reservoirs with depths of less than 5000 ft. However, our field's depth is 6480 ft, rendering steam flooding inappropriate for our reservoir. Our reservoir exhibits specific characteristics, including being oil-wet, highly heterogeneous, and low viscosity. Although alkaline flooding is commonly employed for wettability alteration, it is typically effective for reservoirs with API gravities ranging from 13 to 35. Given that our field has an API gravity of 43.4, alkaline flooding alone is not a viable choice due to the incompatible API range. Regarding nitrogen and flue gas injection, these methods are optimal for reservoirs with viscosities lower than 0.4. Unfortunately, our field's viscosity exceeds 0.63, making nitrogen and flue gas injection less suitable for our circumstances.

3.2. *Machine-Learning-Based Screening*

Dicelytics Ltd. offers an end-to-end solution for reservoir management, which includes an EOR screening tool, that uses machine-learning algorithms for EOR screening purposes [14]. Dicelytics software (https://prod.dicelytics.com/dicelytics/login, accessed on 17 April 2024) provides a production enhancement evaluation using AI and ML, laboratory evaluation, consultation, and data visualization. Dicelytics Ltd.'s physics- and machine-based software is a cloud-based software suite that allows physics-assisted artificial intelligence and machine-learning reinforced models to simulate, analyze, and support the field implementation of reservoir recovery management technologies. Table 2 shows the input data used in the Dicelytics EOR screening software tool.

Table 2. Dicelytics software input.

Parameter	Value
API Gravity	43.4
Oil Viscosity	1.44
Residual Oil Saturation	30%
Depth, ft	6479.659
Temperature, °C	85
Permeability, md	100
Porosity	10%
Formation	Sandstone
Thickness	>20 ft No dip
Composition	High % C1–C7

Tables 3–5 displays the results of screening tests conducted using the Dicelytics software on the input data from Table 2. The screening tests are performed for various flooding methods used in oil recovery operations. The "Result" column indicates the percentage effectiveness of each flooding method in recovering oil under the specified conditions, listed in decreasing order of effectiveness. The methods tested include hot water, chemical flooding, in situ hydrocarbon (I-HC) injection, in situ CO_2 (I-CO_2) injection, microbial flooding, and polymer flooding.

Table 3. Dicelytics software screening test result for Table 2 input data.

Flooding Method	Result
HOT WATER	100.00%
CHEMICAL	80.78%
I-HC	62.37%
I-CO_2	41.84%
POLYMER	21.32%

Table 4. Dicelytics software screening test result for Table 2 data, reducing viscosity to 0.8 cp.

Flooding Method	Result
HOT WATER	100.00%
I-CO_2	80.63%
CHEMICAL	60.21%
I-HC	41.49%
POLYMER	21.07%

Table 5. Dicelytics software screening test result for Table 2 data, reducing viscosity to 0.63 cp.

Flooding Method	Result
HOT WATER	100.00%
CHEMICAL	75.71%
I-HC	52.29%
POLYMER	26.58%

Based on the analytical screening method, we can suggest that there are the following possible EOR methods, that can be applied to the field:

Low Salinity Water (LSW) Flooding: This method modifies the wettability of the reservoir rock, making it more water-wet and facilitating the displacement of oil. The alteration in ionic composition affects the interactions between the oil, water, and rock surfaces, leading to improved oil recovery. It typically involves modifying the water composition and injection strategy, which can be implemented with a relatively low capital and operational costs. This may be the cheapest option for the current scenario.

Surfactant–Polymer (SP) Flooding: Surfactants help to reduce the interfacial tension between the oil and water, improving oil mobilization, while polymers enhance the sweep efficiency by increasing the viscosity of the injected water, thus reducing channeling and improving displacement.

Alkaline–Surfactant–Polymer (ASP) Flooding: Alkalis are added to raise the pH of the injected water, which helps in reducing the reservoir's rock wettability and enhancing oil recovery. Surfactants aid in reducing interfacial tension, while polymers improve the sweep efficiency. The cost depends on the dosage, the frequency of injection, and the specific chemicals used. Alkaline flooding is commonly applied in oil-wet or mixed-wet reservoirs. Alkaline flooding tends to be more effective for heavier oils, with API in the range of 13–35. Therefore, we can use ASP to obtain more effective results.

Chemical Flooding with CO_2 or N_2: Chemical flooding methods, such as CO_2 or N_2 foam or miscible flooding, can be combined with the existing water flooding. These methods enhance oil recovery by reducing oil viscosity, improving displacement efficiency, and altering the reservoir wettability. The current reservoir pressure is 3190 psi, which is sufficient for the miscibility of CO_2. The viscosity is 0.63 to 1.44 cp, which favors CO_2 flooding (for miscible flooding, the viscosity range is 0.1 cp to 100 cp, and, for immiscible flooding, it is perhaps more than 100 cp). Normally, N_2 flooding is used in viscosity of less than 0.3 cp. Based on all these data, CO_2 flooding can be used compared to N_2 flooding. CO_2 or N_2 flooding methods can have higher costs compared to LSW or chemical flooding. The expenses are associated with capturing, compressing, and injecting the gas into the reservoir. The availability and proximity of CO_2 or N_2 sources, as well as the infrastructure required for their transportation and injection, also influence the cost-effectiveness.

