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RESEARCH ARTICLE

Evaluation of Matrix Acidizing Using Formation Water Parameters in Hilal Well, Arqom Field, Indonesia

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Abstract

Formation damage due to scale deposition is a common production problem that reduces reservoir permeability and decreases oil and gas well productivity. One effective remediation technique is matrix acidizing. This study evaluates the effectiveness of matrix acidizing in a sandstone reservoir with carbonate mineral content in Hilal well, Arqom Field, by analyzing production rate changes and formation water characteristics before and after treatment. Formation water analysis plays a critical role in evaluating acid compatibility and revealing mineral dissolution mechanisms during the treatment.

The Stiff method was used to characterize formation water, followed by matrix acidizing planning through optimal injection volume and pressure calculations. The treatment involved preflush, main acid injection, and displacement, along with an Injectivity Rate Test (IRT). The effectiveness was evaluated using Productivity Index (PI) and Inflow Performance Relationship (IPR) analysis.

The results demonstrate that matrix acidizing significantly increased the PI of Hilal well from 1.62 bbl/psi to 3.15 bbl/psi, resulting in a 102% increase in production. Key technical parameters, including formation breakdown pressure (BHFP), acid hydrostatic pressure (pH), and surface treating pressure (STP), aligned with the designed injection volume of 46 bbl. These results demonstrate that matrix acidizing is an effective method for enhancing well productivity.

Keywords: Matrix Acidizing, Formation Damage, Scale Deposition, Injectivity Rate Test (IRT), Productivity Index (PI), Inflow Performance Relationship (IPR).

1. Introduction

Matrix acidizing is a well stimulation technique designed to enhance reservoir productivity by dissolving pore-blocking materials around the wellbore (Shafiq and Mahmud, 2017). This technique is widely applied in both carbonate and sandstone reservoirs, where permeability reduction occurs due to mineral precipitation, scale deposition, or other formation damage mechanisms (Ifeanyi et al., 2015, Kan et al., 2019). Various stimulation and enhanced recovery techniques have been developed to improve hydrocarbon production in mature reservoirs (Hasan, 2022). The effectiveness of matrix acidizing is strongly influenced by reservoir characteristics, fluid–rock interactions, and operational parameters during treatment (Qiu et al., 2018, Khalil et al., 2021). Matrix acidizing is widely recognized as an effective stimulation technique in both sandstone and carbonate reservoirs, particularly in improving permeability and removing formation damage (Khor et al., 2017, Hasan, 2022).

In recent years, significant attention has been given to understanding acid–rock interaction mechanisms, particularly in relation to wormhole formation and mineral dissolution processes that directly affect permeability enhancement (Maheshwari et al., 2016, Liu et al., 2017). These processes are strongly influenced by reactive transport phenomena at the pore scale, which control fluid distribution and mineral dissolution behavior (Liu and Mostaghimi, 2017). However, most previous studies primarily evaluate acidizing performance based on production indicators such as Productivity Index (PI) and flow rate improvement, with limited emphasis on the role of formation water chemistry as a diagnostic parameter ((Bonafé et al., 2020, Talib et al., 2024).

Formation water composition plays a critical role in determining acid compatibility, reaction pathways, and the potential for secondary precipitation during stimulation. Parameters such as salinity, ion concentration, and pH can influence dissolution efficiency and fluid–rock interactions, ultimately affecting the success of acidizing treatments (Kan et al., 2019, Khalil et al., 2021). Despite its importance, the integration of formation water analysis into acidizing evaluation remains relatively underexplored, particularly in sandstone reservoirs containing carbonate minerals.

Arqom Field is one of Indonesia’s mature hydrocarbon-producing fields, characterized by complex geological formations dominated by sandstone with carbonate mineral content. Geochemical characteristics of crude oil and source rock relationships are also important in understanding reservoir behavior and hydrocarbon accumulation systems (Mohialdeen et al., 2015). These conditions create challenges in maintaining optimal reservoir productivity, especially due to pore-blocking materials and mineral interactions. Hilal well, as one of the production wells in this field, has experienced a decline in productivity suspected to be associated with formation damage and fluid–rock incompatibility. Previous studies have demonstrated that reservoir characterization and petrophysical properties significantly influence stimulation effectiveness (Johanna and

Kusumah, 2023, Nurrochmah and Herawati, 2025). Reservoir characterization based on core and log analysis also plays a significant role in identifying fracture systems and fluid flow behavior in complex reservoirs (Riskha et al., 2017).

