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Sustainable Emulsified Acid Treatments for Enhanced Oil Recovery in Injection Wells: A Case Study in the Qusahwira Field

Charbel Ramy [1], Razvan George Ripeanu [1], Salim Nassreddine [2], Maria Tănase [1,*], Elias Youssef Zouein [3], Alin Diniță [1] and Constantin Cristian Muresan [1]

[1] Mechanical Engineering Department, Petroleum-Gas University of Ploiești, 100680 Ploiesti, Romania; charbel.rami10@gmail.com (C.R.); rrapeanu@upg-ploiesti.ro (R.G.R.); adinita@upg-ploiesti.ro (A.D.); office.ccmuresan@gmail.com (C.C.M.)
[2] Department of Chemical Engineering, Lebanese University Faculty of Engineering, Beirut P.O. Box 6573/1, Lebanon; salimnassreddine83@ul.edu.lb
[3] Faculty of Engineering, Conservatoire National des Arts et Métiers, 292 Rue Saint Martin, 75003 Paris, France; eliaszouein@hotmail.com
* Correspondence: maria.tanase@upg-ploiesti.ro

Abstract: Emulsified acid treatments present an innovative and environmentally sustainable alternative to conventional hydrochloric acid (HCl) methods in enhancing oil recovery. This study investigates the application of a stable emulsified acid formulation in matrix acidizing operations to improve injectivity in four wells within the Qusahwira Field. Compared to traditional 15% HCl treatments, the emulsified acid demonstrates deeper acid penetration and retardation effect leading to enhanced injection rate. By delivering deep worm holing effects against calcium carbonate formation, this dual-phase system enhances injectivity by 14 times while minimizing the environmental and material impacts associated with spent acid volumes. The methodology integrates advanced neural network modeling to predict stimulation outcomes based on 15 operational and reservoir factors. This model reduces the trial-and-error approach, cutting operational costs and time for carbonate reservoir. Field trials reveal significant improvements in injection pressure and a marked reduction in circulation pressure during stimulation, underscoring the treatment's efficiency. Developed in a Superior Abu Dhabi laboratory, the emulsified acid achieves high-temperature stability (200 °F) and deep acid penetration, further reducing the ecological footprint of acid stimulation by enhancing operational precision and reducing chemical use. This paper highlights a sustainable approach to optimizing reservoir productivity, aligning with global efforts to minimize environmental impacts in oil recovery processes.

Keywords: sustainable oil recovery; injection wells; sustainable emulsified acid treatments

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1. Introduction

Reservoir stimulation is essential for operators to extract oil and gas from previously unprofitable or difficult to access reservoirs, which becomes increasingly essential as global energy demand grows. This led to a huge increase in production rates and improved global energy supply. For the last few years, the industry has focused on increasing production while maintaining cost-effective. Various applications, such as acid fracturing, matrix acidizing, reperforation and recompletion branched from stimulation

using plain Hydrochloric acid (HCl), can raise the net profit value (NPV) of existing active or inactive wells paper [1]. While effective, these methods pose challenges, including excessive chemical usage, high corrosion rates, and limited environmental sustainability paper [2–8]. The benefit of stimulating near wellbore areas leads to a strong reservoir pressure and clear path to production. Stimulation techniques aim to manage and maximize reservoir expansion where it increases the eventual rate of economic recovery and to increase well profitability paper [1].

Conventional acid stimulation has been the preferred technique in the gulf region to stimulate deep horizontal well, particularly in Abu Dhabi. Conventional acid stimulation involves the application of 15% or 28% Hydrochloric acid to reduce damaged skin into carbonate reservoir. Hydrochloric acid improved permeability and well injectivity, particularly after soaking in an inhibited HCl solution for 6 to 12 h, where it reacts with the iron complex and the deposits that are clogging the reservoir to enhance formation characteristics such as oil productivity and injectivity within the rock pores. However, in some cases the hydrochloric acid treatment is unable to improve reservoir performance, especially when it comes to field cases where the formation permeability drops below 1 millidarcy, indicating a tight formation. It is important to highlight that the hydrochloric acid HCl, reply on acid diffusion and reaction kinetics where a rapid reaction is initiated with the formation near wellbore, leading to excessive acid spending and minimal penetration specially for unconventional reservoirs with low permeability. On top of it, HCl system degrades at temperature of 200 °F and above, producing by products that precipitate and damage the formation, where most of the stimulation operation doesn't sustain long with good productivity due to damaged skin. Compared to other acid stimulation systems, Hydrochloric acid has limited acid penetration and inability to effectively dissolve near wellbore damage in low permeable zones.

As a result, emulsified acid treatment was developed to address the low permeability issue and ensure deep live acid injection while retarding the overall kinetic reaction between hydrochloric acid and carbonate formation, leading to longer warm holing, less spent acid, retard's reaction with the damage near wellbore and provide slow reaction within the rock for better production enhancement.

The study of emulsified acids has advanced significantly in recent years, focusing on addressing challenges related to sustainable energy production, well stimulation, and environmental compatibility. These developments have contributed to a deeper understanding of their formulation, application, and impact on reservoir stimulation. In the realm of formulation and efficiency, researchers have highlighted the importance of tailoring emulsified acid systems for oilfield applications. Elsafih et al. paper [9] demonstrated how emulsifiers improve acid-oil emulsions, ensuring operational safety while enhancing treatment efficiency. Similarly, Al-Taq et al. paper [10] explored emulsification strategies and pH control, emphasizing the reduction of reaction rates to improve acid penetration. These findings underline the critical role of optimized formulations in achieving better performance under diverse field conditions. The emulsified acid treatment was created as a sustainable alternative to the conventional hydrochloric acid systems typically used in stimulation. Unlike traditional methods, emulsified acid decreases acid consumption by 30% and lowers environmental risks by slowing down acid reaction kinetics, leading to deeper acid penetration while reducing the spent acid ratio after reactivity. This method is congruent with sustainability goal through better operational efficiency, reduction of waste and reduced carbon footprint of stimulation operations. When considering sustainability and environmental impact, recent studies have underscored the need for greener practices in acidizing operations. For instance, Li et al. paper [11] used lifecycle assessment to evaluate the carbon footprint of CTM co-production systems, both with and without

CCUS-enhanced oil recovery (CCUS-EOR). The study also identified key emission sources and suggested reduction pathways, offering insights for improving sustainability in CTM and CCUS development in China.

Historically utilized in fracture acidizing, emulsified acids have emerged as a promising solution for matrix acidizing in heterogeneous carbonate formations paper [9,10,12,13]. Recent advancements in theoretical understanding, laboratory experiments, and field applications have highlighted their potential to overcome challenges associated with low permeability and damaged formations. Unlike conventional hydrochloric acid (HCl), which spends primarily on the formation surface at low injection rates, emulsified acids enable effective worm holing by retarding diffusion, facilitating deeper penetration into the reservoir.

The paper [14] compares the performance of emulsified acids and plain HCl through core flow tests, analyzing parameters such as injection rates, viscosity, and acid-to-oil volume ratios. The rheological behavior and temperature stability of emulsified acid systems (up to 250 °F) were evaluated, demonstrating their robustness under challenging reservoir conditions. Additionally, calculations indicate their effectiveness in mitigating high-permeability thief zones in extensive reservoir intervals, ensuring uniform fluid distribution and enhanced stimulation efficacy. By leveraging these properties, emulsified acid treatments present a sustainable alternative to traditional methods, reducing acid consumption while improving reservoir productivity and injectivity.

Matrix-acid treatments aim for deep stimulation and uniform acid distribution, particularly in long or fractured intervals, as exemplified in Italy's major oil fields. Challenges like asphaltene deposition and environmental sensitivity were addressed in paper [15] with a novel emulsified acid system combining asphaltene-dissolving and acid-diversion technologies. Lab tests optimized this oil-external/acid-internal emulsion for stability, viscosity, and controlled reactivity, while operational adaptations enabled safe field applications.

The main goal of the present work is to introduce new acid treatment based on dual phase acid–diesel know as emulsified acid and compare its efficiency versus conventional 15–28% HCl treatment in terms of permeability enhancement and warm holing while having an important impact on reservoir productivity and injectivity to extend its life cycle. Additionally, emulsified acid presents several advantages that distinguish it from traditional acidizing method by:

- Exceptional stability over time and at high temperature
- Homogenous mixture with 70:30 acid-diesel ratio
- Consistent performance under challenging conditions
- High viscosity which enhances acid placement
- Minimizing risk of acid diversion to thief zones
- Reducing risk of water dilution while preserving treatment efficacy
- Optimum corrosion inhibitor dosages
- Optimum chemical use during the job

The emulsified acid treatment on top of all these advantages, addresses multiples key points, particularly regarding reduced acid use, minimized residue and lower environmental impacts. Thus, by reducing acid consumption during each operation by 30% of raw hydrochloric acid 32% due to the system retardation structure versus carbonate formation. Due to emulsified acid composition and its physical properties, the emulsified mixture address some key points related to sustainability and environmental impact such as:

- Reduced Acid Consumption
- Minimized Acid Leak-off
- Lower volume of spent Acid and its byproducts

- Reduced residual chemical Agents due to reduced iron content (iron content in HCl)
- Lower carbon footprint
- Aligns with sustainability goals

The work started by improving emulsion mixture using superior emulsified acid to combine acid and hydrocarbon phases in order to form a stable emulsion, average viscosity and optimum corrosion rate to protect coiled tubing string, completion and downhole tools specially when operating in reservoir conditions. Additionally, a model is build based on various factors filtered from the reservoir data. This regression model after being tried and demonstrated low error, is capable of predicting the outcome of a stimulation job based on chosen factors. The process began by building a model based on numerous factors that covered the zone of interest and its specifications paper [16]. Actual recorded data were extracted from four advanced acid stimulation operations on injection wells in Quasahwira Field, located southern region of Abu Dhabi in the United Arab Emirates. This field is a key onshore asset operated by the Major oil and gas company in Abu Dhabi, known for its carbonate reservoirs and significant contribution to the region's oil production. Pre-acidizing data were recorded and collected from the data acquisition system and compared to post-acidizing data, which revealed a significant improvement in pumping rate and major drop in pressure at a constant rate.