Here, we have a very high heterogeneity in our field, so we may refer to chemical flooding. CO_2 or hydrocarbon gas injection is also recommended because the injected gas can better reach and displace oil in different reservoir zones, including areas with varying permeability. In this paper, we further investigate chemical EOR, in particular, surfactant EOR, as it has been shown to give promising results in sandstone reservoirs and, particularly, for oil-wet rock [40–42].

4. Rock Wettability Assessment

Oil-wet reservoirs typically exhibit an inferior water-flooding efficiency compared to water-wet reservoirs due to the stronger adhesion of oil to rock surfaces. Consequently, water struggles to displace the oil effectively from the reservoir rock pores, resulting in a diminished oil recovery efficiency. To address this challenge, various techniques such as surfactant injection or chemical treatments are often employed to modify the reservoir's wettability and enhance the water-flooding efficiency.

A special core analysis conducted in the laboratory on reservoir rocks sourced from Lithuanian reservoirs has confirmed their oil-wet nature [19]. The determination of rock wettability is established through contact angle measurements, detailed in Table 6 and Figure 6. The wettability index gauges the preference of the reservoir rock for oil or water. A positive wettability index signifies a water-wet condition, indicating a higher affinity for water, whereas a negative wettability index denotes an oil-wet condition, suggesting a greater affinity for oil.

Table 6. Table showing oil-wetness and corresponding contact angle.

Wetting Condition	Contact Angle (Degrees)
Moderately water–wet	30–75
Neutrally wet	75–105
Moderately oil–wet	105–150
Strongly oil–wet	150–180

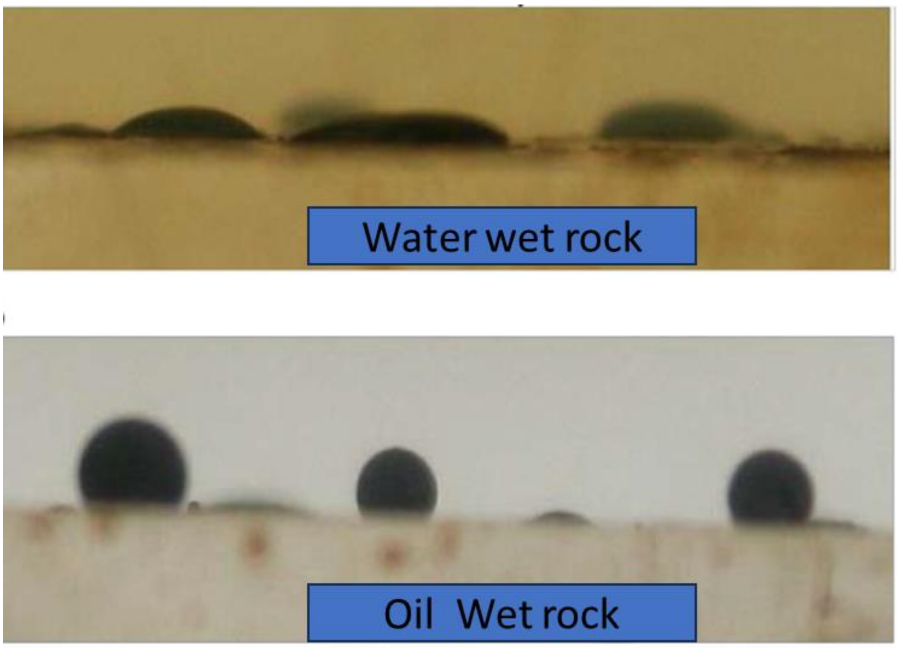

Figure 6. Figure showing an oil-wet and water-wet surface of rock. Images show behavior of oil molecule on surface of rock, which is immersed in brine.

Three tests were conducted on small rock plugs extracted from a Lithuanian reservoir, revealing that two of the tests (plug 1 and plug 2) yielded negative values for the Amott wettability index (IAH = −0.723 and IAH = −0.741, respectively), indicating an oil-wet wettability. This implies that the rock samples from these plugs have a stronger affinity for oil than water. However, an anomaly was observed with plug 3, which exhibited a positive wettability index (IAH = 0.073), contradicting the oil-wet wettability observed in plugs 1 and 2. Consequently, a reassessment of the rock's wettability was warranted using a simple water droplet method. This re-evaluation is crucial as the contact angle plays a pivotal role in determining rock wettability, which, in turn, informs the selection of the appropriate enhanced oil recovery (EOR) methods.

