

EVALUATION AND PLANNING OF ACIDIZING METHOD TO RESOLVE SCALE ISSUES IN WELL "YDK-01," "SANDY" FIELD.

Firdaus, Rohima Sera Afifah, Dharma Arung Laby, Adelia Rohani, Yudha Dwi Kurniawan, Selvy Dwi Rahmawati, Iin Darmiyati
Seolah Tinggi Minyak Gas dan Bumi Balikpapan, Indonesia
email: selvyrhma@gmail.com

Copyright © 2023 The Author



This is an open access article

Under the Creative Commons Attribution Share Alike 4.0 International License

DOI: 10.53866/jimi.v5i2.**

Abstract

The "YDK-01" well has alkaline Formation Water with a pH value of 8,3. Therefore, Scale can form in the productive zone so that over time, Scale will continue to settle and be difficult to solved. From several Acidizing methods, Matrix Acidizing is the most recommended because in the wells examined there are indications of a positive Skin value (Formation Damage). Matrix Acidizing is a Reservoir stimulation method used to overcome Formation Damage in the wells caused by Scale. In this Final Project, it is done using manual calculations using (Stiff & Davis), (Skillman, McDonald & Stiff) and Inflow Performance Relationship Wiggins equations, which aims to evaluate the problem of Scale. Changes in well production rates can be seen from a comparison of several parameters before and after Acidizing such as: Inflow Performance Relationship curve, Permeability value, Productivity Index value, and Skin. In the "YDK-01" well, there was an increase in the $Q_{o\max}$ value of 47.16 bopd. The Productivity Index value of oil which was previously 0.129 bopd/psia, has changed to 0.198 bopd/psia. Permeability value has increased by 12 md and Skin value has decreased by 28.54. Parameters above prove that the Matrix Acidizing method works well in overcome scale on the well.

Keywords: Inflow Performance Relationship; Permeability; Productivity Index.

1. Introduction

1.1. Background

In production well activities, an oil and gas well will produce 3 types of fluid phases, namely water, oil, and gas. These three fluids flow from the reservoir to the surface through subsurface equipment (tubing, artificial lift) and then to the surface equipment through the flowline to the collection tank (Adha, 2021). The contact between the fluid and the tubing can result in changes in fluid pressure and flow rate. Over time, scale can form on the pipe walls and flow interruptions can occur due to the reduction inside diameter of the pipe (Salfigo, 2024). This production problem can occur in both subsurface and surface facilities in an oil field. The type of scale that is deposited depends on the composition of the formation fluid (Diba, 2023). From the results of the analysis of the formation water, the levels of each ionic constituent of the formation water will be obtained (Lestari dkk, 2007). To identify the type of scale formed in the well production can be done by calculating using the method (Stiff & Davis), (Skillman, McDonald & Stiff). After identifying the scale that occurs in the well, steps are planned to control and handle the scale (Megawati, 2022).

Oil and gas production wells generate three primary fluid phases: water, oil, and gas. These fluids flow from the reservoir to the surface through downhole equipment such as tubing and artificial lift systems before being transported to surface facilities via flowlines and gathering tanks (Sima, 2022). The interaction between these fluids and production equipment leads to variations in pressure and flow rates, which can result in the deposition of scale on the internal surfaces of pipes (Ryka, 2020). Over time, this scale buildup reduces the internal diameter of the pipes, disrupting fluid flow (Diba, 2023). This challenge affects both subsurface and surface production facilities in an oil field. The type of scale formed

is influenced by the ionic composition of the formation water, which can be determined through water analysis. Identifying the scale type enables the selection of appropriate mitigation and treatment strategies, often relying on predictive calculations such as the Stiff & Davis and Skillman, McDonald & Stiff methods (Manik, 2025).

