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Low-Salinity Waterflooding for EOR in Field A of Western Offshore Basin: A Pilot Study Analysis with Laboratory and Simulation Studies—Early Observations

Vivek Raj Srivastava [1,*], Hemanta K. Sarma [2,*] and Sharad Kumar Gupta [3]

1 Institute of Reservoir Studies (IRS), Oil & Natural Gas Corporation Ltd. (ONGC), Ahmedabad 380005, Gujarat, India
2 Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, AB T2N 1N4, Canada
3 Indian Institute of Technology, Delhi 110016, Delhi, India; sgupta@chemical.iitd.ac.in
* Correspondence: srivastava_vivekraj@ongc.co.in (V.R.S.); hemanta.sarma@ucalgary.ca (H.K.S.)

Abstract: Carbonate reservoirs hold vast oil reserves, but their complex properties make traditional enhanced oil recovery (EOR) methods challenging. This study explores the application of low-salinity water flooding (LSWF) as a novel EOR method for India's largest offshore carbonate oil field. Conventional EOR techniques were deemed unsuitable due to reservoir heterogeneity, pressure decline, high temperature, and the offshore location. Favorable factors for LSWF included successful seawater flooding history, medium-weight crude oil, and existing infrastructure. Following core flooding experiments demonstrating a 6–16% increase in oil recovery, a multi-pronged evaluation process was implemented. Single-well chemical tracer tests (SWCTT) and reservoir simulations confirmed the potential of LSWF. A specific target area was chosen based on reservoir characteristics, production data, and available facilities. Simulations predicted a 1.5% incremental oil recovery using diluted seawater (25% salinity) at 30% pore volume injection. After a positive techno-economic analysis, the first offshore LSWF project in India was completed within 3 years. Initial monitoring results are encouraging. This study highlights the successful journey of LSWF from concept to field deployment in a challenging carbonate reservoir, showcasing its potential for revitalizing such fields. Furthermore, this work provides valuable data relevant to Indian offshore environments, where factors like salinity, mineralogy, and crude oil composition pose unique challenges compared to other LSWF applications. These detailed data fill a critical gap in the existing literature.

Keywords: low-salinity water flood (LSWF); original oil in place (OIIP); enhanced oil recovery (EOR); single-well chemical tracer test (SWCTT); potential determining ions (PDI)

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1. Introduction

Recovering a significant portion of the original oil in place (OOIP) from petroleum reservoirs necessitates a multi-stage approach. Primary recovery relies on natural reservoir pressure, while secondary recovery supplements it with water or gas injection. However, these methods typically leave behind a substantial amount of oil, often exceeding 50% of the OOIP. Enhanced oil recovery (EOR) techniques address this challenge by manipulating the properties of residual oil to increase its mobility and facilitate extraction.

Oil and Natural Gas Corporation Limited's (ONGC's) achievements with thermal EOR in Santhal, Balol, and Lanwa fields; with miscible gas injection and water alternating gas injection (WAG) in Gandhar; and with polymer flooding in Sanand, demonstrate the potential of EOR onshore. Although ONGC has successfully implemented commercially viable conventional enhanced oil recovery (EOR) methods in onshore clastic reservoirs, replicating this success in offshore carbonate formations presents significant challenges like logistical complexities and high costs. Additionally, declining reservoir pressure and elevated temperatures in offshore settings pose further challenges for implementing conventional EOR techniques.

Given the limitations of conventional EOR methods for offshore carbonate reservoirs, this study explores low-salinity water flooding (LSWF) as a promising EOR method for offshore carbonate reservoirs. LSWF offers several advantages that make it particularly suitable for this context:

Efficacy in Carbonate Reservoirs: LSWF can be particularly effective in altering wettability within carbonate rock formations, potentially mobilizing trapped oil.

Mitigating Reservoir Souring: Lower-salinity brines used in LSWF can help mitigate reservoir souring, a phenomenon where sulfate-reducing bacteria generate hydrogen sulfide gas.

Operational Simplicity: LSWF leverages existing water injection infrastructure, simplifying its implementation.

Field A serves as a case study for this research, representing a mature offshore carbonate reservoir in India. Discovered in 1974 and operational since 1980, the field has undergone extensive development throughout its production history. Peak production reached approximately 300,000 barrels of oil per day during the mid-1980s, followed by a period of stable production. Water injection commenced in March 1987; however, reservoir pressure has exhibited a continuous decline, impacting overall production performance. This decline, evident from 1990 onwards, manifested as an increase in field gas–oil ratio (GOR) and water cut. To address this decline, various remedial measures were implemented, including gas lift installation, water shutoff operations, sidetracking of underperforming wells, enhanced water injection support, and infill drilling utilizing clamp-on structures on existing platforms. Despite these efforts, the need for a robust EOR strategy remains paramount.

Field A possesses characteristics that make it a suitable candidate for LSWF application. Classified as a limestone reservoir with initial oil in place estimated at roughly 1215 million cubic meters (MMm^3), it currently undergoes mature waterflooding, achieving a recovery factor of approximately 31%. Even a modest increase in recovery percentage translates to significant additional oil volumes. Recognizing this potential, LSWF is investigated as a promising EOR approach.

The focus of LSWF implementation is currently on sub-layer E, a limestone formation with estimated ultimate reserves close to 486 MMm^3. Notably, layer E holds a significant portion (94%) of Field A's original oil in place. Reservoir simulations predict a recovery factor of around 35% for Field A by 2035 under the existing waterflooding regime. This suggests that LSWF implementation has the potential to unlock substantial incremental oil recovery from this mature offshore carbonate reservoir.

1.1. LSWF Process

Low-salinity waterflooding (LSWF) deviates from conventional waterflooding by focusing on the injected brine's quality, particularly its ionic composition, to manipulate rock–fluid interactions and enhance oil recovery. Although most formations suitable for conventional waterflooding are also candidates for LSWF, the emphasis is on optimizing brine composition for improved oil mobilization. Pioneering work by Yildiz and Morrow [1] highlighted the impact of brine composition on sandstone recovery. Extensive research followed, solidifying LSWF's potential in sandstone reservoirs [2–7]. Conversely, LSWF research in carbonate reservoirs remains limited [8–15]. Studies suggest the potential for increased oil recovery through sequential salinity reduction [13]. Additionally, specific ions (SO_4^{2-}, Ca^{2+}, Mg^{2+}) have been identified as crucial for optimizing injection brines in carbonates [13–15]. The optimal salinity adjustment for a reservoir depends heavily on the specific interactions between injected brines, crude oil, and rock mineralogy [16–18]. Smart water flood signifies a paradigm shift in EOR, moving from maximizing water injection volume to optimizing brine composition for enhanced oil recovery.

1.1.1. LSWF: Effectiveness and Remaining Challenges

Low-salinity waterflooding (LSWF) has emerged as a promising EOR technique due to its advantages over conventional high-salinity water injection. LSWF utilizes variously termed "smart water," "ion-engineered water," or "advanced ion management water" for its effectiveness and ease of implementation in both sandstone and carbonate reservoirs. Despite its potential, LSWF's success is not guaranteed. Several past projects in promising formations yielded disappointing results. Additionally, the underlying mechanisms remain a subject of debate. Numerous hypotheses have been proposed, including wettability alteration, fine migration, and multi-component ion exchange [19]. The key challenge lies in scaling up from sub-pore-level mechanisms to reservoir-scale phenomena during multiphase flow. Brine–oil interactions, particularly micro-dispersion formation due to crude oil and low-salinity brine contact, are considered a primary recovery mechanism. These micro-dispersions can block pore throats, diverting LSW towards upswept oil zones. Further research is needed to elucidate the dominant LSWF mechanisms and improve prediction accuracy for successful field-scale implementation.

1.1.2. Selection of Field

(1) Favorable Characteristics of Field A for LSWF Application

Carbonate reservoirs, typically composed of calcite and dolomite, exhibit complex characteristics such as dual porosity, fractured systems, and generally low clay content. Extensive laboratory studies and field observations suggest several favorable screening criteria for LSWF implementation in carbonate reservoirs [20], with some exceptions reported in the literature. These criteria include (a) high reservoir temperature: Temperatures exceeding 70 °C are generally considered advantageous; (b) high initial water saturation (Swi): A higher initial water saturation within the reservoir can promote LSWF effectiveness; (c) presence of potential determining ions (PDIs): The injected brine should contain specific ions like Ca^{2+}, Mg^{2+}, and $SO_4{}^{2-}$ that influence rock–fluid interactions; and (d) low acid number of oil: Crude oil with a low acid number tends to be more responsive to LSWF. Field A was selected for LSWF evaluation based on these general screening guidelines and its subsurface and surface properties. Notably, Field A possesses a high reservoir temperature of 90 °C, a low crude oil acid number of 0.56, and injected seawater containing the desired PDIs: Ca^{2+} (401 ppm), Mg^{2+} (1372 ppm), and $SO_4{}^{2-}$ (2950 ppm). Furthermore, several aspects of Field A enhance its suitability for LSWF, like (a) the favorable mobility ratio: Existing conventional seawater flooding with a salinity of approximately 33,000 ppm has established a favorable mobility ratio of 0.5 (less than 1), indicating minimal viscous fingering risk; (b) the presence of polar oil components: The crude oil's composition, containing 10.8 wt.% resins and 4.7 wt.% asphaltenes (polar compounds), might contribute positively to LSWF's effectiveness; (c) intermediate to mixed wettability: The reservoir's wettability characteristics, categorized as intermediate to mixed, offer potential for LSWF-induced wettability alteration towards a more water-wet state; (d) high residual oil saturation (Sorw): The high remaining oil saturation (25–30%) signifies a significant volume of oil that LSWF could potentially mobilize; and (e) existing waterflood infrastructure: The presence of established waterflooding infrastructure facilitates the implementation of LSWF in this offshore environment, making it a technically viable EOR option for Field A. Following this evaluation, a series of laboratory studies was conducted on core samples from the E layer of Field A. These studies included:

- Wettability index measurements;
- Spontaneous imbibition and displacement experiments;
- Salinity optimization through sequential dilution in core flooding experiments;
- Generation of salinity-dependent relative permeability curves for reservoir simulations.

(2) Field A–E Reservoir Description and LSWF EOR Pilot Selection

The E reservoir within Field A is a multilayered carbonate reservoir containing saturated oil. Key reservoir properties are detailed in Table 1. Current production forecasts under conventional seawater flooding (SWF) predict an ultimate recovery factor of approximately 37% by 2040.

Table 1. Average values of key reservoir parameters.

Porosity, fraction	0.25
Dykstra–Parson Coefficient	0.8
Pay thickness, m	40
Formation water salinity, ppm	23,000
API gravity, deg	38°

(3) Selection of E Layer for LSWF Pilot:

Favorable factors like a good mobility ratio, positive response to waterflooding, low free gas saturation, and existing surface infrastructure guided the selection of the E layer for a pilot implementation of low-salinity waterflooding EOR (LSWF EOR). This layer is situated on the western periphery of Field A. The target area encompasses more than 100 well completions within the E layer, including roughly 40 injection wells. This sector contributes significantly to total reservoir production, accounting for approximately 20% with an average gas–oil ratio (GOR) of 170 *v/v* and a water cut of 72%.

