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Improving Acidizing Treatment in Khalda Oil Fields

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ABSTRACT

This field case study focuses on the enhancement of acidizing efficiency in the Alamein-Dolomite reservoir (Western Desert, Egypt) using plain (regular) HCl. The impact of various design parameters and conditions on stimulation efficiency is analyzed using a commercial design simulator (StimCADE), focusing on factors such as acid concentration, injection rate, and dosage. Additionally, an artificial neural network (ANN) is developed from the simulation results and successfully forecasts the productivity index (PI) with a high accuracy. Key findings indicate that optimal acidizing occurs within the temperature range of 200°F to 220°F, with minimal impact above 220°F. A 20% acid concentration is effective across a wide temperature range (200°F–300°F). For maximum skin factor reduction, a 15% concentration with maximum acid dosage is recommended, though cost-effectiveness must be considered. The optimal acid injection rates are 0.5 bpm for concentrations up to 15%, 1.0 bpm for 20%, and 1.5 bpm for 28%. For acid dosages above 200 gal/ft, a rate exceeding 0.5 bpm is beneficial. These findings provide guidelines for the design and implementation of acidizing treatments in oil fields, improving their efficiency and maximizing well productivity for dolomite reservoirs.

KEYWORDS: matrix acidizing; dolomite reservoir; plain HCl; guidelines

تحسين كفاءة عمليات المعالجة بالحامض في حقول شركة خالدة

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الملخص

تهدف هذه الدراسة الميدانية إلى تحسين كفاءة عمليات الحامض في خزان العلمين-دولوميت (بالصحراء الغربية في مصر) باستخدام حمض الهيدروكلوريك العادي. وقد تم دراسة تأثير العوامل والظروف المختلفة على كفاءة تلك العمليات باستخدام محاكي تجاري، مع التركيز على عوامل رئيسية مثل تركيز الحمض المستعمل، ومعدل الحقن، والجرعة. أيضا, تم تطوير نموذج شبكي عصبي أصطناعي إستنادًا إلى النتائج، وقد أظهر دقة عالية في التنبؤ بمؤشر الإنتاج (PI). تشير النتائج الرئيسية إلى أن عمليات الحامض تكون أكثر فعالية ضمن نطاق درجات حرارة للخزان من (٢٠٠°ف إلى ٢٢٠°ف)، مع تأثير محدود لدرجات الحرارة فوق ٢٢٠°ف. كما أظهرت النتائج أن إستعمال تركيز حمض بنسبة ٢٠٪ يكون فعال ضمن نطاق واسع من درجات الحرارة (٢٠٠°ف–٣٠٠°ف). وللحصول على أقل قيمة لعامل التضرر للطبقة (s) ، يُوصى باستخدام تركيز ١٥٪ مع الجرعة القصوى من الحمض، مع مراعاة الجدوى الاقتصادية. أما بالنسبة لمعدل حقن الحامض، فقد أظهرت النتائج أن أقل معدل فعال لحقن الحامض هو (٠,٥ برميل/دقيقة) للتركيزات حتى ١٥٪، و(١,٠ برميل/دقيقة) لتركيز ٢٠٪، و(١,٥ برميل/دقيقة) لتركيز ٢٨٪. وبالنسبة لجرعات الحمض التي تتجاوز ٢٠٠ جالون/قدم، فإن الدراسة توصي بأن يكون حقن الحمض بمعدل أكبر من (٠,٥ برميل/دقيقة). توفر مثل هذه النتائج إرشادات لتصميم وتنفيذ عمليات المعالجة بالحامض في حقول النفط، مما يحسن كفاءتها ويزيد من إنتاجية الآبار في خزنات الدولوميت.

الكلمات المفتاحية : المعالجة بالحامض، خزان الدولوميت، حمض الهيدروكلوريك العادي، إرشادات توجيهية.

1. INTRODUCTION

Acid Stimulation or Acidizing Treatment is one of the most effective stimulation techniques that has been used to minimize the skin effect caused by most forms of damage. In addition, that technique is the oldest stimulation technique, which has been in use since the 1920s [1, 2].

Matrix acidizing is a technique that can be applied in both carbonate and sandstone formations when near-wellbore damage is present. It aims to greatly increase a well's productivity by pumping reactive acidic fluid into the rock matrix at a pressure that is lower than the fracture pressure of the formation to dissolve or eliminate formation damage, enhance permeability, and optimize fluid flow. In carbonate formations, matrix acidizing works by dissolving the matrix itself and forming conductivity channels, called wormholes. These extend and penetrate beyond the near-wellbore zone to bypass the damage. On the contrary, the purpose in sandstones is to dissolve damaging materials and acid-soluble minerals plugging the pore network and thereby restore the permeability [1, 3, 4].

The most often used acids are hydrochloric acid (HCl), which is mostly used to dissolve carbonate minerals, and hydrochloric acid and hydrofluoric acid (HF) mixtures, known as mud acid, which are often used to dissolve silicate minerals in sandstone formations like clays and feldspars. In special cases, like high-temperature wells, other acids, especially some weak organic acids, are utilized. In all cases, the treating acid reacts within a foot or two of the wellbore in sandstone formations and within a few inches to possibly ten feet in carbonates [1, 4].

The acidizing process has a variety of controls that depend on the presence or absence of materials, the acid type, injection parameters, and reservoir conditions. This is because acidizing is essentially a chemical reaction rather than an applied- force process like hydraulic fracturing. Finally, acidizing chemistry must consider all materials, parameters, and conditions that affect the acid-minerals reaction [5, 6].

1.1. Matrix Acidizing

The fundamental principle of acid stimulation is based on the chemical reaction between the acid and the rock minerals. Once the treated acid comes in contact with the reservoir rock, the acid has a chemical reaction with specific minerals found in the formation, mostly carbonates and selected silicates, resulting in their dissolution and the subsequent creation of new channels or pathways inside the rock. This acid dissolution process is used to eliminate several forms of formation damage, including drilling mud particles, scale deposits, and other precipitates that restrict fluid movement by obstructing the pore spaces and ultimately lead to an increase in the rock's permeability [1, 4, 7].

In contrast to sandstone acidizing, which aims to overcome formation damage, carbonate stimulation develops enough productivity enhancement to make it a most desirable treatment even in the absence of formation damage. For this reason, the majority of carbonate reservoirs are acid-stimulated. In addition to the low cost and simplicity of their treatments [8, 9].

1.2. Carbonate Acidizing

Limestone ($CaCO_3$) and dolomite ($CaMg(CO3)_2$) are the two most popular minerals in the carbonate rocks. For carbonate acidizing, hydrochloric acid (HCl) is the best choice as a treated fluid. It is available in large quantities at a relatively low cost, and it also reacts with carbonate minerals easily. Even with the simplified chemistry, carbonate acidizing with HCl is a difficult process to model. The reason for this is that the reactions occur at a high rate as compared with that of HF reacting with the various sandstone minerals [1, 3, 10].

1.3. Acid Types used for Carbonate Acidizing

Several factors must be considered in the process of choosing an adequate treated acid, for instance, temperature, pressure, formation permeability, and acid/oil compatibility. The most common acid used in carbonate matrix acidizing is hydrochloric acid (HCl) because of its intense dissolution reactions with calcite and dolomite, low cost, easy inhibition over a wide range of reservoir conditions, and variety of acid strengths [3, 11, 12]. Weak acids or organic acids (i.e., formic acid and acetic acid) are suggested for various acid treatments of carbonates, typically when low corrosive and lower reaction rates are recommended. Compared to HCl, organic acids react more slowly. In addition, organic acids are less corrosive and have a smaller impact on the environment compared to mineral acids, so they are used instead of HCl mainly at high reservoir temperatures to provide efficient protection against corrosion [10, 12].