The well "YDK-01," situated in the "SANDY" field within the Jambi sub-basin, Sarolangun Regency, Jambi Province, experiences scaling issues due to alkaline formation water conditions. This issue primarily affects the productive zone, where the deposition of scale restricts fluid movement. Among various acidizing techniques, matrix acidizing has been identified as the most suitable method for treating scale-related problems in this well. If left untreated, scale accumulation will continue, leading to a decline in production efficiency. Matrix acidizing involves injecting acid below the formation's fracture pressure to dissolve scale deposits within the rock, restoring permeability and enhancing well performance.

1.2. Objectives of the Study

The objectives of this study are as follows:

1. To analyze the formation water characteristics and identify the type of scale deposits in the well.
2. To determine the suitable acid type, total acid volume, and displacement volume required for the acidizing process.
3. To evaluate the effectiveness of the acidizing treatment by analyzing changes in Inflow Performance Relationship (IPR), Productivity Index (PI), permeability, and skin factor before and after treatment.

By understanding the scale type and its treatment, this study aims to assess production rate improvements post-acidizing. This evaluation will be conducted by analyzing key parameters, including IPR curves, PI, permeability, and skin factor.

1.3. Overview of the "SANDY" Field

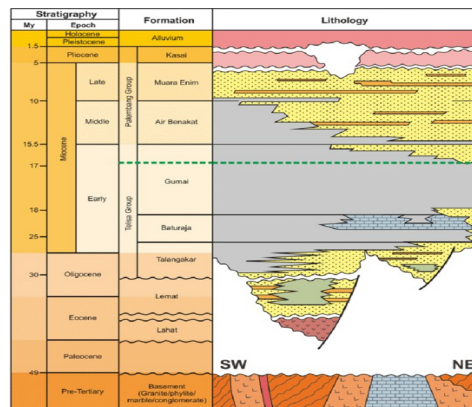
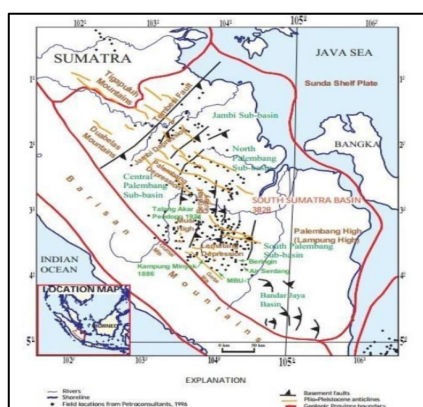
The "SANDY" field is part of the Jambi sub-basin, a region within the South Sumatra Basin known for its hydrocarbon potential. The South Sumatra Basin is one of Indonesia's major petroleum-producing basins, characterized by complex geological structures and a well-established petroleum system. The "SANDY" field is specifically located in Sarolangun Regency, Jambi Province, and contains reservoirs that have been actively producing oil and gas.

The "SANDY" field consists of sandstone-dominated formations interbedded with shale layers. These reservoirs, primarily of Miocene age, exhibit good porosity and permeability, making them ideal for hydrocarbon accumulation. The depositional environment is predominantly fluvial to shallow marine, which has contributed to variations in reservoir quality.

The field's primary reservoirs comprise high-permeability sandstone, which facilitates efficient hydrocarbon flow. However, production has been hindered by scale formation, which reduces effective permeability and well productivity. The formation water in this field is alkaline and contains high levels of calcium carbonate (CaCO_3) and calcium sulfate (CaSO_4), increasing the likelihood of scale deposition.

The "SANDY" field has been in production for several years, targeting oil and gas reservoirs. The "YDK-01" well has encountered scale-related production challenges, which have led to declining flow rates and increased well intervention requirements. Implementing an acidizing treatment is necessary to mitigate scale-related damage and restore well performance.

Several key challenges exist in the "SANDY" field, including: Reduced production efficiency



due to

scale deposition, declining permeability caused by mineral precipitation, and the need for effective scale control and acidizing treatments to optimize production.