2. Materials and Methods

The successful implementation of LSWF projects typically follows a staged approach, which includes screening: This initial phase involves a rigorous evaluation process to determine the reservoir's suitability for LSWF; pilot-scale implementation: Following a positive screening evaluation, a pilot project is implemented on a limited scale to assess the technical and economic feasibility of LSWF in the specific reservoir; and full-field implementation: Upon successful completion of the pilot project, a full-field implementation plan can be developed for broader reservoir application. Rock and fluid characterization plays a crucial role in the screening process for LSWF projects. A thorough understanding of these properties helps predict the potential impact of LSWF on oil recovery. Mineralogical composition, determined using techniques like X-ray diffraction (XRD), influences the initial wettability of the rock and its interaction with brine and oil. Specific mineral assemblages can promote conditions favorable for LSWF effectiveness. The characterization of crude oil, particularly the presence of asphaltenes and resins [21], can provide insights into potential mechanisms by which LSWF may operate. The presence of these components can influence oil-water interfacial properties and interactions with the rock surface, ultimately affecting oil recovery.

2.1. Characterization of Core Plugs by Mineralogical Studies

X-ray diffraction (XRD) analysis was employed to characterize the mineralogical composition of the core samples. This technique utilizes the principle of constructive interference of electromagnetic radiation (X-rays) with crystalline materials. The resulting diffraction patterns enabled the identification and quantification of mineral phases present within the sample. The XRD analysis revealed that calcite was the primary framework mineral, constituting the dominant component of the core samples (Figure 1). Accessory rock-forming minerals like ankerite, quartz, halite, and andalusite were also identified. Additionally, the presence of clay minerals, including clinochlore, montmorillonite, and kaolinite, was confirmed. Notably, clinochlore emerged as the dominant clay mineral based on the XRD results.

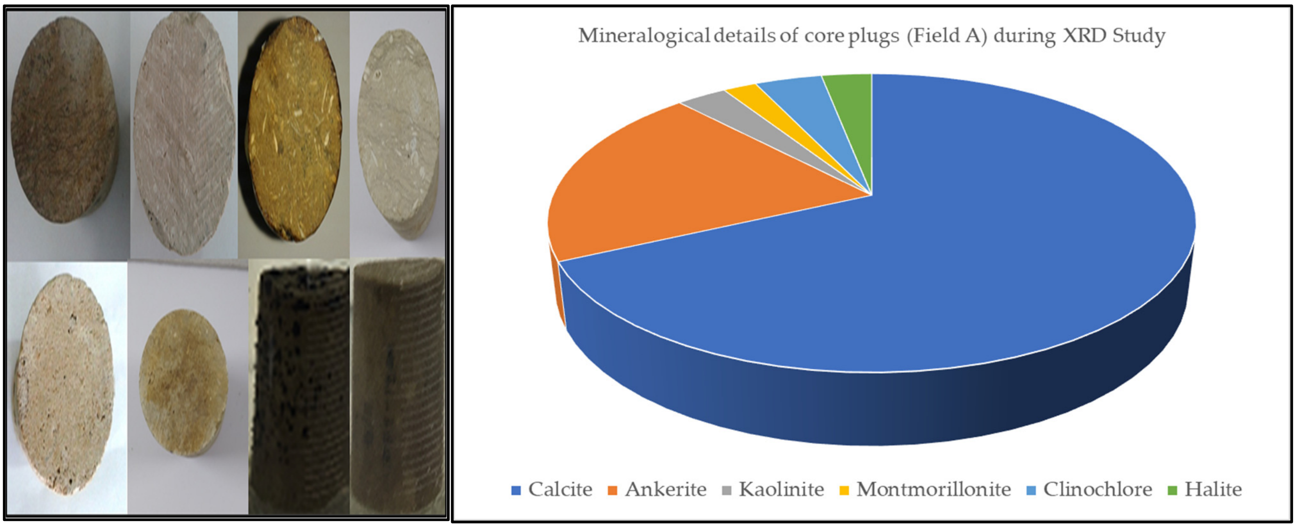


Figure 1. Pictorial representation and semi-quantitative mineralogical estimation of core samples from Field A.

2.2. *Characterization of Crude Oil by SARA Analysis*

Crude oil characterization via SARA analysis (Table 2) revealed asphaltene and resin content impacting oil polarity and rock–brine interaction (wettability). Acid number (AN) is a common screening tool for oil polarity (Table 2). High saturates indicate waxy crude. The asphaltene resin ratio is crucial, as resins stabilize asphaltenes, preventing precipitation and equipment damage. Asphaltenes and resins also stabilize emulsions by forming a film around droplets. These properties impact surface chemistry and interfacial tension (IFT) during enhanced oil recovery.

Table 2. Physical parameters of crude oil.

Sl. No.	Component	Composition, wt%
1	Saturates	73.3
2	Aromatics	11.2
3	Resins	10.8
4	Asphaltene	4.7
5	Acid number	0.56

2.3. *Physico-Chemical Characterization of Seawater/Produced Water and Preparation of Low Salinity Brines*

The Formation water brine salinity, ionic composition, and initial saturation impact rock wettability, influencing LSWF success. The seawater and produced water compositions are presented in Table 3. Low-salinity brine compositions for this study are presented in Table 4. Seawater and dilutions of 50%, 25%, 10%, and 1% were prepared with ultrapure deionized water.

Table 3. Composition of seawater and produced water.

Sl. No.	Parameter	Unit	Seawater (Concentration)	Produced/Formed Water (Concentration)
1	pH	-	7.69	7.75
2	Turbidity	NTU	0.98	3.27
3	Carbonate	mg/L	Nil	Nil

Table 3. *Cont.*

Sl. No.	Parameter	Unit	Seawater (Concentration)	Produced/Formed Water (Concentration)
4	Bicarbonate	mg/L	183	366
5	Chloride	mg/L	20,413	19,703
6	Sulphate	mg/L	2950	1100
7	Calcium	mg/L	401	1003
8	Magnesium	mg/L	1372	490
9	Sodium (Cal.)	mg/L	11,672	11,360
10	Ionic strength	mole/L	0.74	0.64
11	Salinity (as NaCl)	mg/L	33,640	32,468
12	TDS (Cal.)	mg/L	36,990	34,021

Table 4. Ionic concentrations, TDS, and ionic strength of diluted brines of seawater.

Ions	Diluted Brines				
	SW	50% SW	25% SW	10% SW	1% SW
Na^{+} (ppm)	11,672	5836	2918	1167.20	116.72
Ca^{2+} (ppm)	401	200.50	100.25	40.10	4.01
Mg^{2+} (ppm)	1372	686	343	137.20	13.72
Cl^{-} (ppm)	20,413	10,206.50	5103.25	2041.30	204.13
SO_4^{2-} (ppm)	2950	1475	737.5	295	29.50
HCO_3^{-} (ppm)	183	91.50	45.75	18.30	1.83
Total dissolved solids (ppm)	36,990	18,495	9247.5	3699	369.90
Ionic strength (mol/L)	0.74	0.37	0.185	0.07	0.01

X% SW—concentration reduced to x%.

3. Experimental Studies

This section presents the findings from a comprehensive series of laboratory core flood experiments designed to investigate the potential application of low-salinity water flooding (LSWF) in reservoir A. The core flood studies were conducted in a phased approach, encompassing three main stages:

Wettability Characterization and Spontaneous Imbibition: This phase focused on assessing the wettability characteristics of core samples and evaluating the impact of LSWF on oil recovery through spontaneous imbibition processes.

Displacement Studies and Salinity Optimization: The second phase involved core flooding experiments to quantify the incremental oil recovery achievable through LSWF. This stage also included optimization of the injected brine salinity for maximizing oil displacement efficiency.

Generation of Salinity-Dependent Relative Permeability Data: The final phase aimed to generate salinity-dependent relative permeability curves for the oil and water phases. These curves will serve as crucial input data for reservoir simulation studies, enabling a more accurate representation of the two-phase flow behavior under varying salinity conditions within the reservoir model.

3.1. Wettability Index and Spontaneous Imbibition Studies

3.1.1. Wettability Index Studies of Field A

The wettability characteristics of core plugs from Field A were evaluated using Amott–Harvey's wettability index. This index is calculated as the difference between the water wettability index (WWI) and the oil wettability index (OWI).

Water Wettability Index (WWI): The ratio of oil produced by spontaneous water imbibition to the total oil recovered (both through spontaneous and forced imbibition).

Oil Wettability Index (OWI): The ratio of water produced by spontaneous oil imbibition to the total water recovered (both through spontaneous and forced imbibition). Wettability plays a critical role in oil recovery through low-salinity water flooding (LSWF). The results presented in Table 5 suggest that the wettability characteristics of the core plugs from Field A are favorable for the application of LSWF.

Table 5. Amott–Harvey wettability index of Field A.

Field	WWI	OWI	Amott–Harvey Wettability Index	Wettability
A	0.189	0.476	(−) 0.287	Mixed or intermediate wetness

3.1.2. Spontaneous Imbibition Studies

This study employed spontaneous imbibition experiments to evaluate the impact of low-salinity waterflooding (LSWF) on wettability alteration in reservoir rock samples from the E layer of Field A. Wettability, which governs the preferential interaction of fluids with the rock surface, plays a crucial role in oil recovery. A shift towards a more water-wet condition can enhance oil displacement by imbibition. Oil-saturated core plugs were prepared to achieve residual oil saturation (ROS) conditions. Each core plug was then transferred to an imbibition cell maintained at 90 °C for a period of seven days. Four core plugs (Table 6) were subjected to this process, with each experiment utilizing a different diluted seawater solution (50%, 25%, 10%, and 1% salinity). The volume of oil displaced by imbibed water was monitored daily throughout the seven days for each core plug–brine combination. The entire spontaneous imbibition study was completed within five weeks. The multi-step spontaneous imbibition experiments revealed an additional incremental oil recovery ranging from 4.3% to 10% compared to traditional seawater flooding. This enhanced recovery is attributed to the reduction in salinity of the imbibing brine (Figures 2 and 3). These findings suggest that LSWF can promote a shift towards a more water-wet rock surface, thereby facilitating greater oil displacement through spontaneous imbibition. The successful demonstration of the low-salinity effect during the spontaneous imbibition experiments strengthens the rationale for conducting additional displacement studies to explore this mechanism in greater detail.

Table 6. Reservoir rock properties of core plugs used for spontaneous imbibition studies.

Core Sample	Depth (m)	Length (mm)	Diameter (mm)	Porosity Ø (%)	Air Permeability kair (mD)	Residual Oil Saturation, Soi (%)
1	~1400	55.5	38.2	26.03	31.02	50.3
2	~1400	53.0	38.1	20.3	22.03	52.4
3	~1400	54.9	38.0	20.1	11.9	49
4	~1400	51.7	38.0	22.2	5.35	52

A spontaneous imbibition experiment is a reliable method to assess wettability alteration. During imbibition, capillary forces driven by the surrounding brine displace the rock's oil. The imbibed brine volume or displaced oil quantity reflects the wettability change. A higher imbibition rate indicates stronger oil displacement. Utilizing 25% diluted seawater (dSW) resulted in a significantly higher imbibition rate compared to seawater (SW). This observation aligns with the shift in wettability towards a more water-wet state, further supported by the change in contact angle and increased number of oil droplets observed on the rock surface with 25% dSW compared to SW (Figure 4). A key strength of this work lies in performing spontaneous imbibition experiments under realistic reservoir conditions, encompassing both high pressure and high temperature. This approach improves the applicability of findings to real-world oil recovery scenarios.