4.1. Water Droplet Method and Quantification of Wettability

To verify the oil-wet nature of the rock, an experiment was conducted using the water droplet method, where the rock is saturated in oil, and then the wettability is tested by placing a water droplet on the rock and the contact angle is evaluated. To conduct the experimental investigation, reservoir rock, oil, and brine samples have been collected and saturated first in reservoir brine (200,000 ppm) for a period of 4 weeks, followed by oil saturation for 4 weeks.

4.2. Calcite Plate Test for Wettability Alteration

Since the rock is oil-wet in nature, we conduct an experiment using a known oil-wet rock, reservoir brine, and reservoir oil using surfactant solution. A calcite plate is used, as it is known to be oil-wet in nature. The plate is first dipped in reservoir brine, followed by reservoir oil. The saturated plate is then dipped in brine and surfactant solution, which results in changing the calcite plate to change its wettability from oil-wet to water-wet. When this happens, oil droplets start to form on the calcite plate and oil is released from the surface.

The water droplet experiment showed that water does not spread on the surface of the rock but, rather, forms a droplet, indicating the oil-wet nature of the rock. The calcite plate test confirms this result (Figure 7). It is seen that oil droplets start to form and are released from the surface.

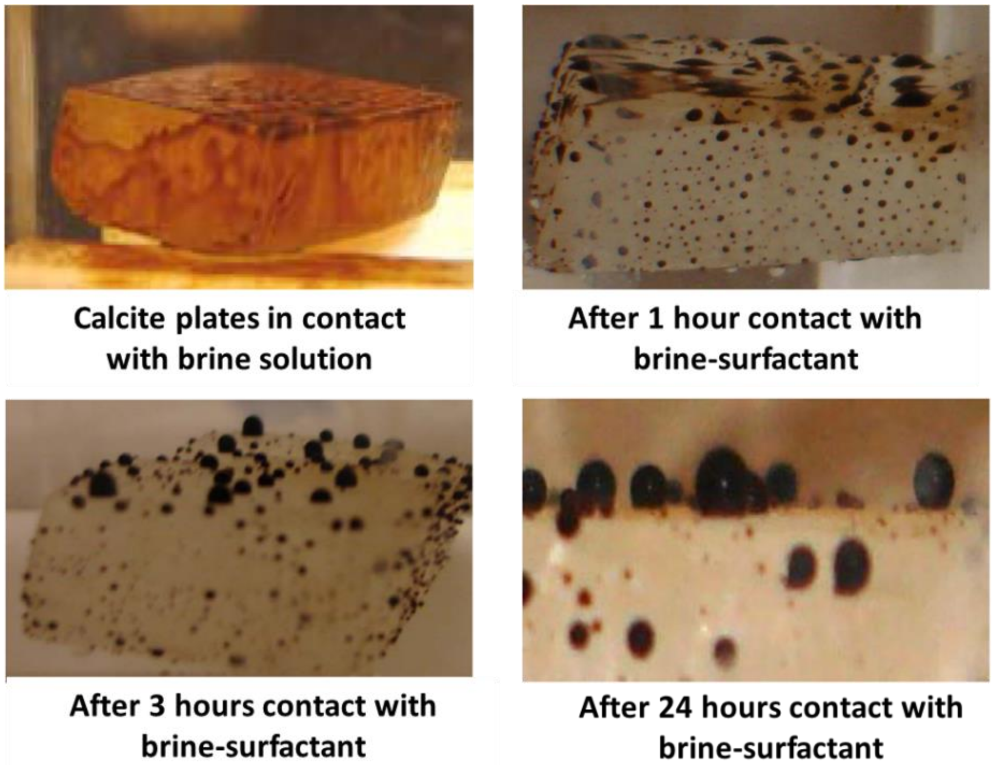

Figure 7. Figure showing reservoir fluid and brine interaction with surfactant solution using a calcite plate.

4.3. Wettability Alteration Using Surfactant

For this experiment, we first prepared reservoir rock, cleaned it, and then placed it in reservoir brine solution for a period of 4 weeks. After aging in reservoir brine for 4 weeks, the rock sample is taken out and pictures are taken. Then, the rock is immersed in an oil bath for a period of 4 weeks. After the ageing in oil is completed, the rock sample is taken out, and then subsequently dipped in a surfactant solution for a few hours.

Similar to the calcite plate experiments, the surfactant solution alters the rock's wettability from oil-wet to water-wet, allowing water to imbibe into the rock and displace oil molecules, as illustrated in Figure 8. The success of these experiments demonstrates the potential of surfactants to enhance oil recovery from the field. Although the exact mechanism and kinetics of wettability alteration are not fully understood yet and require further investigation, it is likely that the surfactant's ability to adsorb onto the rock surface and/or remove polar components is responsible for this change in wettability.

