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Evaluation of Chemical Acidizing Performance Using 15% Hydrochloric Acid (HCl) on Eight Production Wells in Field X

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ABSTRACT - This study evaluates the performance of matrix acidizing, a stimulation process conducted below fracturing pressure using 15% hydrochloric acid (HCl) on eight production wells in Field X, a carbonate reservoir. The assessment compares pre- and post-treatment production performance over a defined 30-day monitoring period. Acid selection was supported by laboratory dissolution analysis using β_{100} and dissolution rate indicators, demonstrating that 15% HCl provided the strongest dissolving power against carbonate minerals compared with formic and acetic acids. The distinction between chemical acidizing (acid-based mineral dissolution) and matrix acidizing (operational mode focused on restoring near-wellbore permeability without inducing fractures) is clarified to align with standard acidizing terminology. Field results show a 90% overall success rate, with average production gains of +778.76 BFPD (fluid) and +49.54 BOPD (oil). One well exhibited an anomalous response, characterized by an increased fluid rate but a reduced oil rate, indicating the potential activation of water-conductive pathways. These findings highlight that, although acid strength is an important factor, treatment success also depends on reservoir heterogeneity, scale distribution, and the effectiveness of acid placement. The integrated workflow combining Scale Index (SI) evaluation with dissolving-power-based acid screening provides a structured approach for designing matrix acidizing in mature carbonate fields.

Keywords: matrix acidizing, chemical acidizing, HCl 15%, dissolving power, carbonate reservoir, production performance.

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INTRODUCTION

Oil is an important source of energy for transportation, industry, and power generation, and sustaining production from aging assets is increasingly important (Al-Mahasneh et al., 2021). According to reports, many fields progress into the mature stage, during which production wells commonly exhibit declining performance due to near-wellbore flow restrictions, including reduced permeability, formation damage, and mineral scale deposition (Mateus Palharini Schwalbert et al., 2020).

Field X is a mature carbonate reservoir, where long-term production decline is strongly associated with carbonate scale, particularly calcite ($CaCO_3$), which can plug pore spaces and perforation tunnels, increase skin factor, and reduce well deliverability (Al-Mahasneh et al., 2021; Kurniawan et al., 2023).

Chemical stimulation through acidizing is widely used to mitigate flow impairment by dissolving mineral deposits and restoring near-wellbore conductivity (Kurniawan et al., 2023). In carbonate formations, hydrochloric acid (HCl) is commonly applied due to its strong reactivity with carbonate minerals. However, operational risks such as rapid acid spending, corrosion, and sludge formation must be considered (Khamehchi Ehsan and Khaleghi, 2024; Yousufi et al., 2024). Successful acidizing requires careful candidate selection and a thorough understanding of the dominant damage mechanism (Al-Mahasneh et al., 2021).

Scale tendency evaluation using the Stiff–Davis Scale Index (SI) provides an early indication of carbonate scale risk and helps guide whether acid-based remediation is appropriate (Al -Mahasneh et al., 2021; Kurniawan et al., 2023).

To complement SI, laboratory dissolving-power screening using â$_{100}$ and dissolution rate parameters provides a quantitative basis for selecting the optimum acid type and concentration. This is carried out particularly in carbonate environments where reaction rate and wormhole development strongly affect stimulation outcome (Nugraha et al., 2019; Salhuteru1 et al., 2025).

Although matrix acidizing in carbonate reservoirs is well-established, several gaps persist in field applications, especially in Indonesian mature fields. These include:

- Candidate selection frameworks that rarely integrate SI analysis with dissolving-power data.
- Limited multi-well evaluations that quantitatively associated with the acid-selection workflow to pre- and post–production outcomes.
- Insufficient emphasis on acid placement challenges despite evidence that diversion quality is a key determinant of success (Abdollahi et al., 2021; Al-Shargabi et al., 2023; F.T Smith & Z Ramji 2024).
- Limited integration of carbonate rock-typing and heterogeneity into treatment design, even though heterogeneity strongly influences acid propagation and wormholing behavior (Turnip et al., 2024; Wibowo 2013).

This study aimed to address these gaps by evaluating the performance of matrix acidizing using 15% HCl on eight production wells in Field X. The evaluation integrates: (i) SI analysis to determine scaling tendency, (ii) laboratory dissolving power results to justify the acid type and concentration, and (iii) quantitative pre–post production analysis to assess field response. By integrating geochemical screening and laboratory evaluation with multi-well field diagnostics, this study proposes a structured workflow to support more reliable matrix acidizing design in mature Indonesian carbonate reservoirs.

METHODOLOGY

Study design and scope

This study applies an integrated, field-based evaluation supported by laboratory analyses to assess the effectiveness of matrix acidizing with 15% HCl on eight production wells in Field X (mature carbonate reservoir). The workflow comprises:

- Candidate screening;
- Formation-water analysis and scale index (SI; Stiff–Davis) calculations;

- Laboratory dissolving-power screening (â$_{100}$ and dissolution rate);
- Treatment design (fluids, stages, diversion);
- Pre–post production performance analysis.

Candidate well screening criteria

Screening logic

Wells were shortlisted to capture cases with likely near-wellbore restrictions (e.g., scale deposition or plugging) rather than reservoir-wide depletion, consistent with established best practices for matrix acidizing in carbonate environments. Screening considered decline trends, pump diagnostics, and water-chemistry indicators to prioritize acid-soluble impairment.