If the formation is not producing in producer wells and not taking in terms of injection in injection wells as quickly as expected for the project, stimulation operation is considered. Before performing a stimulation treatment, it is important to consider the following factors: rock permeability, damage skin, and downhole pressure and temperature paper [17]. Reservoir thickness, oil viscosity, well radius, and permeability all have an impact on reservoir productivity or injectivity index paper [18–20]. As a result, there isn't a particular permeability to implement acidizing treatment. Conventional acid stimulation has been the preferred technique in the gulf region to stimulate deep horizontal well, particularly in Abu Dhabi. Conventional acid stimulation involves the application of 15% or 28% Hydrochloric acid to reduce damaged skin into carbonate reservoir. However, in some cases the hydrochloric acid treatment is unable to improve reservoir performance, especially when it comes to field cases where the formation permeability drops below 1 millidarcy, indicating a tight formation paper [21]. As a result, new emulsified acid treatment was developed to address the low permeability issue and ensure deep live acid injection while retarding the overall kinetic reaction between hydrochloric acid and carbonate formation paper [22]. The global market for well stimulation in terms of revenue was estimated to worth 7.6 billion dollars in 2021 and expected to reach 9.3 billion dollars in 2026 and grow at a CAGR of 4.2% between 2021 and 2026 paper [23].

Although its higher friction pressure, dual phase retarded acid was lunched to stimulate four injection wells surrounding producers' wells, using well intervention technique, a 1¾" coiled tubing to enable deep and better acid placement. On top of that, an advanced acid schedule was implemented allowing acid pumping into stages using a high velocity jetting tool. Combination of new acid treatment and abrasive jetting into stages through coiled tubing demonstrated a remarkable enhancement in the carbonate formation in terms of efficiency, injection rate and deep acid placement creating warm holes while reducing the spent acid volume and acid leak-off. The acid injection led to dissolve the damaged skin onto rock formation allowing an impressive enhancement in the permeability, where the acid was abrasively pumped through four jets covering 360 degrees, creating conductive channels known as warm holes. Successful acid stimulation generally depends on three factors that directly affect the formation which are acid injected volume, injection rate and pressure and fluid type. These factors were evaluated by the client's engineers to optimize the new acid treatment volume, as well as its viscosity and anticipate the injection flow

rate. As long as the acid injection is equal or greater than the optimum injection rate using high velocity jetting tool, more acid will be forced to penetrate into clogged pores, dissolve damaged skin and result in more branching and less spent acid.

Generally hydrochloric acid improves permeability and well injectivity, particularly after soaking in an inhibited HCl solution for 6 to 12 h, where it reacts with the iron complex and the deposits that are clogging the reservoir to enhance formation characteristics such as oil productivity and injectivity within the rock pores. Acid injection into pure limestone formation leads to multiple dissolution patterns within formation which directly relay on injection rate (bpm), pumping pressure (Psi), Kinetic reaction, flow geometry and the fluid loss rate.

The injection rate can be calculated through empirical formula:

$$Q_{\max} = \frac{4.92 \times 10^{-6} \times L \times \sqrt{K_h \times K_v}}{\mu \times \beta \times F}\left(g_f \times D - \Delta P_{safe} - P_r\right) \quad (1)$$

$Q_{\max}$ = maximum allowable injection rate
L = Length of horizontal reach section
K_h = horizontal permeability
K_v = vertical permeability
g_f = fracture gradient
ΔP_{safe} = safety factor (200–500 Psi)
P_r = average reservoir pressure
μ = fluid viscosity
β = formation volume factor
F = {({1/2 L_n[(8 × h × L_{ani})/(P_i × r_w (1 + L_{ani})) cot ⟦(P_i × L_w)/(2 × h)⟧ })/1} + 1/2 [s − ((h − L_w) x $Lani$)/L]
H = reservoir height
L_w = distance from reservoir bottom to horizontal well
S = Skin damage
R_w = wellbore radius
L_{ani} = function of horizontal and vertical permeability anisotropy $\sqrt{}$(Kh/Kv)

Factors μ and β refers to the viscosity of the fluid and the formation factors of the injected fluid under downhole reservoir conditions. Taking into consideration that β is =1.0 RB/STB for non-energized fluids.

This paper introduces a sustainable alternative: an emulsified acid system combining dual-phase acid and diesel, designed to improve permeability and warm holing while mitigating the environmental and material impacts of traditional acidizing treatments. Unlike conventional 15–28% HCl, this formulation offers enhanced stability, reduced reaction kinetics, and minimized spent acid volumes, making it suitable for carbonate reservoirs with low permeability.

Developed and field-tested in the Quasahwera Field, the emulsified acid demonstrated a remarkable 14-fold injectivity improvement in injection wells surrounding production wells. The integration of high-velocity jetting tools ensured deep acid penetration and minimized waste, addressing environmental concerns. Additionally, a neural network model incorporating 15 critical operational factors was developed to predict stimulation outcomes with minimal error, optimizing future applications and reducing experimental inefficiencies.

By reducing chemical consumption and enhancing operational efficiency, this dual-phase emulsified acid system exemplifies the industry's shift toward sustainable stimulation practices. The study underscores the importance of combining advanced technology

with environmentally responsible strategies to extend reservoir life cycles, improve oil recovery rates, and support the global transition to more sustainable energy systems.

2. Materials and Methods

2.1. Oilfield Potential and Its Production

Quasahwira Conventional oil field located in Abu Dhabi, UAE (Data, 15 November 2023). Quasahwira is a producing conventional oil field located onshore the United Arab Emirates and is operated by ADNOC Onshore. The field is located approximately 260 km south Abu Dhabi and covers an area of 7525 square kilometres. (Data, 15 November 2023).

Currently, the goal is to increase the oil production by 25,000 barrels per day where the client intends to deploy advanced technique starting with advanced acidizing technique proposed by its contractors, then enhanced oil recovery EOR that compensate the natural depletion of the oil reserves of the field and enable the client to recover up to 50% of the original oil in place OOIP (Anonym, 2021). Several water injector wells or water alternative gas injector wells were drilled and interconnected between each other's. Generally, all injector wells surround oil producer wells to increase and maintain optimum reservoir pressure to improve oil production. Stimulation jobs were scheduled for all the injector wells especially those with low injection rate per day.

2.2. Field Reservoir Parameters

The low injection rate due to precipitates and deposits within the formation that are creating damaged skin and clogging the fluid path in and out of the rock. An important factor to consider is the reduced permeability K, a concept first presented by Darcy in 1856 and the source of the well-known Darcy's law, is essential to this flow paper [17]. According to this law, the pressure gradient ΔP and the flow rate Q are directly proportional paper [1] (Michael J):

$$Q = \alpha K \Delta P \quad (2)$$

Additionally, the viscosity μ also enters the relationship, and for radial flow through an area 2πrh, thus the equation become:

$$p - p_{wf} = (q\ \mu)/(2\ \pi\ k\ h)\ \ln\ r/r_w \quad (3)$$

where, p_{wf} and r_w are the bottomhole flowing pressure and wellbore radius, respectively [1]. The near-wellbore area encounters additional differential pressure regardless of reservoir flow. Various factors affect the radial and horizontal flow converging into the reservoir. As a result, the skin effect s is introduced to describe alterations in the near-wellbore zone, where the Van Everdingen and Hurst in 1949 skin effect has been defined as causing a steady-state pressure difference. Skin effect is mathematically dimensionless. However, it reflects the skin permeability Ks at a distance r_s [1]. A relationship among the skin effect, reduced permeability and altered zone radius is extracted. The skin effect, is comparable to the film coefficient in heat transmission, defines a zone of tiny extent that results in a steady-state pressure difference, which is conveniently described as:

$$\Delta\ p_s = (q\ \mu)/(2\ \pi\ k\ h)\ s \quad (4)$$

Adding the last two Equations (3) and (4), results in

$$p - pwf = (q\ \mu)/(2\ \pi\ k\ h)\ (\ln\ r/\mathrm{rw} + s) \quad (5)$$

A negative skin effect allows for a higher constant flow rate q, while a positive skin effect necessitates a lower p_{wf}. A significant positive skin is harmful for producers and

injection wells. Therefore, a new emulsified acid treatment is presented to address the challenge and dissolve the damaged skin layer and penetrates the clogged pores due to its retardation effect. thereby, reducing acid leak-off and providing deeper acid penetration. On top of that, the acid injection tool capable to diverting the acid in each stage into four directions enhancing acid penetration rate.

Conventional stimulation fell behind schedule, instead an advanced acid technique combined with a new acid retarder (dual phase emulsified acid system) was proposed to stimulate the low permeable reservoirs in order to create warm holes and improve rock proprieties such as wettability, permeability, differential pressure and injection flow rate via the zone of interest. Superior Abu Dhabi introduced the client to emulsified acid treatment, which was evaluated under reservoir conditions with a stable combination. The job was designed to pump stationary 15 Bbls of emulsified acid system using high velocity jetting tool to allow the new acid treatment to penetrate the clogged permeability causing a pressure drop while injecting it into the formation.

2.3. Introduction of Emulsified Acid Treatment

In conventional matrix acidizing, 15–28% HCl acid recipe is injected into the porous medium to dissolve damaged skin and formation rock creating branches. Due to the high reactivity of HCl with limestone formation and availability of damaged skin onto the rock, the acid is barely reacting with the skin and penetrates the formation (limited penetration ratio) [1], instead, it is diverted to the open channels where it can flow easily leaving some zones untreated. As a consequence, damaged skin for a significant portion of the zone of interest (open hole) will remain intact. Therefore, retardation technique was introduced using dual phase emulsified acid system where the acid is presented as internal phase capable of moving into droplet shape within a hydrocarbon phase. The relative slow mobility of acid droplets create retardation by slowing down the reaction between hydrochloric acid and carbonate formation leading to deeper penetration and better diffusion rate.

