Scientific Contributions Oil & Gas, Vol. 49. No. 1, March: 127 - 135

SCIENTIFIC CONTRIBUTIONS OIL AND GAS

Testing Center for Oil and Gas
LEMIGAS

Journal Homepage:http://journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

Reservoir Engineering Evaluation of Water Rock Compatibility and Permeability Damage in PX Field

Cece Rahayu, Maulana Hardi, M. Daffa Rizquallah, and Oktaviani Kusuma Wardani

PT. Pertamina Hulu Rokan, Laboratory North (Duri)
PHR Duri Camp, Mandau District, Bengkalis Regency, Riau, 28784, Indonesia.

Corresponding author: Cece Rahayu (cecerahayu13@gmail.com)

Manuscript received: January 09th, 2026; Revised: January 30th, 2026
Approved: February 04th, 2026; Available online: March 09th, 2026; Published: March 10th, 2026.

ABSTRACT - Compatibility between injection fluids and reservoir rocks is a crucial factor in the success of waterflooding operations, particularly in reservoirs with complex characteristics. Therefore, this study aimed to evaluate injection water–reservoir rock compatibility from a reservoir engineering perspective, focusing on permeability impairment mechanisms associated with fine migration and suspended solids during water injection in the PX Field. Rock samples were obtained from a selected formation, while injection water was collected from the Water Injection Plant (WIP). Laboratory experiments were conducted by injecting both Total Suspended Solids (TSS)-free water and water containing TSS into 1.5-inch core plugs positioned vertically in a Hassler-type core holder under an overburden pressure of 1,725 psi, backpressure of 250 psi, and room temperature conditions. Moreover, the injection water viscosity during the process of the experiment was 0.95 cP. The results showed a pronounced permeability reduction of up to 98% in the PX Field sample. The permeability decline occurred rapidly and intermittently in distinct stages, which initially proposed clay swelling as a possible mechanism. However, X-ray diffraction (XRD) analysis presented negligible smectite content, excluding clay swelling as the dominant cause of damage. Permeability impairment was primarily attributed to pore blockage from fine migration and suspended particles, as supported by particle size distribution (PSD) and TSS analyses. These results showed the importance of comprehensive rock–fluid compatibility evaluation before water injection implementation to minimize formation damage and optimize waterflooding performance.

Keywords: waterflooding, reservoir rock compatibility, injection water, fine migration, formation damage.

How to cite this article:

Cece Rahayu, Maulana Hardi, M. Daffa Rizquallah, and Oktaviani Kusuma Wardani, 2026, Reservoir Engineering Evaluation of Water Rock Compatibility and Permeability Damage in PX Field, Scientific Contributions Oil and Gas, 49 (1) pp. 127-135. DOI org/10.29017/scog.v49i1.1955.

INTRODUCTION

Waterflooding is an Enhanced Oil Recovery (EOR) method that has been extensively applied due to its effectiveness in displacing oil toward production wells. However, the success of this method strongly depends on the compatibility between the injection fluid and the reservoir rock (Khormali et al., 2025). Incompatibility between these features, particularly with respect to mineral interactions and the presence of suspended particles, can lead to formation damage, permeability reduction, and severe pore blockage (Esmaeilinasab et al., 2025). The complexity of reservoir characteristics, including the occurrence of clay minerals and suspended particles, further elevates the risk of formation damage during water injection (Cardenas et al., 2025). Experimental investigations have shown that divalent ions in injection water promote inorganic scale precipitation and induce alterations in rock properties (Park et al., 2025). In addition, calcium sulphate precipitation and fine particle migration have been proven to cause permeability reduction of up to 88% in certain reservoirs (Petrowiki 2025).

Previous studies indicated that water injection and improved oil recovery processes significantly affected reservoir integrity and injectivity, particularly in mature sandstone reservoirs where mineral–fluid interactions as well as water–rock compatibility governed formation damage behavior (Steven Chandra et al., 2021; Usman Pasarai et al., 2021). Permeability reduction is further aggravated by the migration of fine particles and suspended solids in the injection fluid. Although parameters such as Nephelometric Turbidity Unit (NTU) and Total Suspended Solids (TSS) are commonly used to assess fluid clarity, particle size distribution (PSD) is more effective in predicting the probability of pore and formation blockage (Reddy et al., 2020; Wals 2025a). Compatibility testing between fluids and reservoir rocks, commonly conducted through permeability measurements and core flooding experiments, represents a critical method for understanding water-rock interactions under water injection conditions (Gong et al., 2024; Parvazdavani et al., 2025).