Screening criteria (operational)

The following criteria were applied to all candidates:

- Average oil rate (last 3 months) < 50 BOPD.
- Wellhead temperature 180–250 °F (compatibility with acid system & additives).
- Dynamometer trend confirming pump operability and fluid load behavior.
- No known sand-production history.
- Area context & logs suggest potential plugging/ damage near perforations.

Per-well screening summary

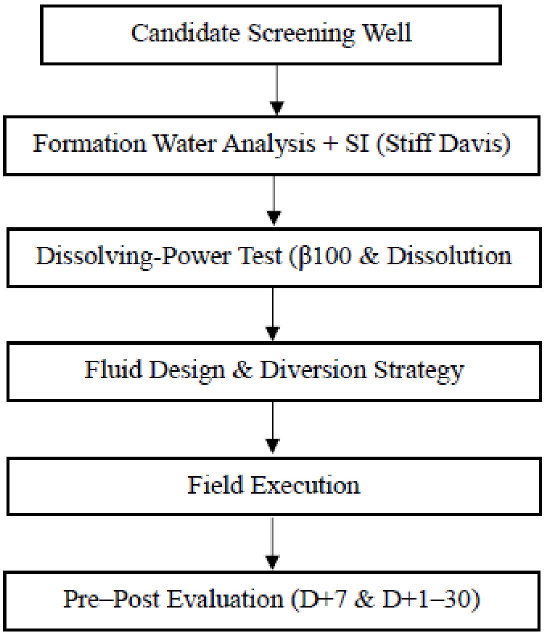

Figure1. Workflow pre-well screening summary

Note: The dissolution rate is calculated as $(m_0 - m_1) / (t \cdot A)$, with units of $g \cdot cm^{-2} \cdot min^{-1}$; t = 30 minutes, T = 25 °C, and a solid-to-liquid ratio of 1 g : 50 mL.

Rationale: Candidate selection is a main determinant of matrix-acidizing success in carbonate reservoirs.

Table 1. Well screening summary

Well	Oil Baseline (BOPD)	SI (Field)	Note Screening
1	20.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
2	57.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
3	18.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
4	111.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
5	2.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
6	52.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
7	87.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.
8	191.00	+1.69	Indication of carbonate scale; near-wellbore flow restriction.

Formation-water analysis and scale index (SI)

Sampling and laboratory measurements

The representative formation-water samples were collected with attention to pH preservation and ion speciation (HCO_3^-/CO_3^{2-}, Ca^{2+}, Mg^{2+}, Na^+, Cl^-, SO_4^{2-}) for Stiff–Davis SI calculations and compatibility checks.

Stiff–Davis method and definitions

In this study, the Stiff-Davis expression was adopted:

$$Sl = pH - (K - pCa - pAlk) \quad (1)$$

where K depends on ionic strength (l); pCA = [-Log (Ca^{2+})]; pAlk = [-Log (CO_3^{2-} + HCO_3^-)]. Positive SI indicates a tendency to form carbonate scale, guiding the technical rationale for acid remediation.

Ionic strength and K-value (worked example)

To increase transparency (as requested by reviewers), the ionic strength III was computed from measured ion concentrations (Table 1) using Equation 2 :

$$I = \frac{1}{2}\sum c_i . z_i^2 \quad (2)$$

where c_i is the molar concentration and z_i the ionic charge. The resulting I is then used to retrieve/compute the Stiff–Davis K-value, which accounts for activity effects at given salinity/ temperature. The illustrative steps (based on Field X data in Table 1): (i) convert mg/L to mol/L for Ca^{2+}, Mg^{2+}, Na^+, Cl^-, HCO_3^-; (ii) evaluate I; (iii) map I to K per Stiff–Davis correlation; (iv) compute SI using Field X pH 7.33 and alkalinity terms. This procedure yielded SI = +1.69 for Field X (Table 2), indicating a positive scaling tendency. (A detailed numerical example is provided in Appendix-A).

Interpretation: Positive SI supports the hypothesis that near-wellbore flow impairment is partly due to carbonate scaling, which is acid-soluble and thus suitable for HCl-based treatment when other operational risks are mitigated.

Laboratory acid screening: dissolving power

Objective and indicators

This study evaluated dissolution effectiveness of HCl, formic (HCOOH), and acetic (CH_3COOH) acids at 5%, 10%, 15% using â$_{100}$ and dissolution rate to justify acid type and concentration for carbonate plugging minerals (limestone/$CaCO_3$).

Materials and sample source

- Rock/mineral: carbonate standard (limestone/ $CaCO_3$; ñ ≈ 2.71 g/cc).
- Acids: HCl, HCOOH, CH_3COOH (analytical grade) at target concentrations (5/10/15%).
- Brine: DI water for rinsing; no complexing agents during baseline screening.

Procedure (Expanded)

- Specimen prep: carbonate chips/pellets were cleaned, dried, and weighed prior to analysis (m_0).
- Acid contact: ratio solid: liquid = 1 g: 50 mL; contact time 30 minutes; T = 77 °F (25 °C); gentle agitation.
- Quench & rinse: The reaction was terminated, after which the samples were rinsed and dried to a constant weight, and then reweighed (m_1).
- Calculations: Dissolution rate = $(m0-m1)/(t \cdot A)$

Outcome: 15% HCl consistently showed the highest â$_{100}$ and dissolution index vs organic acids, hence selected as the main acid.