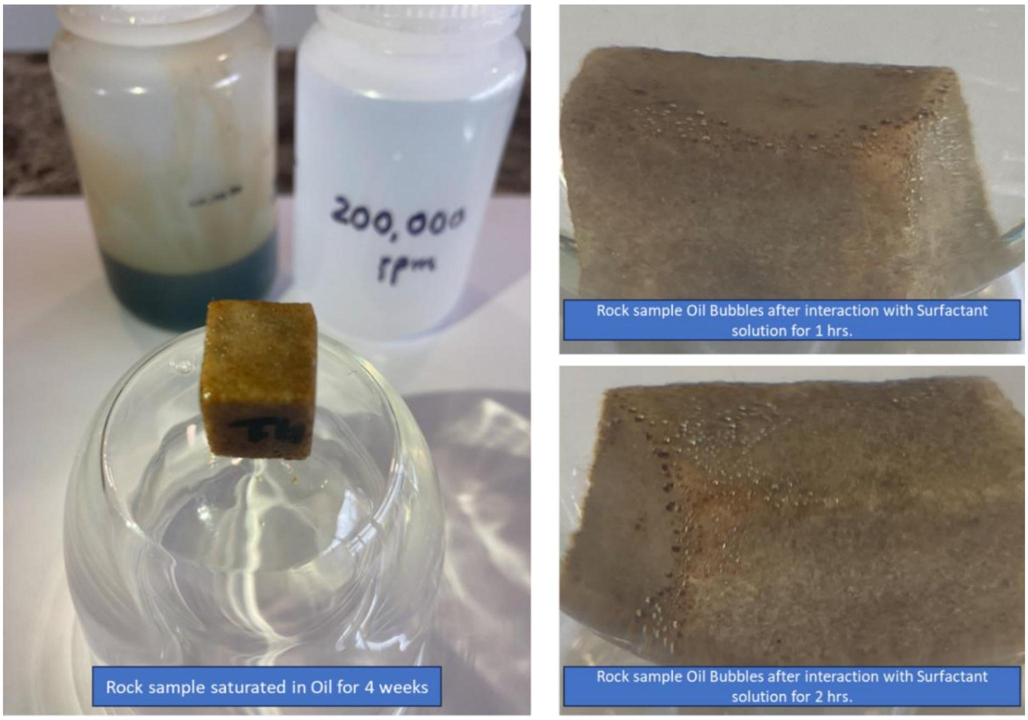

Figure 8. Figure showing rock sample from the field saturated with reservoir oil for 4 weeks, and then subsequently dipped in surfactant solution.

5. Injection Improvement via Wettability Alteration

The oil-wet nature of the rock results in a poor water-flooding efficiency. The impact of wettability on water-flood efficiency in sandstone and carbonate reservoirs has been investigated by several authors [51–53]. If the wettability of the rock could be changed, then the water-flooding efficiency can be improved; this is achieved through the alteration of the water-relative permeability curve due to the adsorption of wettability-altering surfactants on the rock surface. Such changes in relative permeability curves have been demonstrated in [39–42]. The effect of a wettability-altering surfactant on injectivity improvement has been discussed in detail in [40,41].

A review of the field's injection and production data [4,9] suggest that, for every 6 bbls. of water injected, 1 extra bbl. of oil can be produced. Therefore, if we can obtain a ~15% injectivity increase with surfactant injection, this would amount to having approximately five new water injectors. Similarly, a ~10% increase with surfactant injection would amount to having approximately four new water injectors. Figure 9 shows the number of water injection wells that can be replaced with the respective injectivity increase obtained from surfactant injection. There is also a direct implication of the injection improvement on electricity consumption and the running of water injection pumps. Figure 9 below shows that, even if a small injectivity increase is made through wettability alteration, the energy savings are equivalent to running additional injection wells with the same electrical consumption. Therefore, the wettability changes through a surfactant should also be seen as a cost-effective way of improving the field water-flooding efficiency.