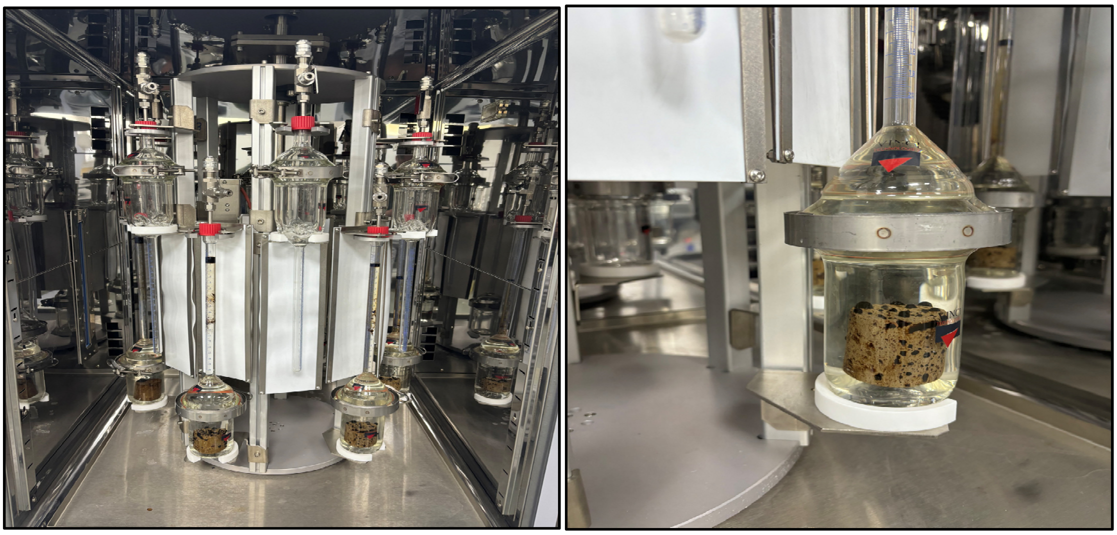


Figure 2. Pictorial representation of spontaneous imbibition studies on core samples from Field A.

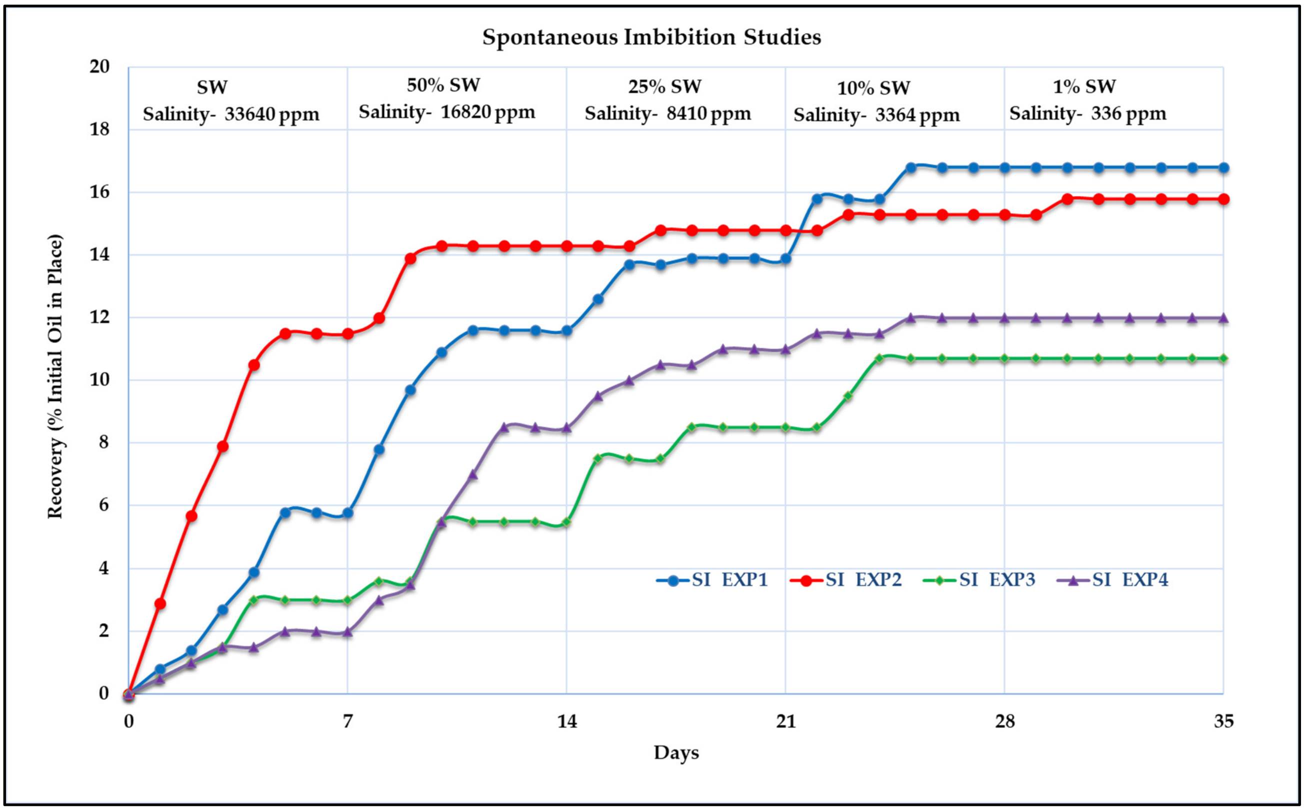


Figure 3. Experimental result of spontaneous imbibition studies.

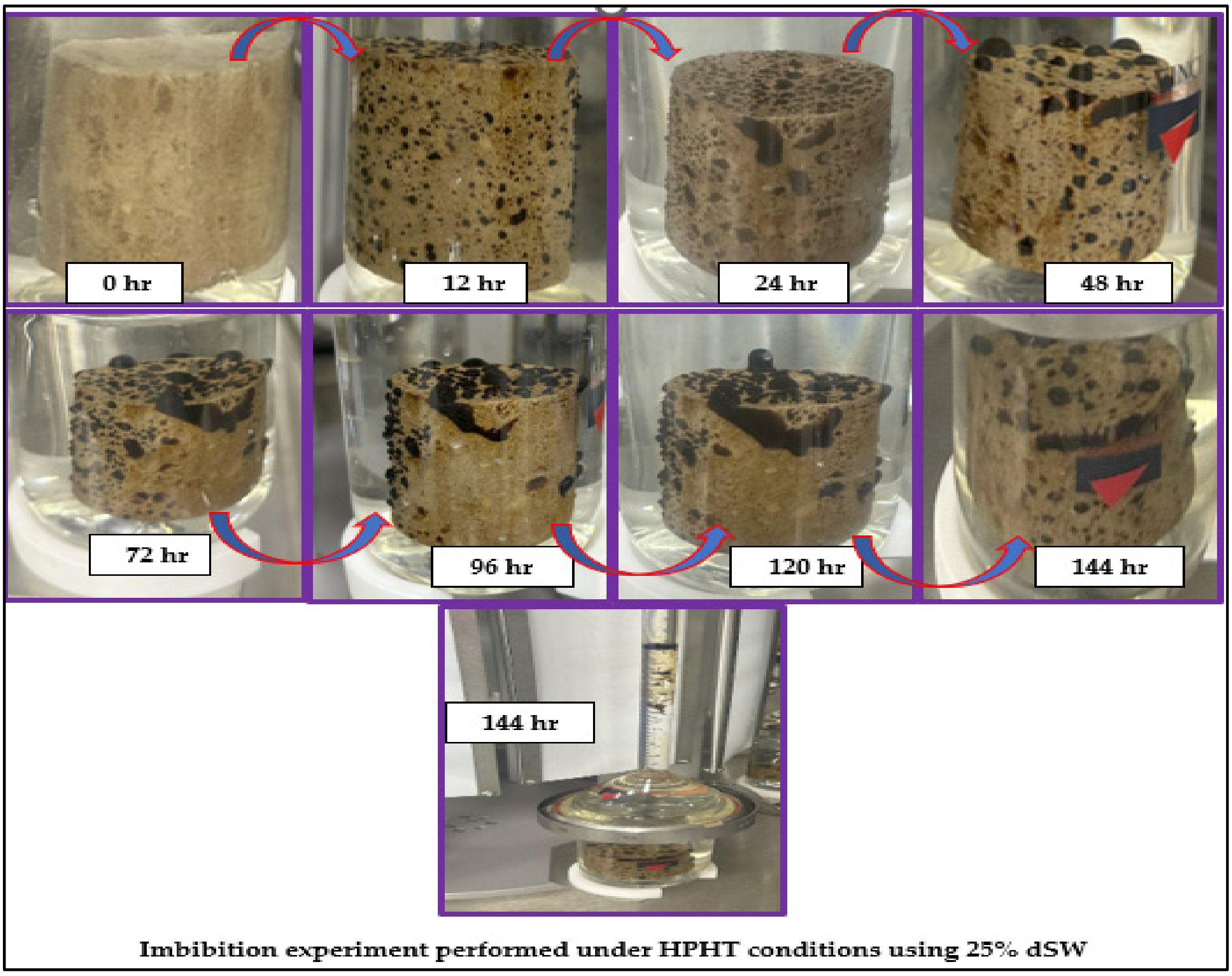


Figure 4. Experimental result of spontaneous imbibition studies (SI Exp 4).

Contact Angle Measurement (Rock–Oil–Brine Interaction)

The initial wettability of the rock is crucial for oil recovery in LSWF. Although some studies [22] observed a decrease in interfacial tension (IFT) between oil and water using low-salinity brines, a clear link between IFT and enhanced oil recovery hasn't been established yet. Therefore, to understand the impact of LSWF, measuring the contact angle (CA) is essential. This provides a baseline wettability before introducing different brines. In this study, the initial contact angle measured with seawater, oil, and rock was approximately 106°. Reproducible results confirmed this value, indicating the rock was very weakly water-wet at the outset. Figure 5 compares the rate of water imbibition into the rock using contact angle measurements over time. The findings align with previous research conducted under high-temperature conditions [5,19]. However, this study incorporated the additional factor of high pressure, which significantly accelerated the imbibition process.

The decreasing contact angle during imbibition signifies a shift towards a more water-wet rock surface. This enhanced water-wetness translates to a stronger imbibition effect. Furthermore, the oil droplets (Figure 4) noticeably increased in size during imbibition. This visually confirms the effectiveness of low-salinity waterflooding in promoting favorable imbibition, ultimately leading to higher oil recovery in high-pressure, high-temperature reservoirs like Field A.