1.4. Wormhole Formation

Carbonate acidizing is a process that aims to dissolve the matrix minerals around the damage and develop new permeability, during this process the surface reaction rates are very high, so mass transfer often limits the overall reaction rate, resulting in irregular dissolution patterns of a few large channels (conductive pathways), often known as wormholes, as shown in **Fig. 1** [1, 9].

The development of wormholes plays a significant role in acid stimulation, especially in carbonate reservoirs. These wormholes act as preferred flow paths for fluids, providing better communication between the reservoir and the wellbore. The optimization of acid treatments and the improvement of fluid flow efficiency requires the maximization of wormhole length [13, 14].

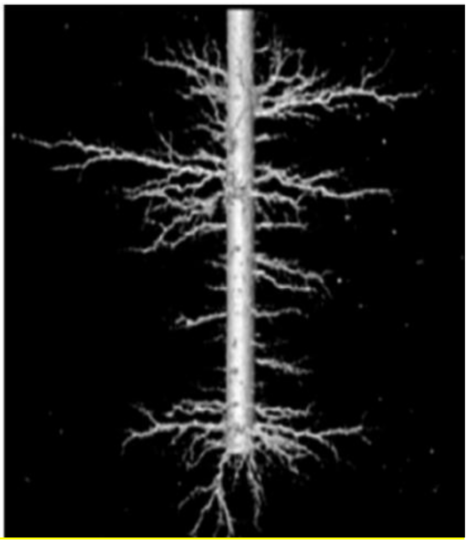

Fig. 1: Wormholes created in a large experiment in the dissolution of limestone by HCl [9].

2. METHOD AND WORK PROCEDURE

2.1. Scope of Work

The research is a case study aimed at evaluating and enhancing the efficiency of acidizing treatment in the Alamein-Dolomite carbonate reservoir (Western Desert, Egypt). The scope of this work is to essentially conduct a comprehensive sensitivity analysis with different combinations of reservoir conditions and operational parameters to deeply understand the relationships between the various design parameters in matrix acidizing and to enhance stimulation efficiency. The objective of this work is to determine the optimal acid type and concentration, acid injection rate, and acid volume for given reservoir conditions to effectively design carbonate acidizing treatments. In other words, guidelines for design specifications are established to select the optimal parameters that lead to a successful acidizing job.

The primary tool used in this study is the matrix acidizing simulator 'StimCADE,' which is employed to analyze the effects of key factors (variables) on the acidizing efficiency. This simulator is capable of modeling carbonate reservoir acidizing treatments, addressing all aspects of stimulation and predicting skin evolution following the proposed treatment.

Additionally, an Artificial Neural Network (ANN) model is developed based on simulation results to predict the productivity index (PI) after acidizing. A feed-forward ANN with backpropagation training is trained using over 300 simulation runs (simulated PI values), with 70% of the data used for training to minimize mean square error (MSE) and 30% for testing and validation to ensure model accuracy.

2.2. Reservoir Description and Well Data

This study focuses on the carbonate reservoirs, in particular the Alamein-Dolomite reservoir, one of the major producing reservoirs in Egypt's Western Desert. This reservoir mainly consists of dolomite mineral. The X-D field was discovered in 2019 by Khalda Petroleum Co. in the north of the Western Desert. Many wells in this field are producing from Alamein-Dolomite formation. **Fig. 2** shows the location map of this field.

Fig. 2: X-D field location map.

Well (XD-05) is candidate for this study. **Table 1** illustrates the complete well data and reservoir properties that will be used to be the simulator input data set for the base case of the present study and for other next sensitivity runs.

Table 1: Well data and reservoir properties of the base case.

Well Type	**Vertical**
Reservoir Type	Carbonate/ Dolomite
Interval	(9660-9690) 30 ft
Formation	Alamein-Dolomite
Wellbore Dim.	8 ½”
Prod. CSG size	7”
Packer Status	7” PKR @ 9440 ft
Wellbore radius (r_w)	0.354 ft
Net Pay Thickness (h)	30 ft
Porosity (Ø)	10%
Initial Water Saturation (S_w)	20%
Permeability (k)	135 md
Fracture Gradient	0.65 psi/ft
Reservoir Temperature	250 °F
Average Reservoir Pressure	2400 psi
Bubble Point Pressure	126 psi
GOR (gas oil ratio)	18 scf/stb
Water Gravity	1.01
Salinity	180,000 ppm
Oil API	35°
Drainage Area	60 acres
Drainage Radius (r_e)	912 ft
Oil formation volume factor (β_0)	1.1 RB/STB
Oil viscosity (μ_0)	0.817 cp
Initial Skin Factor (s)	+20
Initial Productivity index (PI)	1.1 BPD/psi

2.3. Work Procedure

Operational data collected from the field, including reservoir properties and acid job parameters, form the basis of this case study, which primarily examines the effect of using plain (regular) HCl, the main treating fluid in this study, on the stimulation results. Thus, the base case is represented by a conventional acidizing job performed using 15% plain HCl, repeated multiple times in the field. Both the base case and sensitivity runs cover all relevant acidizing design parameters, including operational job parameters such as acid concentration, acid injection rate, and acid volume, along with reservoir properties like reservoir temperature, matrix porosity, and damage penetration depth. Multiple scenarios (cases) are generated by combining these parameters to effectively design the acidizing jobs, allowing for the determination of the optimum job parameters through further analysis.

Two groups of studying parameters are listed below:

1) Operational Job Parameters
   - HCl acid concentration
   - Acid dosage (acid job volume)
   - Acid injection rate
2) Reservoir Properties
   - Reservoir temperature
   - Matrix porosity
   - Damage penetration depth

3. RESULTS AND DISCUSSION

3.1. Base Case Description

Utilizing data collected from the field, the base case describes an acid stimulation job conducted using plain HCl to stimulate the Alamein-Dolomite reservoir. The operational parameters for this stimulation job include 15% plain HCl with an acid dosage of 100 gal/ft (acid gallons used per foot of reservoir height) and an injection rate of 1.0 bpm (barrel per minute) through the subject reservoir. A complete sensitivity analysis was performed over a pre-defined input data range for each parameter. The HCl acid concentration is changed from 5% to 28%, the acid job volume (acid dosage) is changed from 50 to 400 gal/ft, the injection rate is changed from 0.5 to 2.5 bpm, the reservoir porosity is adjusted from 7 to 14%, and the damage penetration depth is changed from 3 to 24 inches with the combination of varying the reservoir temperature from 200°F to 300°F.

Table 2 summarizes all software runs, including simulation input data and the results. The base case input values are shown in the top row. For the rest of the cases reported, the design variables are changed over the pre-defined range while keeping the values of the remaining variables in the base case. A blank cell indicates that the base case value remains in effect. The output data represented by the skin factor (s) and productivity index (PI) are recorded in the last two columns. The values of the skin factor are obtained from the simulator. For vertical well, the following equation is used to compute the productivity index (PI) [1]:

$$\mathrm{PI} = \frac{kh}{141.2\ \mu_0 \beta_0 [\ln\frac{r_e}{r_w} + s]} \qquad \text{Eq. (1)}$$

The calculated PI measured by BPD/psi (barrel/day/psi) and the required input data for the productivity index calculation were presented in **Table 1.**

Table 2: Simulation input data and results.