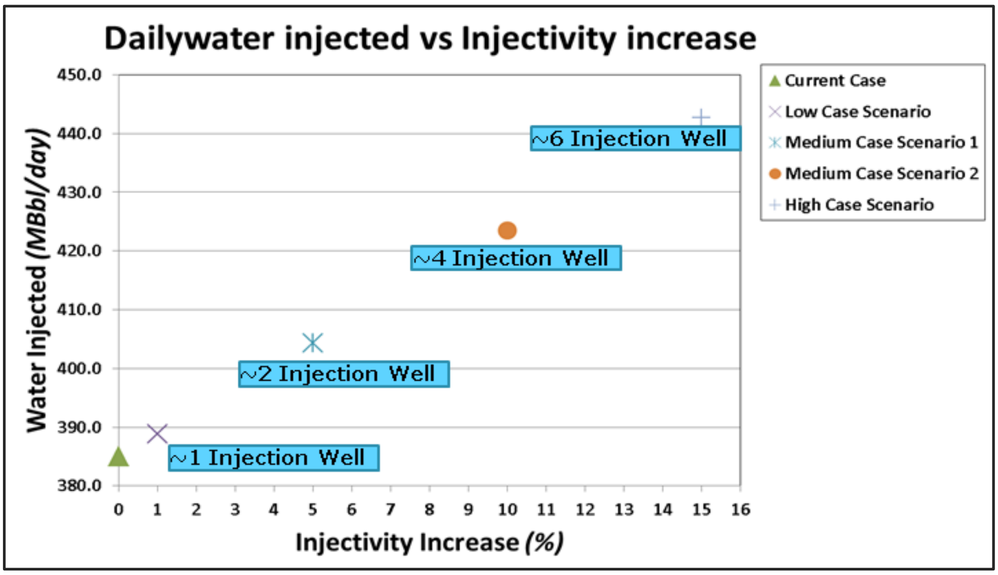

Figure 9. Potential cost savings in terms of injection capacity by using surfactant injection.

6. Conclusions

In conclusion, the study focuses on a highly heterogeneous, oil-wet hydrocarbon field with permeability ranging from 0.01 to 100 md and porosity from 1% to 12%. Preliminary experimental testing using reservoir fluids and rocks shows that the use of a wettability-altering surfactant can help in improving oil recovery through wettability changes.

Due to the oil-wet nature and heterogeneity of the reservoir, traditional water flooding faces challenges like early water breakthrough and channeling through fractures. Therefore, it is recommended to use Surfactant–Polymer (SP) or Alkali–Surfactant–Polymer (ASP) flooding for enhanced oil recovery (EOR). The initial analysis and experiments indicate that surfactant flooding is effective for incremental oil recovery. It is suggested that we conduct extensive core flooding tests using reservoir fluids and rocks to further investigate this method. Surfactant treatment can improve the water-flooding efficiency by altering rock wettability, enhancing injectivity, and potentially reducing the need for additional injection wells, thus lowering operational costs

The work also suggests that the use of diluted surfactant injection will improve the water injection efficiency due to changes in the wettability of the rock, making it more water-wet. This will eventually result in changes in the relative permeability of the rock through surfactant adsorption, which will result in cost savings through injection efficiency improvements.

7. Recommendation

Based on the preliminary screening and experimental investigations demonstrating promising results with surfactant-based EOR methods in oil-wet reservoirs, it is recommended that we proceed with further investigation through core flooding experiments. These experiments will allow for a comprehensive quantification of expected recoveries and pave the way for future field trials. Following short-term injectivity trials, longer-term assessments should be conducted to evaluate the impact of surfactant injection on residual oil saturation and injectivity improvement. For field trials, we suggest implementing single-well tracer test (SWCTT), and log-inject-log with an observation well. These trials will provide valuable insights for optimizing surfactant-based EOR methods in oil-wet reservoirs and enhancing the hydrocarbon recovery efficiency.

Author Contributions: For research articles, both authors contributed equally, in the writing, reviewing, and conceptualization of the study. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: Data are contained within the article.

Acknowledgments: The authors are thankful to Thomas M. Haselton from UAB Minijos Nafta for the fruitful discussion carried out during the course of the work presented in this paper.

Conflicts of Interest: The authors declare no conflicts of interest.