For emulsified acid, the degree of retardation depends on the volume fraction of the acid internal phase: reducing the concentration of acid droplets retards the reaction rate and diffusion rate into the formation resulting by deeper penetration and warm holing. Emulsified acid is a treatment that reacts slowly with the formation, permitting deep live acid penetration. It is generally used at fracturing pressures, where it cleans out and enlarges existing fissures and also creates new ones. Because of its viscosity, emulsified acid carries sand effectively and can also be used as a fracturing fluid.

2.4. Materials and Sample Preparation

2.4.1. Acid Emulsifier Composition

The acid emulsifier treatment is a dual phase acid retarder combining two organic and inorganic phase creating stable emulsion to overcome all the formation capabilities of reducing treatment efficiency and improving retardation effect and deep acid penetration.

The described emulsified acid formulation includes hydrochloric acid phase (inorganic phase) along with the diesel phase referring to organic phase. Both phases can be split into several ratio with an optimum ration of 70:30, to ensure stabilized emulsion with 2% weight percentage non-ionic surfactant, during mixing, during snake testing and finally while being inject into the formation.

The created emulsion of acid–diesel oil, demonstrate a continuous body of hydrocarbon surrounds the droplets of acid. This reduces the effective area of contact, means that less acid is reacting with the formation at any given time. When the acid on the formation's surface reacts, it must be replaced by live acid transported there via diffusion and convection. These processes occur more slowly in hydrocarbon than in a 'more fluid' medium

(formation), lowering the acid's reaction rate. Bringing the two liquids together and physically breaking up the one to be dispersed by mechanical agitation results in an emulsion of inhibited acid in diesel. Stable emulsions for well stimulation are easy to create. The continuous phase Diesel is placed in a frack tank of 500 Bbls capacity with a stabilizing surfactant "Acid Emulsifier" that will serve to control the extend of retardation.

2.4.2. Equipment for Laboratory Testing

Stability Testing Emulsion

Emulsion stability test using conventional testing procedure required by the main operator such as proceeding with a proper normal mixing using magnetic stirrer and 30 s of treatment mixing under 1800 rpm mixer to ensure homogenous phase. The main goal is evaluating the ability of Superior Abu Dhabi developed Emulsified acid to maintain its uniform composition without phase separation under standard and reservoir conditions, such as room and elevated temperature and extended durations.

The tests are performed using sealed glass tubes accommodated into testing bottle and subjected to operational conditions as mixing at high temperature, withstand mixture stable at high temperature and reservoir conditions as elevated temperature of 200 °F for 6 h. The testing bottles along with the sealed tubes are inserted into a digital high elevated temperature oven as shown in Figures 1 and 2.

Corrosion Testing Treatment

Dynamic corrosion tests are conducted to assess the corrosivity of emulsified acid treatment on downhole equipment such as coiled tubing string pipe, abrasive jetting tool under realistic operating conditions such as high temperature and high pressure with continuous movement of the testing cells.

As mentioned in Figure 3, OFITE HPHT corrosion tester machine was used to perform the corrosion tests. The machine simulates the flow of the new developed emulsified acid treatment within the wellbore during stimulation operation.

Corrosion metal coupons, typically made of similar materials as coiled tubing and exact materials as the downhole production tubing such as low carbon steel L-80. These coupons are placed in the new emulsified acid treatment fluid into a glass testing bottle with special lid and placed into high-pressure and high temperature HPHT rotating corrosion cell.

Viscosity Test

The viscosity test under high-pressure and varying temperature is conducted to evaluate the performance of emulsified acid treatment, where both pressure and temperature affects its viscosity and its resistance to flow. The adjusted pressure is 200 Psi where it can reach up to 5000 Psi and temperature from room temperature 25 °C up to 260 °C.

The treatment is tested at a shear rate of 100 s^{-1}, 200 Psi pressure and 94 °C as temperature where the BOB shaft movement at a constant rpm to provide the exact viscosity and fluid resistance reading.

Density Test

The density test for emulsified acid using laboratory densimeter or hydrometer is to measure the mass per unit volume and to be recorded. The test provides hint about the treatment behavior while being injected through the coiled tubing.

pH Metering

The pH test is performed using electronic pH meter and field pH strips to access the acidity level of the emulsified acid which impacts its effectiveness in reacting with the formation materials. Also, the test result determines the aggressiveness of the treatment.

2.4.3. Treatment Properties

The viscosity and the level of retardation of emulsified acid can be modified by changing the ratio of acid and hydrocarbon phase (diesel) paper [14]. In emulsified acid mixture, using a ratio of 50:50 acid–diesel will provide stable emulsion although it will increase tremendously the viscosity, which will affect the pumping rate & time followed by the inhibition time of the whole system. The emulsified acid treatment with a 70:30 acid-to-diesel ratio has 30% less acid than the typical HCl acid system. While increasing the diesel and emulsified phase from 30 to 50, there are limitations in terms of high diesel sensitivity to elevated temperatures, where the diesel acts as an exterior shell or barrier, protecting the acid and retarding its reaction. At high temperatures, diesel loses stability, resulting in treatment separation. The aim was to develop a stable mixture including 30% diesel phase and only 2 wt% emulsified acid that would stabilize both the acid and diesel phases at room and high temperatures while considering cost optimization.

Additionally, increasing the acid ratio in the mixture for a 70:30 acid–diesel, provides higher propagation rate and deeper acid penetration paper [24].

In our case, the ratio acid–diesel is 70:30, where the raw acid quantity for a recipe of 20% Emulsified acid is equivalent to the same raw acid dosage in a conventional 15% HCl acid recipe. To explain more, the acid recipe will include two phases:

- Diesel phase including 80% diesel and % Acid Emulsifier (SUP-AE-03)
- Acid phase including the required amount of fresh water, chemical additives and raw acid HCl 32%.

The best retardation of hydrochloric acid is accomplished by the addition of special emulsifier designed to give a retarded reaction rate and stable emulsion on low and high temperatures carbonates.

This type of system is recommended for treatments where the following apply:

- Highly soluble formation
- Reservoirs with high bottomhole temperatures
- Interventions where high volumes of treatment is required
- Cases where low injectivity is present after conventional matrix acidizing.

Moreover, the corrosion inhibitor in use is affecting the system stability in terms of emulsion and corrosivity. Multiples tests were carried out to create a stable emulsion at low and high temperature using an optimum dosage of emulsified acid (SUP-AE-03). After achieving a stable emulsion, corrosion test were performed using the gravimetry method to optimize the corrosion inhibitor and corrosion inhibitor dosage at 200 F for 12 h. Additionally, viscosity tests were run using high pressure high temperature viscometer to predict the average system viscosity at high temperature and compare it with the actual.

3. Results

3.1. Experimental Trials Conducted in Laboratory to Evaluate the Mixture of Fluid

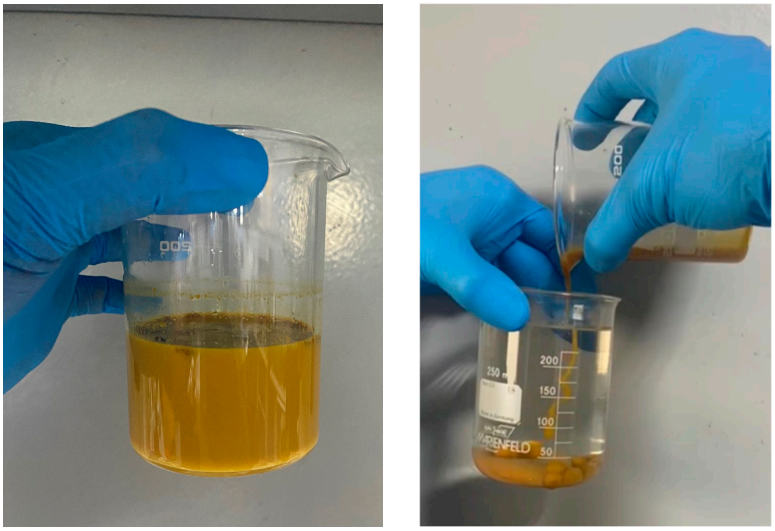
Multiple tests were carried out to determine the optimum dosage of each chemical in order to have a one phase homogenous mixture and, secondly to pass the corrosion test with 12 h inhibition time and no pits.

Homogenous Treatment & Stable Emulsion

In the first step, the focus was on creating this emulsion combining both hydrocarbon phase with acid phase using Superior Abu Dhabi Acid Emulsifier and corrosion inhibitor SUP-CI-68 that enable stable emulsion for more than 6 h, at room and reservoir downhole temperature. After getting a constant and stable emulsion a "snack test" is performed to ensure that the final homogenous mixture will remains stable while contacting water.

Emulsions are characterized as macro or micro based on their dispersal phase and droplet size. Emulsions can be classified into four categories based on the dispersed phase. Emulsions come in several types, such as oil-in-water, water-in-oil, oil-in-water-in-oil, and water-in-oil.

Emulsions typically appear foggy or white due to light dispersion from the interphases between the mixture's components (Figure 1). The emulsion would appear white if all light is scattered uniformly. Generally, emulsion require oil, water, surfactant and energy in terms of agitation to be stable paper [25]. Each component affects the shape, kind, characteristics and stability of the emulsion. According to Pandya, Wadekar, and Cassidy paper [26], corrosion inhibitors decrease emulsion stability. When oil and water combine separately, they form an interface. Emulsion formation requires energy in the form of mixing to break down the interface and create scattered droplets in one of two phases. Surfactants produce low-energy droplets at interfaces. Emulsions can be mixed by hand or with stirrers.



(**a**) (**b**)

Figure 1. The aspect of obtained emulsion: (**a**) 20% Emulsified Acid Recipe Stable Emulsion; (**b**) snack test performed using beaker full of fresh water to simulate the actual case of emulsified acid injection into the reservoir.