Parameters	Res. Temp. °F	Acid Type	Acid Conc. %	Acid dosage (gal/ft)	Inj. Rate bpm	Porosity %	Damage Depth (inch)	Skin Factor	PI BPD/psi
Base-Case	250	Plain HCl	15	100	1.0	10	6	-1.67	5.32
Effect of Reservoir Temperature	200							-1.27	5.00
	210							-1.54	5.21
	220							-1.64	5.30
	230							-1.66	5.31
	270							-1.69	5.34
	300							-1.71	5.35
Effect of Acid Concentration			5					-0.82	4.68
			10					-1.41	5.10
			15					-1.67	5.32
			20					-1.96	5.58
			28					-1.35	5.06
Effect of Acid Dosage				50				-1.30	5.02
				100				-1.67	5.32
				200				-2.05	5.67
				300				-2.20	5.82
				400				-2.32	5.94
Effect of Acid Injection Rate					0.5			-1.75	5.39
					1.0			-1.67	5.32
					1.5			-1.60	5.27
					2.0			-1.56	5.23
					2.5			-1.53	5.21
Effect of Reservoir Porosity						7		-1.60	5.26
						10		-1.67	5.32
						12		-1.70	5.35
						14		-1.75	5.39
Effect of Damage Penetration Depth							3	-1.67	5.32
							6	-1.67	5.32
							12	-1.47	5.15
							18	-1.19	4.94
							24	-1.00	4.80

3.1.1. Base case results and analysis

The top row of **Table 2** shows the output values (i.e., skin factor and PI) for the base case, which illustrate how the base case effectively improved the productivity index (PI) approximately 5-fold, resulting in a higher production rate. This improvement in the productivity index is primarily due to the reduction in the skin factor. The stimulation efficiency of this base case is sufficient to reduce the initial skin factor from +20 to a negative value of -1.67 after the acid treatment.

3.1.2. The effect of reservoir temperature

Evaluating the relationship between reservoir temperature and skin factor is necessary to improve stimulation efficiency. **Fig. 3** shows the relationship between the reservoir temperature and the skin factor. This figure illustrates that the skin factor decreases (improved) as reservoir temperature increases. Between 200°F and 220°F, there is a sharp reduction in the skin factor, which indicates that acidizing is significantly effective in this temperature range. Beyond 220°F, the decrease in skin factor becomes gradual, which reflects the modest effect of the reservoir temperature on the skin factor in this temperature range.

At moderately higher temperatures, the improvement in the skin factor with temperature indicates that higher temperatures enhance the reactivity between the acid and dolomite, leading to a better acid dissolution and removal of near-wellbore damage [1]. However, above 220°F suggests diminishing returns in acidizing efficiency with further temperature increases, likely due to rapid acid spending and consequently limited acid penetration depth due to high reaction rates, which may limit the acidizing process. While the high temperature of the reservoir causes a rapid reaction rate of acid fluid with the rock, the treated acid cannot penetrate deep into the formation and form an efficient network of wormholes [11, 15].

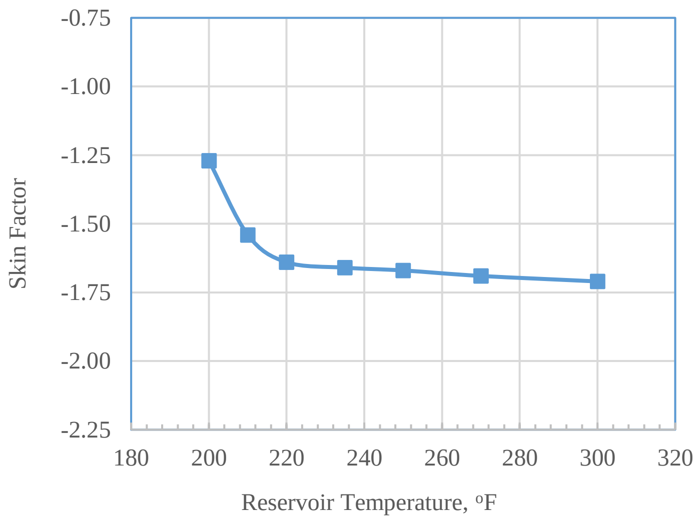

Fig. 3: Skin factor versus reservoir temperature for plain HCl.

3.1.3. The effect of HCl acid concentration

For the present field case, the relationship between the HCl concentration and the skin factor is examined and the results are shown in **Fig. 4**, which illustrates that the skin factor is reduced with increasing HCl acid concentration up to a value of 20%, which is a minimum skin. When increasing acid concentration above 20% (specifically at 28%), the skin factor increases back again (impairing). Increasing the acid concentration in high-temperature wells will extremely accelerate the acid reaction rate, which consequently diminishes the extension of live acid penetration into the matrix and minimizes the wormhole length by developing an inefficient pattern. In more detail, the reduction of live acid penetration creates a wormhole network that is denser and wider but isn't deep enough into the matrix to bypass any damage and, often, significantly affects the final skin [13, 16].

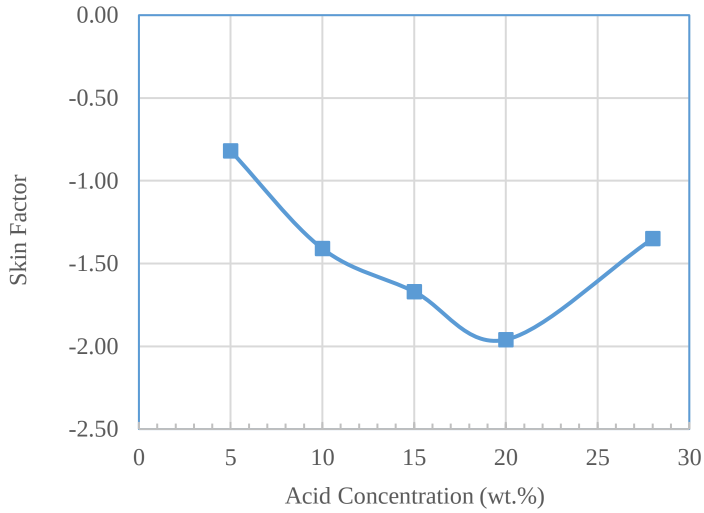

Fig. 4: Skin factor versus plain HCl concentration.

3.1.4. The effect of acid dosage (acid volume)

Total acid job volume is expressed as "acid dosage," where a number of acid gallons is used per every foot of reservoir height (gal/ft). **Fig. 5** shows the relationship between the acid dosage and the skin factor. The figure demonstrates that there is an inverse proportion between the acid dosage and skin factor. In other words, as the acid dosage increases, the skin factor decreases.