References

1. Shogenova, A.; Sliaupa, S.; Vaher, R.; Shogenov, K.; Pomeranceva, R. Balti bassein: Ehitus, reservuaarikivimite omadused ja CO_2 geoloogilise ladustamise võimalused. *Est. J. Earth Sci.* **2009**, *58*, 259–267. [CrossRef]
2. Terasmaa, J. Estonia, the land of lakes. *J. Int. Géosciences Environ.* **2018**, 358–366. [CrossRef]
3. Rashid, A.; Malik, S.; Karaliute, V.; Makauskas, P.; Kaminskaite, I.; Pal, M. Lithuania's geo-energy landscape: A brief overview of CCUS, hydrogen, and geothermal. *Adv. Carbon Capture Util. Storage* **2023**, *1*, 33–43. [CrossRef]
4. Haselton, T.M.; Nafta, M. Exploiting the ROZ in Lithuania. In Proceedings of the 19th Annual CO_2 Flooding Conference, Midland, TX, USA, 14 December 2013; Volume 14.
5. Brock, W.; Bryan, L. Exxon Co USA, "SPE". 1989. Available online: http://onepetro.org/SPERMPTC/proceedings-pdf/89LPR/All-89LPR/SPE-18977-MS/3214040/spe-18977-ms.pdf/1 (accessed on 23 February 2024).
6. Manrique, E.; Thomas, C.; Ravikiran, R.; Izadi, M.; Lantz, M.; Romero, J.; Alvarado, V. SPE 130113 EOR: Current Status and Opportunities. 2010. Available online: http://onepetro.org/SPEIOR/proceedings-pdf/10IOR/All-10IOR/SPE-130113-MS/1771110/spe-130113-ms.pdf/1 (accessed on 23 February 2024).
7. Hill, L.B.; Li, X.C.; Wei, N. CO_2-EOR in China: A comparative, review. *Int. J. Greenh. Gas Control* **2020**, *103*, 103173. [CrossRef]
8. Ghedan, S. SPE/EAGE Reservoir Characterization and Simulation Conference. 2009. Available online: http://onepetro.org/SPERCSC/proceedings-pdf/09RCSC/All-09RCSC/SPE-125581-MS/2720391/spe-125581-ms.pdf/1 (accessed on 23 February 2024).
9. Haselton, T.M.; Nafta, M. *Minijos Nafta Clean Energy Project*; Baltic Carbon Forum: Tallinn, Estonia, 2019.
10. Mathisen, A.; Skagestad, R. Utilization of CO_2 from Emitters in Poland for CO_2-EOR. *Energy Procedia* **2017**, *114*, 6721–6729. [CrossRef]
11. Dangi, S.L.; Malik, S.; Makauskas, P.; Karliute, V.; Sharma, R.; Pal, M. An approach for assessment of CO_2 leakage using mechanistic modelling: CO_2 injection in deep saline aquifer of Lithuanian basin in presence of fault and fractures. *Adv. Carbon Capture Util. Storage* **2024**. [CrossRef]
12. Dangi, S.L.; Malik, S.; Makauskas, P.; Karliute, V.; Sharma, R.; Pal, M. Assessment of CO_2 leakage using mechanistic modelling approach for CO_2 injection in deep saline aquifer of Lithuanian basin in presence of fault and fractures. *Balt. Carbon Forum* **2023**, *2*, 15–16. [CrossRef]
13. Dangi, S.L.; Malik, S.; Sharma, R.; Pal, M. Geomechanical Implications of CO_2 Sequestration in Saline Aquifers. In Proceedings of the 14th Biennial International Conference SPG 2023, Kochi, India, 3–5 November 2023. Available online: https://spgindia.org/Kochi2023-expanded-abstracts/14th-conference-kochi23-top-177.pdf (accessed on 23 February 2024).
14. Dicelytics Pvt. Ltd. Available online: https://www.linkedin.com/company/dicelytics/ (accessed on 23 February 2024).
15. Taber, J.J.; Martin, F.D.; Seright, R.S. EOR Screening Criteria Revisited Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects. 1997. Available online: http://onepetro.org/RE/article-pdf/12/03/189/2532146/spe-35385-pa.pdf/1 (accessed on 23 February 2024).
16. Taber, J.J.; Martin, F.D.; Seright, R.S. EOR Screening Criteria Revisited-Part 2: Applications and Impact of Oil Prices. *SPE Reserv. Eng.* **1997**, *12*, 199–206. [CrossRef]
17. Aladasani, A.; Bai, B. SPE 130726 Recent Developments and Updated Screening Criteria of Enhanced Oil Recovery Techniques. Available online: http://onepetro.org/SPEIOGCEC/proceedings-pdf/10IOGCEC/All-10IOGCEC/SPE-130726-MS/2342995/spe-130726-ms.pdf/1 (accessed on 23 February 2024).
18. Šliaupa, S.; Šliaupienė, R. Prospects of Geological Storage of CO_2 in Lithuania BALTIC CARBON FORUM 2021. In *Baltic Carbon Forum*; Gamtos Tyrimu Centras: Vilnius, Lithuania, 2021. Available online: https://bcforum.net/presentations2021/0303_Saulius%20Sliaupa.pdf (accessed on 23 February 2024).
19. "Pal V15 Kerno Drėkinimo Testai". Minijos Nafta Internal Report 1997—SCAL Analysis. Available online: www.minijosnafta.com/en (accessed on 23 February 2024).
20. Morrow, "Wettability and Its Effect on Oil Recovery". 1990. Available online: http://onepetro.org/JPT/article-pdf/42/12/1476/2222566/spe-21621-pa.pdf/1 (accessed on 27 March 2024).
21. Abdallah, W.; Buckley, J.S.; Carnegie, A.; Edwards, J.; Herold, B.; Fordham, E.; Graue, A.; Habashy, T.; Seleznev, N.; Signer, C.; et al. Fundamentals of Wettability. *Technology* **1986**, *38*, 268.
22. Hirasaki, G.; Zhang, D.L. Surface Chemistry of Oil Recovery from Fractured, Oil-Wet, Carbonate Formations. 2004. Available online: http://onepetro.org/SJ/article-pdf/9/02/151/2572183/spe-88365-pa.pdf/1 (accessed on 23 February 2024).
23. Jadhunandan, P.P.; Morrow, N.R. Spontaneous Imbibition of Water by Crude Oil/Brine/Rock Systems. *In Situ* **1991**, *15*. Available online: https://www.osti.gov/biblio/5847471 (accessed on 23 February 2024).