Recent laboratory and field-scale investigations have shown the importance of effective water quality management and injection design in mitigating formation damage and sustaining long-term reservoir performance. These studies signify that parameters beyond conventional water clarity indicators play a critical role during water injection operations, including PSD and fines mobility (Hamzah et al., 2021). Previous experimental investigations have indicated that chemical composition and ionic interactions in aqueous systems strongly influenced fluid–rock behavior and reservoir stability (Kristiawan et al., 2018). PSD analysis is widely used to identify pore-blocking mechanisms (Xing et al., 2025; Zhu et al., 2025). In addition, several studies have reported that injection of low-quality water leads to direct damage to reservoir rocks, where the damage may be mitigated through appropriate acid stimulation treatments (Zhu et al., 2025). Water injection optimization methods based on artificial intelligence and numerical modelling have been developed to predict and reduce the risk of formation damage (Zhu et al., 2025). Methods such as surrogate modelling and the ensemble Kalman filter enable long-term water injection simulations with high predictive accuracy, even in heterogeneous reservoir systems (Karami et al., 2023; Ku³ynycz & Janowski 2017; Sori et al., 2025).

As reservoir complexity increases and production demands intensify, evaluating rock–fluid compatibility before water injection becomes a crucial step in the design and implementation of a successful waterflooding project. An established method for assessing this compatibility includes permeability testing based on throughput volume, which provides quantitative comprehension into changes in the capacity of the rock to transmit fluids after the injection process (Khormali et al., 2025; Yu et al., 2024). This study shows the necessity of systematic rock-fluid compatibility evaluation before water injection to minimize formation damage risk and optimize waterflooding efficiency. Although carbon capture, utilization, and storage (CCUS) and CO_2-enhanced oil recovery (CO_2-EOR) have achieved increasing recognition as sustainable EOR strategies, the

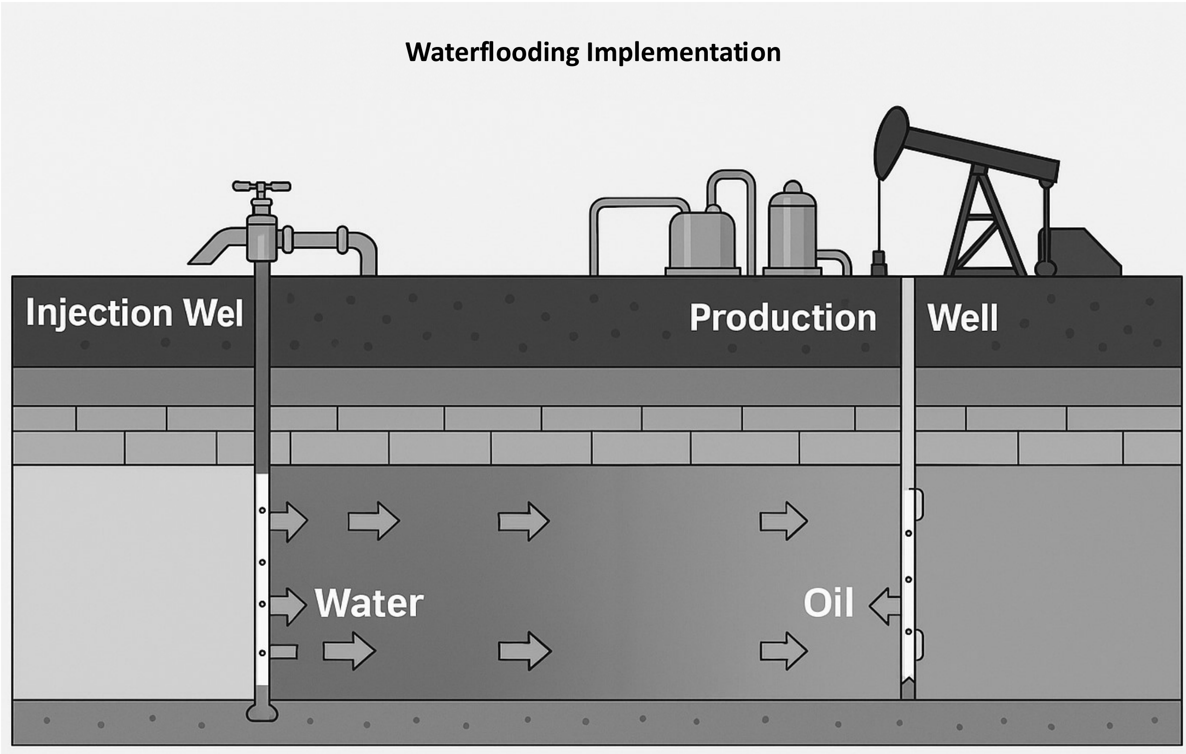

Figure 1. Waterflooding process (Karami et al., 2023)

effective implementation remains strongly dependent on reliable injection operations and robust fluid-rock compatibility (Sugihardjo 2022).