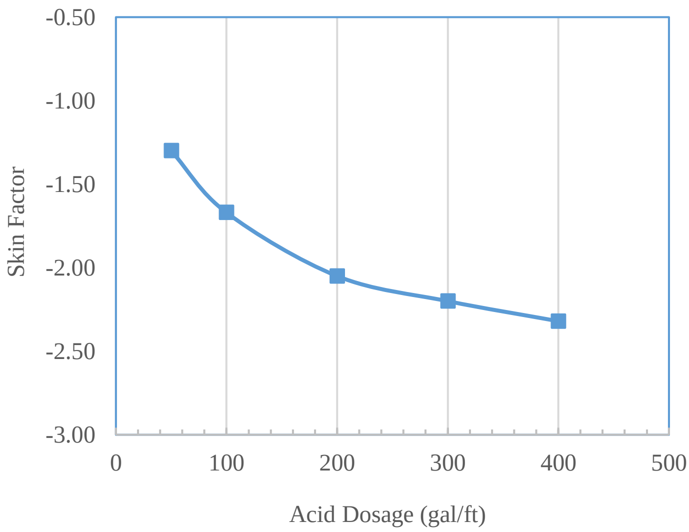

Fig. 5: Skin factor versus plain HCl acid dosage.

The dissolving power of the HCl is the property that directly affects the trends seen in **Fig. 5**. The dissolving power of an acid expresses the amount of formation minerals that can be dissolved (consumed) per unit volume of acid. As the acid dosage increases, the dissolution reaction increases to creating larger wormholes or deep pathways into the formation that may explain why increasing acid dosage reduces the skin factor [1, 17]. Ultimately, optimizing acid dosage (volume) is critical to balancing cost and effectiveness

3.1.5. The effect of acid injection rate

Fig. 6 displays the relationship between the acid injection rate and the skin factor, which illustrates that the skin factor is slightly increased (impaired) with increasing acid injection rate. The most improved skin is achieved at the lowest injection rate.

McLeod, one of the researchers, sees that a relatively low injection rate may be preferable for dolomites. This allows the temperature of the treated acid invading the formation to rise, and thus, the reaction rate increases [18, 19]. McLeod's recommendation supports our conclusion, which suggests that the most improved skin is achieved at the lowest injection rate, particularly since our field case research is focused on the stimulation of the dolomite reservoirs.

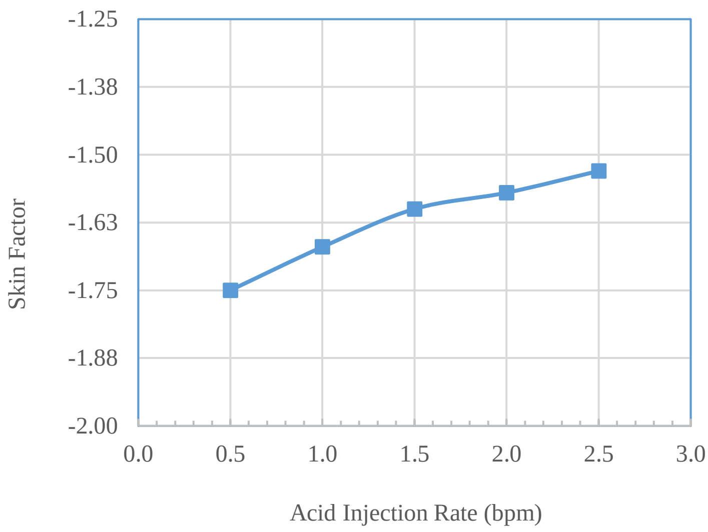

Fig. 6: Skin factor versus acid injection rate (plain HCl).

3.1.6. The effect of reservoir porosity

The effect of the reservoir porosity on the skin factor is studied by changing the reservoir porosity over the range of 7% to 14% (compared to 10% for the base case). These values of the reservoir porosity are selected based on data collected from the field. **Fig. 7** shows how increasing the reservoir porosity slightly lowers the value of the skin factor. In other words, the final skin is slightly improved with an increase in reservoir porosity. Wormhole penetration distance in matrix acidizing is controlled by many factors such as reservoir porosity, permeability contrast, and acid volume. Reservoirs with lower porosity have fewer interconnected pores. This leads to higher flow resistance for acid fluid and a higher skin factor. While porosity increases, the interconnected pores network improves, which naturally reduces the flow resistance, extending wormholes deeper and lowers the skin factor [20].

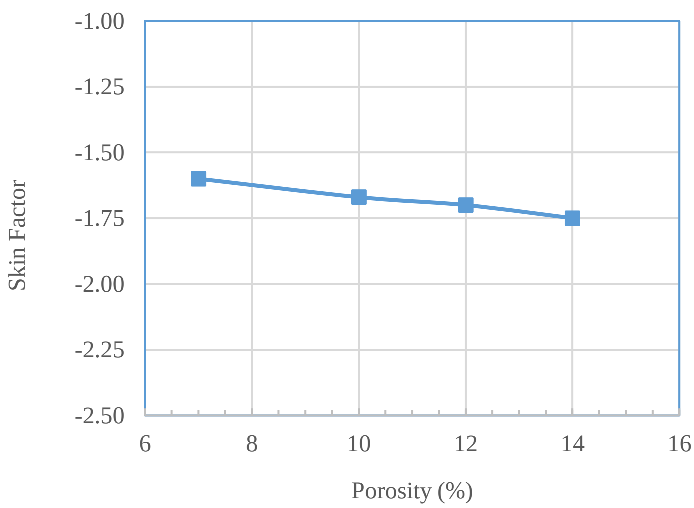

Fig. 7: Skin factor versus reservoir porosity (plain HCl).

3.1.7. The effect of damage penetration depth

Damage penetration is the distance of invasion of damage materials, such as drilling or workover fluids, behind the wellbore in the reservoir matrix, measured in inches. The objective of this section is to determine how the damage penetration depth affects the value of skin factor. **Fig. 8** shows that as the damage penetration depth increases, the skin factor is increased (worsened) and that the effect of damage penetration on the skin factor is negligible for damage depths up to 6 inches.

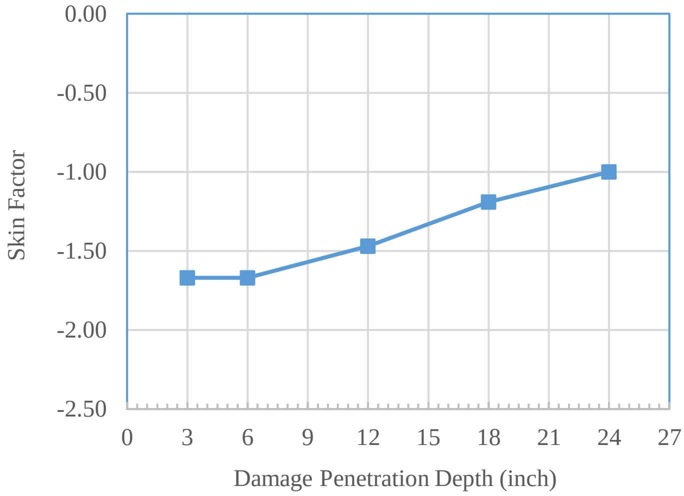

Fig. 8: Skin factor versus damage penetration depth (plain HCl).

The damage acts as a barrier to fluid flow, and the deeper the damage, the more significant is the resistance to flow near the wellbore, which results in reduced well productivity. In addition to that, the deeper damage reduces the effectiveness of acidizing in improving permeability and requires higher acid volumes to effectively stimulate the formation. For deeply damaged zones, acid volume, reactivity, and placement techniques become limiting factors to improve the acidizing efficiency [4].