The acid recipe develops a continuous flow in a form of snack without interfering with the outside hydrophilic phase (water).

As a consequence, the ideal ratio of 70:30 Acid–Diesel led to a consistent and homogeneous combination that allows acid to penetrate deeper into the formation and creates a more robust emulsion when employing Superior Abu Dhabi emulsified acid additive. The emulsified acid mixture showed tremendous promise in developing a stable emulsion, its stability being maintained for 6 h at room temperature and elevated temperatures of 25 degrees C and 94 degrees C. treatment's sustained stability at high temperatures is therefore highly promising as it reflects the treatment stability under the field conditioning environment. In general, emulsified acid treatment is a good candidate for a repeatable and reliable

homogenous behavior. The snake test was successful and enabled a further understanding of the effectiveness of the treatment while being spot into hydrophilic environment, focusing on reaching deep into the reservoir tackling oil pathways.

3.2. Emulsion and Corrosion

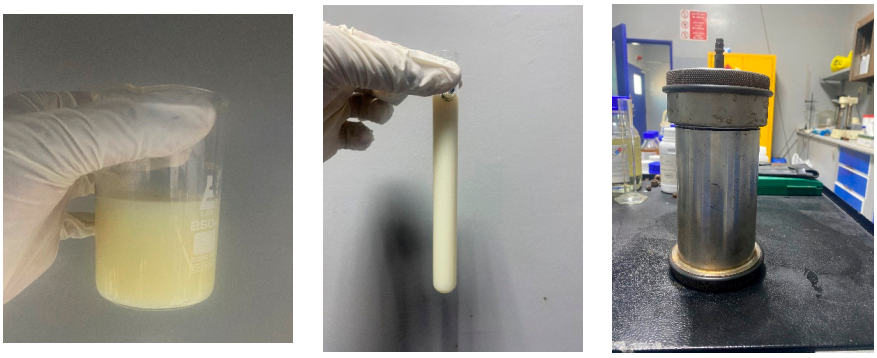
3.2.1. Corrosion Test Preparation

Corrosion tests were performed to ensure the protection of low carbon steel L-80 of the production tubing as well as the coiled tubing string against the acid corrosive impact. The corrosion tests were carried out using gravimetry method utilizing OFITE testing and Equipment HTHP corrosion tester, with the reservoir conditions (BHT = 94 C and BHT = pressure 13.79 MPa) and testing time (21,600 s (6 h) and 43,200 s (12 h) testing).

There are three steps necessary for performing the corrosion test:

Mixing procedure: Mix both mixtures separately, mix the diesel along with the SUP-AE-03 in one beaker, then mix the acid recipe including fresh water, corrosion inhibitor (SUP-CI-68), Corrosion inhibitor intensifier (SUP-ICI-85L), Iron sequestering agent (SUP-IS-90L), raw acid HCl 32% in the second one. Pour the acid mixture slowly above the first Emulsified diesel mixture developing an Emulsified acid system.

Emulsified Acid Stability: After mixing the emulsified acid mixture as stated in the above mixing procedure, a homogenous one phase mixture is present. A compatibility test is performed by placing the SUP emulsified acid fluid system in testing tubes at room temperature and high temperature (94 °C) for 6 h testing [15].



(**a**) (**b**) (**c**)

Figure 2. Emulsified acid recipe tests at high temperature: (**a**) Emulsified acid recipe; (**b**) Homogenous mixture; (**c**) Corrosion test cell for high temperature.

After 6 h testing, the one homogenous phase of the emulsified acid is assessed to confirm emulsion and mixture stability at 25 °C (80 F) and 94 °C (200 F). As shown in the Figure 3, multiple mixture trials were performed to reach a stable emulsion. Some of acid recipe demonstrated a complete separation after two to three hours (Figure 3a). On the other hand, some acid recipes were stable during testing time in both temperature conditions as demonstrated in Figure 3b,c.

After confirming the emulsion stability using 4 families of corrosion inhibitors A, B, C & D, the laboratory engineers proceed with the corrosion tests.



(**a**) (**b**) (**c**)

Figure 3. Stability of emulsified acid recipe: (**a**) Separation acid–diesel (unstable); (**b**) Corrosion test cell at high temperature 94 °C (200 F); (**c**) Stable emulsion after testing for 6 h at 94 °C (200 F).

3.2.2. Corrosion Testing Procedures

Corrosion test was conducted using gravimetry method, a high temperature high pressure (HTHP) corrosion tester machine (refer to Figure 4a) is used in dynamic status to control the corrosion utilizing different combination of corrosion inhibitors A, B, C and D. After testing the compatibility of chemicals, a corrosion test was performed revealing that combination B showed passing corrosion rate 48.8 g/m^2.



(**a**) (**b**)

Figure 4. Corrosion tester machine for testing: (**a**) OFITE HTHP corrosion tester; (**b**) 4 specimens to run four tests.

As seen in the Figure 4b, the four acid recipes were tested simultaneously and placed in glass bottles. The space between the jacket and the testing bottles is filled with organic oil for heating purposes. During corrosion test, two types of heat transfer occur: the heated double jacket transmits heat from the jacket to the oil surrounding the acid recipe by conduction, and the oil itself transfers heat to the acid recipe via convection. To ensure the appropriate distribution of heat, the corrosion tester machine is in dynamic position during the testing time, as a result, the acid recipe is tested at similar conditions to the reservoir in terms of downhole pressure and temperature, to estimate the exact corrosion rate and acid additives performance.

Multiples corrosion tests were performed in order to select the best corrosion inhibitor for the combination of Diesel and Acid to generate a protective layer on the metal against the emulsified acid recipe. In Table 1, corrosion inhibitor B was the best option, protecting the metal for a minimum of 6 h with a passing corrosion rate of 48.8 g/m^2 (below the limit). As highlighted in the last columns in yellow, the metal coupons used in low carbon steel

L-80 which refers to the type of metal used in the intervention as a contractor and refers to the type of metal that the completion of well is made of. Moreover, the corrosion rate unit is g/m^2 specially when considering the gravimetry method (weight loss (gram)/Area (m^2)) and the pitting index.

Table 1. Corrosion tests using different corrosion inhibitor families demonstrating corrosion rate g/m^2.

Chemical Code	Water	SUP-CI-68	SUP-IS-90L	SUP-FA-01	HCL Acid	Diesel	SUP-AE-03	Low Carbin Steel L-80	Corrosion Rate (g/m^3)	Pitting Index
		Corrosion Inh. A								
1	253	17	3	10	417	280	20	ZW625	292.9	NO PITS
		Corrosion Inh. B								
2	253	17	3	10	417	280	20	ZW626	48.8	NO PITS
		Corrosion Inh. C								
1	253	17	3	10	417	280	20	ZW627	258.7	NO PITS
		Corrosion Inh. D								
2	253	17	3	10	417	280	20	ZW628	278.2	NO PITS

Actually, the weight-loss measurement is one of the precise methods of detecting accurate metal corrosion rate because the procedure is relatively simple and allows for easy replication of the experimentation, even though long exposure times is required.

After selecting an adequate combination of corrosion inhibitor, tests were conducted to optimize the dosage of corrosion inhibitor (SUP-CI-68) and corrosion inhibitor intensifier (SUP-FA-01) under reservoir conditions.

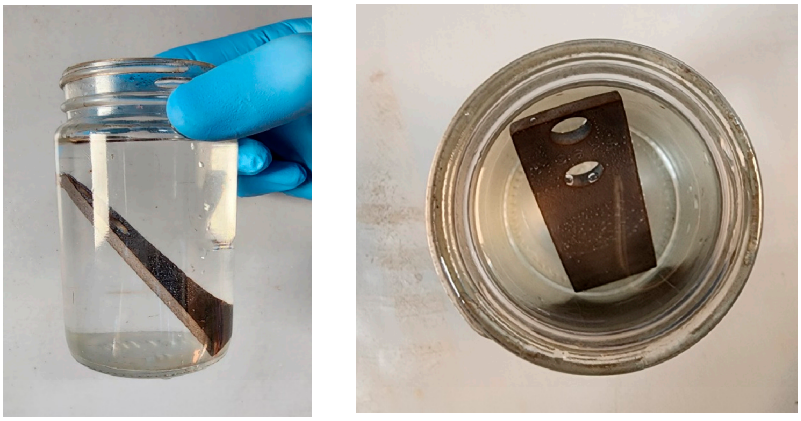
In the oil and gas industry, the acid recipe is performed for 1000-gals recipe where the total volume of a stand acid recipe is 1000 gals. In order to conduct the las test and acid mixture for corrosion testing a lab scale recipe is prepared using a conversion from gals to Liters (mL) as following:

In reference to the passed corrosion rate in acid recipe 2 in Table 1, the conversion calculation is presented in Table 2.

Table 2. Conversion calculation for recipe 2.

Additives	Imperial Dosage	Dosage (SI)
Fresh water	253 gal/1000-gal	37.95 mL/150 mL
SUP-CI-6	17 gal/1000-gal	2.55 mL/150 mL
SUP-IS-90L	3 gal/1000-gal	0.45 mL/150 mL
SUP-FA-01	10 gal/1000-gal	1.5 mL/150 mL
Acid HCl	417 gal/1000-gal	62.55 mL/150 mL
Diesel	280 gal/1000-gal	42 mL/150 mL

A lab scale mixture of 150 mL is mixed to fit corrosion test glass bottles and perform the required corrosion test at reservoir conditions. The volume is selected to cover the low carbon steel coupon within the bottle as demonstrated in Figure 5.



(**a**) (**b**)

Figure 5. Corrosion testing bottles containing low carbon steel L-80 coupons: (**a**) corrosion test bottle containing low carbon steel L-80 coupon profile view; (**b**) corrosion test bottle containing low carbon steel L-80 coupon top view.