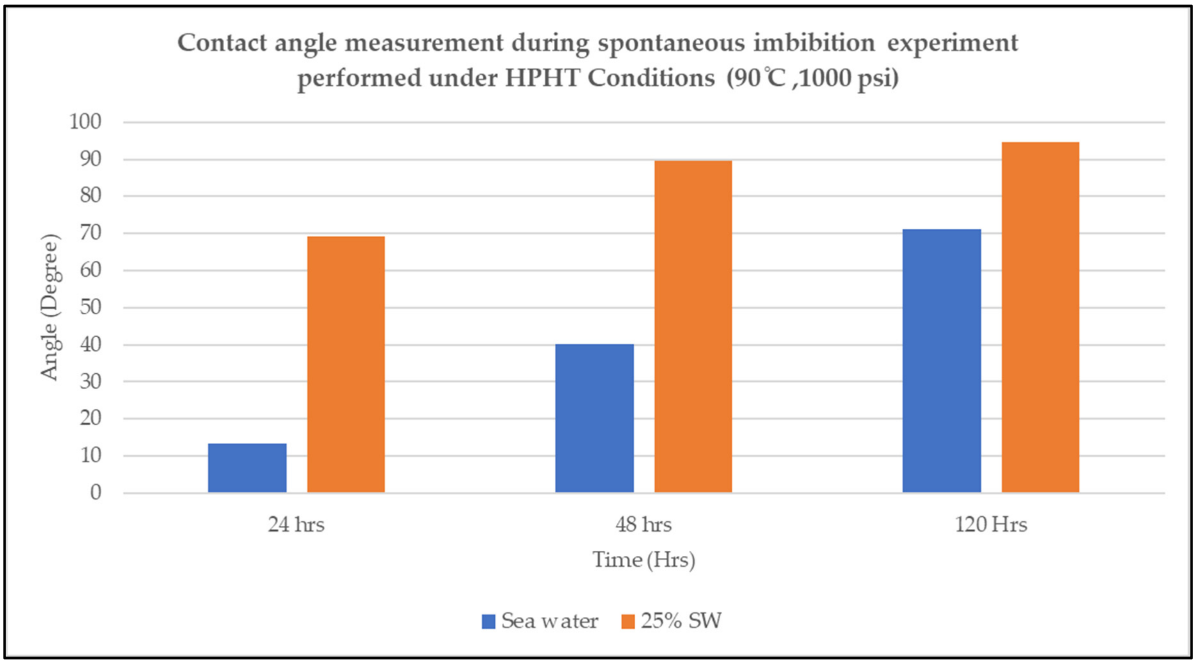


Figure 5. Contact angle measurement during spontaneous imbibition study to time.

3.2. Displacement and Salinity Optimization Studies

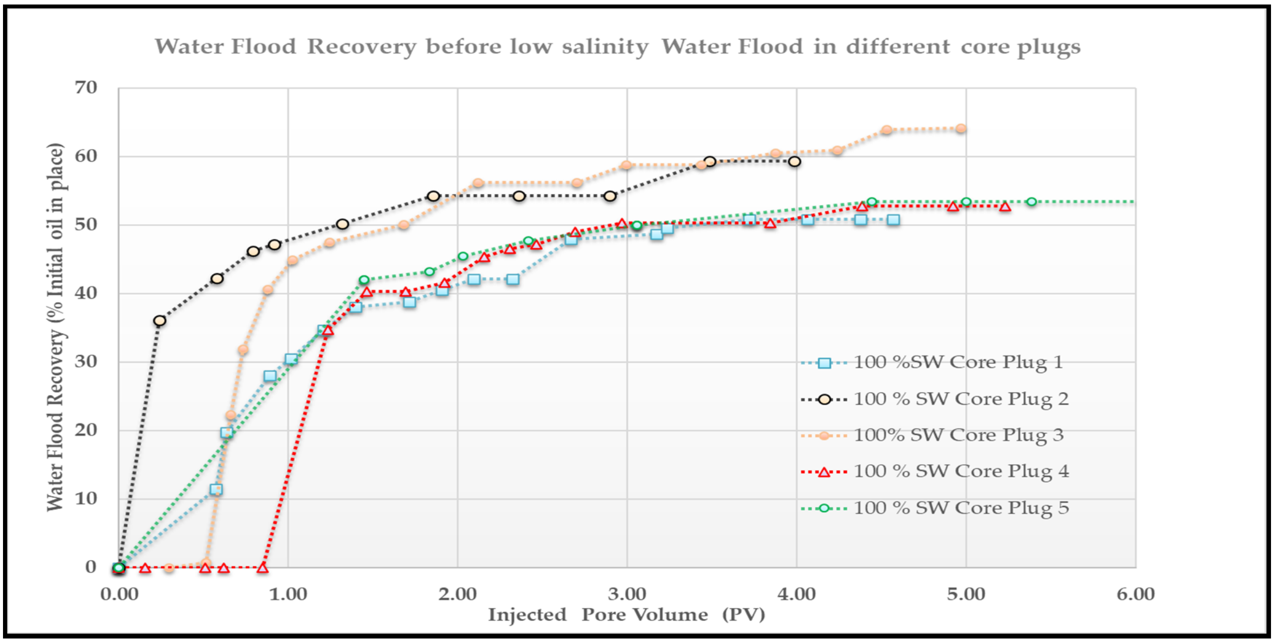
3.2.1. Core Flood Displacement Studies on Core Plugs of Field A

This study investigated the application of low-salinity water flooding (LSWF) for enhanced oil recovery (EOR) in reservoir zone E of Field A. A series of core flood displacement experiments was conducted in tertiary mode (i.e., after waterflooding) to assess the effectiveness of LSWF. Five core plugs from the E layer were utilized for the core flood experiments. The relevant reservoir rock properties of these core plugs are detailed in Table 7. Diluted seawater solutions with salinities of 50%, 25%, 10%, and 1% were employed for displacement. The core flood experiments yielded a significant increase in incremental linear displacement efficiency (ILDE) for all core plugs when displaced with diluted seawater compared to the initial seawater flood (Table 8 and Figure 6a,b). These findings suggest a pronounced low-salinity effect in the core samples from Field A. Total incremental oil recovery due to LSWF ranged from 6% to 16%, leading to ultimate recoveries of between 59% and 71% (Figure 7).

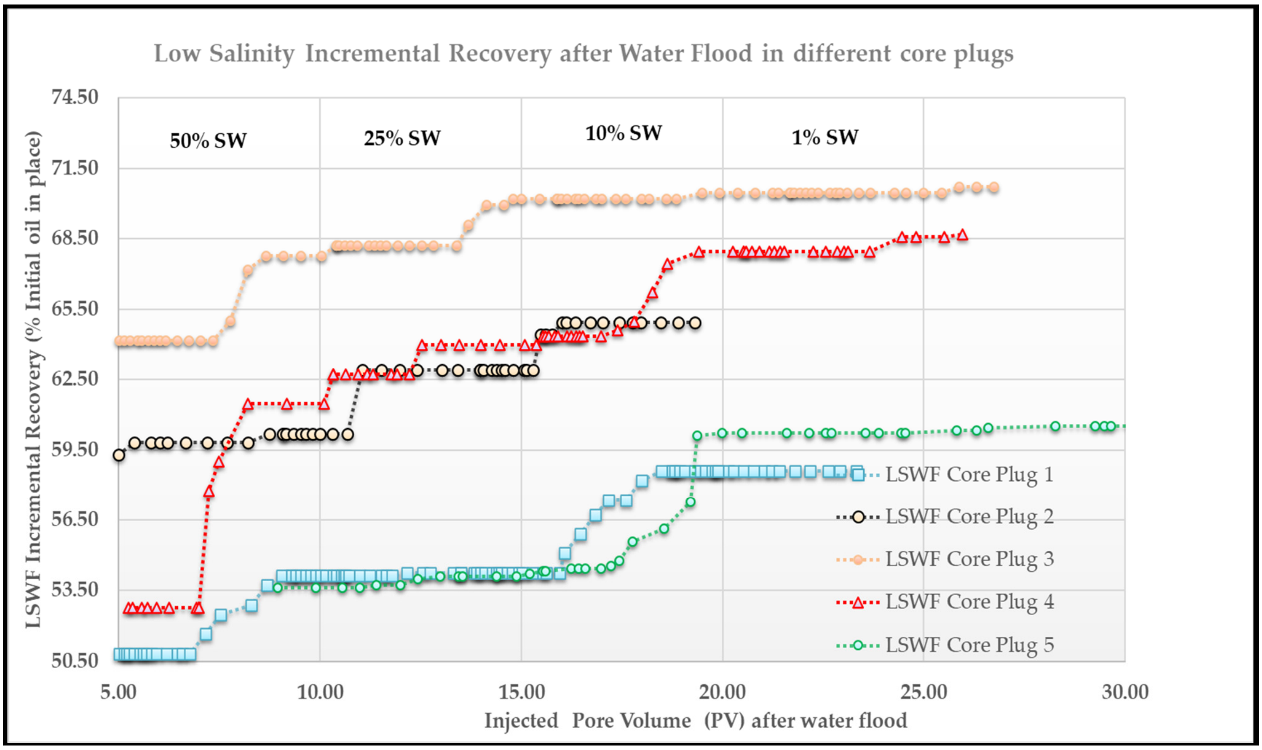
A temporary delay in pressure increase was observed upon switching to LSWF. This is attributed to the process of refilling the injection brine after seawater flooding and a slight reduction in injection rate. However, the pressure subsequently increased over time. The observed pressure increase is believed to have been a consequence of fine particle migration within the core plugs. This phenomenon was corroborated by an increase in turbidity measured during the experiments.

Table 7. Reservoir rock properties.

Core Sample	Depth (m)	Length (mm)	Diameter (mm)	Porosity Ø (%)	Air Permeability kair (mD)	Residual Oil Saturation, Soi (%)
1	~1400	70	37.9	25	17.5	61.4
2	~1400	70	38.1	18.8	12.5	66.7
3	~1400	76	38.0	21.5	17.8	67.5
4	~1400	91	38.0	16.4	43.4	61.9
5	~1400	73.0	38.1	20.3	22.03	49



(**a**)



(**b**)

Figure 6. (**a**) Core flood displacement results of core plugs 1 to 5. (**b**) Core flood displacement results of core plugs 1 to 5.

Table 8. Core flood displacement recovery results.