3.2. Combinations of the design Parameters affecting the skin Behavior

Based on the previous results, five key factors—reservoir temperature, HCl acid concentration, acid dosage (volume), acid injection rate, and damage penetration depth—have been identified as significantly impacting the skin factor value. In the next phase of the study, investigating the relationships between these parameters is crucial for optimizing the stimulation efficiency. The following discussions explore how different combinations of these key parameters influence the behavior of the skin factor. By analyzing these combinations, additional cases are generated to optimize the design of acidizing jobs and determine the most effective operational parameters.

3.2.1. Factors affecting the skin factor at different HCl acid concentrations

The value of the acid concentration is the most important variable that correlates with the other operational parameters. Thus, the next section determines how the other effective parameters affect the relationship between the skin factor and the plain HCl acid concentration.

3.2.1.1. The effect of reservoir temperature

Fig. 9 displays the effect of the HCl concentration on the skin factor at different reservoir temperatures (as a third variable). This figure illustrates that for all reservoir temperatures, the skin factor is significantly improved with increasing the HCl concentration up to a value of 20%

(minimum skin). With increasing the acid concentration to 28%, the skin factor increases back again (impairing). That aligns with the previous conclusion illustrated in **Fig. 4**.

At constant HCl concentrations of 5%, 10%, 15%, and 20%, the skin factor decreases rapidly (improves) as the temperature increases between 200°F and 220°F. Beyond this range, the temperature curves become very close to each other (overlapping), suggesting minimal further reduction in the skin factor despite the continued increase in temperature.

However, a 28% HCl concentration exhibited an odd behavior. The skin factor shows a significant initial decrease (improvement) as the reservoir temperature increases from 200°F to 220°F (best skin factor is achieved at 220°F). Beyond 220°F, the reduction in the skin factor diminishes and begins to slightly increase (impair) with further temperature rises. This indicates that the 28% HCl concentration is highly effective at lower temperatures, particularly between 210°F and 220°F.

As mentioned earlier, the significant reduction in the skin factor with increasing temperature indicates that higher temperatures enhance the reaction rate of the acid with formation minerals, leading to better acid dissolution and deeper penetration. However, employing high concentrations in extremely high temperature reservoirs significantly accelerates the acid reaction rate, thereby limiting the live acid penetration and leading to the formation of an inefficient wormhole network. This explains why the high concentration of 28% HCl is highly effective only at lower temperatures.

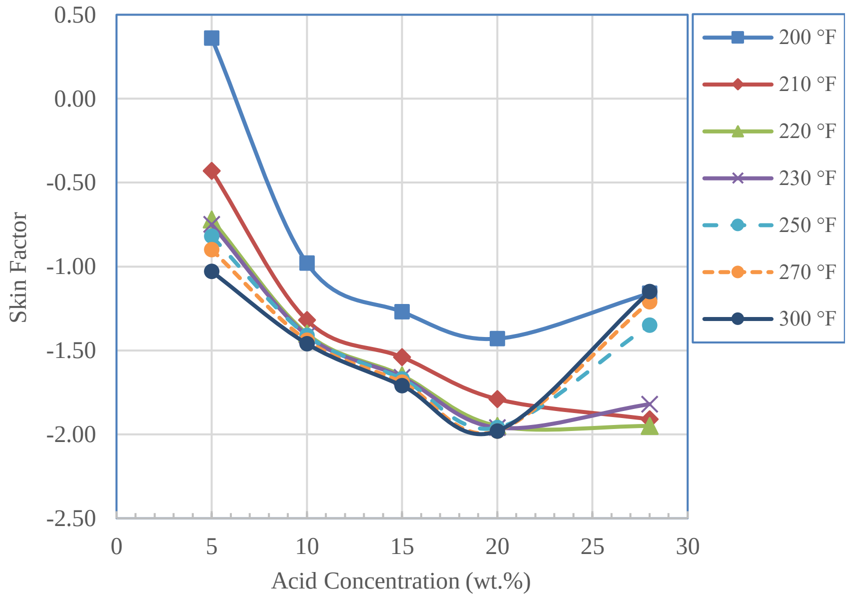

Fig. 9: Effect of the plain HCl concentration on the skin factor at various reservoir temperatures.

3.2.1.2. The effect of HCl acid dosage

Fig. 10 shows the effect of the HCl acid concentrations on the skin factor at different acid dosages (as a third variable), which illustrates that for all acid dosages above 50 gal/ft, the skin factor is improved with increasing the acid concentration up to a value of 15% (the best skin is achieved at 15% concentration). Above 15% concentration, the acid dosage has a slight impact on the skin factor, particularly at 20% with acid dosage more than 100 gal/ft, while at acid dosage equal to 100 gal/ft or less, the best skin is achieved at 20% concentration. Furthermore, the skin factor tends to worsen if the concentration is increased to 28%.

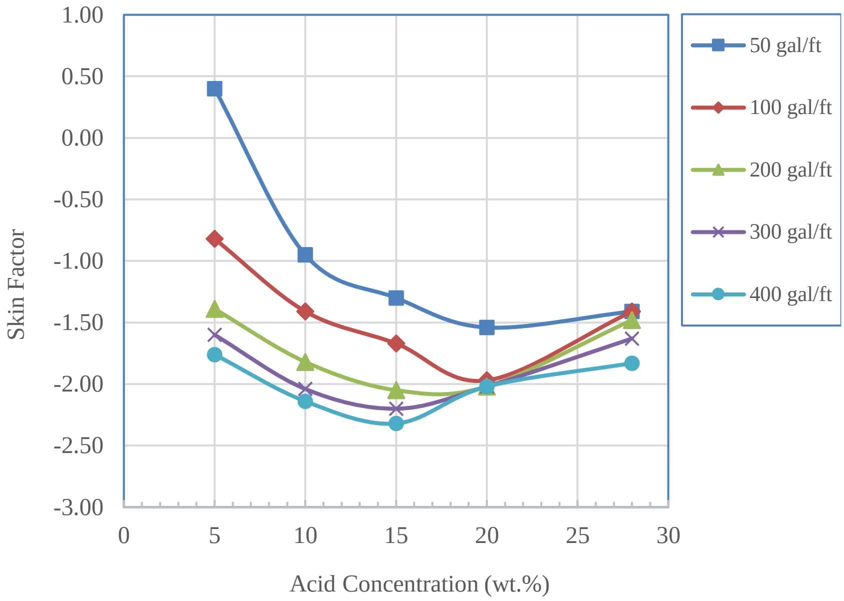

Fig. 10: Effect of the plain HCl concentration on the skin factor at various acid dosages.

This reduction in the acidizing efficiency with further acid dosage can be explained by the fact that at higher temperatures and concentrations (>15 wt.%), the acid reacts too rapidly with the formation, resulting in shallow penetration. Increasing the volume doesn't improve the penetration because the acid is already consumed near the wellbore. This results in the development of inefficient wormholes that aren't deep enough to bypass any damage. Emulsified or retarded acid systems are recommended for such cases requiring deeper penetration and larger acid volumes [1, 10, 11].

3.2.1.3. The Effect of Acid injection rate

The effect of HCl concentration on the skin factor at different acid injection rates (IR) is shown in **Fig. 11.** This figure illustrates that for all acid injection rates, the skin factor is improved with increasing HCl acid concentration, except at low injection rates. Specifically, at rates of 0.5 bpm and 1.0 bpm, an odd behavior was shown when the skin factor gets worse with increased HCl concentration to 15% and 20%, respectively.