2. Methods

2.1. Formation Water Analysis

Formation water, also known as connate water or oil field water, is produced alongside oil and gas and contains dissolved ions that can precipitate as scale when solubility limits are exceeded (Ahmad & Said, 2015). The physical properties of formation water, such as pH, temperature, pressure, specific gravity, and dissolved gas content, significantly influence scale formation. For instance, high pH and temperature increase the likelihood of CaCO_3 scale, while low pH accelerates corrosion (Ratna P.S, 2011). The ionic composition of formation water (Table 1) includes cations (Na^+ , Ca^{2+} , Mg^{2+}) and anions (Cl^- , HCO_3^- , SO_4^{2-} , CO_3^{2-}), which react to form insoluble compounds like CaCO_3 , CaSO_4 , and BaSO_4 (Pranondo & Agusandi, 2017).

Table 2.1. Formation Water Composition
Komposisi Air Formasi

Kation	Anion
Na^+	Cl^-
Ca^{2+}	HCO_3^-
Mg^{2+}	SO_4^{2-}
	CO_3^{2-}

2.2. Scale Prediction Methods

Stiff & Davis Method (CaCO_3):

- Ionic strength (μ) for each ion is calculated by multiplying its concentration by a conversion factor (Table 2).

Table 2.2 Conversion factor value

Ion	Konversi (10^{-5})
Na^+	2,2
Ca^{2+}	5
Mg^{3+}	8,2
CO_3^-	3,3
HCO_3^-	0,82
Cl^-	1,4

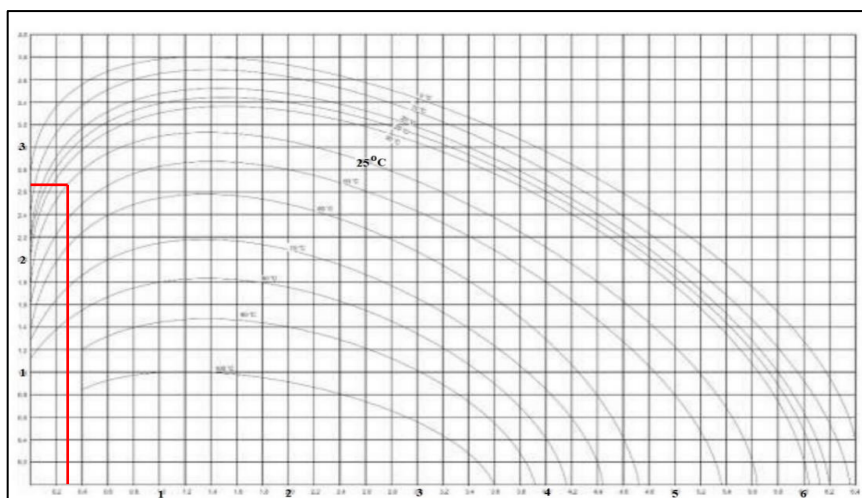


Figure 2. Price of 'K' at various prices of 'Ionic strength' (Alighiri et al., 2018)

Total ionic strength (μ) is summed, and the constant (K) is determined from a μ vs. temperature graph (Figure 2).

- Scaling Index (SI) is computed using:

$$pCa^{2+} = 4,5997 - 0,4337 \ln [Ca^{2+}] \quad (1)$$

$$pAlk = 4,8139 - 0,4375 \ln [CO_3^{2-} + HCO_3^-] \quad (2)$$

$$SI = pH - (K - pCa^{2+} + pAlk) \quad (3)$$

2. Skillman, McDonald & Stiff Method ($CaSO_4$):

- Gypsum solubility (S) is calculated using:

$$S = 1000 [(X^2 + 4K_{sp})^{0.5} - X] \quad (4)$$

where $X = Ca^{2+} + SO_4^{2-}$ and K_{sp} is obtained from Figure 3.

If $S < S'$ (actual $CaSO_4$ solubility), scale formation is likely.