After the testing period, the acid recipes are cooled down through the machine's cooling system then evaluated by weighing it. The coupons are removed from the acid recipe, well cleaned and kept for drying. After deep cleaning with required additives, the coupon is weighed, and the weight loss is calculated. The corrosion rate is estimated by dividing the weight loss over the surface area of the testing coupons (Figure 6). The circle in the diagram from Figure 6, represents the optimal dose range of corrosion inhibitor SUP-CI-68 and corrosion inhibitor intensifier SUP-FA-01 within the acid formula, which ensures both chemical compatibility and emulsion stability. These optimized dosages are the result of intensive laboratory research and analysis to determine the most efficient amounts that prevent corrosion without using too many chemicals. By operating within this range, the formula retains its integrity under field circumstances, providing strong protection for metal surfaces during acid stimulation. Furthermore, this precise optimization creates a compromise between cost-effectiveness and environmental responsibility, avoiding unnecessary chemical use while getting the intended results. This technique not only ensures technical dependability and compatibility of the acid system, but also reduces operational expenses and environmental footprint, making it an economically. After calculating the corrosion rate of each coupon, each coupon should be evaluated to indicate the pitting index demonstrating small and tinny holes in the metal surface. After evaluating all the corrosion aspects in terms of corrosion rate and pitting index, an optimum dosage of corrosion inhibitor and corrosion inhibitor intensifier was selected as mentioned in the graph above. As per Table 3, an optimum of 12 gals per thousand of SUP-CI-68 and 5 gals per thousand of SUP-FA-01 were enough to demonstrate an average corrosion rate of 141.59 g/m^2 with a pitting index equivalent to zero. Figure 7 shows some sample of the corrosion coupons weighed and evaluated using the optimum selected dosage.

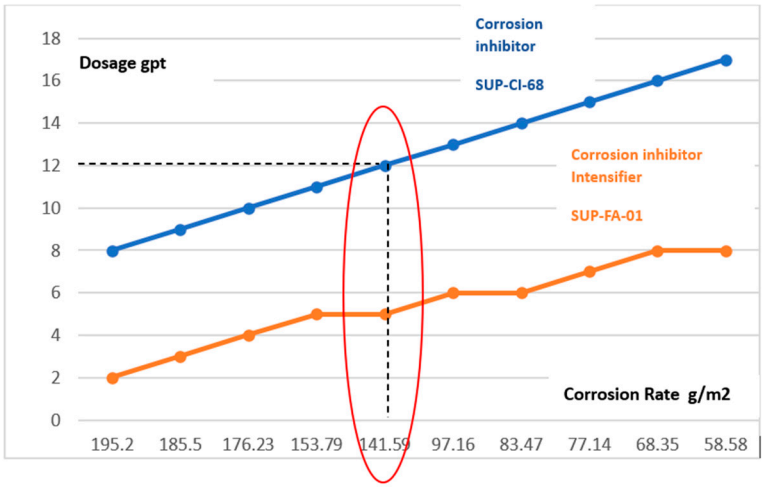


Figure 6. Corrosion rate vs. corrosion inhibitor dosage.

Table 3. Optimization of corrosion inhibitor & intensifier dosage.

Chemical Code	Water	SUP-CI-68	SUP-IS-90L	SUP-FA-01	HCL Acid	Diesel	SUP-AE-03	Low Carbin Steel L-80	Corrosion Rtae (g/m^3)	Pitting Index
		Corrosion Inh. B								
1	270	8	3	2	417	280	20	ZW701	195.2	NO PITS
2	268	9	3	3	417	280	20	ZW702	185.5	NO PITS
3	266	10	3	4	417	280	20	ZW703	176.23	NO PITS
4	264	11	3	5	417	280	20	ZW704	153.79	NO PITS
5	263	12	3	5	417	280	20	ZW705	141.59	NO PITS
6	261	13	3	6	417	280	20	ZW706	97.16	NO PITS
7	260	14	3	6	417	280	20	ZW707	83.47	NO PITS
8	258	15	3	7	417	280	20	ZW708	77.14	NO PITS
9	256	16	3	8	417	280	20	ZW709	68.35	NO PITS
10	255	17	3	8	417	280	20	ZW710	58.58	NO PITS



(**a**) (**b**)

Figure 7. Carbon steel coupons surface behavior: (**a**) Low carbon steel L-80 surface before performing corrosion test; (**b**) Low carbon steel L-80 surface before performing corrosion test.

To summarize, the above approach generated a stable emulsion using four different families of corrosion inhibitors, with constant performance over several hours at room

and high temperatures. A transient rate of corrosion that satisfied the contractor standard limit when employing corrosion inhibitor family B on low carbon steel L-80 strengthened the mixture's stability. Continual optimization of inhibitor dosages and intensifiers, maintained a balance between corrosion inhibition/operational efficiency. This method relates to the performance of emulsified acid treatment in delivering a robust option for stimulation operation, in high temperature application, and in the same time minimizing the corrosion effect on production tubing and contractor coiled tubing string and reducing treatment costs.

It is important to highlight that corrosion rates were also strongly impacted by the concentration of the corrosion inhibitor, where high concentrations guaranteed compliance to industry standards without affecting emulsion stability and lower amounts generated inadequate protection. Therefore, the optimization process has a direct impact on the treatment's efficiency, making it more practical and competitive when compared to conventional HCl treatments. Also, it helps in minimizing unnecessary chemical consumption while preventing a stable emulsion and providing efficient corrosion prevention by striking the ideal balance of chemical dosages. Additional benefits for the environment result from approach since less chemical is used, which reduces the amount of additives pumped into the well, lowering the possibility of chemical precipitation and the operation's environmental impact. These results highlight the significance of precise optimization to guarantee an economical, environmental awareness and highly successful emulsified acid treatment technique.

In addition to the above-mentioned tests, viscosity test was performed to estimate the viscosity of the new fluid system and its effect on the injection rate during operation. The viscosity was measurement at room temperature and high temperature to match reservoir condition and predict the estimated viscosity that will affect the pumping rate and friction factor. The viscosity test was carried out using advanced high temperature high pressure Chandler viscometer HTHP 5550 that will assess the viscosity of the fluid instantly under the reservoir conditions.

After mixing and creating a stable emulsion, the viscosity tests results are as presented in Table 4.

Table 4. Viscosity test of Emulsified Acid at Room and High temperature.

RPM	Room Temp. (25 °C)	High Temp. (94 °C)
600	0.101 Pa.s	0.070 Pa.s
300	0.064 Pa.s	0.044 Pa.s
200	0.048 Pa.s	0.032 Pa.s
100	0.028 Pa.s	0.020 Pa.s
60	0.018 Pa.s	0.014 Pa.s
30	0.010 Pa.s	0.009 Pa.s
3	0.003 Pa.s	0.003 Pa.s

The above table (Table 4) shows a viscosity of 44 mPa.s or 44 °Centipoise at a rpm of 300. The test was performed to estimate the viscosity of the emulsified acid fluid under reservoir conditions during operation to predict the pumping rate and pumping time.

The corrosion tests were performed to inhibit the corrosivity of HCl in the recipe for 12 h continuous. The acid dosage implemented was 15 gals per foot equivalent to 0.056 m^3 per foot, as a result, the injection rate and inhibition time depends on the total volume of the injected acid.

In the first case, the total open hole length is 4975 ft equivalent to 1516.38 m. Total acid volume is calculated as follows: 4975 ft $\times$15 gals/ft = 74,625 gals equal to 282.52 m^3.

In short, Superior Abu Dhabi treatment performed exceptionally well, with an average viscosity of 44 mPa.s at reservoir temperature. It demonstrates the emulsion's exceptional stability, which is attributed to its homogeneous and consistent acid-diesel ratio and optimum chemical additions. The stable emulsion significantly lowers the possibility of dilution by water, resulting in improved performance and penetration into the formation. These features make the emulsified acid treatment a strong and effective solution for stimulation operations, offering consistent performance under challenging high temperature conditions and leading to increased well production.

3.3. Field Description

The selected wells are injection wells surrounding oil producers. These wells are injected for 6 months with fresh water then 6 months with processed gas from the station. After reviewing their history, some of it are drilled since 2018/2019 and stimulated with conventional 15% HCl treatment showing very low injectivity which is affecting the estimated oil production. Therefore, the major oil and gas company accepted Superior Abu Dhabi proposal for advanced acid stimulation, where all operation details and job design were included, reviewed, and discussed and then performed on four water alternative gas (WAG) wells in Quasahwira field.

The four wells presented lateral open holes with long zone of interest (Table 5).

Table 5. Wells characteristics.

Well Number	QW-181	QW-129	QW-133	QW-138
Measuring Depth:	12,205 ft	10,910 ft	9262 ft	11,346 ft
Open hole length	6098 ft	4484 ft	4287 ft	4050 ft
Open hole diameter	6″	6″	6″	6″
Completion size	3 ½″	3 ½″	3 ½″	3 ½″
Type of formation	$CaCO_3$	$CaCO_3$	$CaCO_3$	$CaCO_3$
Type of well	Injection	Injection	Injection	Injection
Well Profile	Lateral	Lateral	Lateral	Lateral

3.4. Simulation Run and Data Gathering

The well data were interpretated through stimulation software "StimPro Software" version (10.13.16) which designed to model the behavior of acid treatment in reservoir formations where it utilizes complex algorithms and numerical simulations to predict results in terms of fluid flow dynamics, reaction kinetics, diffusion mechanism, permeability enhancement by reducing the damage skin, differential pressure across the skin along with reservoir length, acid injection rate and rock performance.

Reservoir data are utilized as input to conduct the simulation, which estimates the final rock properties, predicts injectivity index and reservoir performance as well as simulate the flow of new emulsified acid treatment.

Well data are shown in Table 6.

Table 6. Well petrophysical data.