Treatment design and field Execution

Fluids, stages, and additives

- Preflush: clay stabilizer (Clayfix-5) for conditioning.
- Main acid: 15% HCl.
- Overflush: NH_4Cl to displace spent acid and reaction products.
- Additives: corrosion inhibitor and mutual solvent (AS-10) for equipment protection and compatibility.
- Diverter: ball sealers for perforated completions to improve zonal coverage. These choices

align with prevailing practices and literature on carbonate matrix acidizing and diversion efficacy.

Operational parameters

Injection rate/pressure, stage volumes, and compatibility were tuned to enhance placement and mitigate secondary issues (rapid spending, corrosion, sludge). Diversion through ball sealers was applied where heterogeneity implied intake bias.

Production performance evaluation (pre–post acidizing)

Pre–post windows and measurement timing

To standardize comparisons, the following are defined:

- Pre-treatment baseline: average of the last 30 production days before the job (or the longest stable window available).
- Post-treatment assessment: D+7 point check (early response) and D+1–30 average (stabilized response). The days post-treatment are now explicitly indicated in Table 4 (revision item).

Success criteria

A job is Successful if any of the following are met relative to the baseline window:

- ÄBOPD ≥ +10 BOPD or ≥ +20% (whichever is more stringent), with no decline in operational stability
- ÄBFPD ≥ +300 BFPD with no decrease in net oil production (for cases involving water-handling). Wells not meeting the thresholds are Non-Responsive, while negative oil response with large fluid gains is classified as water-path activation and discussed separately.

Data processing and presentation

- Pre- and post-treatment production results were organized in tables and visualized through comparative plots (fluid and oil rates).
- The SI results and dissolving power outcomes were used to support the technical justification for selecting 15% HCl and to interpret differences in well response.
- A qualitative diagnostic discussion was performed for the one well showing performance decline, emphasizing the role of well-specific conditions and reservoir heterogeneity on acidizing outcomes.

Matrix/chemical acidizing in carbonate settings is well established. However, four persistent gaps that reduce field reliability were identified, including: 1). Candidate selection frameworks for mature Indonesian fields rarely integrate formation-water scaling tendency (e.g., SI) with laboratory dissolving-power screening to justify acid type/ concentration; 2). There is limited, multi-well evidence that quantitatively links pre/post KPIs (ÄBFPD, ÄBOPD) to such an integrated selection workflow; 3). Field reports often downplay placement/coverage risks and the role of diversion, despite its decisive influence on outcomes; and 4). Publications for Indonesian carbonate reservoirs emphasize rock heterogeneity but seldom connect it to acid placement decisions at job-design level. Recent local studies on matrix-acidizing candidate selection in mature fields highlight the need for structured screening approaches tailored to Indonesian conditions. However, these studies do not quantitatively associate the SI and acid dissolving capacity with multi-well field outcomes.

This study addresses these gaps by: 1). Combining SI evidence with lab-screened dissolving power (â100, dissolution rate) to select 15% HCl as the main acid; 2). Reporting a multi-well (n=8) implementation with explicit pre-post deltas (avg. +778.76 BFPD and +49.54 BOPD) and a 90% success rate; 3). Diagnosing one non-responsive case and linking it to placement bias/water-path activation, thereby motivating stronger diversion strategies; 4); Situating the results within Indonesian carbonate heterogeneity/ rock-typing literature to explain response variability and improve candidate vetting (Haruna et al., 2020; Turnip et al., 2024).

As diversion quality is a known determinant of acidizing efficiency, the results are related to *profile-modification/diversion* studies to justify enhanced placement control in future campaigns (Sugihardjo 2005).