METHODOLOGY

This study was conducted to evaluate the compatibility between injection water and reservoir rocks through a permeability testing method based on throughput volume.

Experimental

The method used during the process consisted of several main stages as follows.

Sampling

Core rock samples were collected from two different reservoir zones in PX Field, namely the M1 and B1 reservoirs. The samples were prepared as core plugs with diameters of 1.5 inches, representing the petrophysical characteristics of each formation. Before testing, the models were cleaned of hydrocarbons, dried, and subjected to porosity as well as air permeability measurements. Additionally, the cores were saturated with synthetic brine water to simulate initial reservoir conditions.

Injection water preparation

The injection fluid used in this study was obtained from the outlet of the Water Injection Plant (WIP). Two types of water were applied in the tests, which were as follows:

- Filtered injection water using 0.45-micron pore size filter paper (free of TSS)
- Original injection water (containing TSS)

The characteristics of the injection water, such as viscosity (0.95 cP), ionic content, and PSD, were analyzed before use.

Permeability testing

The tests were conducted using a vertically positioned Hassler-type core holder. The testing conditions were adjusted to simulate reservoir conditions, including:

- Overburden pressure: 1.725 psi
- Back pressure: 250 psi
- Room temperature (±25°C)

Injection fluid was continuously flowed through the core plug samples, and permeability was measured based on the throughput volume for each pore volume. Flow rate and pressure data were recorded periodically to monitor permeability reduction during the injection process, following changes in flow rate and differential pressure. The calculation of permeability values was based on Darcy's Law, Equation 1:

where:

K brine : Permeability Absolute for Brine, mD
Q : Flow Rate, cc/second
µw : Water Viscosity, cP
L : Sample Length, cm
A : Surface Area, cm2
dP : Differential Pressure of the Sample, psi
14700 : Unit Conversion

Data analysis

The experimental data were analyzed to quantify the degree of permeability reduction in each formation by comparing initial and final permeability values following injection. PSD and TSS content were systematically evaluated to assess pore-blocking potential. Moreover, patterns of permeability decline were observed and compared between the M1 and B1 formations. Additional analyses were conducted on both PSD and TSS during the process. The scientific gap in this study was the lack of an incorporated method that simultaneously:

- Mapped injection water quality using PSD and TSS as relevant predictors of pore-blocking risk.
- Validated formation damage mechanisms through core flooding experiments conducted under overburden and backpressure conditions that simulated the reservoir.
- Systematically ruled out the clay swelling hypothesis using X-ray diffraction (XRD) as quantitative mineralogical evidence (Patarachao et al., 2019; Reddy et al., 2020; Wals, 2025b).

This study, conducted in the PX Field, introduced several novel contributions aimed at addressing the identified gap. First, analysis of PSD/TSS effluent data, with permeability decline trajectory as a function of pore volume (PV), showed that the dominant formation damage mechanism was not the commonly assumed clay swelling process, but rather fine particle migration and pore blockage caused by suspended solids. This interpretation was further supported by XRD results indicating a smectite content of 1.6%, which was below the 2% threshold generally associated with significant clay swelling. Consequently, the clay swelling mechanism was excluded as the primary cause of permeability impairment in this system (Patarachao et al., 2019; Xing et al., 2025).

Second, stepwise reverse injection was used as a functional assessment of damage irreversibility. This signified negligible permeability recovery and implied that the formation damage remained permanent once the pore-plugging phase was established (Gong et al., 2024).

Third, Hassler test configuration, using an overburden pressure of 1,725 psi, a backpressure of 250 psi, and a water viscosity of 0.95 cP, provided a stronger causal connection between particle characteristics (size <10 µm) and permeability response under operationally relevant conditions. This method surpassed previous studies that relied solely on statistical or Artificial Neural Network (ANN) modeling or focused exclusively on ionic interactions (Esmaeilinasab et al., 2025; Khormali et al., 2025).