Factors	UOM	Quantity
Reservoir Temperature	F	191
Pore Fluid Permeability	mD	3.00×10^{-1}
Reservoir Viscosity (Pa.s)	cP	0.5
TVD to top of open Section (m)	ft	5734
Acidizing Type	Carbonate	
Avg. Surface Pressure	Psi	702
Initial Skin	N/A	5.08
Avg. Reservoir Pressure	Psi	2372
Porosity	%	22.1
Frac Pressure	Psi	4000
TVD to Bot of Open Section	ft	5774
Acid Volume	bbls	1405
Max. Surface Pressure	1724	1724
Final Skin	N/A	−0.10

In order to estimate the fluid progression and invasion into the formation and through the damaged skin, some fluid characteristics were used as an input into the simulation run considering the acid concentration, density, diffusivity, friction factor and retardation factor as well as initial K factor, as demonstrated in the Table 7.

Table 7. Fluid properties versus reservoir properties.

Fluid Name	2% KCl Brine	15% HCl	20% Emulsified Acid
Description	Pre-flush/overflush fluid	HCl Acid	Emulsified Acid
Fluid density	1.013	1.075	1.08
Diffusivity (ft2/min)	4.30×10^{-6}	4.30×10^{-6}	4.30×10^{-6}
Retardation factor	1	1	5
Diverter Concentration (% Vol)	0	0	0
Filtercake Porosity	0.01	0.01	0.01
Filtercake Permeability (mD)	1.00×10^{-4}	1.00×10^{-4}	1.00×10^{-4}
Initial Viscosity (cP)	1	1	100
initial n′	0	0	1
Initial K′ (lbs.s^n/ft2)	0	0	2.10×10^{-5}
Wellbore Friction Multiplier	0.3	0	0.5

Taking into consideration the well deviation survey and reservoir layers, parameters detailing layers from 7046 ft down to 11,986 ft such as rock lithology, pore fluid permeability, reservoir viscosity, compressibility, porosity, pore pressure, frac pressure and permeability ratio are utilized to estimate the dual phase acid injection and rate of penetration of acid into the layers as indicated in Table 8.

Table 8. Reservoir layers properties.

Layer #	Top of Zone TVD (ft)	Top of Zone MD (ft)	Lithology	Pore Fluid Permeability (mD)	Reservoir Viscosity (cp)	Compressibility (1/psi)	Porosity	Pore Pressure (psi)	Frac Pressure (psi)	Kh/Kv
1	0.0	0.0	Shale	$0.00 \times 10^{+00}$	0.030	$1.00 \times 10^{+00}$	0.010	2372	5580	1.000
2	5727.6	7046.0	Limestone	3.05×10^{-1}	0.500	$1.00 \times 10^{+00}$	0.125	2372	4000	1.000
3	5733.7	7200.0	Limestone	6.21×10^{-1}	0.500	4.00×10^{-4}	0.197	2372	4000	10.000
4	5742.1	7455.0	Limestone	7.26×10^{-1}	0.500	4.00×10^{-4}	0.173	2372	4000	10.000
5	5748.0	7758.0	Limestone	8.53×10^{-1}	0.500	4.00×10^{-4}	0.209	2372	4000	10.000
6	5749.4	7839.5	Limestone	8.64×10^{-1}	0.500	4.00×10^{-4}	0.226	2372	4000	10.000
7	5752.8	8058.0	Limestone	8.61×10^{-1}	0.500	3.99×10^{-4}	0.243	2372	4000	10.000
8	5753.5	8109.5	Limestone	8.95×10^{-1}	0.500	3.99×10^{-4}	0.227	2372	4000	10.000
9	5757.8	8590.0	Limestone	$1.19 \times 10^{+00}$	0.500	3.99×10^{-4}	0.271	2372	4000	10.000
10	5760.4	8899.5	Limestone	$1.18 \times 10^{+00}$	0.500	3.99×10^{-4}	0.275	2372	4000	10.000
11	5762.1	9111.0	Limestone	$1.13 \times 10^{+00}$	0.500	3.99×10^{-4}	0.247	2372	4000	10.000
12	5763.9	9325.5	Limestone	7.98×10^{-1}	0.500	3.99×10^{-4}	0.243	2372	4000	10.000
13	5765.3	9486.0	Limestone	8.02×10^{-1}	0.500	3.99×10^{-4}	0.238	2372	4000	10.000
14	5767.2	9681.5	Limestone	8.69×10^{-1}	0.500	3.98×10^{-4}	0.221	2372	4000	10.000
15	5768.7	9841.0	Limestone	$1.04 \times 10^{+00}$	0.500	3.98×10^{-4}	0.239	2372	4000	10.000
16	5770.0	9999.5	Limestone	$1.42 \times 10^{+00}$	0.500	3.98×10^{-4}	0.218	2372	4000	10.000
17	5772.7	10,321.0	Limestone	$1.17 \times 10^{+00}$	0.500	3.98×10^{-4}	0.183	2372	4000	10.000
18	5773.9	10,583.6	Limestone	9.75×10^{-1}	0.500	3.98×10^{-4}	0.201	2372	4000	10.000
19	5773.7	10,496.9	Limestone	6.89×10^{-1}	0.500	3.98×10^{-4}	0.175	2372	4000	10.000
20	5773.6	10,475.2	Limestone	7.90×10^{-1}	0.500	3.98×10^{-4}	0.206	2372	4000	10.000
21	5773.9	11,500.0	Limestone	9.14×10^{-1}	0.500	3.98×10^{-4}	0.222	2372	4000	10.000
22	5774.1	11,690.1	Limestone	9.34×10^{-1}	0.500	3.98×10^{-4}	0.230	2372	4000	10.000
23	5774.2	12,000.0	Limestone	8.85×10^{-1}	0.500	3.98×10^{-4}	0.251	2372	4000	10.000
24	5774.2	11,985.6	Shale	$0.00 \times 10^{+00}$	0.500	3.98×10^{-4}	0.000	2372	4000	1.000

3.5. Damaged Skin Profile

The damage severity was evaluated as light considering that the damage penetration is medium with a damage depth of 0.5 ft among the open hole length and reservoir thickness from 7046 ft down to 12,205 ft. The composition of the damage is a combination of deposition and precipitation of calcium carbonate mixed with formation water ion complexes. The main target of advanced acid stimulation is to overcome the damaged skin and enhance acid penetration rate throughout these layers to improve well injectivity index.

After running the simulation using all the reservoir data, Rate and Pressure were estimated during acid injection demonstrating a decrease in circulation pressure from 3950 Psi down 3200 Psi within 6 h for fixed pumping rate of 2 bpm as shown in Figure 8. Additionally, a remarkable decrease in wellhead pressure is noticed (Figure 8) conforming acid deep penetration and permeability enhancement.

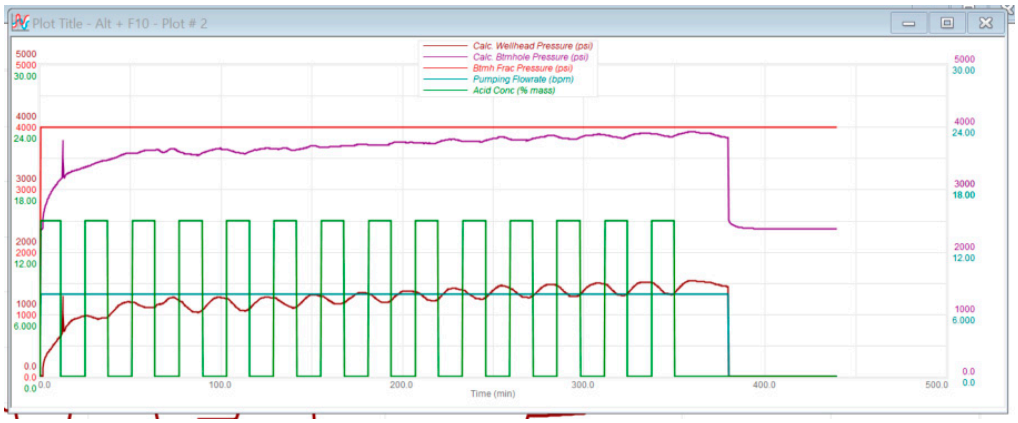


Figure 8. Simulation Run for acid stimulation using Emulsified Acid.

Moreover, damaged skin profile is demonstrated in the above graph (Figure 9) where the post treatment skin slop demonstrated a decrease from 5 down to 0.5 within 9 h of emulsified acid injection for a fixed pumping rate.

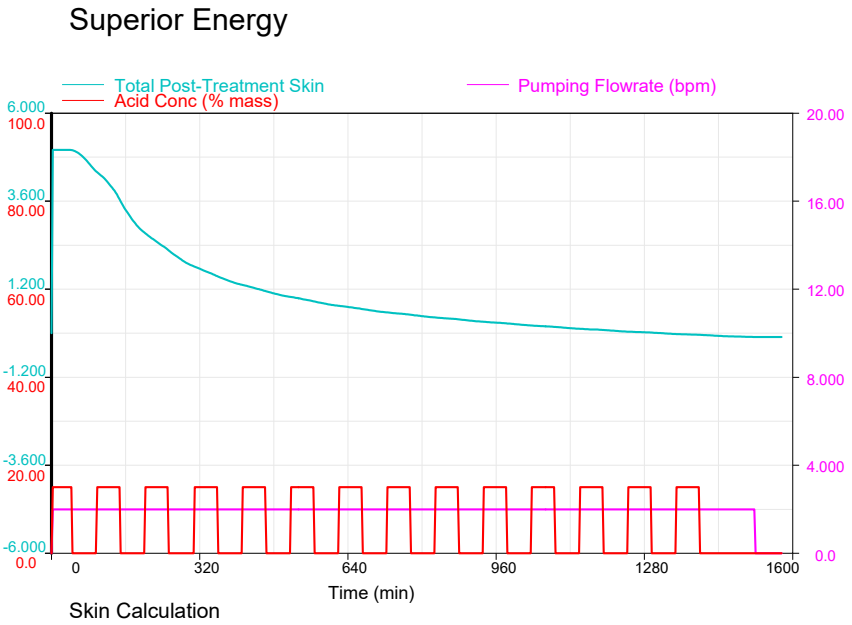


Figure 9. Skin damage profile after stimulation.