Therefore, this study aims to evaluate the effectiveness of matrix acidizing in Hilal well by integrating production performance analysis with formation water characterization. Unlike conventional approaches that rely solely on production data, this study emphasizes the use of formation water parameters to provide a more comprehensive understanding of acid–rock interaction mechanisms and their impact on reservoir performance. The findings are expected to contribute to the optimization of acidizing design and improve decision-making in reservoir stimulation practices. Reservoir heterogeneity and petrophysical characteristics significantly affect stimulation outcomes and fluid flow behavior (Bior Barach et al., 2022). The study area is illustrated in Fig 1.

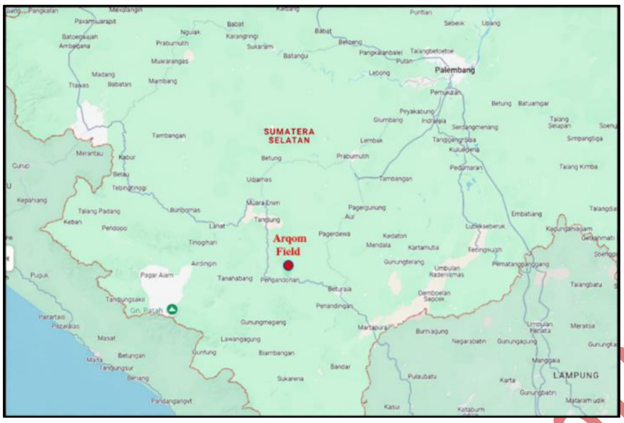

Fig 1. Arqom Field Research Location

2. Methodology

This study was conducted to evaluate the effectiveness of matrix acidizing in the Hilal well, Arqom Field, by integrating production performance analysis with formation water characterization. The research methodology consists of several main stages, as illustrated in Fig 2.

A comprehensive literature review was conducted using scientific journals and published studies related to matrix acidizing, reservoir characteristics, and formation water chemistry to establish the theoretical framework of the study.

The data used in this study include well data, reservoir properties, production data, acidizing treatment data, and laboratory results of formation water analysis. These datasets were obtained from field measurements and laboratory testing.

Formation water characteristics were analyzed to evaluate fluid compatibility and identify potential risks such as mineral precipitation and scaling. The Stiff diagram method was used to interpret ionic composition by comparing the relative concentrations of cations (Na$^+$, Ca^{2+} , Mg^{2+}) and anions (Cl$^-$, SO$_4$ $^{2-}$, HCO$_3$ $^-$). This method allows identification of water type, salinity level, and geochemical behavior that may influence acid–rock interactions during treatment.

Based on formation water analysis, matrix acidizing treatment was designed to optimize stimulation effectiveness. The treatment consists of three main stages:

1) Preflush, to condition the formation and prevent unwanted reactions
2) Main acid injection, to dissolve pore-blocking minerals and improve permeability
3) Displacement, to push the reacted acid further into the formation and clean residual fluids.

The designed acidizing treatment was applied to the Hilal well, followed by evaluation of its performance through changes in production rate and reservoir parameters. An Injectivity Rate Test (IRT) was conducted before and after treatment to assess formation injectivity and ensure injection pressure remained below fracture pressure.

The effectiveness of the treatment was evaluated by comparing Productivity Index (PI) and Inflow Performance Relationship (IPR) before and after acidizing. These parameters were used to quantify improvements in reservoir deliverability and flow efficiency.

All calculations, including pressure analysis, volume design, and performance evaluation, were carried out using standard petroleum engineering equations. Data processing and analysis were performed using Microsoft Excel to ensure consistency and accuracy in computation.

The success of matrix acidizing was determined based on improvements in production performance, injectivity behavior, and formation water characteristics after treatment.