Core Sample	Water Flood (Recovery)	Recovery with 50% SW	Recovery with 25%SW	Recovery with 10% SW	Recovery with 1% SW	Total Incremental Recovery (After Water Flood)	Ultimate Recovery
1	50.83	3.31	0.12	4.34	0	7.77	58.6
2	59.30	0.90	2.71	2.01	0	5.63	64.93

Table 8. *Cont.*

Core Sample	Water Flood (Recovery)	Recovery with 50% SW	Recovery with 25%SW	Recovery with 10% SW	Recovery with 1% SW	Total Incremental Recovery (After Water Flood)	Ultimate Recovery
3	64.16	4.07	1.99	0.26	0.26	6.58	70.74
4	52.80	9.94	1.61	3.60	0.75	15.9	68.70
5	53.52	0.80	5.91	0.28	0	6.99	60.51

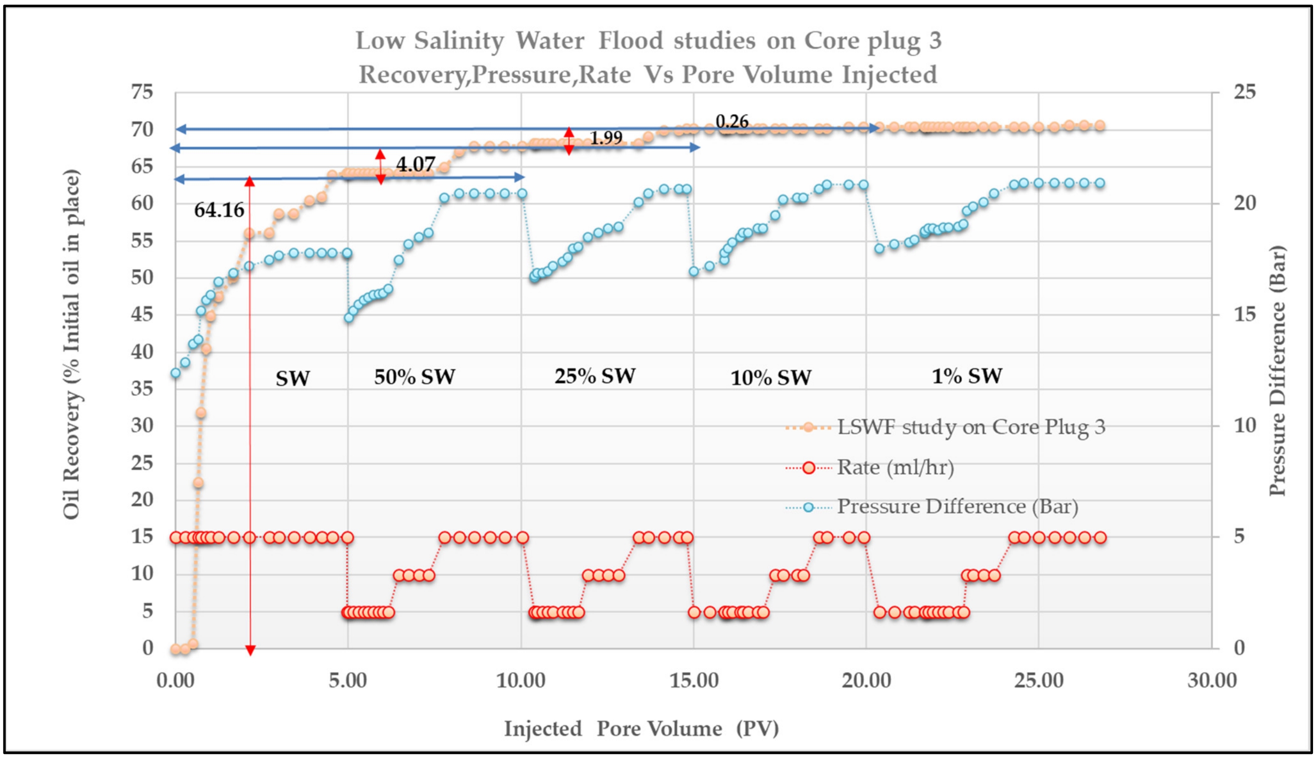


Figure 7. Effect of different parameters in low-salinity water flood study for core plug 3.

3.2.2. Salinity Optimization Study on Target Layer (Field A; E Layer)

Encouraged by the positive outcomes of laboratory core flood displacement studies employing low-salinity water, this work investigated the feasibility of implementing this enhanced oil recovery (EOR) technique as a pilot project in Field A. The primary criterion established for pilot area identification was the presence of single-layer completions in both injector and producer wells. Based on this criterion, the western sector of Field A emerged as a potential candidate due to the availability of numerous single-layer injector–producer well configurations within reservoir zone E. Following the selection of a pilot area, salinity optimization of the injected brine was deemed necessary. Long core plugs (20 cm) obtained from the E layer were employed for salinity optimization studies. These core plugs were saturated with oil to residual oil saturation (ROS) conditions. Subsequently, displacement experiments were conducted in tertiary mode (i.e., after waterflooding) to evaluate the impact of brine salinity on oil recovery.

The experimental results indicated that a 25% seawater dilution yielded the highest incremental oil recovery (ILOR) of 7.5%. Notably, dilutions of 50% and 10% seawater salinity also resulted in significant ILOR values of 6.3% and 6.8%, respectively (Figure 8). Interestingly, the study found minimal performance difference between 25% and 10% dilutions, suggesting that 25% offers a balance between effectiveness and potentially lower treatment costs.

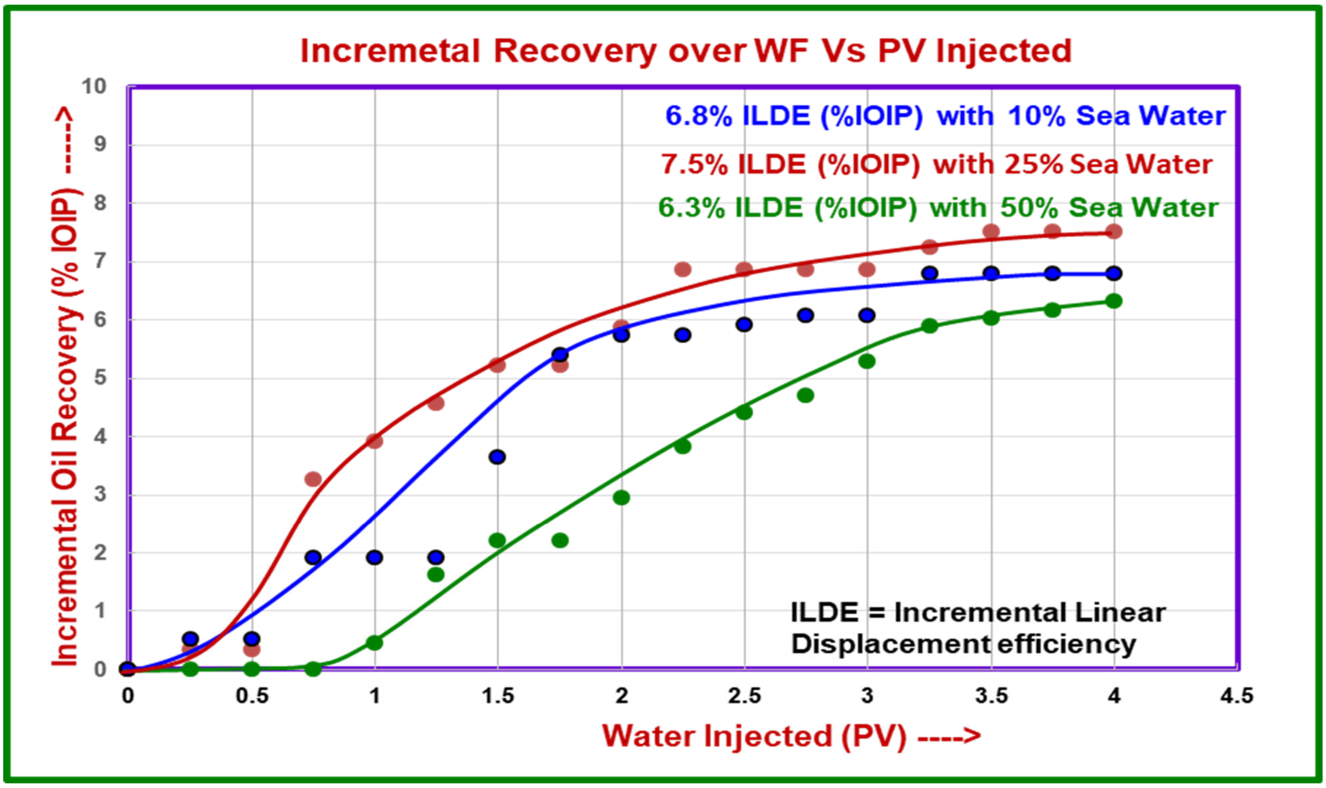


Figure 8. Incremental oil recovery over water flood vs. injected pore volume.

3.3. Generation of Salinity-Dependent Relative Permeability Curves for Simulation

This study aimed to elucidate the influence of low-salinity water flooding on two-phase (oil–water) flow behavior in core samples from reservoir A. The research focused on comparing the effectiveness of seawater flooding and a 25% diluted seawater solution (low-salinity water) in enhancing oil recovery. Core flood experiments were conducted under simulated reservoir conditions to determine residual oil saturation (ROS) after displacement by both seawater and low-salinity water.

Wettability-restored core samples from reservoir A were utilized in the core flooding experiments. The study observed a significant improvement in oil recovery achieved through low-salinity water flooding compared to seawater flooding. Notably, residual oil saturation decreased by approximately 13 saturation units (Figure 9) under low-salinity flooding in imbibition mode. The findings from the core flood experiments, particularly the salinity-dependent oil–water relative permeability curves, are intended to be used as input data for reservoir simulation studies. These data will allow for a more accurate representation of the two-phase flow behavior under varying salinity conditions within the reservoir model.

Oil recovery was consistently higher, with 25% diluted seawater injection compared to 10% dilution. In multiple core flood experiments, recovery ranged from 0.12% to 5.91% for 25% seawater compared to 0.26% to 4.34% for 10% seawater. This trend continued in a long core pack study (salinity optimization study), where recovery reached 7.5% with 25% seawater and 6.8% with 10% seawater. Beyond core floods, separate relative permeability experiments showed a significant 13% reduction in residual oil saturation with 25% seawater injection. This further strengthens the case for 25% dilution.

Importantly, the study found minimal performance difference between 25% and 10% dilutions. This suggests that a 25% seawater injection offers the best balance between effectiveness and potentially lower costs.