3. Oddo-Tompson Method ($BaSO_4$):

- The Scaling Index (SI) is determined via:

$$SI = \log\left(\frac{(Kation)(Anion)}{Kc}\right) \quad (5)$$

2.3. Acidizing Design and Implementation

1. Acid Selection:

- A 15% HCl solution was chosen for its effectiveness in dissolving $CaCO_3$ scale (reaction: $CaCO_3 + 2HCl \rightarrow CaCl_2 + H_2O + CO_2$).

2. Design Calculations:

- Fracture pressure:

$$\text{Fract Pressure} = \text{Gradient} \times \text{Fract} \quad (6)$$

- Injection volume:

$$V. \text{ Inject} = ((\text{Length interval}) \times \text{Cuft/Shoot} \times \text{SPF}) \times 0,1781 \quad (7)$$

- Displacement volume: Sum of acid volumes in tubing, annulus, and casing

$$\text{Vol. Acid in tubing} = \text{EoT} \times \text{Gradient} \times \text{tub. cap} \quad (8)$$

$$\text{Vol. Acid in ann} = (\text{Boc} - \text{EoT}) \times \text{Gradient} \times \text{ann. cap}$$

$$\text{Vol. Acid in casing} = (Boc - EoT) \times \text{Gradient cas. cap} \quad (9)$$

$$(10)$$

$$\text{V. Displacement} = (\text{V. acid in tubing} + \text{V. Acid in ann} + \text{V. Acid in.....}) \quad (11)$$

3. Stages:

- Preflush: Removes carbonate minerals.
- Main Acid: Dissolves scale.
- Afterflush: Flushes acid into the formation.

2.4. Performance Evaluation Metrics

1. Skin Factor (S):

- Calculated using:

$$\Delta P_s = \frac{141,2 \times (Q_o \times B_o \times \mu_o)}{k \times h}$$

$$S = \frac{0,00708 \times h \times k}{Q \times B_o \times \mu} \times \Delta P_s \quad (12)$$

- $S > 0$ indicates formation damage; $S < 0$ suggests improvement.

2. Productivity Index (PI):

$$J = \frac{Q}{P_r - P_{wf}} \quad (13)$$

- Classified as low (<0.5), moderate (0.5–1.5), or high (>1.5).

3. IPR Curves:

- Wiggins' 3-Phase Method:

$$Q_{o\max} = \frac{Q_o}{(1 - 0,52 \left(\frac{P_{wf}}{P_r}\right) - 0,48 \left(\frac{P_{wf}}{P_r}\right)^2)} \quad (14)$$

Oil phase:

$$Q_{w\max} = \frac{Q_w}{(1 - 0,72 \left(\frac{P_{wf}}{P_r}\right) - 0,28 \left(\frac{P_{wf}}{P_r}\right)^2)} \quad (15)$$

Water phase:

4. Permeability (k):

$$k = \frac{Q_o \times \mu_o \times B_o \times \ln\left(\frac{r_e}{r_w}\right)}{0,00708 \times h \times (P_r - P_{wf})} \quad (16)$$

5. Oil Production Increase:

$$\%Oil = ((Q_o \text{ after} - Q_o \text{ before}) / (Q_o \text{ after})) \times 100\% \quad (17)$$

3. Result and Discussion

3.1. Field Data Analysis

The study utilized field data from the well "YDK-01" (Firdaus, 2022), including parameters such as Cuft/Shoot (0.2 bpm), SpF (12), net pay zone (44.3 ft), casing and tubing dimensions, temperature gradient (1.6°F/100ft), fracture gradient (0.4828 psia), and pH (8.3). Production data before and after acidizing were also collected, revealing significant changes in flow rates, pressures, and permeability (Tables 3-5).