PX results expanded the water–rock compatibility evaluation framework from a purely NTU/TSS-based method to a pore-scale PSD perspective, practically and theoretically. This prioritized the necessity of injection water quality control, particularly filtration and particle management before waterflooding implementation, specifically in quartz-dominated, low-clay reservoirs where formation damage was primarily governed by fines mobilization rather than clay swelling (Wals, 2025b; Zhu et al., 2025).

This study proposed an incorporated verification paradigm that combined geochemical evidence (PSD/TSS, ionic), geophysical testing (core flooding under pressure), and mineralogical analysis (XRD). The combination was to predict and mitigate permeability decline during water injection operations, while providing more precise design guidance for fields with similar characteristics (Parvazdavani et al., 2025; Sori et al., 2025).

RESULT AND DISCUSSION

Evaluation of Injection Water Quality, the Impact on Core Permeability, and Fluid Characteristics

Figure 2 shows the permeability decline in PX Field as a function of injected water volume, expressed in pore volumes. The base permeability was initially at its maximum normalized value (1.00), indicating an undamaged formation. However, a sharp decrease in permeability was observed during the filtered water injection phase, with the permeability fraction dropping drastically to approximately 0.10 in the first 100 pore volumes. This behavior showed significant formation damage, probably caused by particle migration that blocked the pore throat and restricted fluid flow.

The figure showed two reverse injection events when the analysis was conducted. The first reverse injection, which occurred at approximately 50 pore volumes, led to only a minor permeability recovery. In addition, permeability remained low at around 0.05, indicating that the damage was largely irreversible or the reverse flow was insufficient to dislodge the blocking particles. The second reverse injection at 100 pore volumes showed no obvious permeability recovery, further confirming the persistent low permeability. During the unfiltered water injection phase (between 60 and 90 pore volumes), permeability remained relatively stable at a low level (0.05), signifying that the formation had reached a damaged equilibrium state.

The graph supported the hypothesis that water incompatibility was major contributor to permeability reduction in the PX Field. The inability to restore permeability through reverse injection further prioritized the necessity of a comprehensive water compatibility analysis before injection operations.

Permeability testing of core plug sample M1, conducted at a constant flow rate of 2 mL/min, showed a 96% reduction in permeability after injection of 50 pore volumes of filtered water. This was followed by an additional 2% reduction after injecting 50 pore volumes of unfiltered (original) water. Permeability decline occurred gradually and progressively and was attributed to particle migration processes that continuously obstructed pore throats, leading to a sustained decrease in permeability.

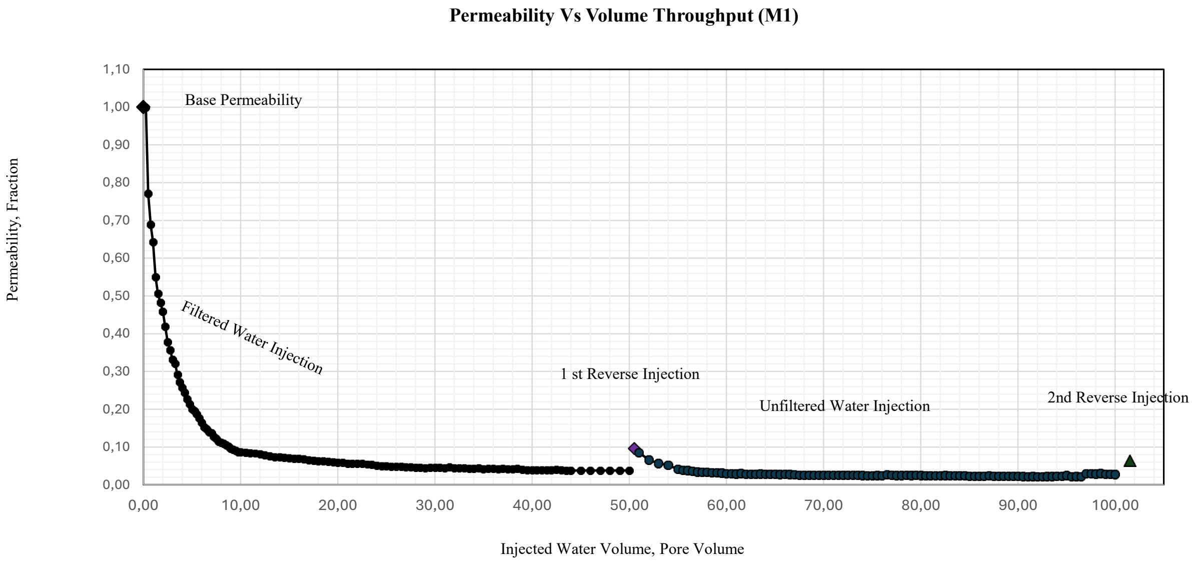

Figure 2. Graph of permeability decline M1 Area (Permeability vs Volume Throughput M1)