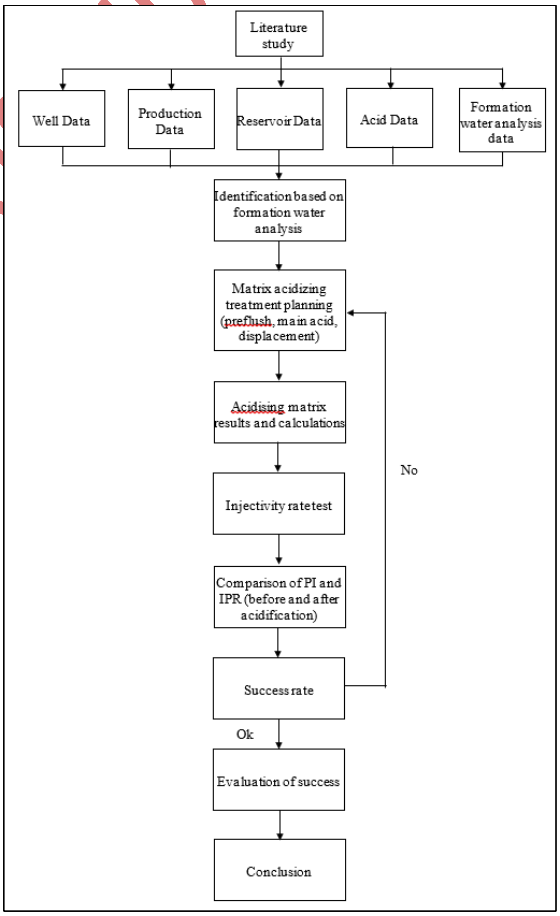

Fig 2. Flow Chart Research

2.1 Data

The data used for matrix acidizing calculations in the Hilal well are summarized in **Tables 1–6**. All parameters have been standardized in terms of units and notation to ensure consistency and readability.

Table 1. Well Data

No	Parameter	Hilal Well	Unit
1	Depth	4095	ft
2	Perforation	3854 – 3944	ft
3	Top perforation	3854	ft
4	Mid perforation (D)	3934	ft
5	Bottom Perforation	3944	ft
6	Well radius (rw)	0.3	ft
7	Layer thickness (h)	23.3	ft
8	Casing OD	7	in
9	Casing ID	6.276	in

Table 2. Reservoir Data

No	Parameter	Hilal Well	Unit
1	Reservoir Pressure	1140	Psi
2	Reservoir Temperature	220	°F
3	Porosity	14	%
4	Radial Acid Penetration (ri)	5	ft
5	Formation Reakah Gradient	0.7	Psi/ft
6	SG Oil	0.91	-
7	SG Water	1.0	-
8	Permeability	22.975	mD
9	Oil Viscosity	7.2	cP
10	BHST	185	°F
11	BHSP	1190	Psi

Table 3. Acid Data

No	Parameter	Hilal Well	Unit
1	Acid Viscosity	0.65	cP
2	Acid Density	8.96	ppg
3	SG HCl 15%	1.074	-
4	SG HCl 32%	1.16	-
5	HCl 15% Friction Press@ 2 BPM	111.5	psi
6	Brine Water Friction Press@ 2 BPM	92	psi
7	SG Brine	1.011	-
8	Brine Density	8.43	ppg

Table 4. Production Data

No	Parameter	Hilal Well	Unit
1	Pws (before acidizing)	1140	Psi
2	Pwf (before acidizng)	948	Psi
3	Pws (after acidizing)	1169	Psi
4	Pwf (after acidizng)	973	Psi
5	Qo (before acidizng)	12.38	bopd
6	Qo (after acidizng)	25	bopd
7	Water cut (before acidizing)	96.01	%
8	Water cut (after acidizng)	96.08	%
9	Qt (before acidizing)	312	bfpd
10	Qt (after acidizing)	629	bfpd
11	Tubing ID	2.441	In
12	Tubing Length	3838	ft

Table 5. Formation Water Data

No	Parameter	Hilal Well
1.	SI (Stability Index)	-1.84
2	pH	6.5

Table 6. Hilal Well Formation Water Analysis Laboratory Data

Ion	Concentration	Unit
Natrium Na+	5236.16	mg/L
Calcium Ca++	10	mg/L
Magnesium Mg++	60.8	mg/L
Karbonat CO3=	30	mg/L
Bikarbonat HCO3-	732	mg/L
Sulfat SO4=	8	mg/L
Chlorida Cl-	7810	mg/L
Besi Fe+++	0,14	mg/L
Total Dissolved Ion	13887.1	mg/L

2.2 Problem Identification

The Hilal well in the Arqom field experienced a decrease in oil and water production rate of 312 BFPD. Formation water analysis using the Stiff method shows the absence of scale, but there is carbonate content (CO_3^{2-}) in the reservoir rock (Alighiri et al., 2018). Based on the identification results, matrix acidizing was carried out on the sandstone of the Talang Akar Formation to increase permeability and production flow rate (Shafiq and Mahmud, 2017). Scale formation and chemical interactions in formation water systems have been widely studied, showing that ionic composition significantly influences precipitation behavior and reservoir performance (Kamal et al., 2018, Kan et al., 2019). Field applications have shown that chemical treatment plays an important role in controlling scaling and improving production efficiency in mature oil fields (Rini et al., 2024).