For the HCl concentration up to 15%, the skin factor is slightly increased (impaired) with increasing the acid injection rate. This effect can be obviously observed at the minimum concentration; however, the most improved skin factor is observed at the minimum injection rate of 0.5 bpm. In contrast, at a 20% concentration, the minimum injection rate, that achieved the best skin factor, is 1.0 bpm. Additionally, a 28% concentration results in better skin improvement when injected at a rate of 1.5 bpm or more.

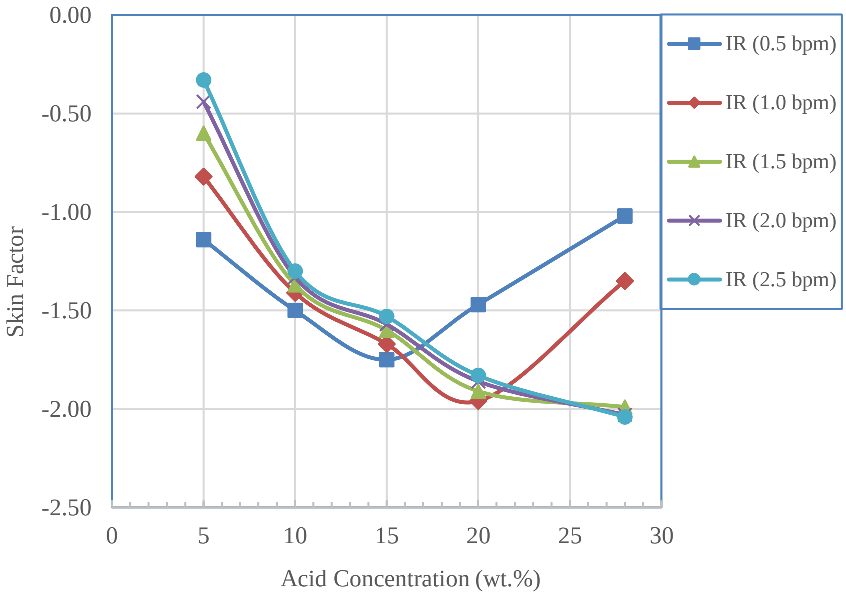

Fig. 11: Effect of the HCl concentration on the skin factor at various acid injection rates (IR).

There is an odd behavior of the skin factor at low rates of 0.5 bpm and 1.0 bpm, with increased HCl concentration above 15% and 20%, respectively. This behavior can be attributed to increasing the contact time of the HCl. As previously highlighted, the acid contact time is controlled by adjusting both the rate and volume of the injected acid. Extremely increasing the contact time by lowering the injection rate at high temperatures may lead to the formation of a face dissolution pattern, prevent acid deep penetration, and limit the acidizing process [9, 11]. Accordingly, the minimum effective rate (i.e., the rate that achieves the best skin) used during the acidizing job is sensitive to the acid concentration value.

3.2.1.4. The effect of damage penetration depth

Fig. 12 shows the effect of the HCl concentration on the skin factor at different damage penetration depths, which indicates that for all damage penetration depths, the skin factor is reduced with increasing HCl concentration up to a value of 20% concentration (most improved skin). With increasing the acid concentration to 28%, the skin factor increases back again.

At a constant HCl acid concentration, the skin factor is increased (impaired) with increasing the damage penetration depth. However, the impact of damage penetration on the skin factor is insignificant for penetration depths of 6 inches or less (the 3” and 6” damage depth curves are overlapping).

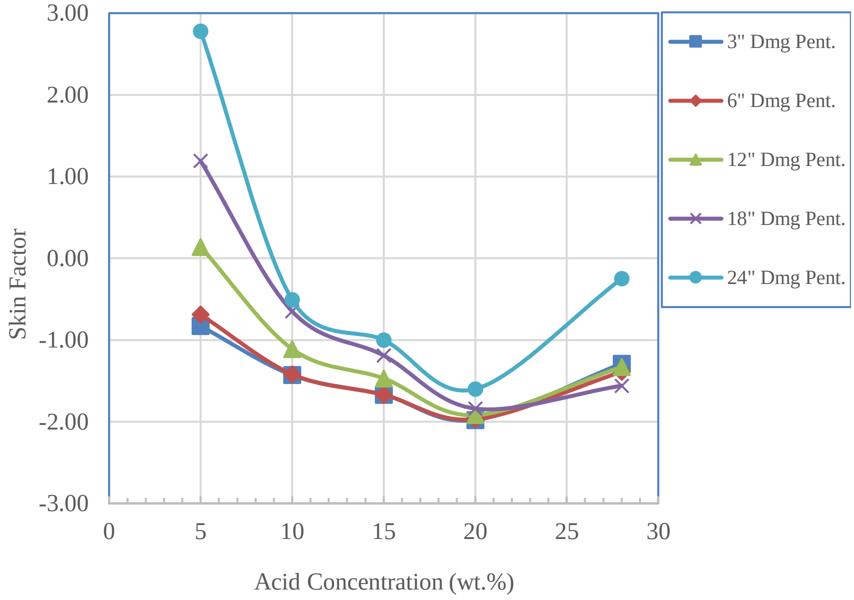

Fig. 12: Effect of the HCl concentration on the skin factor at various damage penetration depths.

According to the previous figure, at 20% concentrations, the impact of damage penetration on the skin factor is limited (the damage depth curves become too close to each other). This suggests that with a 20% concentration, acidizing efficiency continues to improve, regardless of how far the damage penetrates. In other words, at relatively high acid concentrations, the effectiveness of acidizing is sufficient to improve permeability and penetrate up to 2 feet, thus bypass the damage. Hence, using a 20% plain HCl with a 100 gal/ft is enough to overcome the damage depths up to 2 feet (24 inches).

3.2.2. Factors Affecting the Skin Factor at Different HCl Acid Dosages

The objective of this section is to determine how the other effective parameters affect the relationship between the skin factor and the acid job volume.

3.2.2.1. The effect of reservoir temperature

Fig. 13 shows the effect of the HCl acid dosage on the skin factor at different reservoir temperatures (as a third variable). The figure illustrates that for all reservoir temperatures, the skin factor is reduced (improved) with increasing HCl acid dosage (the best skin improvement is at maximum acid dosage). The dissolving power of HCl is the key factor that explains why increasing the acid dosage reduces the skin factor.

At a constant HCl acid dosage, the skin factor improves significantly with increasing the reservoir temperature up to 220°F. Above 220°F, the reduction in the skin factor diminishes, and the curves begin to overlap, indicating the limited impact of reservoir temperature on the skin factor. However, at reservoir temperatures between 210°F and 220°F, it remains clear that this temperature range significantly enhances the effectiveness of acidizing, which supports the previous findings.

Consequently, using the maximum acid dosage yields the best skin results, regardless of how high the reservoir temperatures are. However, cost-effectiveness serves as a limiting factor in selecting the optimum acid dosage.