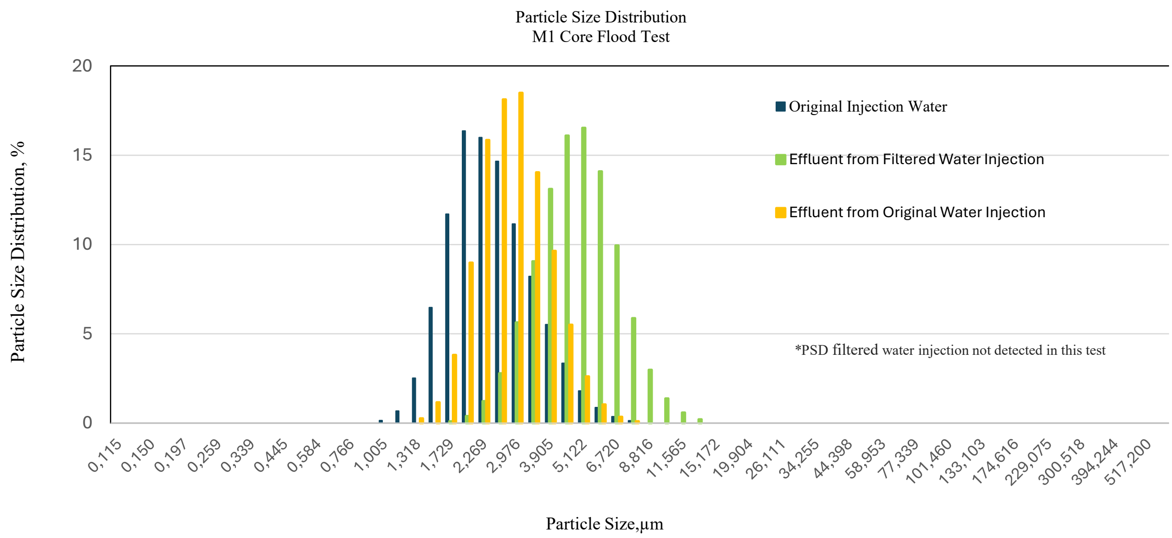

Figure 3. Graph of particle size distribution M1 area core flood test

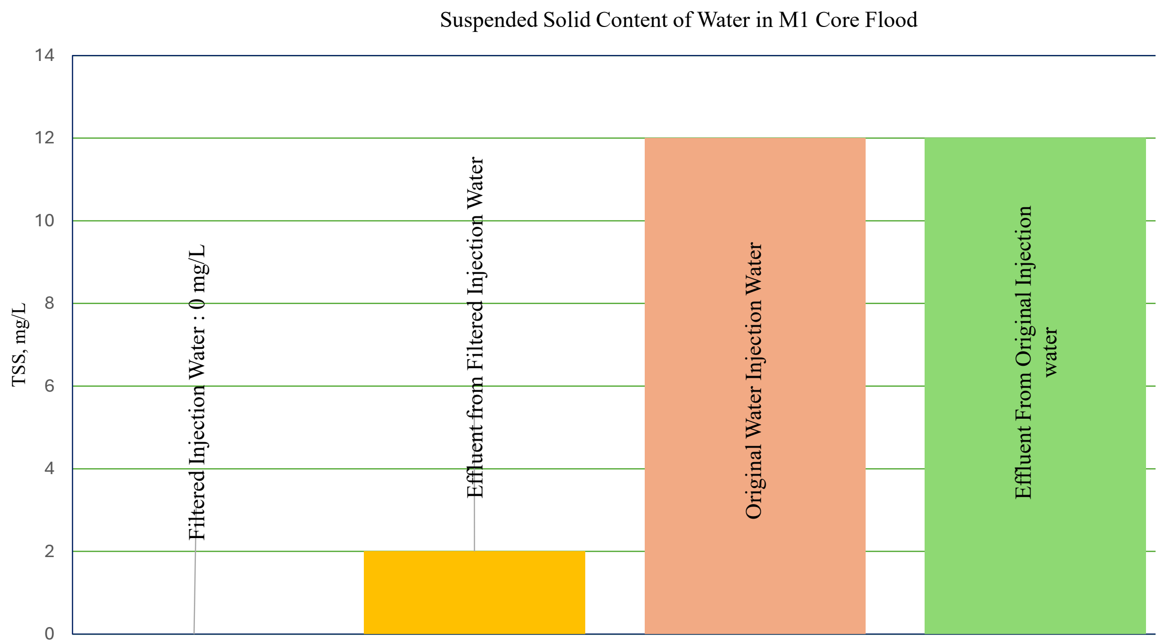

Figure 4. Graph of Suspended Solid Content of Water in M1 Core Flood Area

The particle migration mechanism was further advanced by temporary permeability increases of approximately 3% and 6% during reverse flow, showing partial unclogging of pore throats. Analysis of the effluent water signified that the measured PSD and TSS values included particles not originally present in the injection water, signifying mobilization of fines from the rock matrix.

PSD data shown in Figure 3 supported this interpretation during the process. The presence of fine particles in the original injection water, specifically those smaller than 10 µm, indicated a high potential for particle migration. During injection, these particles were mobilized and subsequently trapped in pore throats, contributing to permeability reduction.

Reverse injection events conducted at 50 and 100 pore volumes showed no significant recovery in permeability, implying that the damage was largely irreversible. This observation was consistent with results from core flood studies, which attributed permanent permeability impairment primarily to the particle migration process.

Figure 4 further supported the assumption by showing TSS in both filtered and unfiltered water. The filtered injection water contained 0 mg/L of suspended solids, while its effluent showed a slight increase to 2 mg/L, probably due to mobilized fines from the core, implying significant particle migration and retention in the core. The original injection water contained 12 mg/L of suspended solids, and its effluent retained 12 mg/L.

Table 1. XRD analysis result

Mineralogy in wt%	**Sample**	
Clay	Smectite	1.6
	Illite-Smectite	2.8
	Illite	-
	Kaolinite	-
	Chlorite	-
Carbonate	Calcite	-
	Dolomite	-
	Siderite	-
Other	Quartz	88.4
	Potash- Feldspar	4.2
	Plagioclase	-
	Gypsum	1.0
	Pyrite	0.1
1	Clay	6.3
	Carbonate	0.0
	Other	93.7

Table 1 showed the rock composition containing 1.6% smectite, signifying that swelling clay had not occurred. According to the study by Patarachao et al. (2019), swelling clay occurred in rocks with smectite content above 2% (Patarachao et al., 2019).

CONCLUSION