Despite the SI value being less than zero, matrix acidizing is still required due to the presence of carbonate minerals (CO_3^{2-}) within the sandstone reservoir. Carbonate minerals can partially occupy pore spaces and reduce permeability even in the absence of scale precipitation. In such conditions, hydrochloric acid (HCl) is effective in dissolving carbonate components, thereby improving pore connectivity and enhancing fluid flow (Shafiq and Mahmud, 2017, Mohammadi, 2024). Despite the SI value being less than zero, matrix acidizing is still required due to the presence of carbonate minerals (CO_3^{2-}) within the sandstone reservoir. Carbonate minerals can partially occupy pore spaces and reduce permeability even in the absence of scale precipitation. In such conditions, hydrochloric acid (HCl) is effective in dissolving carbonate components, thereby improving pore connectivity and enhancing fluid flow (Shafiq and Mahmud, 2017; Mohammadi, 2024). This condition is closely related to the thermodynamic and chemical interactions within the reservoir system, which control mineral precipitation and fluid compatibility (Haghtalab et al., 2015).

The presence of carbonate minerals in a predominantly sandstone reservoir is also significant in determining the effectiveness of acidizing treatment. While sandstone formations typically require specific acid systems to avoid secondary damage, the existence of carbonate minerals increases the reactivity of HCl, allowing more efficient mineral dissolution. This condition supports the formation of conductive flow channels and improves reservoir permeability (Maheshwari et al., 2016, Liu et al., 2017).

In addition, the ionic composition of formation water plays an important role in acid–fluid compatibility. The Hilal well formation water is characterized by high concentrations of sodium (Na^+ = 5236.16 mg/L) and chloride (Cl^- = 7810 mg/L), indicating high salinity conditions. High salinity can influence acid reaction kinetics and increase the risk of secondary precipitation during treatment. Furthermore, the presence of bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}) ions suggests active geochemical interactions that may affect acid efficiency and potentially lead to by-product formation if not properly controlled (Kan et al., 2019, Khalil et al., 2021)

Therefore, the integration of formation water analysis into acidizing design is essential to ensure treatment effectiveness. Understanding the chemical characteristics of formation water enables better evaluation of acid compatibility, optimization of treatment design, and minimization of potential formation damage during stimulation.

Solubility Test

A solubility test was conducted to evaluate the effectiveness of acid in dissolving reservoir minerals. Similar experimental studies have demonstrated that high solubility values indicate effective acid–rock interaction and improved permeability potential (Siratovich et al., 2017). The test was performed by reacting the rock sample with 15% HCl under Bottom Hole Static Temperature (BHST) conditions, followed by measurement of insoluble residue. The solubility percentage was calculated using Equation (1).

The results show (Table 7), a solubility value of 99.33%, indicating that the acid is highly effective in dissolving the target minerals and has strong potential to improve reservoir permeability (Villeneuve et al., 2017, Khalil et al., 2021)

$$S = \frac{Wtotal - Winsoluble}{Wtotal}\ x\ 100\% \qquad (1)$$

Where:
S = Solubility (solubility, in per cent)
Wtotal = Initial weight of sample (gram)
Winsoluble = Weight of the insoluble part of the sample (grams).

Table 7. Solubility results obtained using 15% HCL

Formulation	Sollubility (%)	Weight of Sample	
		Sample weight	After Soak
HCl 15%	99.33	3.00	0.02

2.3 Acidizing Matrix Planning

Determining Cracking Pressure

$$BHFP = Grf\ x\ Top\ Perforasi \qquad (2)$$

Where:
BHFP = Bottom Hole Flowing Pressure (psi)
Grf = Formation Fracture Gradient (psi/ft)
Top Perforasi = Depth of the highest perforation zone in the well (ft)

Determining Hydrostatic Pressure and Surface Pressure of Acid (HCL 15%) and Brine

$$HP = 0{,}052\ x\ \rho\ x\ L \qquad (3)$$

$$STP = BHFP - HP + FP \qquad (4)$$

Where:
HP = Hydrostatic Pressure (psi)
ρ = Density (ppg)
L = Tubing Length (ft)
STP = Surface Tubing Pressure (psi)
BHFP= Bottom Hole Flowing Pressure (psi)
HP = Hydrostatic Pressure (psi)
FP = Friction Pressure (psi)

Determining Tubing and Casing Capacity

$$CT = \frac{DT^2}{1029{,}4} \qquad (5)$$

$$CC = \frac{DC^2}{1029{,}4} \qquad (6)$$

Where:
CT = Tubing Capacity (bbl/ft)
CC = Casing Capacity (bbl/ft)
DT = Inside diameter of tubing (inch)
DT = Inside diameter of casing (inch)
1029,4 = Constant used for unit conversion