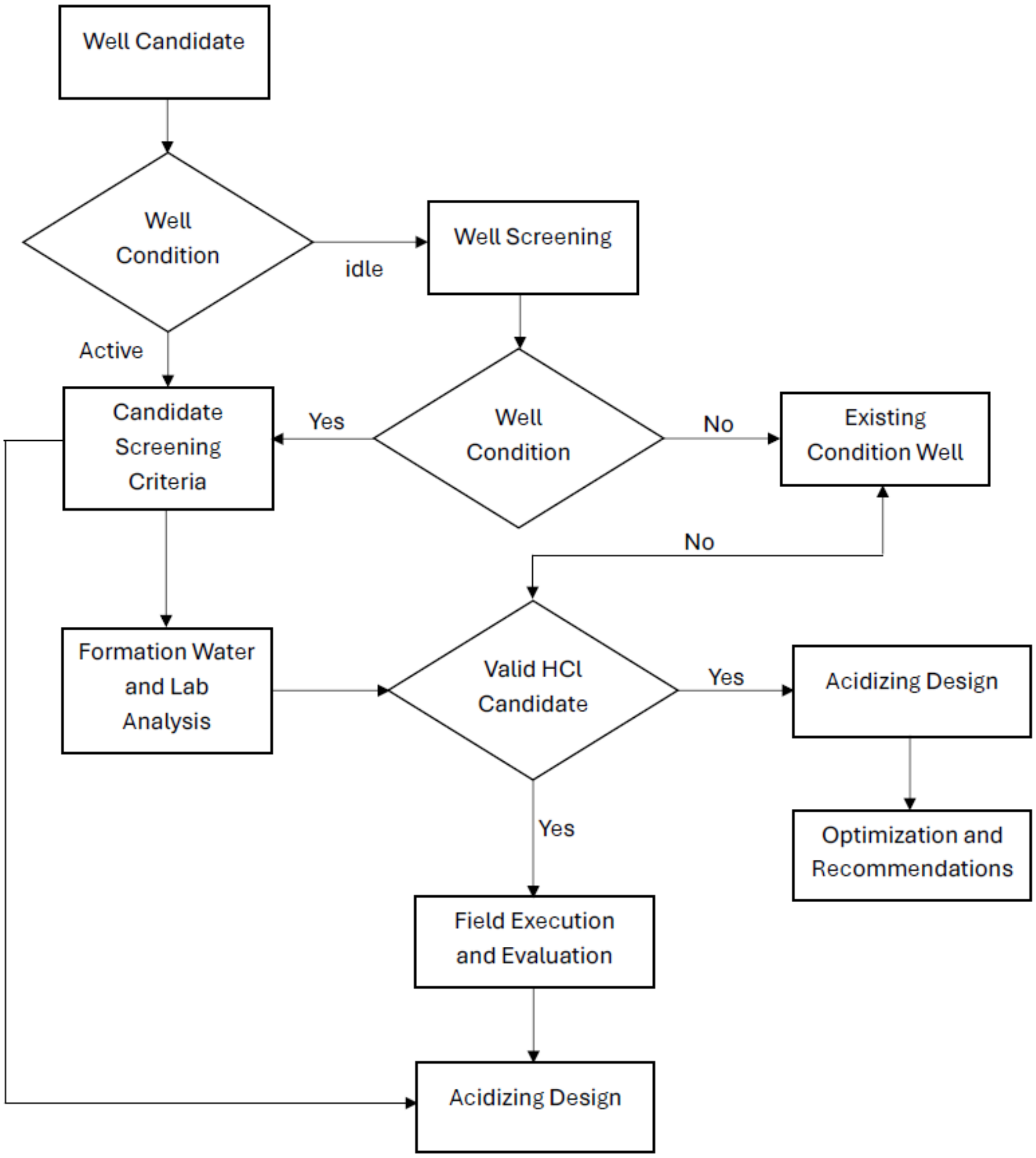

Figure 2. Workflow acidizing design

RESULT AND DISCUSSION

Scaling tendency from formation-water analysis

As shown in Table 2, the formation water analysis for field X shows a pH of 7.33, bicarbonate (HCO_3^-) of 1013.34 mg/L, calcium (Ca^{2+}) of 16.82 mg/L, and carbonate (CO_3^{2-}) of 0 mg/L. The combination of a near-neutral to slightly alkaline pH and high alkalinity (dominated by bicarbonate) indicates a carbonate system primarily buffered by HCO_3^-, which can promote carbonate-scale formation (e.g., $CaCO_3$) when operating conditions change (pressure/temperature shifts or changes in dissolved gases).

In addition, chloride (Cl^-) of 699.87 mg/L and sodium (Na^+) of 809.16 mg/L suggest a brine system with a relatively high ionic strength. From an operational perspective, the presence of such brines underscores the need for careful chemical compatibility management during treatments (including acids and additives) to minimize the risk of secondary precipitation or other adverse reactions (Wang et al., 2023).

The reported SI for Field X is +1.69, and under the Stiff Davis approach used in this study, a positive SI indicates that the formation water tends to form scale (scaling tendency). Therefore, the

Table 2. Formation-water analysis data at X Field

No	Analysis parameters	Unit	X field
1	Carbonate (CO_3^{2-})	mg/L	0.00
2	Bicarbonate (HCO_3^-)	mg/L	1013.34
3	Sodium (Na^+)	mg/L	809.16
4	Calcium (Ca^{2+})	mg/L	16.82
5	Magnesium (Mg^{2+})	mg/L	5.05
6	Sulfate (SO_4^{2-})	mg/L	3.88
7	Chloride (Cl^-)	mg/L	699.87
8	pH (at 77 °F)	-	7.33
9	Temperature	°C	-

Table 3. Derived scaling indicator at Field X

Location	Scaling index	Interpretation
X Field	+ 1.69	Positive SI → scalling tendency

Field X water chemistry provides technical support that production impairment in this area may be associated with mineral deposition contributing to near-wellbore flow restriction, making chemical remediation relevant.

SI is a thermodynamic tendency indicator rather than a direct measurement of deposited scale type. Confirmation of the dominant scale species is ideally supported by deposit sampling/analysis or well operating trends; however, SI remains an effective screening metric for identifying scaling risk (Alnetaifi 2025).

For carbonate scale conditions, particularly $CaCO_3$, HCl is commonly applied because of its strong reactivity toward carbonate minerals and its effectiveness in removing near-wellbore restrictions. In this study, selecting 15% HCl is further supported by the laboratory dissolving power screening, where 15% HCl demonstrated the highest dissolution performance against carbonate plugging minerals compared with formic and acetic acids. Consequently, in an area such as Field X with a positive SI (scaling tendency), the use of 15% HCl as the main acid is technically consistent because it targets predominantly acid-soluble carbonate deposits.