In conclusion, this study showed that incompatibility between injection water and reservoir rock was a major factor contributing to permeability impairment in the PX Field. Core flooding experiments signified a permeability reduction of up to 98%, implying severe formation damage under the evaluated experimental conditions. This impairment was primarily associated with fine particle migration and pore throat blockage induced by suspended solids in the injection water, as evidenced by TSS and PSD analyses.

Mineralogical characterization using XRD signified that smectite content was less than levels typically associated with clay swelling. The process showed that clay swelling was not a dominant mechanism in this reservoir. Permeability reduction was mainly attributed to fines mobilization and subsequent entrapment in the pore network. Furthermore, reverse-flow tests showed partial permeability recovery, implying that the damage was largely irreversible once pore plugging had occurred.

These results prioritized the importance of incorporating injection-water quality evaluation and water-rock interactions during reservoir engineering design. Effective filtration, solids control, and comprehensive geochemical characterization were essential to mitigate formation damage and ensure the effectiveness of waterflooding operations in reservoirs with similar characteristics. This study provided reservoir engineers with a clearer understanding of formation damage mechanisms related to water injection and offered a valuable understanding for improving waterflooding performance and protecting reservoir integrity.

ACKNOWLEDGEMENT

The authors are grateful to PT Pertamina Hulu Rokan for providing the data to publish this paper. The authors are also grateful for the contributions from the Laboratory PHR team, study team, and collaborators for the support during this study.

GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbols	Definition	Unit
TSS	Total Suspended Solids	mg/l
PSD	Particle Size Distribution	µm
cP	Centipoise, unit of viscosity	cP
Psi	Pound per square inch, unit of pressure	Psi
PV	Pore Volume, volume of fluid equivalent to pore space in the core	PV
K	Permeability of the rock sample	mD
Q	Flow rate during core flooding	cc/s
ΔP	Differential pressure across the core	psi
XRD	X-ray Diffraction analysis for mineralogy	-

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