Table 3.1.1. Well Data “YDK-01”

Data	value	unit
Cufl/Shoot	0,2	Bpm
Shoot per Feet (SpF)	12	-
Net Pay Zone	44,3	ft
ID casing	6,049	In
OD casing	6,625	in
ID Tubing	2,441	in
OD Tubing	2,875	In
End of Tubing (EoT)	3187,49	ft
Top Perfo	3203,9	Ft
Bott. Perfo	3248,19	Ft
Temperature Gradient	1,6	°F/100ft
Gradient Fracture (GF)	0,4828	psia
pH	8,3	-
Price K (Graph)	2,75	-
Temperature	25	°C

Table 3.1.2 Well Production Data before

Data	Value	Unit
Pressure Reservoir (Pr)	765,41	psia
Pressure Flowing (Pwf)	140,67	psia
Qf	649,375	bfpd
Water Cut (WC)	87,5	%
Permeability (k)	22	md
Viscosity	5,72	cp
Bo	1,188	bbl/stb
Wellbore radius	0,2652	ft
Drainage radius	656,2	ft
Gas Liquid Ratio (GLR)	800	scf/stb

Table 3.1.3. Well Production Data after

Data	Value	Unit
Pressure Reservoir (Pr)	765,41	psia
Pressure Flowing (Pwf)	153,63	psia
Qf	1,395,965	bfpd
Water Cut (WC)	91,3	%
Permeability (k)	33,58	md
Viscosity	5,72	cp
Bo	1,188	bbl/stb
Wellbore radius	0,2652	ft
Drainage radius	656,2	ft
Gas Liquid Ratio (GLR)	800	scf/stb

3.2. IPR Analysis Before Acidizing

The Inflow Performance Relationship (IPR) curve was constructed using reservoir pressure ($P_r = 765.41$ psia) and flowing bottomhole pressure ($P_{wf} = 140.67$ psia). The maximum oil flow rate ($Q_{o,max}$) was calculated as 91.33 bopd, while the maximum water flow rate ($Q_{w,max}$) was 662.12 bwpd, resulting in a total maximum flow rate ($Q_{t,max}$) of 753.462 bfpd. The IPR curve illustrated the relationship between P_{wf} and flow rates (Q_o , Q_w , Q_t), as shown in Figure 3.

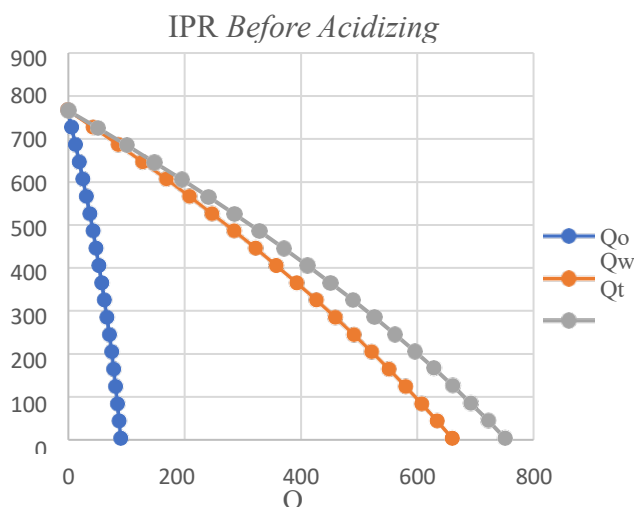


Figure 3.1. Plot graphs IPR before Acidizing sumur “YDK-01”

3.3. Productivity Index and Permeability Before Acidizing

The Productivity Index (PI) for liquid and oil was determined as 1.03 bfpd/psia and 0.1299 bopd/psia, respectively. Permeability was calculated at 22 md, indicating moderate reservoir quality. The skin factor analysis revealed a value of 29.53, confirming significant formation damage (Table 6)

Table 3.1.4 Comparison of changes in production rate, PI, Permeability, and Skin at well “YDK-01”

“YDK-01”	Qmax	Qomax	PI liquid	PI oil	k	Skin
<i>Before</i>	753,462	91,33	1,039	0,13	22	29.53
<i>After</i>	1648,32	138,49	2,281	0,2	34	0,99
Δ Change	+894,86	+ 47,16	+1,242	+0,07	+12	-28,54

3.4. Formation Water and Scale Analysis

Formation water analysis identified potential scaling issues. The Stiff & Davis method indicated a Scaling Index (SI) of 1.7 for CaCO₃, suggesting a high likelihood of scale formation. Conversely, the Skillman, McDonald & Stiff method showed no CaSO₄ scaling tendency, as the gypsum solubility ($S = 46.17$) exceeded the actual CaSO₄ solubility ($S' = 12.492$) (Tables 7-8).