Confirmation of the dominant scale species is ideally supported by deposit sampling and analysis or by monitoring well operating trends. However, SI remains an effective metric for screening and identifying scaling risk. The sulfate (SO_4^{2-}) concentration in Field X is 3.88 mg/L, which is relatively low compared with the very high bicarbonate level. This suggests that sulfate-scale risk (e.g., $CaSO_4$/$BaSO_4$/$SrSO_4$) is likely less significant than carbonate-scale risk in this location, making HCl-based acidizing more reasonable than scenarios dominated by sulfate scale (which is typically much less soluble in HCl). Even when a clear scaling tendency is identified, the success of acidizing in the field is largely determined by effective acid placement and coverage. The SPE PetroWiki guidance highlights that a major cause of unsuccessful acid treatments is failure to contact all damaged zones because injected fluids preferentially flow through the path of least resistance. Therefore, for wells in scaling-prone areas such as Field X, applying diversion techniques can improve acid distribution and increase the likelihood that plugged intervals are effectively treated. Ball sealers have been reported as an effective diversion method for matrix acidizing of perforated intervals, while broader reviews of diversion techniques also highlight that diverter effectiveness depends on reservoir heterogeneity and completion characteristics.

Acid selection based on dissolving power screening

The acid selection in this study was justified through dissolving power screening against carbonate rock (limestone/$CaCO_3$). As shown in Table 4, dissolution performance is controlled by both acid type and acid concentration, and the results consistently indicate that HCl provides the highest carbonate dissolution capability among the tested acids.

Table 4. Derived scaling indicator for Field X

Mineral	Asam	β_{100}	Konsentrasi (X)		
			5%	10%	15%
Limestone	HCl	1.37	0.026	0.053	0.082
$CaCO_3$	HCOOH	1.09	0.020	0.041	0.062
ρ = 2.71 g/cc	CH_3COOH	0.83	0.016	0.031	0.047

Quantitatively, HCl exhibits the highest β100 value (1.37), exceeding formic acid (HCOOH, 1.09) and acetic acid (CH_3COOH, 0.83). This higher β100 reflects a stronger dissolution potential of HCl toward carbonate minerals, supporting its suitability for removing calcite-based plugging in the near-wellbore region. In addition, increasing acid concentration from 5% to 10% to 15% enhances dissolution indices for all acids; however, HCl remains dominant at every concentration level.

At the 15% concentration, the dissolution index for HCl reaches 0.082, which is higher than HCOOH (0.062) and CH_3COOH (0.047). Therefore, 15% HCl was selected as the main acid because it delivers the highest dissolving power against carbonate scale/plugging minerals (particularly calcite), making it technically appropriate for chemical acidizing aimed at restoring near-wellbore flow conductivity. The selection of HCl as a primary acid aligns with the broader industry practice for carbonate acidizing, while acknowledging its operational considerations (e.g., reactivity/corrosion/sludging risks) discussed in recent reviews (Delaviz et al., 2024).

Field implementation and production response (Eight wells)

Water-cut values presented in Table 4 were calculated based on the ratio of oil to total produced fluid (BOPD/BFPD), a commonly used approach in production evaluations when detailed fluid-fraction measurements are not recorded. The identification of trends in fluid composition, particularly in Well 6, where an increase in total fluid rate was accompanied by a decrease in oil rate, is consistent with the activation of water-conductive flow pathways.

Chemical acidizing with 15% HCl was implemented on eight production wells. The field results show an overall improvement in production, where total fluid rate increased from 9808.00 BFPD to 16038.11 BFPD (+6230.11 BFPD; +63.52%), and total oil rate increased from 538.00 BOPD to 934.34 BOPD (+396.34 BOPD; +73.67%). On an average basis, fluid rate increased from 1226.00 to 2004.76 BFPD (+778.76 BFPD), and oil rate increased from 67.25 to 116.79 BOPD (+49.54 BOPD). These results indicate that the selected chemical acidizing program generally improved near-wellbore deliverability in the studied wells, consistent with the primary objective of matrix/chemical acidizing to reduce flow restriction in the damaged region.

Table 5. Pre–post acidizing production response per well (Field X)

No	Before fluid (BFPD)	After fluid (BFPD)	Δ Fluid	%Fluid	Before oil (BOPD)	After oil (BOPD)	Δ Oil	%Oil	Water cut before (%)	Water cut after (%)
1	570	618.39	+48.39	+8.49	20	123.97	+103.9	+519.9	96.49	79.95
2	981	2627	+1646	+167.79	57	87.81	+30.81	+54.1	94.19	96.66
3	71	262.75	+191.8	+270.07	18	21.68	+3.68	+20.4	74.65	91.75
4	4488	5208	+720	+16.04	111	178.11	+67.11	+60.5	97.53	96.58
5	947	1406.6	+459.6	+48.53	2	110.69	+108.69	+5434.5	99.79	92.13
6	162	2604	+2442	+1507.41	52	42.7	-9.30	-17.9	67.90	98.36
7	251	696.16	+445.2	+177.35	87	174.86	+87.86	+100.9	65.34	74.88
8	2338	2615.2	+277.2	+11.86	191	194.52	+3.52	+1.84	91.83	92.56
Tot	9808	16038.1	+6230.1	+63.52	538	934.34	+396.3	+73.7	94.51	94.17
Average	1226	2004.8	+778.8	+63.52	67.25	116.79	+49.5	+73.7	94.51	94.17