Determining Tubing and Casing Volumes

$$VT = CT\ x\ LT \qquad (7)$$

$$VC = CC\ x\ LC \qquad (8)$$

Where:
VT = Tubing Volume (bbl)
VC = Casing Volume (bbl)
CT = Tubing Capacity (bbl/ft)
CC = Casing Capacity (bbl/ft)
LT = Tubing Length (ft)
LC = Casing Length (ft)

Determining the Preflush Volume

$$V = \pi((ri + rw)^2\ x\ \emptyset\ x\ h\ x\ K \qquad (9)$$

$$Vacid/ft = V/h \qquad (10)$$

$$Preflush = 15\%\ x \frac{Vacid}{ft} x\ h \qquad (11)$$

Where:
V = Preflush Volume (gallon)
π = Constanta (≈ 3.1416)
ri = Internal radius of casing or wellbore (ft)
rw = Well or tubing radius (ft)
ϕ = Rock porosity (decimal or per cent)
h = Thickness of the injected target zone (ft)
K = Conversion factor from ft³ to gallon

Determining the Volume of Main Acid

$$V\ =\ \pi((ri + rw)^2\ x\ \emptyset\ x\ h\ x\ K \qquad (12)$$

Where:
V = Main Acid Volume (gallon)

Determining Displacement Volume

$$VD = VC + VT \qquad (13)$$

Where:
VD = Volume displacement (bbl)

3. Results and Discussion

3. 1 Acidizing Matrix Planning Results

Acidizing design parameters such as injection pressure and fluid composition play a critical role in determining treatment success (Qiu et al., 2018, Khalil et al., 2021). The results of matrix acidizing design for the Hilal well are presented in Table 8.

Table 8. Calculation results of acidizing matrix plannin

Parameter	Result
BHFP	2697.47 psi
HP Acid (HCL 15%)	1788 psi
HP Brine	1682 psi
STP (HCL 15%)	1021 psi
STP Brine	1107 psi
CT	0.00579 bbl/ft
CC	0.03826 bbl/ft
VT	2 bbl
VC	4 bbl
Preflush Volume	7.77 bbl
Main Acid Volume	50.9 bbl
Displacement Volume	26 bbl

The calculated Bottom Hole Fracture Pressure (BHFP) of 2697.47 psi indicates that the planned injection pressure remains below the fracture limit, ensuring that the treatment is performed under matrix conditions without inducing formation fracturing.

The calculated hydrostatic pressure and surface treating pressure (STP) for both acid and brine fluids demonstrate that the injection design is within safe operational limits. This condition is essential to maintain controlled acid placement and avoid unwanted formation damage.

The designed volumes, including preflush (7.77 bbl), main acid (50.9 bbl), and displacement (26 bbl), indicate a balanced treatment strategy. The preflush stage plays a crucial role in conditioning the formation and preventing secondary reactions, while the main acid volume is sufficient to dissolve carbonate minerals within the pore space. Similar findings were reported by Osuala et al. (2022), where optimized preflush and acid volume significantly improved stimulation effectiveness.

3. 2 Injectivity Rate Test

The Injectivity Rate Test results **(Table 9)** show a gradual increase in injection pressure with increasing injection rate, indicating stable formation behavior without signs of premature fracturing. At the maximum injection rate of 1 bpm, the pressure reached 1150 psi, which is still below the calculated fracture pressure.

This behavior suggests that the reservoir has good injectivity characteristics and can accommodate acid injection effectively. According to (Bonafé et al., 2020), a stable pressure–rate relationship indicates favorable reservoir conditions for matrix acidizing, as it ensures uniform acid distribution and minimizes the risk of channeling or localized damage.

Table 9. Result Injectivity Rate Test Hilal Well

Rate (bpm)	Press (psi)	Vol Cum (bbl)
0.2	600	13
0.4	700	
0.6	900	
0.8	1000	
1	1150	

3. 3 Acidizing Treatment Implementation

Preflush

The preflush stage utilized 336 gallons of fluid to condition the formation and reduce the risk of undesirable chemical reactions. The use of KCl and mutual solvent helps stabilize clay minerals and improve fluid compatibility. This is consistent with previous studies, which highlight that proper preflush design is essential to prevent precipitation and enhance acid effectiveness (Gomaa et al., 2015, Osuala et al., 2022).