24. Sheng, J.J. Chapter 12. Surfactant Enhanced Oil Recovery in Carbonate Reservoirs Review of Surfactant Enhanced Oil Recovery in Carbonate Reservoirs. *Adv. Pet. Explor. Dev.* **2013**, *6*, 281–299.
25. Rohilla, N.; Hirasaki, G.J. Pore Structure of Vuggy Carbonates and Rate Dependent Displacement in Carbonate Rocks. SCA2011-21. 2011. Available online: https://jgmaas.com/SCA/2011/SCA2011-21.pdf (accessed on 23 February 2024).
26. Rohilla, N.; Ravikiran, R.; Carlisle, C.T.; Jones, N.; Davis, M.B.; Finch, K.B.H. Design of a Robust ASP Formulation for Clay Rich and Moderate Permeability Sandstone Reservoir: From Laboratory to Single Well Chemical Tracer Test in the Field. In Proceedings of the SPE-DOE Improved Oil Recovery Symposium Proceedings, Tulsa, OK, USA, 11–13 April 2016. [CrossRef]
27. Mohan, K.; Gupta, R.; Mohanty, K.K. Wettability altering secondary oil recovery in carbonate rocks. *Energy Fuels* **2011**, *25*, 3966–3973. [CrossRef]
28. Patil, P.D.; Rohilla, N.; Katiyar, A.; Yu, W.; Nelson, C.; Falcone, S.; Rozowski, P. Surfactant Based EOR for Tight Oil Unconventional Reservoirs through Wettability Alteration: Novel Surfactant Formulations and Their Efficacy to Induce Spontaneous Imbibition. In Proceedings of the SPE/AAPG/SEG Unconventional Resources Technology Conference 2018, URTC 2018, Houston, TX, USA, 23–25 July 2018. [CrossRef]
29. Patil, P.D.; Rohilla, N.; Katiyar, A.; Yu, W.; Falcone, S.; Nelson, C.; Rozowski, P. Surfactant Based EOR for Tight oil Reservoirs through Wettability Alteration: Novel Surfactant Formulations and Their Efficacy to Induce Spontaneous Imbibition. In Proceedings of the Society of Petroleum Engineers-SPE EOR Conference at Oil and Gas West Asia 2018, Muscat, Oman, 21–23 March 2016. [CrossRef]
30. Standnes, D.C. Analysis of oil recovery rates for spontaneous imbibition of aqueous surfactant solutions into preferential oil-wet carbonates by estimation of capillary diffusivity coefficients. *Colloids Surf. A Physicochem. Eng. Asp.* **2004**, *251*, 93–101. [CrossRef]
31. Standnes, D.C.; Austad, T. Wettability alteration in chalk 2. Mechanism for wettability alteration from oil-wet to water-wet using surfactants. *J. Pet. Sci. Eng.* **2000**, *28*, 123–143. [CrossRef]
32. Standnes, D.C.; Austad, T. Wettability alteration in carbonates: Low-cost ammonium surfactants based on bio-derivatives from the coconut palm as active chemicals to change the wettability form oil-wet to water-wet conditions. *Colloids Surf. A Physicochem. Eng. Asp.* **2003**, *218*, 161–173. [CrossRef]
33. Standnes, D.C.; Austad, T. Nontoxic low-cost amines as wettability alteration chemicals in carbonates. *J. Pet. Sci. Eng.* **2003**, *39*, 431–446. [CrossRef]
34. Strand, S.; Standnes, D.C.; Austad, T. Spontaneous imbibition of aqueous surfactant solutions into neutral to oil-wet carbonate cores: Effects of brine salinity and composition. *Energy Fuels* **2003**, *17*, 1133–1144. [CrossRef]
35. Seethepalli, A.; Adibhatla, B.; Mohanty, K.K. Physicochemical interactions during surfactant flooding of fractured carbonate reservoirs. *SPE J.* **2004**, *9*, 411–418. [CrossRef]
36. Xie, X.; Weiss, W.W.; Tong, Z.; Morrow, N.R. Improved oil recovery from carbonate reservoirs by chemical stimulation. *SPE J.* **2005**, *10*, 276–285. [CrossRef]
37. Gupta, R.; Mohan, K.; Mohanty, K.K. Surfactant Screening for Wettability Alteration in Oil-Wet Fractured Carbonates. In Proceedings of the SPE Annual Technical Conference and Exhibition, New Orleans, LA, USA, 4–7 October 2009. [CrossRef]
38. Sharma, G.; Mohanty, K.K. Wettability alteration in high-temperature and high-salinity carbonate reservoirs. *SPE J.* **2013**, *18*, 646–655. [CrossRef]
39. Bennetzen, M.V.; Mogensen, K.; Frank, S.; Mohanty, K. Dilute surfactant flooding studies in a low-permeability oil-wet Middle East carbonate. In Proceedings of the Society of Petroleum Engineers-International Petroleum Technology Conference 2014, IPTC 2014: Unlocking Energy Through Innovation, Technology and Capability, Kuala Lumpur, Malaysia, 10–12 December 2014. [CrossRef]
40. Pal, M.; Gilani, S.F.; Tarsaulia, G.; Geremia, G. SPE-190373-MS Offshore Surfactant Injectivity Trials: From Core to Successful Field Trials in the Al-Shaheen Field. In Proceedings of the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, 26–28 March 2018. [CrossRef]
41. Rohilla, N.; Katiyar, A.; Saxena, P.; Pal, M.; Rozowski, P.; Gentilucci, A. *Successful Wettability Alteration Pilot in an Offshore Reservoir: Laboratory Analysis to Support Planning, Implementation and Interpretation*; IOR: Austria, 2021. Available online: https://www.earthdoc.org/content/papers/10.3997/2214-4609.202133124 (accessed on 23 February 2024).
42. Pal, M.; Saxena, P.; Rohilla, N.; Katiyar, A.; Rozowski, P.; Knight, T. Successful Wettability Alteration Pilot in Offshore Reservoir: Pilot Planning, Execution, Monitoring and Interpretation. 2021. Available online: https://www.earthdoc.org/content/papers/10.3997/2214-4609.202133109?crawler=true (accessed on 23 February 2024).
43. Malik, S.; Makauskas, P.; Karaliūtė, V.; Pal, M.; Sharma, R. Assessing the geological storage potential of CO_2 in Baltic Basin: A case study of Lithuanian hydrocarbon and deep saline reservoirs. *Int. J. Greenh. Gas Control* **2024**, *133*, 104097. [CrossRef]
44. Chavan, H.K.; Sinharay, R.K.; Kumar, V.; Patel, D. An approach of using machine learning classification for screening of enhanced oil recovery techniques. *Pet. Sci. Technol.* **2023**, 1–19. [CrossRef]
45. Aminzadeh, F.; Temizel, C.; Hajizadeh, Y. Machine Learning Applications in Enhanced Oil Recovery (EOR). In *Artificial Intelligence and Data Analytics for Energy Exploration and Production*; Wiley: Hoboken, NJ, USA, 2022. [CrossRef]
46. You, J.; Ampomah, W.; Sun, Q.; Kutsienyo, E.J.; Balch, R.S.; Dai, Z.; Cather, M.; Zhang, X. Machine learning based co-optimization of carbon dioxide sequestration and oil recovery in CO_2-EOR project. *J. Clean Prod.* **2020**, *260*, 120866. [CrossRef]
47. Cheraghi, Y.; Kord, S.; Mashayekhizadeh, V. Application of machine learning techniques for selecting the most suitable enhanced oil recovery method; challenges and opportunities. *J. Pet. Sci. Eng.* **2021**, *205*, 108761. [CrossRef]