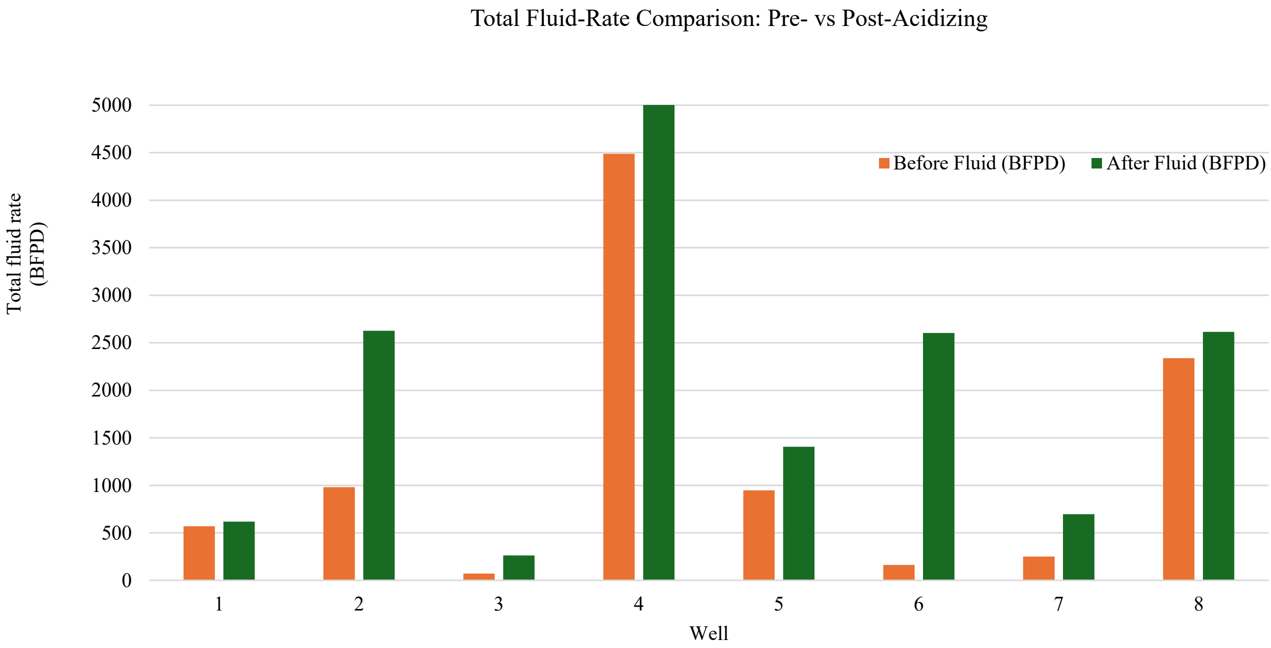

Figure 3. Total Fluid-rate comparison: pre-vs post-acidizing

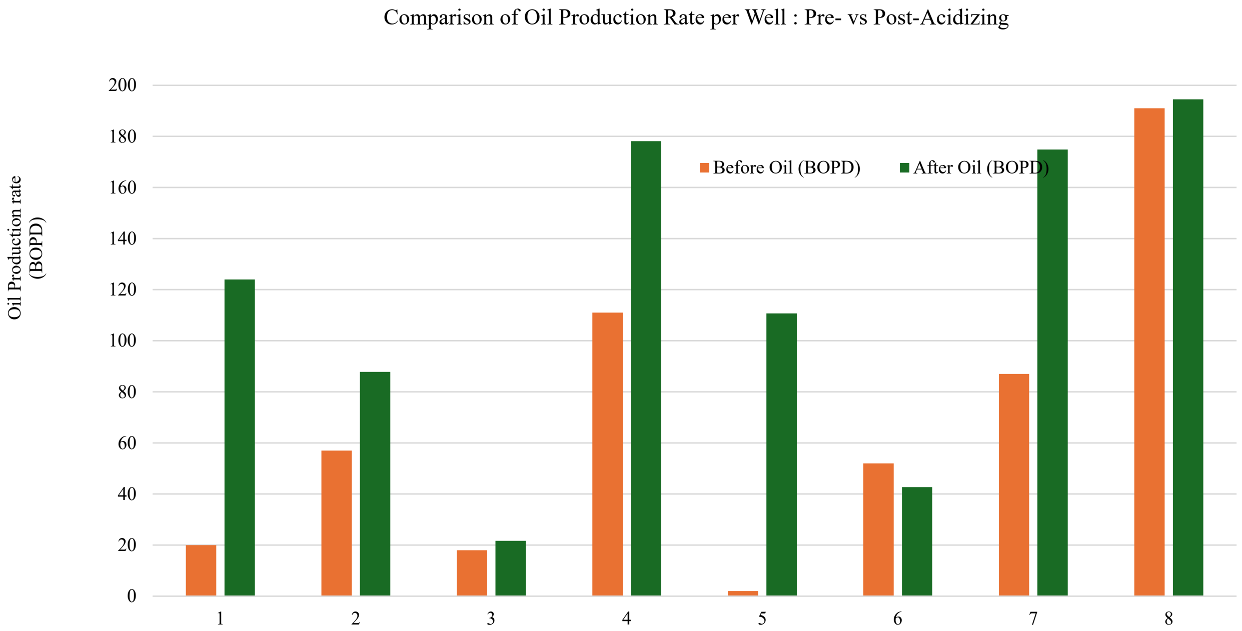

Figure 4. Comparison of oil production rate per well: pre-vs post-acidizing

Table 5 shows the pre- and post-acidizing production rates for each well. The largest fluid gains were observed in Well 6 (+2442 BFPD) and Well 2 (+1646 BFPD). The largest oil gains were observed in Well 5 (+108.69 BOPD) and Well 1 (+103.97 BOPD), showing substantial productivity restoration after treatment (Alnetaifi 2025).