Table 10. Hilal Well Preflush Composition

No	Additive	Volume
1	Fresh Water	318 gall
2	2% KCl	56 lbs
3	Mutual Solvent	17 gall
4	Noionic Surfactant	1 gall

Main Acid

The main acid injection of 2100 gallons plays a key role in dissolving carbonate minerals within the sandstone formation. The presence of carbonate components enhances the reactivity of hydrochloric acid, leading to improved pore connectivity. This dissolution process contributes to the formation of conductive flow channels, which significantly improves permeability and fluid flow (Maheshwari et al., 2016, Liu et al., 2017).

Table 11. Hilal Well Main Acid Composition

No	Additive	Volume
1	Fresh Water	1035 gall
2	Corrosion Inhibitor	55 gall
3	Corrosion inhibitor Acid	-
4	Iron Control	63 gall
5	Mutual Solvent	95 gall
6	Noionic Surfactant	4 gall
7	Hydrochloric Acid	911 gall

Displacement

The displacement stage ensures that the reacted acid is pushed deeper into the formation and prevents acid residues from remaining near the wellbore. This process improves the effectiveness of the treatment by maximizing the contact between acid and formation minerals. Previous studies have shown that proper displacement is essential to avoid secondary damage and ensure optimal stimulation results (Muhammad, 2020).

Table 12. Hilal Well Displacement Composition

Additive	Volume
Formation Water	26 bbl

3. 4 Mechanism of Productivity Improvement

The increase in productivity observed after matrix acidizing is primarily attributed to the dissolution of carbonate minerals and removal of pore-blocking materials. This process enhances pore connectivity and reduces flow resistance, allowing hydrocarbons to flow more efficiently toward the wellbore.

In addition, acid–rock interaction may lead to the formation of conductive channels within the formation, improving permeability distribution. This mechanism is consistent with the concept of wormhole formation in reactive acid systems, which has been widely reported in previous studies (Maheshwari et al., 2016, Liu et al., 2017).

Furthermore, the compatibility between injected acid and formation water plays a critical role in determining treatment success. Proper fluid design minimizes the risk of secondary precipitation, ensuring that permeability improvement is sustained after treatment (Khalil et al., 2021).

The observed improvement in well performance, including the increase in Productivity Index (PI), is consistent with previous studies on matrix acidizing. For instance, Talib et al. (2024) reported significant productivity enhancement in carbonate-rich formations following acidizing treatment. Similarly, Ifeanyi et al. (2015) demonstrated that matrix acidizing can effectively improve permeability and production rate in sandstone reservoirs.

Compared to these studies, the Hilal well shows a relatively high improvement in productivity, indicating that the presence of carbonate minerals within the sandstone formation contributes positively to acid reactivity and treatment effectiveness. Optimization approaches in reservoir stimulation have been developed to improve treatment efficiency and predict performance more accurately (Lai et al., 2022).

3.6 Limitations and Uncertainty

Despite the significant improvement in production performance, this study is limited to short-term evaluation after acidizing treatment. The long-term effectiveness of the stimulation may be influenced by factors such as re-precipitation, fines migration, and reservoir heterogeneity.

In addition, the analysis is based on available field data and simplified modeling assumptions, which may introduce uncertainties in predicting reservoir behavior. Therefore, further monitoring and long-term evaluation are recommended to assess the sustainability of the acidizing treatment.

3. 7 Inflow Performance Relationship (IPR) of Hilal Well

The Inflow Performance Relationship (IPR) model was used to evaluate the relationship between bottom hole flowing pressure (Pwf) and production rate before and after matrix acidizing treatment. Production performance analysis is commonly evaluated using decline curve and IPR models to assess reservoir deliverability (Jongkittinarukorn et al., 2020). Various IPR models have been developed to better represent well performance under different flow conditions, including dimensionless approaches for improved accuracy (Kalantariasl et al., 2022). The empirical equations (14)–(23) were applied to calculate oil rate (qo), water rate (qw), and total fluid rate (qt) as a function of pressure and water cut (WC). These equations incorporate reservoir fluid behavior and multiphase flow characteristics to estimate well performance under varying operating conditions.

In this study, parameters P1 and P2 were used to represent the effect of water cut on fluid flow behavior, while constants A0, A1, and A2 were employed to approximate the IPR curve under multiphase conditions. The parameter qtmax represents the maximum production capacity of the well when Pwf approaches zero, which is an important indicator of reservoir deliverability.

IPR Before Matrix Acidizing Treatment

The results presented **in Table 13 and Fig. 3** show that prior to acidizing, the well exhibited limited production capacity, with a relatively low oil rate and high water production. The IPR curve before treatment has a relatively gentle slope, indicating high flow resistance within the formation.