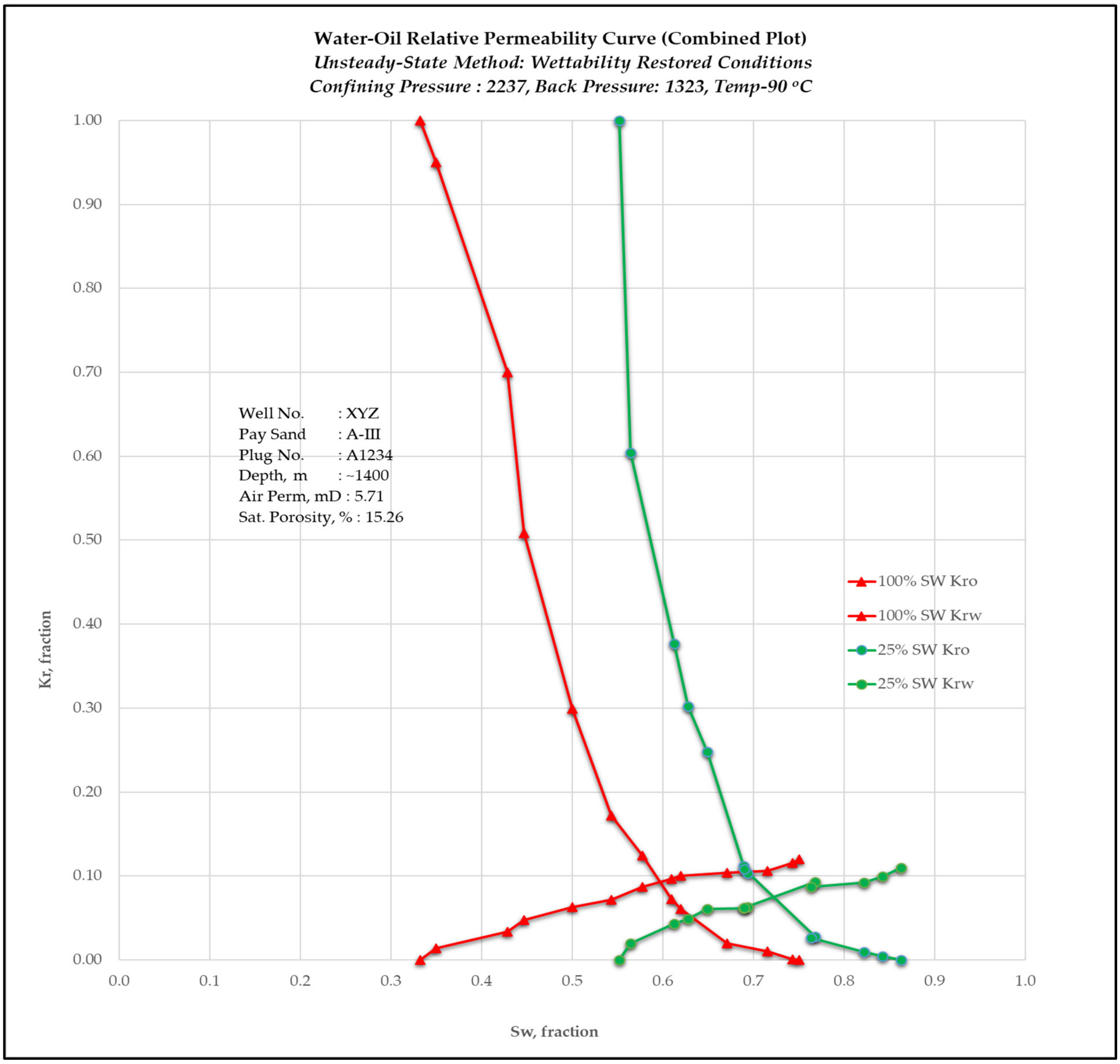


Figure 9. Relative permeability curve for simulation.

4. Simulation

4.1. Core Flood Simulation

A 1D core flood simulation accurately replicated recovery trends observed in laboratory experiments. A homogeneous core model (20 × 1 × 1 grid cells) was constructed to replicate the recent LSWF core flood experiment 1. The core dimensions (length: 7 cm, diameter: 3.8 cm) and reported properties (porosity: 0.25, permeability: 17.5 md) were used in the model. To simulate fluid injection, an injector–producer pair was defined at opposite ends of the 1D model grid. The relative permeability curves employed were identical to those used in the previous simulations.

Base Case Simulation (Seawater Injection):

In the base case, the core was flooded with seawater (salinity: 33.6 kg/m^3) at a constant rate of 10 mL/h for 30 h. The simulated oil recovery at the end of the injection period was 50.67%.

LSWF Simulation with Staged Salinity Reduction:

A subsequent simulation variant involved sequential injection of diluted brines (salinities: 16.8, 8.4, 3.0, and 0.3 kg/m^3) for a duration of 6 h each. The maximum incremental oil recovery (3.18%) was achieved with a 50% dilution of seawater, which is close to the reported laboratory value of 3.3%. The cumulative incremental recovery observed across all salinity stages was 6.67%, slightly lower than the 7.7% reported in the laboratory experiment. This discrepancy was attributed to the significantly lower pore volume injected in the simulation model (around 12 pore volumes) compared to the laboratory experiment (24 pore volumes) (Figure 10 & Table 9).

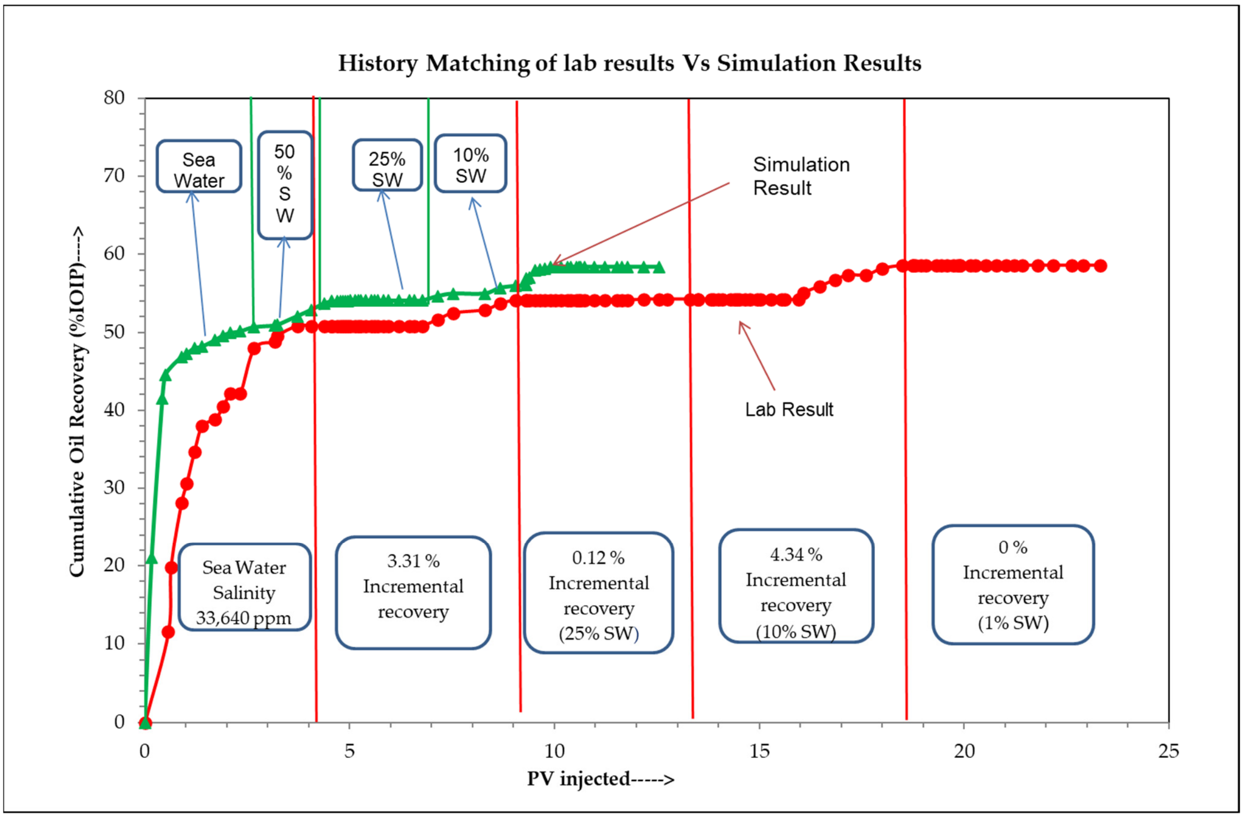


Figure 10. Comparison of results of core simulation vs. core flood experiment.

Table 9. Comparison of results of core simulation vs. core flood experiment.

Results	Water Flood (Recovery)	Recovery with 50% SW	Recovery with 25%SW	Recovery with 10% SW	Total Incremental Recovery (After Water Flood)	Ultimate Recovery
Laboratory	50.83	3.31	0.12	4.34	7.77	58.6
Simulation	50.67	3.18	0.12	3.37	6.67	57.34

4.2. Pilot Area Simulation

Reservoir simulation remains the most cost-effective tool for assessing the incremental oil recovery potential of LSWF compared to conventional seawater flooding during the conceptualization phase of an EOR pilot project. To accurately evaluate the LSWF response in a target area, it is crucial to understand the simulation approach employed. This study utilized a black oil simulator incorporating a salinity-tracking function employed within ECLIPSE100 [23]. ECLIPSE-100 offers a robust framework for simulating LSWF by incorporating salinity-dependent properties and allowing for adjustments based on laboratory data and weighting factors.

Modeling Salinity and Relative Permeability:

- The simulator introduces an additional salt phase to the existing fluid phases (oil, water) within the reservoir model. A dedicated mass conservation equation is solved for this new phase in each grid block. The model tracks water salinity and defines an additional set of "low salinity" saturation functions based on laboratory data. Fluid mobilities are assigned based on the grid block's salinity. When the salinity falls within a specific range, the corresponding "low salinity" relative permeability functions are used. For intermediate salinity values, relative permeability is estimated through interpolation between the "high salinity" and "low salinity" curves.

- Salinity as a Single Component: Salt is modeled as a single, lumped component dissolved in the aqueous phase. This component can be injected and its movement tracked within the reservoir.
- Salinity-Dependent Fluid Properties: The viscosity and density of the aqueous phase are dynamically adjusted based on the prevailing salinity within a grid block.
- Salinity-Dependent Relative Permeability and Capillary Pressure: The ECLIPSE model allows relative permeability and capillary pressure curves to be defined as functions of salinity. High-salinity and low-salinity relative permeability data serve as the input, with the model performing interpolation for intermediate salinity values

Simulating the LSWF Mechanism:

The low-salinity oil recovery mechanism is modeled by calibrating relative permeability and residual oil saturation (Sor) as functions of salinity. During the simulation, salinity-dependent relative permeability curves are generated dynamically using a weighting function:

$$\mathrm{krw} = \mathrm{F1} \times \mathrm{krw_L} + (1 - \mathrm{F1}) \times \mathrm{krw_H}$$

$$\mathrm{kro} = \mathrm{F1} \times \mathrm{kro_L} + (1 - \mathrm{F1}) \times \mathrm{kro_H}$$

$$\mathrm{F1} = (\mathrm{Cs}^2 - \mathrm{Cs})/(\mathrm{Cs}^2 - \mathrm{Cs}^1)$$

where

Cs: interpolated salinity concentration
Cs^1: lower limit of the salinity range
Cs^2: upper limit of the salinity range
krw: relative permeability of the water
kro: relative permeability of the oil
Pcow: capillary pressure
Superscripts "L" and "H" denote low- and high-salinity data, respectively.

4.2.1. Pilot Area Reservoir Description

The pilot area simulation encompasses a complex reservoir system involving 13 platforms and an original oil-in-place (OOIP) estimated at approximately 121 million cubic meters (MMm^3). The reservoir configuration includes around 80 producers and 30 injectors concentrated within the E layer. Current production at the pilot area reflects an oil production rate of 15,000 barrels of oil per day (bopd) and a water injection rate of 80,000 barrels of produced water per day (bwpd). The average water cut and gas-to-oil ratio (GOR) observed in the pilot area are 60% and 140 v/v, respectively.

4.2.2. LSWF Pilot Design and Simulation Results

A crucial aspect of the pilot design involved determining the volume of low-salinity water required for injection and its anticipated impact on incremental oil recovery. The simulation envisioned a total water injection requirement of 125,000 bwpd of low-salinity water sourced from a dedicated facility planned for platform L.

Salinity-dependent relative permeability curves, derived from laboratory experiments, were integrated into the simulation model. These curves predicted a potential reduction in residual oil saturation (Sor) of up to 13 units for low-salinity water (LSW) with a salinity of 8250 ppm. The model was then employed to simulate both a base case scenario and an LSWF prediction scenario. Production profiles were generated for both scenarios (Figure 11). Figure 11 depicts a predictive scenario for LSWF performance, developed through an upscaling approach that leverages laboratory data, field observations, and simulation results. The key findings from the pilot area simulation are summarized below:

- By March 2035 (Mar-35), an incremental oil gain of 0.795 million metric tons (MMt) is anticipated compared to the base case (conventional seawater injection), translating to an incremental oil recovery of 0.8%.
- By March 2040 (Mar-40), with a cumulative pore volume injection of approximately 30%, the simulation predicts an incremental oil gain of 1.37 MMt over the base case, representing an incremental oil recovery of 1.5%.