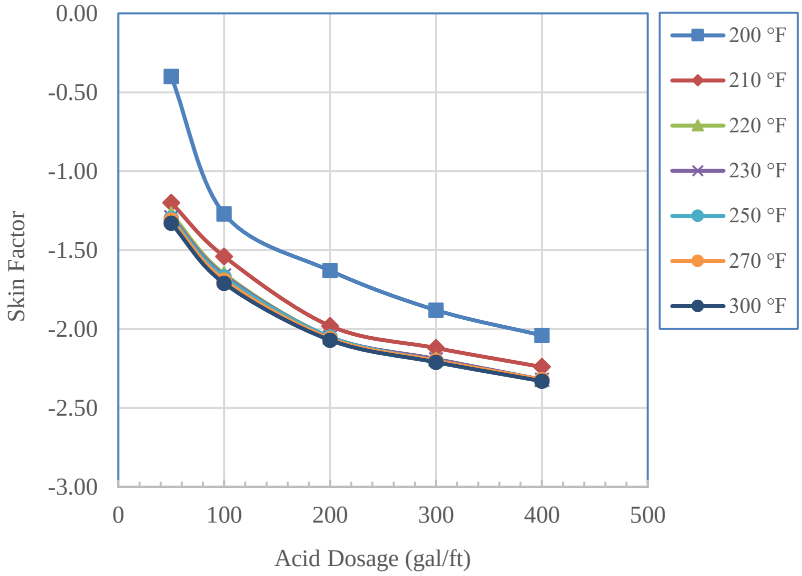

Fig. 13: Effect of the plain HCl acid dosage on the skin factor at various reservoir temperatures.

3.2.2.2. The effect of acid injection rate

The effect of the HCl acid dosage on the skin factor at different acid injection rates (IR) is shown in **Fig. 14**, which illustrates that for all acid injection rates, the skin factor is improved with increasing the acid dosage, except at the minimum rate (specifically at 0.5 bpm), which showed a constant skin factor value regardless of increasing acid dosage above 200 gal/ft. Thus, to improve the skin factor, it is recommended to inject the acid at a rate greater than 0.5 bpm while increasing the acid dosage to be more than 200 gal/ft.

At a constant acid dosage, the skin factor is slightly increased (worsened) with increasing the acid injection rate up to a value of 200 gal/ft acid dosage. Above this value, the 1.0 bpm is the effective rate (dashed line), which achieves the best skin factor.

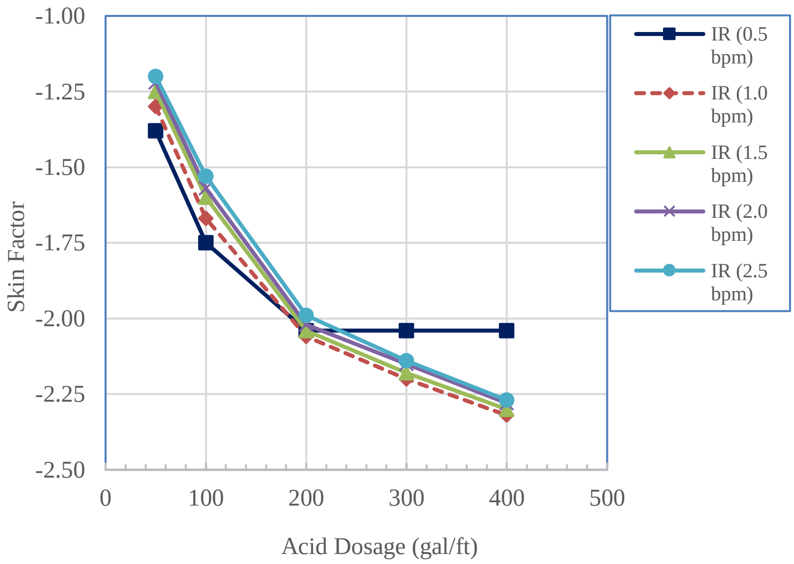

Fig. 14: Effect of the plain HCl acid dosage on the skin factor at various injection rates (IR).

3.2.2.3. The effect of damage penetration depth

Fig. 15 shows the effect of the plain HCl acid dosage on the skin factor at different damage penetration depths (as a third variable). This figure illustrates that for all damage penetration depths, the skin factor is improved with increasing the HCl acid dosage up to 200 gal/ft, while above 200 gal/ft, only a slight improvement is observed. Therefore, using a 15% plain HCl with a dosage of 200 gal/ft is sufficient to overcome the damage depths up to 2 feet (24 inches).

At a constant HCl acid dosage, the skin factor is increased (impaired) as the damage penetration depth increases, with limited impact on the skin factor for damage depths up to 6 inches (the 3” and 6” damage depth curves are typically overlapping), where the skin factor stays at its lowest value.

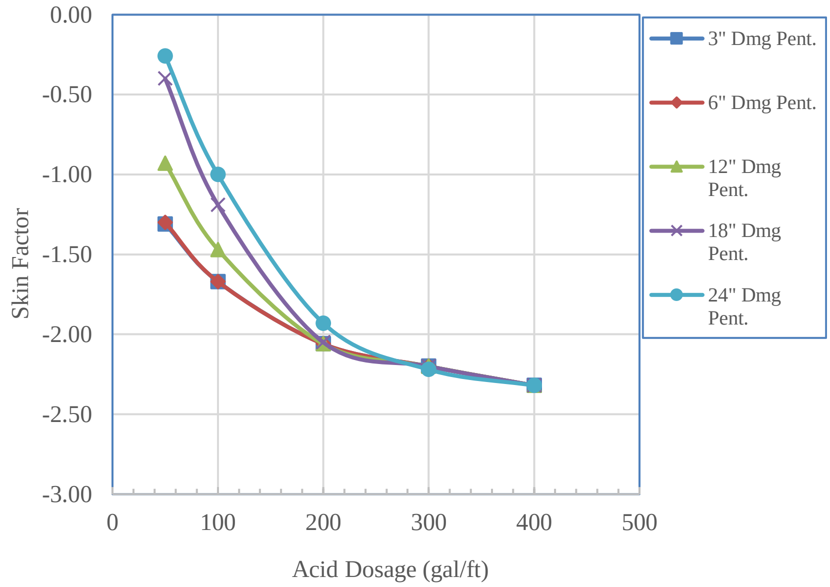

Fig. 15: Effect of the plain HCl acid dosage on the skin factor at various damage penetration depths.

3.3. ANN Model Development

An artificial neural network (ANN) is an optimization tool designed to predict an object's optimal performance based on a given set of input data. An ANN typically consists of an input layer, one or more hidden layers, and an output layer. Each layer consists of multiple processing elements, known as (neurons). These neurons are connected to the neurons in the next layer through linking parameters called (weights) [21, 22]. For the studied case of the plain HCl, the output from the matrix stimulation simulator was utilized to create a feed-forward neural network model with back-propagation training. Seventy percent of the data (70%) was used during the training phase to minimize the mean square error (MSE), while the remaining thirty percent (30%) was allocated for validating the model's reliability and accuracy.

3.3.1. Model architecture

The model consists of three layers: an input layer with one input, a hidden layer with ten neurons that employs the Tan-sigmoid function as a transfer function, and an output layer with one estimated PI output. The architecture of the ANN model is shown in **Table 3**. **Table 4** illustrates input and hidden layer weights and biases, and biases and weights between the hidden and output layers.

Table 3: ANN model architecture and parameters.