This behavior suggests that the reservoir experienced permeability reduction due to pore-blocking materials, which restricted fluid flow toward the wellbore. As a result, the well required higher pressure drawdown to produce fluids, indicating inefficient reservoir performance.

Calculation of P1 and P2

$$P1 = 1{,}606207 - 0{,}130447 \ln(WC) \quad (14)$$

$$P2 = 0{,}51792 - 0{,}110604 \ln(WC) \quad (15)$$

Calculation WC @Pwf =Pr

$$WC@Pwf = \mathrm{Pr} = \frac{WC}{P1\ x\ e^{(P2^{(P2\frac{Pwf}{Pr}))}}} \quad (16)$$

Calculation of Constants A0, A1, and A2

$$A0 = 0{,}980321 + (-0{,}115661\ x\ 10^{-1})(WC) + (0{,}17905\ x\ 10^{-4}\ (WC)^2 \quad (17)$$

$$A1 = -0{,}414360 + (0{,}32799\ x\ 10^{-2})(WC) + (0{,}237075\ x\ 10^{-5}\ (WC)^2 \quad (18)$$

$$A2 = -0{,}564870 + (0{,}762080\ x\ 10^{-2})(WC) - (0{,}202079\ x\ 10^{-4}\ (WC)^2 \quad (19)$$

Calculation of qtmax Constant

$$qt\ max = \frac{q0}{A0+(A1)\left(\frac{Pwf}{pr}\right)+(A2)(\frac{Pwf^2}{Pr})} \quad (20)$$

Calculation of qo for various assumed Pwf prices

$$q0 = qtmax\ x\ (A0 + (A1)\left(\frac{Pwf}{Pr}\right) + (A2)(\frac{Pwf^2}{Pr}) \quad (21)$$

Calculation of qw at each assumed Pwf price

$$qw = (\frac{WC}{(100-WC)}\ x\ q0) \quad (22)$$

Calculation of qt at each assumed Pwf price

$$qt = q0 + qw \quad (23)$$

The overall results of the Hilal well calculation before matrix acidizing are as follows:

Table 13. Hilal Well Calculation Result before Acidizing

Pwf (psi)	qo (bopd)	qw (bwpd)	qt (bfpd)
0	50,06938	1204,802	1254,872
100	47,92066	1153,098	1201,019
200	45,34179	1091,044	1136,386
300	42,33277	1018,639	1060,972
400	38,89359	935,883	974,7768
500	35,02427	842,777	877,8012
600	30,72479	739,320	770,0449
952	12,38	297,896	310,2757
1000	9,2	221,987	231,2122
1140	0	0	0

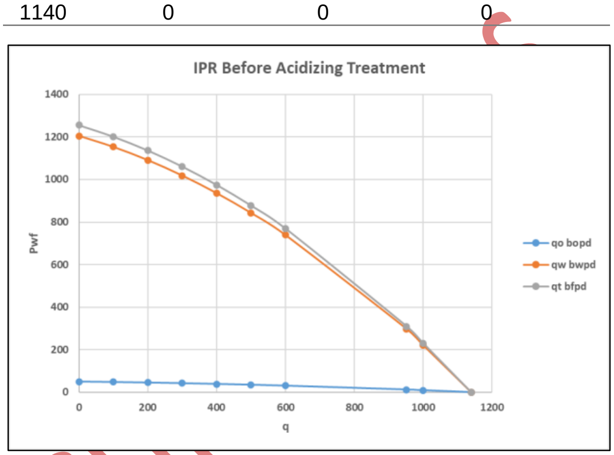

Fig 3. IPR Before Acidizing Treatment

IPR After Matrix Acidizing Treatment

After matrix acidizing treatment, the results in Table 14 and Fig. 4 show a significant improvement in well performance. The IPR curve becomes steeper compared to the pre-treatment condition, indicating increased reservoir deliverability and reduced flow resistance.

The increase in production rate at similar Pwf conditions demonstrates that the formation permeability has improved. This improvement is attributed to the dissolution of carbonate minerals and removal of pore-blocking materials, which enhances pore connectivity and facilitates fluid flow.

Furthermore, the increase in qtmax after acidizing indicates that the well has a higher maximum production potential. This behavior is consistent with previous studies that show matrix acidizing can significantly enhance permeability and well productivity by improving fluid flow pathways (Ifeanyi et al., 2015, Talib et al., 2024).