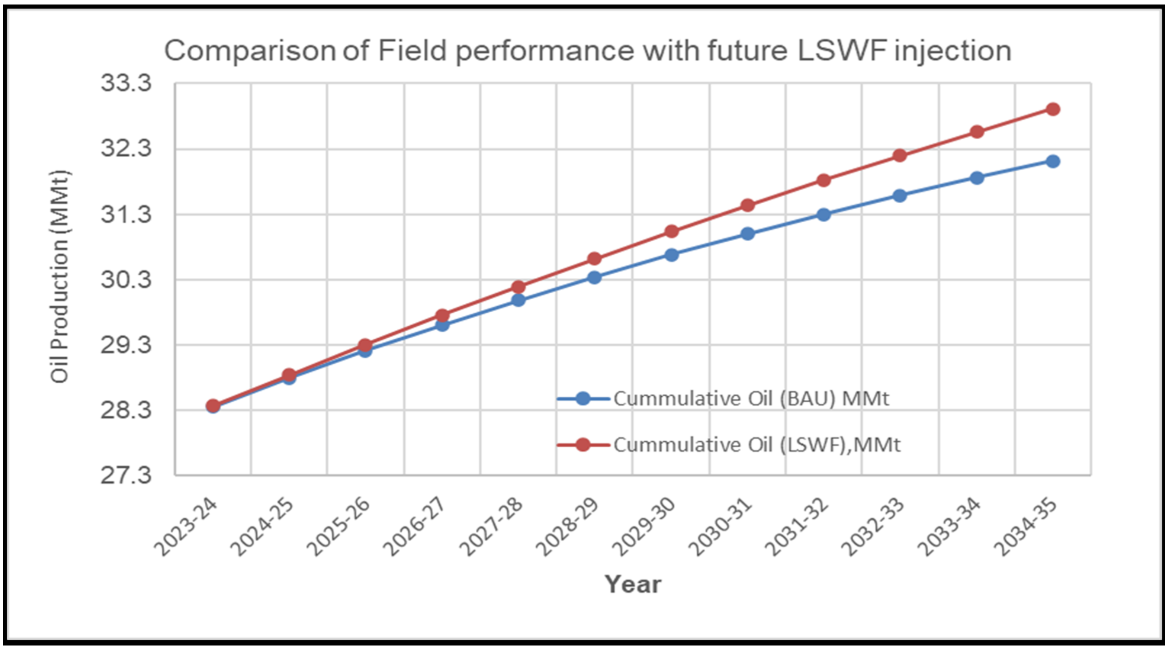


Figure 11. Field performance with pore volume injection.

These results suggest that LSWF holds promise for enhancing oil recovery within the target carbonate reservoir pilot area.

5. LSWF Pilot

5.1. Single-Well Chemical Tracer Test (SWCTT)

To bolster confidence before implementing a pilot-scale LSWF project, a laboratory-scale SWCTT technique was designed to quantify residual oil saturation (ROS). This technique utilizes partitioning, material balance, and cover tracers to assess ROS changes within the reservoir. Ethyl acetate, isopropyl alcohol (IPA), and methanol were chosen as the partitioning tracer, material balance tracer, and cover tracer, respectively. The partitioning coefficient and hydrolysis constant of the partitioning tracer (ethyl acetate) were determined to be 6.1 and 0.18/day, respectively. The SWCTT experiment was conducted within the E layer of Well Z. The procedure involved the following steps:

- Baseline ROS Establishment: Injection water was initially introduced to establish the field's residual oil saturation near the wellbore.
- Well Backflow: The well was then flowed back to ensure no oil production was occurring.
- Initial SWCTT for ROS Measurement: The first SWCTT was performed to measure the initial ROS.
- Low-Salinity Water Injection: Subsequently, low-salinity water was injected into the well.
- Secondary SWCTT for ROS Comparison: A second SWCTT was conducted to determine the reduction in ROS following low-salinity water injection.

The collected water samples were analyzed using gas chromatography to quantify the concentration of tracers (ethyl acetate, ethanol, IPA, and methanol). The SWCTT data was interpreted using CMG and H. Dean software for reservoir simulation purposes. The simulated results revealed a decrease in ROS saturation units from 12% to 7%, attributable to the low-salinity water injection.

5.2. Field Pilot Project

The Oil and Natural Gas Corporation (ONGC) has spearheaded the implementation of low-salinity waterflooding (LSWF) in offshore Field A, marking a significant milestone as the first-ever application of this enhanced oil recovery (EOR) technique in a carbonate reservoir within India. The pilot project has been ongoing for the past year and is designed to achieve the following key objectives:

- Field Validation of LSWF Concept: demonstrate the practical effectiveness of LSWF as a viable EOR method under real-world reservoir conditions;
- Performance Evaluation: quantify the incremental oil recovery achieved through LSWF compared to traditional seawater injection;
- Upscaling Feasibility Assessment: evaluate the technical and economic feasibility of scaling up the LSWF process from pilot to full-field implementation.

5.2.1. Innovative Water Injection Infrastructure

To facilitate field-scale LSWF deployment, a dedicated water injection platform (Figure 12) with a capacity of 125,000 barrels of produced water per day (bwpd) was commissioned. This platform incorporates a novel energy recovery device (ERD) that leverages reject water pressure from the reverse osmosis (RO) plant. The ERD efficiently boosts the inlet water pressure for the RO plant within the LSWF unit. This two-stage pressurization system, involving the ERD and a booster pump, achieves up to 96% of the required inlet water pressure. The resulting reduction in energy consumption translates to a significant annual CO_2 emission reduction of approximately 8314 metric tons [24], contributing to a smaller carbon footprint for the operation.

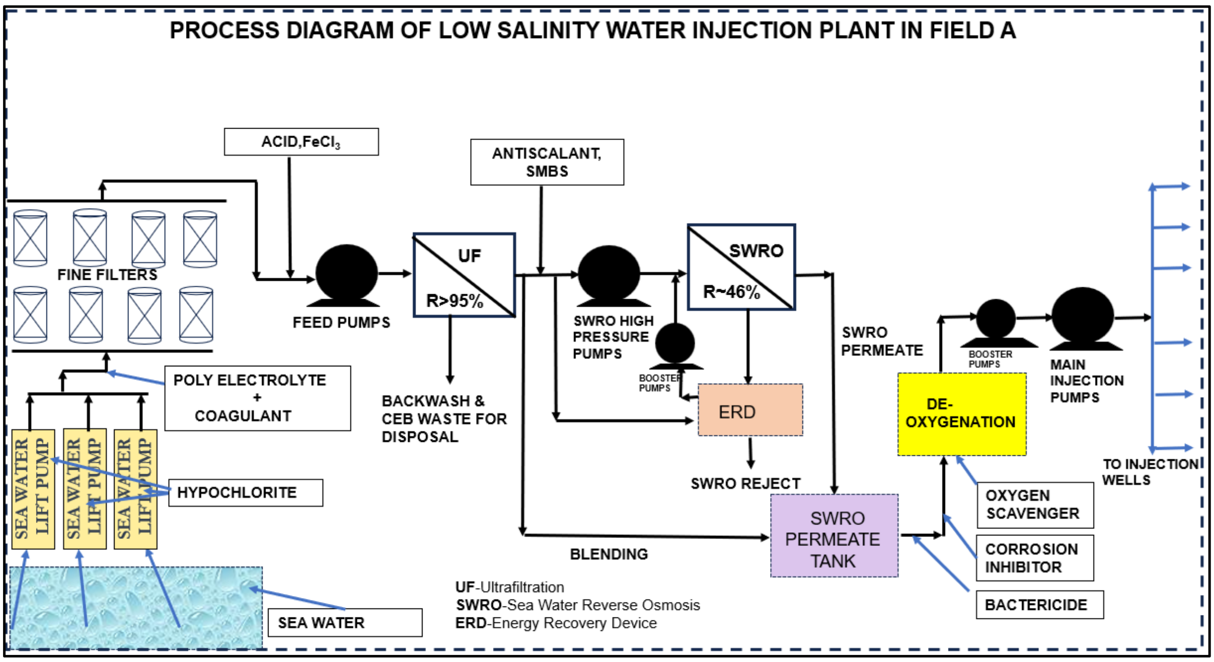


Figure 12. Process diagram of low-salinity water injection facility.

5.2.2. Pilot Area Monitoring

Effective monitoring is crucial for evaluating the success of any enhanced oil recovery (EOR) process, and LSWF is no exception. Here, we discuss the key monitoring strategies employed in India's first LSWF pilot project deployed in a carbonate reservoir (Field A).

Essential Monitoring Parameters:

- Baseline and Post-Flood Residual Oil Saturation (Sor): Determining Sor before and after LSWF application allows for a quantitative assessment of oil recovery attributable to the process.
- Low-Salinity Front Movement: Tracking the movement and arrival time of the low-salinity front at producing wells is essential for understanding sweep efficiency and optimizing injection strategies.
- Injection Water Quality: Maintaining consistent injection water quality is critical. Parameters like salinity, pH, and ionic concentrations (Ca^{+2}, Mg^{+2}, $SO_4{}^{-2}$, Cl^-) are monitored at both the injection platform and individual well nodes to ensure conformance.
- Reservoir Simulation Model Calibration: Monitoring data are used to calibrate and refine reservoir simulation models for improved performance prediction.

Monitoring Program Design:

The monitoring program is categorized into three primary domains:

- Well Fluid Parameters: This category encompasses routine monitoring of oil rate, water cut, injection rate, salinity, pH, and key ionic concentrations (Ca^{+2}, Mg^{+2}, $SO_4{}^{-2}$, Cl^-) at the wellhead.
- Reservoir Parameters: Baseline oil saturation, reservoir connectivity, and sweep efficiency are evaluated using various techniques.
- Well Interventions for Fluid Profiling: Techniques such as production logging tools (PLTs), injection logging tools (ILTs), and profile modification procedures can provide valuable insights into fluid flow behavior within the reservoir.

Monitoring Well Selection:

A total of 53 wells (28 oil producers and 25 water injectors) [25] were designated for intensive monitoring throughout the LSWF pilot. The monitoring activities are classified into two categories based on the well type:

- Activities of oil producers
    1. A total of 28 producers have been identified for periodic monitoring, of which 22 lie inside the LSWF area, whereas 6 are in the region adjacent to the pilot area;
    2. Quarterly testing of wells for well fluid parameters.
- Activities on water injectors
    1. A total of 25 water injectors have been identified for periodic monitoring in the LSWF area;
    2. Monthly testing (WI rate, ITHP, Salinity) and the backwash of WI wells;
    3. Quarterly collection and measurement of water quality parameters of injection water, including ionic concentration (Ca^{+2}, Mg^{+2}, $SO_4{}^{-2}$, Cl^-) and backwash samples, filterability salinity, pH, TSS, etc.

Monitoring Results and Observations:

To ensure proper LSWF implementation, frequent wellhead sampling is crucial. This includes oil producers: monitoring salinity changes in produced oil, and water injection wells: confirming conformance between injected brine salinity at the LSWF facility and wellhead salinity. These combined efforts allow for (a) verification of injected brine salinity and (b) quantification of LSWF's impact on oil producers. Dedicated teams have been established to collect and analyze wellhead samples for these purposes.