Table 3.1.5. Formation water test analysis data of well e“YDK-01”

Ion	mg/l	Faktor Konversi	Ionic Strength
Na ⁺	6791,91	$2,2 \times 10^{-5}$	0,14942202
Ca ²⁺	240,6	5×10^{-5}	0,01203
Mg ²⁺	109,35	$8,2 \times 10^{-5}$	0,0089667
CO ₃ ²⁻	120,02	$3,3 \times 10^{-5}$	0,00396066
HCO ₃ ⁻	1342,44	$8,2 \times 10^{-5}$	0,01108008
SO ₄ ²⁻	22	$2,1 \times 10^{-5}$	0,000462
Cl ⁻	10295,5	$1,4 \times 10^{-5}$	0,144137
Total μ			0,329986388

Table 3.1.6 Assumed Pwf value of well “YDK-01” after Acidizing

Pwf	Qo	Qw	Qt
-----	----	----	----

765.41	0	0	0
725.41	10.5305	99.841	110.371
685.41	20.6979	197.379	218.071
645.41	30.5022	292.596	323.098
605.41	39.9433	385.509	425.453
565.41	49.0213	476.114	525.135
525.41	57.7363	564.409	622.145
485.41	66.088	650.395	716.484
445.41	74.0767	734.073	808.149
405.41	81.7023	815.441	897.143
365.41	88.9647	894.5	983.464
325.41	95.864	971.249	1067.11
285.41	102.4	1045.69	1148.09
245.41	108.573	1117.82	1226.39
205.41	114.383	1187.64	1302.03
165.41	119.83	1255.16	1375
125.41	124.914	1320.36	1445.28
85.41	129.634	1383.26	1512.89
45.41	133.992	1443.84	1577.83
5.41	137.986	1502.12	1640.11
0	138.499	1509.82	1648.32

3.5. Acidizing Design

To address the scaling and formation damage, a matrix acidizing treatment was designed. Key steps included:

1. Calculating fracture pressure (1568.18 psi) and bottomhole static temperature (131.97°F).
2. Determining injection volume (18.93 bbl) and acid volume in casing (1.57 bbl).
3. Estimating displacement volume (22.3 bbl).

A 15% HCl solution was selected due to the well's permeability (<100 md).

3.6. Post-Acidizing Evaluation

The IPR curve after acidizing showed notable improvements. Q_o max increased to 138.49 bopd, and Q_w max rose to 1509.82 bwpd, yielding a Q_{max} of 1648.32 bfpd (Figure 4). The PI for liquid and oil improved to 2.28 bfpd/psia and 0.198 bopd/psia, respectively. Permeability increased to 34 md, and the skin factor reduced dramatically to 0.99, indicating successful damage removal (Table 6).

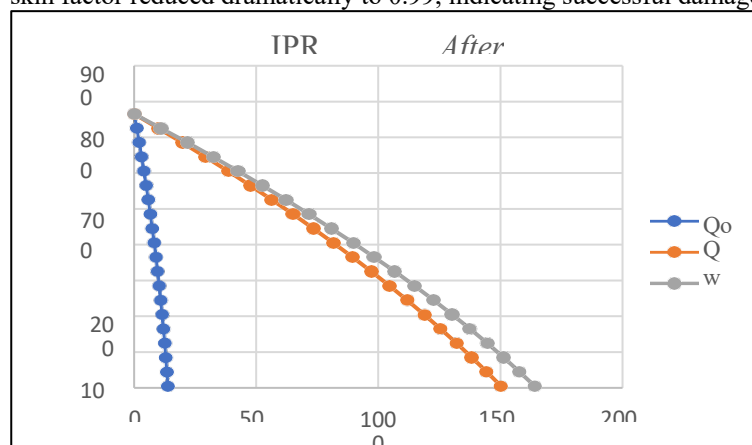


Figure 3.6. Plot graphs IPR after Acidizing sumur "YDK-01"