48. Salehi, E.; Mohammadi, M.R.; Hemmati-Sarapardeh, A.; Mahdavi, V.R.; Gentzis, T.; Liu, B.; Ostadhassan, M. Modeling Interfacial Tension of N_2/CO_2 Mixture + n-Alkanes with Machine Learning Methods: Application to EOR in Conventional and Unconventional Reservoirs by Flue Gas Injection. *Minerals* **2022**, *12*, 252. [CrossRef]
49. Pirizadeh, M.; Alemohammad, N.; Manthouri, M.; Pirizadeh, M. A new approach for ranking enhanced oil recovery methods based on multi-gene genetic programming. *Pet. Sci. Technol.* **2023**, *41*, 64–85. [CrossRef]
50. Karovic-Maricic, V.; Lekovic, B.; Danilovic, D. Factors influencing successful implementation of enhanced oil recovery projects. *Podzemn. Rad.* **2014**, *22*, 41–50. [CrossRef]
51. McDougall, S.R.; Sorbie, K.S. The Impact of Wettability on Waterflooding: Pore-Scale Simulation. *SPE Res. Eng.* **1995**, *10*, 208–213. [CrossRef]
52. Al-Nofli, K.; Pourafshary, P.; Mosavat, N.; Shafiei, A. Effect of Initial Wettability on Performance of Smart Water Flooding in Carbonate Reservoirs—An Experimental Investigation with IOR Implications. *Energies* **2018**, *11*, 1394. [CrossRef]
53. Agbalaka, C.; Dandekar, A.Y.; Patil, S.L.; Khataniar, S.; Hemsath, J.R. The Effect of Wettability on Oil Recovery: A Review. In Proceedings of the SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 20–22 October 2008. [CrossRef]

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.