- Salinity Reduction: Regular wellhead sampling of both oil producers and water injectors plays a vital role in detecting changes in salinity within the study area. A significant reduction in produced water salinity (>500 ppm) was observed in oil producers located within the pilot area compared to baseline values recorded under conventional waterflooding (Figure 13). The figure depicts pre-LSWF data in green and post-LSWF data in blue.
- Oil Rate Increase: A detailed analysis was conducted to assess the impact of LSWF on oil production rates and water cuts in producing wells. Approximately 10 wells

exhibited a notable increase in oil rate alongside a corresponding decrease in salinity and stabilization of water cut (Figure 14).

- Water Cut Reduction: Further stabilization or reductions in water cuts were observed at the well level (Figure 15), signifying a positive trend and potential improvement in overall oil recovery due to LSWF.
- pH Increase: Wellhead samples also indicated a positive sign, with an average pH increase from 7.3 to 7.6 observed during LSWF implementation.

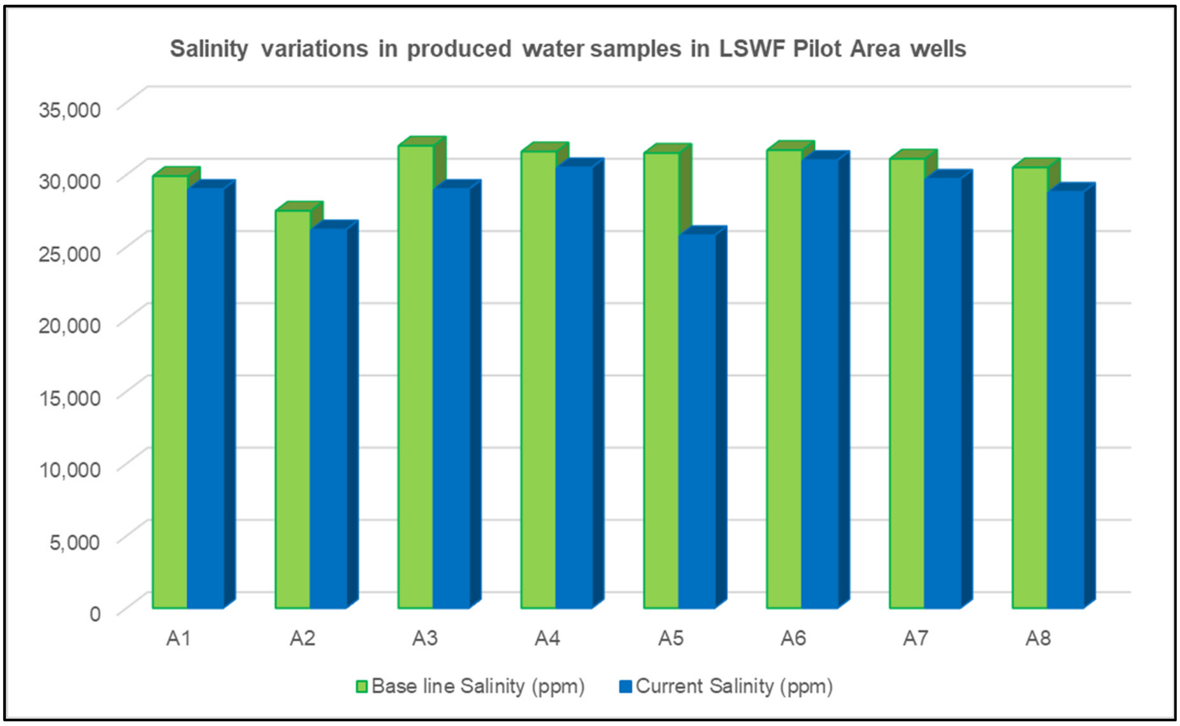


Figure 13. Salinity variations in produced water samples in LSWF pilot area wells.

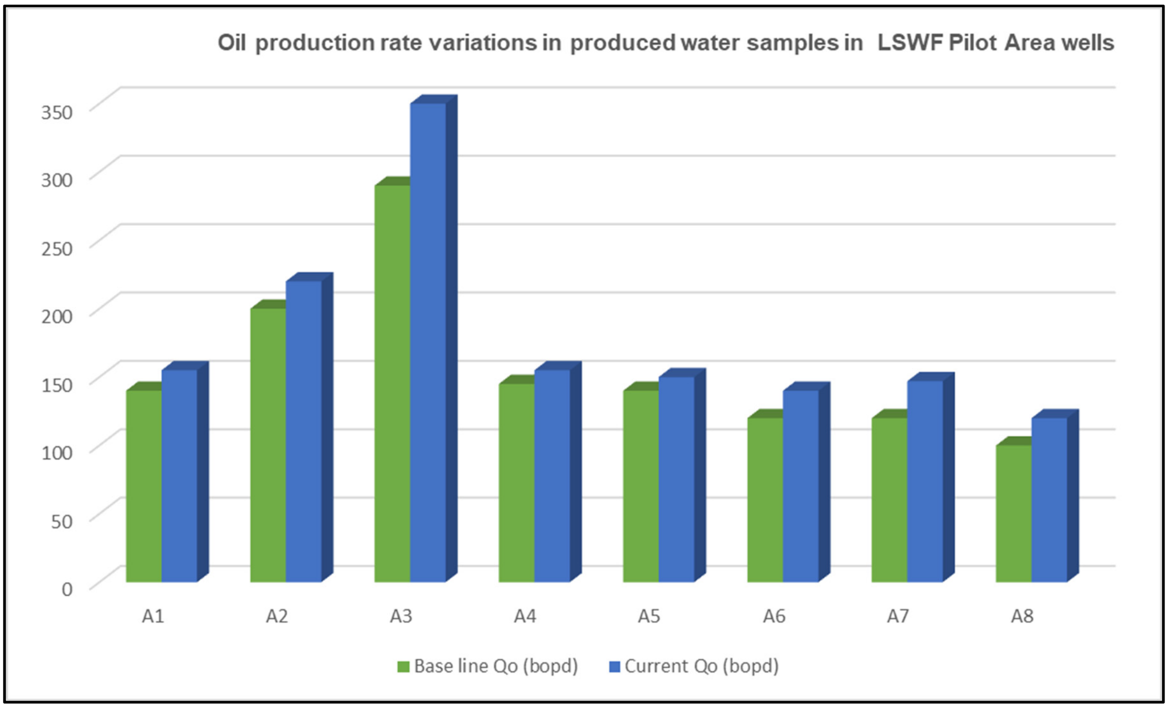


Figure 14. Oil production variations in produced water samples in LSWF pilot area wells.

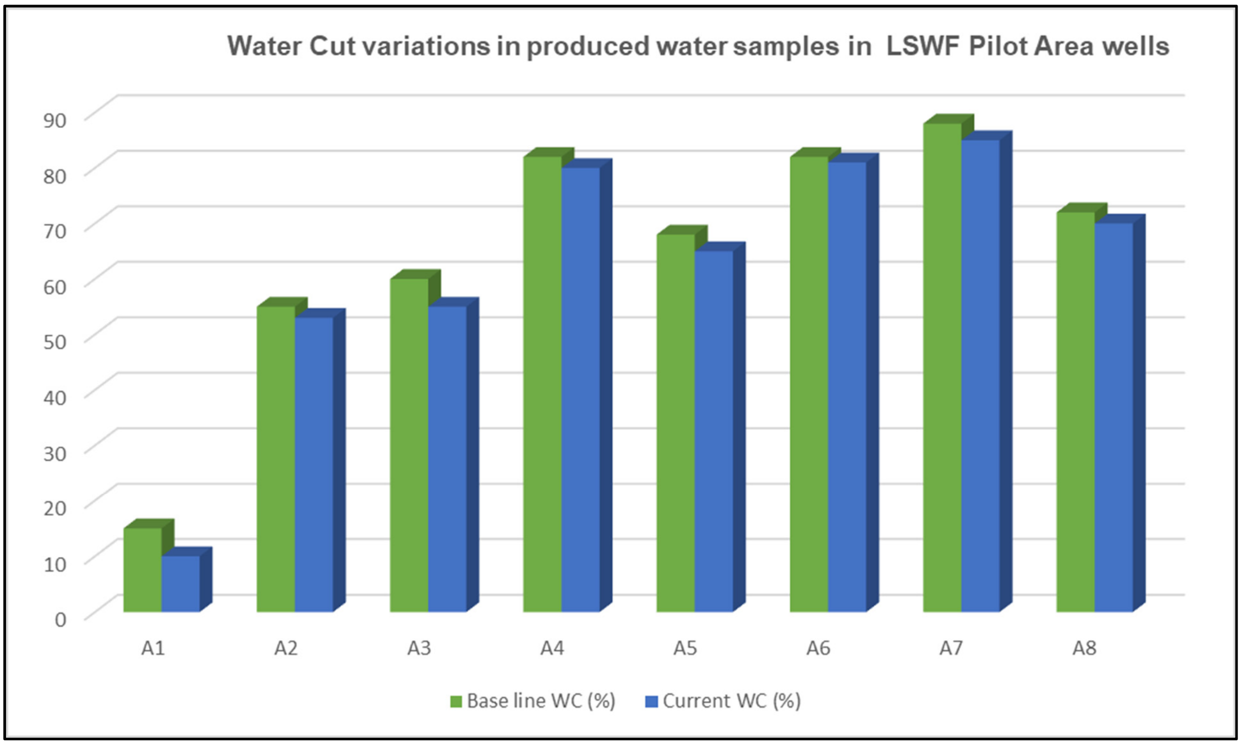


Figure 15. Water cut variations in produced water samples in LSWF pilot area wells.

Future Considerations:

Although the initial results are encouraging, it is important to acknowledge that this is an ongoing pilot project. As time progresses and more data are collected from a larger area swept by the low-salinity waterfront, our confidence in LSWF's efficacy for enhancing production in mature fields like Field A will be further solidified.

6. Summary and Conclusions

This study presents a comprehensive workflow for implementing low-salinity water flooding (LSWF) in a mature carbonate reservoir, exemplified by Field A, the largest multi-well LSWF project in India for this reservoir type. The project successfully navigated the entire process, from initial laboratory screening and reservoir simulation to facility construction and field deployment.

A multi-level approach integrating laboratory and field studies was employed to evaluate, simulate, and design the LSWF process for this specific reservoir. Laboratory core flood experiments demonstrated the suitability of LSWF for Field A, with multi-step imbibition and displacement studies indicating incremental oil recoveries exceeding those achieved with traditional seawater flooding. Reservoir simulation studies further supported the promise of LSWF, predicting an incremental oil gain of over 1 million metric tons.

Early monitoring data from the ongoing field pilot project also suggests a positive impact of LSWF, with observations of improved oil rate, stabilized water cut, and reduced produced water salinity. Additionally, the salinity optimization study identified a 25% seawater salinity as the optimal level for maximizing incremental oil recovery.

These findings offer valuable insights into the potential of LSWF as a viable EOR technique for mature carbonate reservoir rejuvenation. The ongoing monitoring program will further solidify the understanding of LSWF's effectiveness in this specific field and its broader applicability for brownfield redevelopment.

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