3.6. Stimulation Process Enhancement

Conventional stimulation was now improved by implementing a scheduled acid pumping via the abrasive tool involving 4 jetting nozzles that diverts the emulsified acid treatment in a straight sharp direction towards the carbonate reservoir increasing the kinetic reaction of the acid solution with the layer and effectively creating conductive channels while HCl in the normal acid is pumped to cover the 6″ reservoir thickness and usually HCl takes the path of the least resistance. Therefore, the high velocity jetting tool is spreading the acid into 4 different directions covering 360° degree each stage with further invasion. The invasion progression is showed in the Figure 10.

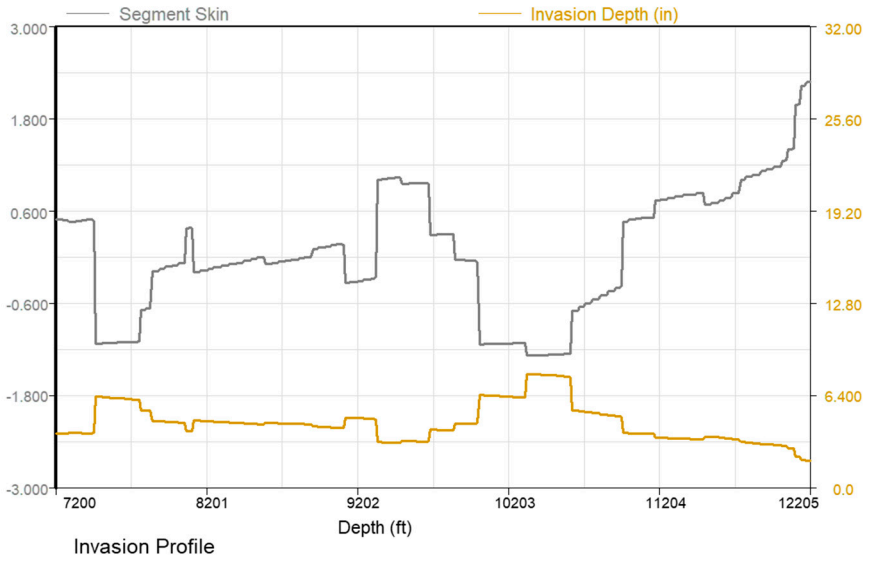


Figure 10. Acid invasion profile within the rock properties.

3.7. Petrophysical Data Enhancement

Figure 11 is demonstrating the enhancement of permeability and porosity along with the reservoir depth. The permeability shows tremendous improvement up to 1.97 μm^2 (2 milli Darcy) explaining the invasion process through the damaged skin as well as the porosity where it shows the ability of the void space in the rock to house maximum oil and gas that should be produced.

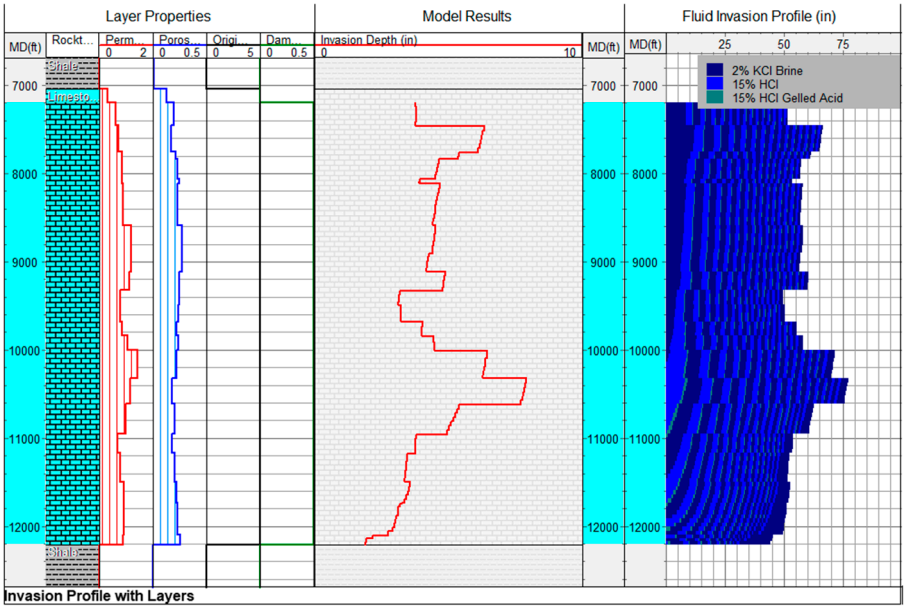


Figure 11. Permeability results.

Compared with the conventional treatment, the new dual phase acid retarder has demonstrated remarkable increase in reservoir permeability by reducing the damaged skin, opening the clogged tiny pores of the rock for an improved injectivity. The retardation technique helped for better and deeper placement of the live acid into the rock creating warm holing. Additionally, the tools implemented diverted the fluid against the rock by reducing spent acid and its leak-off.

4. Results Obtained in Four Cases of Actual Acid Treatment

The four cases were simulated showed impressive injectivity improvement (Figure 12). The injectivity test was performed before and after the acid stimulation and sustained a stable injectivity index. The graphs from Figure 12 show the outcomes of four different scenarios, with the interplay between injection rate and pressure as the major parameters. The red line indicates the injection or production rate, which has improved over time, whereas the blue column represents the related pressure behavior, which have decreased. These visualizations highlight the dynamic link between these two variables, with an increase in injection rate resulting in a decrease in pressure, indicating improved fluid injectivity and system efficiency. The increasing rising of the red line shows that the injection process has been successfully optimized or that reservoir responsiveness has improved, whereas the dropping blue column indicates that pressure needs have been properly reduced.

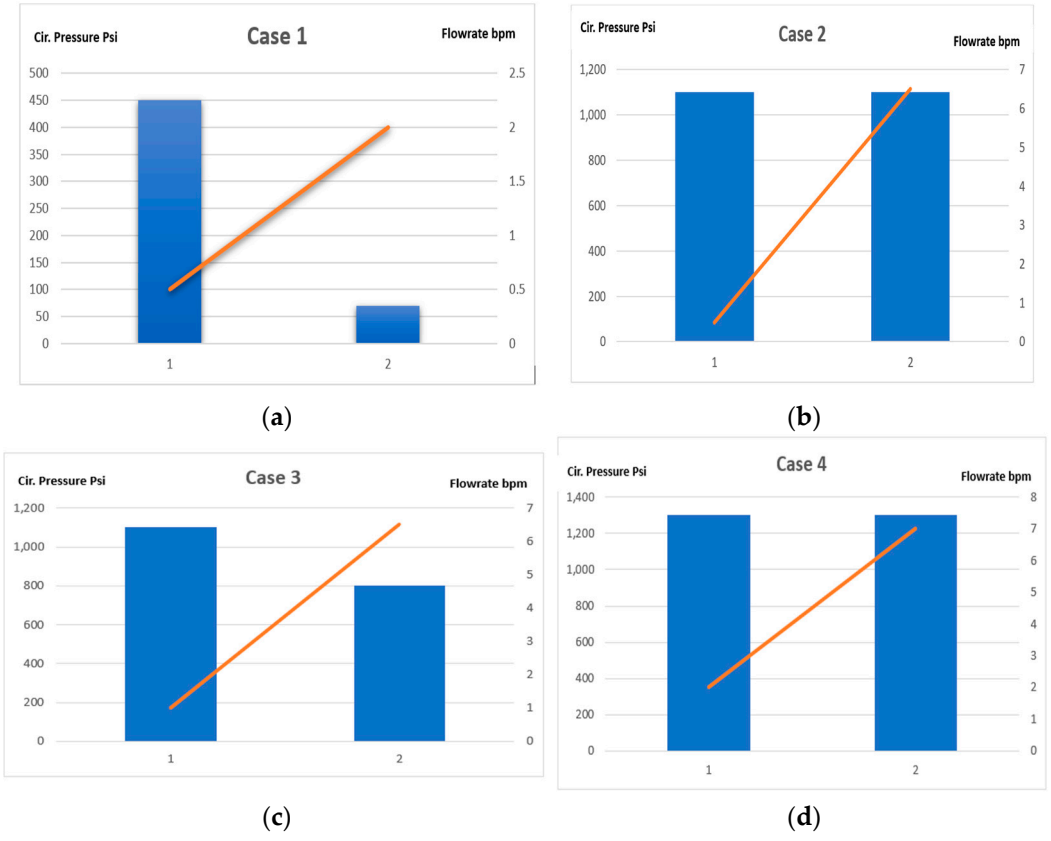


Figure 12. Post-injectivity result for 4 cases tested in the field: (**a**) Post-injectivity result for case 1; (**b**) Post-injectivity result for case 2; (**c**) Post-injectivity result for case 3; (**d**) Post-injectivity result for case 4.

For the first case: injectivity was around 0.5 bpm at 450 Psi increased to 5.2 bpm at 200 Psi.

For the second case: injectivity was around 0.5 bpm at 1100 Psi increased to 6.5 bpm at 1100 Psi.

For the third case: injectivity was around 1 bpm at 1100 Psi increased to 6.5 bpm at 800 Psi.

For the fourth case: injectivity was around 2 bpm at 1300 Psi increased to 7 bpm at 1300 Psi.

The above-mentioned results (Figure 12) were recorded during emulsified acid jobs where the new treatment enhanced the well injectivity index from 3 up to 10 times. The

main target is to maintain the injection steady for an extended period of time. As a result, after the acid stimulation using emulsified acid treatment, injection began from the station to the well, and the flowrate and pressure were recorded.

As shown in the graph from Figure 13, NOV real-time data monitoring recorded the acid injection with coiled tubing relative data utilizing the NOV orien system. The graph demonstrated that coiled tubing lock-up was at 12,000 feet.