4. Kesimpulan

This study systematically evaluated scale formation mechanisms and the effectiveness of acidizing treatments in restoring well productivity through a comprehensive analytical approach. The investigation commenced with detailed formation water analysis utilizing the Stiff & Davis and Skillman-McDonald-Stiff methods, which revealed critical scaling tendencies under specific downhole conditions. Computational results demonstrated a positive scaling index ($SI = 1.7$) and significant gypsum solubility differentials ($S = 46.17$ vs $S' = 12.492$), conclusively identifying calcium carbonate (CaCO_3) as the predominant scale type in Well "YDK-01". These findings were substantiated through rigorous examination of key parameters including pH (8.3), temperature profiles ($25^\circ\text{C}/77^\circ\text{F}$), and ionic strength measurements (0.329).

The acidizing treatment design incorporated advanced hydraulic calculations to optimize operational parameters while maintaining formation integrity. Critical design elements included fracture pressure determination (1,568.18 psi), bottom-hole temperature estimation (131.97°F), and precise fluid volume calculations (20.5 bbl total acid volume with 22.3 bbl displacement volume). The engineered injection pressure (154.59 psi) was carefully maintained below the fracture threshold to prevent formation damage, demonstrating the importance of geomechanical considerations in stimulation design.

Post-treatment evaluation revealed substantial production improvements across all measured parameters. The three-phase IPR analysis showed remarkable production increases, with oil output rising 51.6% (91.33 to 138.49 bopd) and total fluid production improving by 118.7% (753.46 to 1,648.32 bfpd). These gains were further corroborated by productivity index enhancements, where liquid PI increased 121.4% and oil PI improved 53.5%. Permeability measurements confirmed significant formation conductivity restoration, increasing from 22 md to 34 md (54.5% improvement). The dramatic reduction in skin factor from 29.53 to 0.99 (96.6% decrease) provided conclusive evidence of successful near-wellbore damage remediation.

The collective results demonstrate that the implemented acidizing protocol effectively addressed scale-induced formation damage while optimizing production potential. The methodology's success is particularly evident in the sustained production uplifts, improved reservoir connectivity, and complete mitigation of near-wellbore damage. This case study establishes a validated technical framework for scale management and production enhancement in similar well conditions, highlighting the critical importance of integrated formation evaluation, precise treatment design, and comprehensive performance monitoring in well intervention operations. The significant improvements across all measured parameters confirm the treatment's technical and economic viability, providing a replicable model for analogous scaling scenarios in carbonate reservoirs.

Bibliography

- Adha, I. (2021). *Reservoir di Lapangan Cipluk Kendal*, 3(September), 39–50.
- Ahmad, N. M., & Said, L. (2016). Formation water analysis for scale precipitation tendency in X, Y and Z wells. *Proceedings of National Scholar Symposium*, 112–125.
- Agustin, M. V., Novian, M. I., Darmawan, A., & Agung, T. (2021). Stratigraphic sequence of South Palembang Sub-Basin based on drilling data from "SSB" well, Musi Waras Regency, South Sumatra Province. *Journal of Southeast Asian Earth Sciences*, 15(3), 45–62. <https://doi.org/10.1016/j.jseae.2021.104782>
- Ahmed, T. H. (2019). *Hydrocarbon reservoir engineering handbook* (4th ed.). Gulf Professional Publishing.
- Alida, R., & Fandra, P. (2018). Calcium carbonate scale mitigation in PF1 well at Field 26, PT Pertamina EP Asset 2 Limau. *Patra Akademika Technical Journal*, 9(2), 35–45. <https://doi.org/10.15242/10.15242/IICBE.C1016063>
- Alighiri, D., Fatmala, C., Syafi'i, I., & Haditya, E. B. (2018). Study of CaCO_3 and CaSO_4 scale formation in Cepu oilfield formation water. *Journal of Physics*, 8(1), 23–34.
- Anisa, M., & Sudibjo, R. (2016). Acidizing treatment design for JRR-2 and JRR-4 wells in Y Field. *Proceedings of National Scholar Symposium*, 226–235.
- Bishop, M. G. (2001). Petroleum systems of South Sumatra Basin: Lahat-Talang Akar-Cenozoic total petroleum. *USGS Bulletin*, 2188, 1–25.
- Brown, K. E. (1967). *Gas lift theory and practice*. Petroleum Publishing Company.