Using equations (14) to (23), the following parameters were calculated after matrix acidizing treatment:

Table 14. Hilal Well Calculation Result after Acidizing

Pwf (psi)	qo (bopd)	qw (bwpd)	qt (bfpd)
0	101,0053	2475,66	2576,665
100	96,86728	2374,237	2471,104
200	91,92475	2253,094	2345,019
300	86,17769	2112,233	2198,41
400	79,62609	1951,652	2031,278
500	72,26996	1771,351	1843,621
700	55,14409	1351,593	1406,737
990	25	612,7551	637,7551
1000	23,42127	574,0601	597,4814
1185	0	0	0

The comparison between Fig. 3 and Fig. 4 clearly illustrates a shift in the IPR curve toward higher production rates after acidizing treatment. This shift indicates a reduction in skin factor and improved reservoir conductivity. The steeper slope of the post-acidizing curve confirms that less pressure drawdown is required to achieve higher production rates, which reflects improved efficiency of fluid flow toward the wellbore.

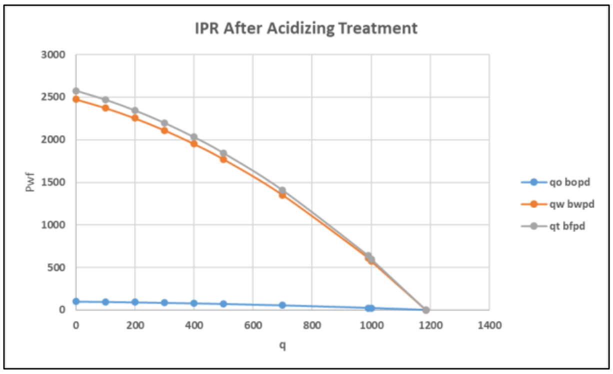

Fig 4. IPR After Acidizing Treatment

3. 5 Productivity Index (PI)

The Productivity Index (PI) was calculated using Equation (24) to quantify the improvement in well performance after acidizing. The results show a significant increase in PI from 1.62 bbl/psi to 3.15 bbl/psi, indicating enhanced formation productivity.

This increase in PI reflects a substantial improvement in reservoir permeability and fluid mobility. From a physical perspective, the higher PI value indicates that the well can produce more fluid for the same pressure drawdown, which confirms the effectiveness of the acidizing treatment.

The observed improvement is consistent with previous studies, where matrix acidizing significantly increased PI due to enhanced pore connectivity and reduced formation damage (Ifeanyi et al., 2015; Talib et al., 2024). Compared to these studies, the Hilal well shows a relatively high improvement, which may be attributed to the presence of carbonate minerals that are highly reactive to acid treatment.

$$PI = \frac{q}{Ps - Pwf} \qquad (24)$$

Where:
PI = Productivity Index (bbl/psi)
q = Flow Rate/Production Rate (bopd)
Ps = Static Reservoir Pressure (psi)
Pwf = Bottom Hole Flowing Pressure (psi)
Using equation (24) the result is obtained:

Table 15. Hilal Well PI Calculation Result

Productivity Indeks (bbl/psi)	
Before Acidizing	After Acidizing
1,62 bbl/psi	3,15 bbl/psi

3. 6 Evaluation of Success

The overall success of the acidizing treatment is reflected not only in the numerical increase in production rate but also in the improvement of reservoir flow characteristics. The percentage increase in oil production confirms the effectiveness of the treatment; however, the key indicator of success lies in the improved reservoir deliverability and reduced flow resistance, as evidenced by the IPR and PI analysis.

$$percentage\ of\ success\ (\%) = \frac{qbefore - qafter}{qbefore}\ x\ 100\% \qquad (25)$$

4. Conclusion

This study demonstrates that matrix acidizing is effective in improving the productivity of the Hilal well by enhancing reservoir permeability and fluid flow capacity. The treatment successfully reduced flow resistance near the wellbore, leading to improved reservoir deliverability as reflected in the IPR and Productivity Index (PI) analysis.

A key contribution of this study lies in the integration of formation water analysis into the evaluation of acidizing effectiveness. The results show that even in the absence of scale formation (SI < 0), the presence of carbonate minerals and specific ionic composition can significantly influence acid–rock interaction and stimulation performance. This finding highlights that formation water parameters should be considered as an essential factor in designing and evaluating acidizing treatments.

From a practical perspective, the results suggest that acidizing design in sandstone reservoirs containing carbonate minerals should incorporate detailed formation water characterization to optimize acid selection, minimize compatibility issues, and improve treatment efficiency. Proper integration of chemical analysis and stimulation design can reduce the risk of secondary damage and enhance overall reservoir performance.

However, this study is limited to short-term evaluation of production performance. Further studies are recommended to assess the long-term sustainability of the treatment, particularly regarding potential re-precipitation and reservoir heterogeneity effects.

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