Parameter	Value
Number of layers	3
Number of input layer neuron	6
Number of hidden layer neuron	10
Training algorithm	Levenberg-Marquadrt
The activation function of the hidden layer	Tan Sigmoid
The activation function of the output layer	Pure-Linear

3.3.2. Mathematical model description

For i = 1 to no of neurons, the hidden inputs are calculated using the following equation [21, 22]:

$$S_{i.1} = \sum_{i=1}^{6}\left(w_{1,i}x_i\right) + b_i \qquad \text{Eq. (2)}$$

x_i: $input$, $normalized$ of reservoir temperature, acid concentration, acid dosage, injection rate, porosity and damage penetration. The normalized values can be obtained using the following equation:

$$x = 2*(x - x_{(min)})/(x_{(max)}-x_{(min)})-1 \qquad \text{Eq. (3)}$$

Finally, Equations 4 and 5 can be used to compute PI:

$$\text{Normalized PI} = \sum_{i=1}^{6} w_{2,i}\left(\frac{2}{1+e^{-2S_{i.1}}} - 1\right) + b_2 \qquad \text{Eq. (4)}$$

$$\text{PI}=1.45803*(\text{ Normalized PI}+1) + 3.093305 \qquad \text{Eq. (5)}$$

Table 4: Input and hidden layer weights and biases.

No of Neurons	W1.1	W1.2	W1.3	W1.4	W1.5	W1.6	b1	W2	b2
1	-0.00871	-0.10834	-0.07437	0.025541	-0.0086	-0.00316	0.246964	-1.89649	-52.1467
2	-0.47097	-0.38179	-1.27638	0.004422	-0.03702	0.354086	-1.84163	-1.10785	
3	-0.24604	0.810429	-0.14186	-0.01125	-0.24488	0.727105	10.59844	-11.1017	
4	-4.96079	3.075921	3.068781	0.040958	-15.7325	0.84886	0.792739	0.007165	
5	-0.01937	11.8564	0.020227	-2.79413	-0.07282	0.283418	-12.6308	-0.37096	
6	0.010256	0.907999	0.01495	6.215632	0.012124	0.032747	0.324604	-0.00326	
7	0.099142	-5.81652	-0.13383	0.204709	-0.07397	0.463187	-8.89211	-62.7117	
8	-19.3843	0.028436	-5.13504	-0.00995	17.73627	0.02792	-1.22175	0.045038	
9	-0.09037	-0.34542	4.982062	-0.01579	-23.0142	-0.29805	0.041197	0.027827	
10	-1.59826	0.274376	0.047391	0.247241	-0.131	0.263631	3.078686	0.358657	

The cross plot of the PI measured data (from simulation results) versus the calculated PI (Equation 5) is presented in **Fig. 16**. The results of the presented correlation fall very close to the 45° line.

Statistical and graphical analysis are used to estimate the performance of the developed ANN model in this work [23]. The correlation developed in this work (Equation 5) shows a high accuracy. It gives an average relative error (E_r) of (-0.3408) and absolute relative error (E_a) of (1.081) with a high correlation coefficient (r^2) of (0.942).

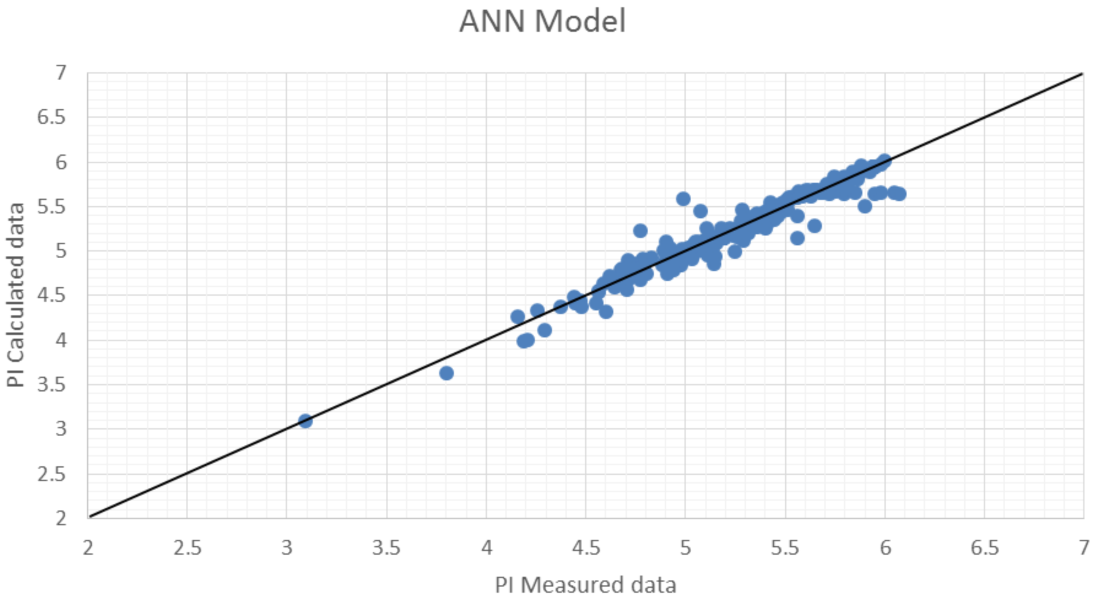

Fig. 16: Cross plots of PI model.

CONCLUSIONS

This field case study highlights the enhancement of acidizing efficiency in the Alamein-Dolomite reservoir using plain HCl. Based on the study's results, a set of key design guidelines has been developed to improve the efficiency of future acidizing treatments in this reservoir.

The following conclusions provide the main guidelines:

- Regarding the effective range for reservoir temperature, the optimal range is typically between 200°F and 220°F, where acidizing shows the most significant improvement in the skin factor. However, above 220°F, the impact of the reservoir temperature on the skin factor becomes limited.
- The 20% concentration achieves consistently lower skin factors, as it remains effective at higher temperatures, indicating its suitability for a wide range of reservoir temperatures, typically between 200°F and 300°F.
- For reservoir temperatures between 210°F and 220°F, the 28% concentration is most effective for achieving maximum skin factor reduction. For reservoirs with temperatures above 220°F, using the 28% concentration may not be the best choice. Alternative options, such as reducing the acid concentration, using additives like retarders, or employing emulsified acids, should be considered.
- Using the maximum acid dosage yields the best skin results; however, cost-effectiveness serves as a limiting factor. This is applied to a wide range of reservoir temperatures (between 200°F and 300°F).
- Optimal design parameters:
    - For our studied case, the most improved skin is achieved at a 15% concentration with the maximum acid dosage; nevertheless, it is critical to have a way to compare the costs and benefits economically. Otherwise, for an acid dosage of 100 gals per foot or less, a 20% concentration is adequately effective. Therefore, both selected parameters might be recommended as optimal design parameters. Ultimately, a 20% concentration with a dosage

of 100 gal/ft or 15% concentration with a dosage of 200 gal/ft is sufficiently optimal if the target is to overcome damage penetration depths up to 2 feet (24 inches).

- In terms of the acid injection rate, the results exhibit that the best skin improvement occurs at the lowest injection rate. Specifically, an injection rate of 0.5 bpm is the minimum effective rate (i.e., the rate that achieves the best skin) for concentrations up to 15%. In contrast, the minimum effective rate for a 20% concentration is 1.0 bpm. Additionally, a 28% concentration provides a better skin improvement when injected at a rate of at least 1.5 bpm or higher.
- Moreover, based on the skin results from the relationship between the acid injection rate and acid dosage, when the acid dosage exceeds 200 gal/ft, it is recommended to inject the acid at a rate greater than 0.5 bpm (i.e., the minimum effective rate is 1.0 bpm), as this is beneficial to improving the skin factor.

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