Discussion: drivers of variable well response and non-responsive case.

Why do responses vary across wells?

This variability is consistent with carbonate rock-typing work that documents strong heterogeneity in pore systems/fabrics, which can steer acid flow and coverage. Accordingly, placement-aware design is expected to outperform one-size-fits-all acid stages (Wibowo 2013).

Despite a consistent main acid system (15% HCl), well responses varied significantly, which is expected in field operations due to heterogeneity in damage extent, permeability distribution, and completion-level flow paths. A key cause of underperformance in matrix/chemical acidizing is incomplete acid contact with the damaged zones because injected fluids follow the path of least resistance, resulting in poor placement and incomplete coverage. Consequently, diversion strategies (mechanical or chemical) are critical in heterogeneous intervals to promote more uniform acid distribution (Mohammadi 2024).

In this study design, ball sealers were incorporated as a diversion method to improve placement across perforated intervals. Field literature reports that buoyant ball sealers can provide effective diversion and improve stimulation outcomes, supporting their selection when zonal coverage is a concern. However, diversion effectiveness can still be limited by well-specific conditions, perforation geometry, interval heterogeneity, and operational constraints (Mohammadi 2024; Society of Petroleum Engineers 2025).

Diversion efficacy is important, and profile-modification/diversion studies show permeability-biased intake without effective diversion, leading to uneven stimulation and water-path activation; our findings mirror these mechanisms (Sugihardjo 2005).

Non-responsive behavior (oil decline despite fluid increase)

A notable anomaly occurred in Well 6, where fluid rate increased substantially (+2442 BFPD) but oil rate decreased (−9.3 BOPD). This pattern suggests that the treatment may have preferentially enhanced flow through water-bearing pathways or increased water production (higher water cut), rather than improving oil-bearing conductivity.

Several mechanisms can explain this behavior:

- Placement bias and diversion limitation: acid may have entered high-permeability or already open channels, improving fluid throughput but not the targeted oil-contributing zones, consistent with the placement/coverage challenge highlighted in acid placement guidance.
- Heterogeneous scale deposition: if scale or damage is localized, incomplete coverage can leave critical oil flow pathways untreated, even as other paths are improved.

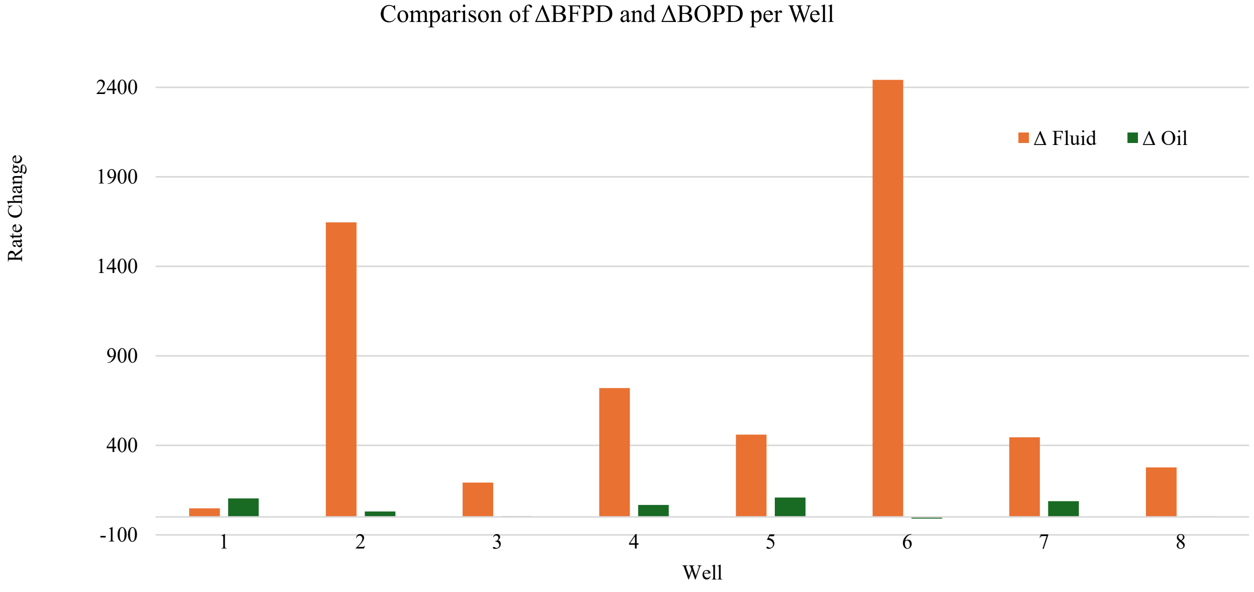

Figure 5. Comparison of ΔBFPD and ΔBOPD per well

- Secondary damage effects: acidizing may trigger emulsions, asphaltene sludge, or iron-related precipitation that can reduce effective oil permeability, as shown by recent laboratory investigations emphasizing sludge/precipitation as a major risk factor.
- Non–acid-soluble dominant damage: if the well impairment is dominated by non-acid-soluble mechanisms (e.g., wax/asphaltene or mechanical restrictions), HCl-based acidizing may not address the primary limitation, leading to weak or negative oil response.

In general, the results indicate that SI and dissolving power provide a strong basis for acid selection, but execution factors (placement/ diversion) and damage mechanism specificity remain decisive for ensuring oil gains, especially in wells with complex near-wellbore conditions.