- Brown, K. E. (1977). *Artificial lift methods: Vol. 1. Fundamentals of inflow performance and multiphase flow*. PennWell Books.
- Diba, A. F., Mukmin, M. N., & Afifah, R. S. (2023). Analisa lumpur pemboran terhadap swelling clay pada sumur "X" Lapangan "Affikah". *Petrogas: Journal of Energy and Technology*, 1(1), 46–56. <https://doi.org/10.58267/petrogas.v1i1.151>
- Guo, B., Lyons, W. C., & Ghalambor, A. (2017). *Petroleum production engineering* (2nd ed.). Elsevier.
- Indriana, I. N., Kasmungin, S., & Kustono, B. (2018). Matrix acidizing evaluation in U-48 geothermal well. *Proceedings of National Scholar Symposium*, 385–390.
- Irawan, A., & Isjudarto, A. (2015). Flowline scale problem solution in TLJ-XXX well. *Indonesian Petroleum Journal*, 12(2), 89–102.
- Liestyana, R., Said, L., & Pratiwi, R. (2018). Formation water analysis for calcium carbonate and calcium sulfate scaling tendency. *Proceedings of National Scholar Symposium*, 725–734.
- Manik, N., Rozi, F., Paindan, E. N., Tinggi, S., & Migas, T. (2025). Analisis pengaruh penambahan PAC-R terhadap. *Petrogas*, 7(1), 62–72.
- Megawati, E., Pradipta, Y. H., Warsa, I. K., & Yuniarti. (2022). Optimasi flow feed gas terhadap flow amine pada kolom CO₂ removal. *Petrogas*, 4, 19–25.
- Musnal, A. (2013). Formation damage remediation using compatible acidizing method. *Earth Energy Engineering Journal*, 2(2), 1–7. <https://doi.org/10.1088/1755-1315/42/1/012015>
- Pranondo, D. (2017). Scale problem evaluation in SA series wells. *Patra Akademika Technical Journal*, 8(1), 11–21.
- Ratna, P. S. (2011). *Integrated scale management from near-wellbore to flowline in Limau oil field* [Undergraduate thesis, University of Indonesia].
- Ryka, H., Jamaluddin, J., Pasha, R., & Pratikno, F. A. (2020). Interpretasi lingkungan pengendapan sumur R-2 berdasarkan analisis elektrofases. *Petrogas: Journal of Energy and Technology*, 2(2), 44–51. <https://doi.org/10.58267/petrogas.v2i2.43>
- Salfigo, R. F., Paindan, E. N., Studi, P., Perminyakan, T., Tinggi, S., & Migas, T. (2024). Prediksi pore pressure dan fracture gradient (PPFG) pada sumur HSN menggunakan pendekatan sumur RHN & FGO pada Lapangan Bunyu. *Petrogas*, 6(2), 1–10.
- Sima, N., Friadi Sinaga, J., Perminyakan, T., Migas Balikpapan, Jl. Soekarno-Hatta Km, S., & Joang Kalimantan Timur, K. (2022). Optimasi hydraulic pumping unit pada sumur "WN-98" Lapangan "X". *Petrogas*, 4(1), 47–56.