Practical implications for future acidizing campaigns

Based on the observed variability and the non-responsive case, future campaigns should: 1). Strengthen candidate selection beyond SI (e.g., incorporate water cut trend, deposit identification); 2). Optimize diversion design and placement strategy for heterogeneous intervals, and; 3). Apply rigorous compatibility and additive screening (e.g., iron control/anti-sludge) for wells prone to sludge or precipitation risks.

In summary, chemical acidizing using 15% HCl delivered substantial average gains across eight wells, but one well exhibited a non-responsive oil outcome, highlighting that production uplift depends not only on acid strength (dissolving power) but also on acid placement effectiveness, heterogeneity, and potential secondary damage mechanisms.

The study couples SI with dissolving-power screening to justify 15% HCl, then validates the choice over eight field cases with explicit ÄBFPD/ ÄBOPD and a 90% success rate. It also documents a fluid-increase/oil decline anomaly, attributing it to placement bias/water-path activation, thus highlighting the need for more robust diversion in heterogeneous carbonates. The approach complements Indonesian matrix-acidizing candidate selection frameworks and carbonate rock-typing insights, offering a practical screening-to-execution workflow for mature fields (Turnip et al., 2024).

CONCLUSION

Formation-water analysis indicates a strong scaling tendency in the study area, as shown by positive SI values of +1.69 (Field X). These positive SI values suggest conditions favorable for mineral scale deposition that can restrict near-wellbore flow.

Acid selection for chemical acidizing was supported by dissolving power screening, where 15% HCl exhibited the highest dissolution capability for carbonate rock (limestone/$CaCO_3$) compared with formic acid (HCOOH) and acetic acid (CH_3COOH). This is evidenced by the highest β100 (1.37) and the highest dissolution index at 15% concentration (0.082), justifying the selection of 15% HCl as the main acid.

Field implementation of 15% HCl acidizing on eight wells resulted in an overall positive production response. The total fluid rate increased from 9808.00 BFPD to 16038.11 BFPD (+6230.11 BFPD), and the total oil rate increased from 538.00 BOPD to 934.34 BOPD (+396.34 BOPD).

On an average basis, fluid production rose from 1226.00 BFPD to 2004.76 BFPD (+778.76 BFPD), while oil production increased from 67.25 BOPD to 116.79 BOPD (+49.54 BOPD). These results confirm that chemical acidizing with 15% HCl effectively improved overall well performance in most cases.

Despite the generally positive outcome, one well showed a decline in oil rate (negative ΔBOPD) even though its fluid rate increased. This indicates that acidizing success is not governed solely by acid strength, but also by well- and reservoir-specific factors such as heterogeneity, scale distribution, acid placement effectiveness, potential water production dominance, or damage mechanisms that are not acid-soluble.

In general, this study demonstrates that integrating SI screening with dissolving power–based acid selection provides a structured basis for designing chemical acidizing programs and improving the probability of success. However, reducing the likelihood of non-responsive wells requires additional attention to acid placement/ diversion strategy, fluid compatibility, and post-treatment diagnostics (e.g., water-cut trends).

The integrated SI (+) dissolving-power workflow provides not only lab-based justification for 15% HCl but also a practical screening path aligned with Indonesian mature-field candidate selection guidance; this closes a recurring gap where acid choice is decoupled from local scaling risk.

Field variability is consistent with carbonate rock-typing/heterogeneity and the known dependency of stimulation on placement/diversion effectiveness. Future studies should elevate diversion design (mechanical/chemical) in line with profile-modification learnings to mitigate water-path activation.

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GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbols	Defination	Unit
HCl	Hydrochloric acid used as the main acid system for chemical and matrix acidizing.	-
HCOOH	Formic acid evaluated in dissolving-power screening.	-
CH_3COOH	Acetic acid evaluated in dissolving-power screening.	-
SI	Scale Index (Stiff–Davis), indicating carbonate scale-forming tendency.	-
pH	Acidity/alkalinity of formation water.	dimensionless
K	Ionic-strength correction factor in Stiff–Davis equation.	-
pCa	Calcium activity term ($-\log Ca^{2+}$) in SI calculation.	-
pAlk	Alkalinity activity term ($-\log (CO_3^{2-} + HCO_3^{-})$) in SI calculation.	-
β_{100}	Acid dissolving-power parameter used for comparative evaluation.	-
ρ	Density of carbonate mineral (limestone).	g·cm^{-}00B3
BOPD	Oil Production Rate.	bbl·day^{-1}
BFPD	Total fluid production rate.	bbl·day^{-1}
ΔBOPD	Change in oil production rate (after − before acidizing).	bbl·day^{-1}
ΔBFPD	Change in fluid production rate (after − before acidizing).	bbl·day^{-1}
Acidizing	Stimulation process using acid to dissolve near-wellbore plugging materials	-
Chemical Acidizing	Acid treatment focused on chemical dissolution of mineral damage (e.g., carbonate scale)	-
Matrix Acidizing	Acidizing performed below formation fracturing pressure to restore near-wellbore permeability	-
Preflush	luid injected before the main acid to condition the formation.	-
Main Acid	Primary reactive acid stage (15% HCl in this study).	vol%
Overflush	Fluid injected after the main acid to displace spent acid and reaction products.	-
Diverter	Material or technique used to redirect acid into untreated zones.	-
Ball Sealer	Mechanical diverter used in perforated completions.	-

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