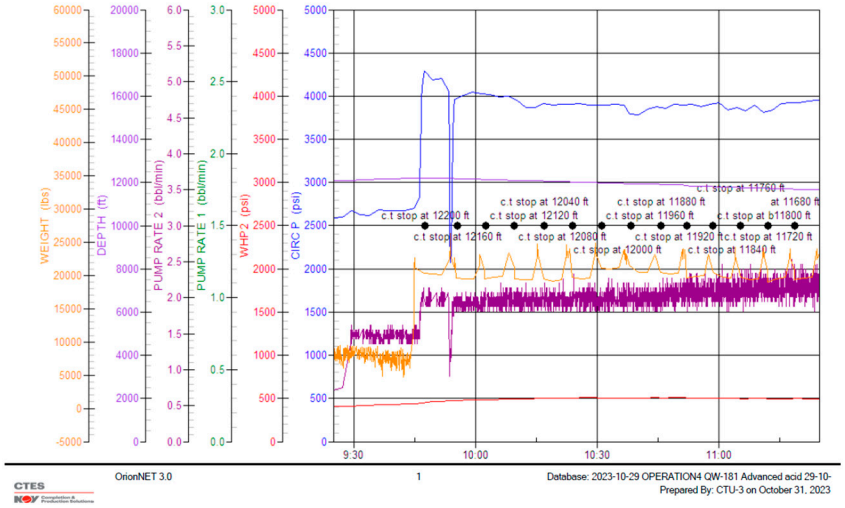


Figure 13. Real-time data monitoring from the field during acid stimulation.

The plan/stimulation program was to pump stationery every 40 feet, with 15 Bbls of emulsified acid injected at each stage, creating warm holing and improving reservoir performance.

As mentioned previously, the treatment injection was carried out through high velocity abrasive jetting tool, where the emulsified acid was diverted into four sides covering 360 degrees allowing to the viscous fluid to overcome the damaged skin and penetrate into the rock allowing creation of warm holing.

The abrasive jetting tool (Figure 14) was composed a 1.5-foot length and composed of tungsten carbide alloy that can resist to inhibited acid treatment. The viscosity of the system improves wellbore coverage, and the emulsified acid treatment is diverted to the low-permeability/damage zones. The low diffusivity of the acid provides efficient wormholing at low injection rates. The wormholes are narrow but penetrate deep into the formation. Contrary to HCl acid treatment which reacts fast and does not penetrate deep into the formation at high temperature [14].

As shown in Figure 14 the acid is injected into the formation at a rate of 2 bpm for 7.5 min continuously where a drop in pressure is noticed and increase in pumping rate is there (in reference to Equation (2) and Figure 15).

Initially, the pumping rate and pressure were around 1.7 bpm at 3900 Psi, but after 30 min, the rate increased to 2 bpm at 3900 Psi (refer to Figure 16).

After 1 h of acid pumping the injection flow rate increases up to 2.3 bpm at a constant pressure of 3900 Psi (refer to Figure 17).



Figure 14. Abrasive Jetting Tool used in Emulsified Acid Job.

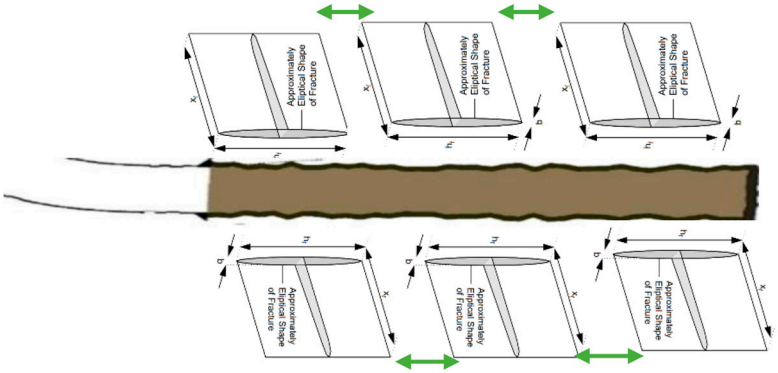


Figure 15. Acid injection profile with the formation through abrasive jetting tool.

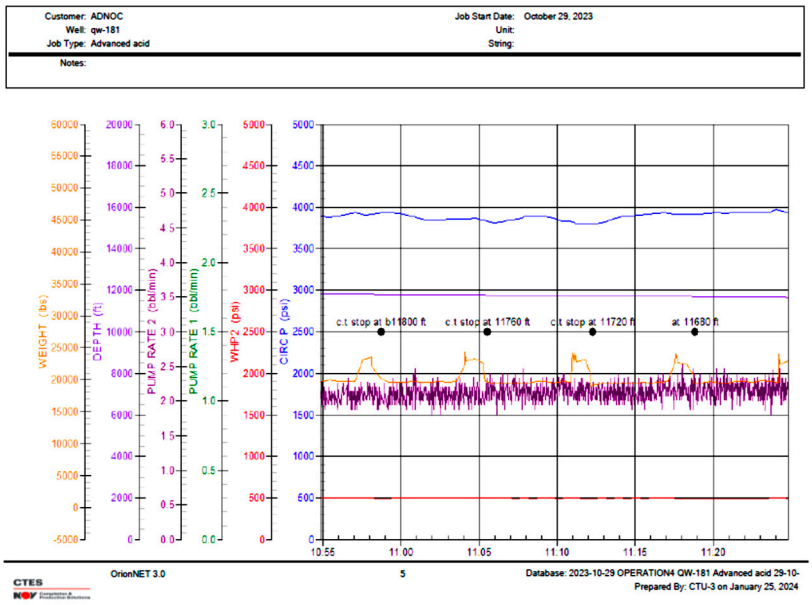


Figure 16. Real-time data monitoring of pumping emulsified acid.

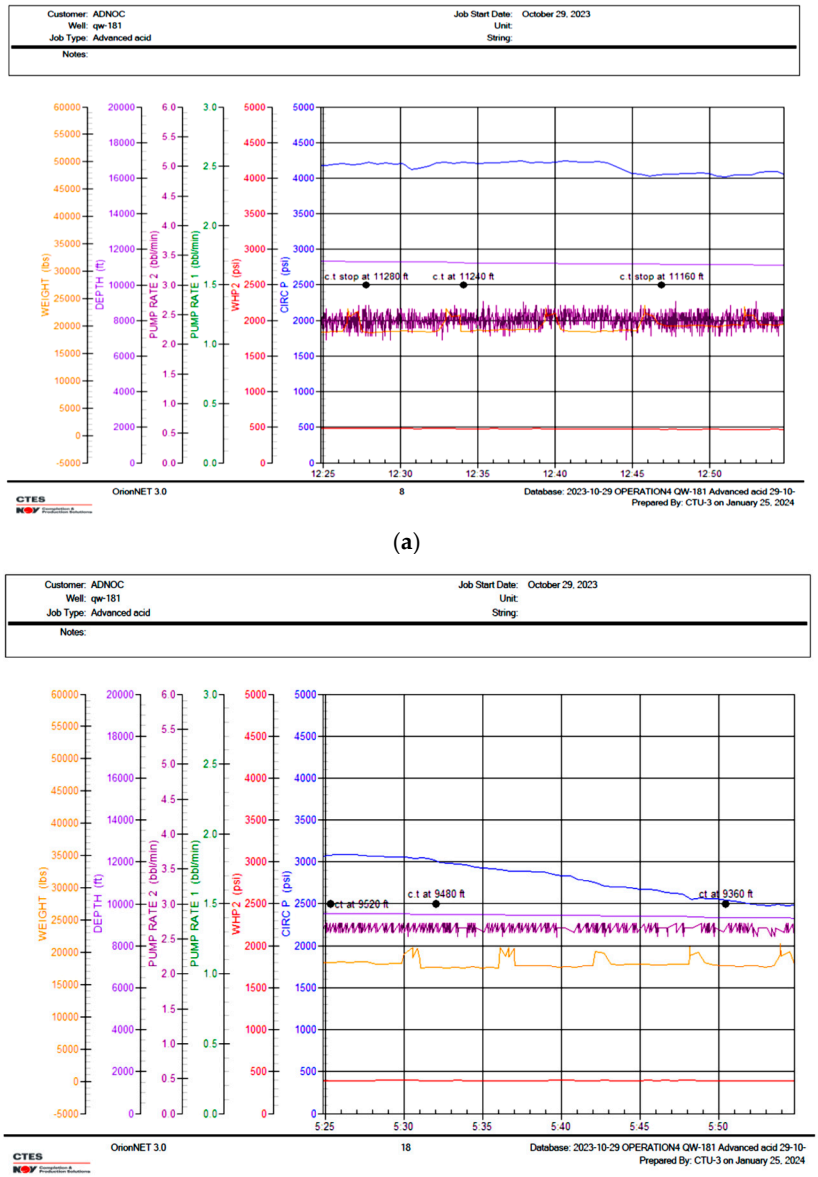


Figure 17. Injection rate and pressure performance during emulsified acid: (**a**) Pumping emulsified acid treatment within the formation; (**b**) Pumping emulsified acid treatment within the formation.

As expected, the combination of mechanical and chemical solution enhanced the injection of emulsified acid into the formation while penetrating the damaged skin (refer to Equations (3) and (4)) reaching an increase of 35% in pumping rate.

Figure 17 shows a stable injection rate of emulsified acid into the formation at a rate of 2.8 bpm and a remarkable drop in pressure from 3900 Psi down to 3000 psi then 2500 Psi within 1.5 h continuous acid pumping. The retardation effect of the new treatment is effective showing a drop in the pressure and an increase in flowrate within less than 2 h.

The nature of radial flow is that the pressure difference in the reservoir increases with the logarithm of distance. For instance, the same pressure is consumed within the first foot as within the next ten, hundred. when the permeability of the near-wellbore zone is reduced significantly it is entirely conceivable that the largest portion of the total pressure gradient is consumed within the very near-wellbore zone [27].

As a result, to evaluate the emulsified acid injection efficiency, an injectivity test is performed at the Wireline entry guide (bottom component) of the completion.

An injectivity test was conducted after completing the acid stimulation operation, where the injectivity demonstrated an increase in the flowrate at a constant pressure (Figure 18):

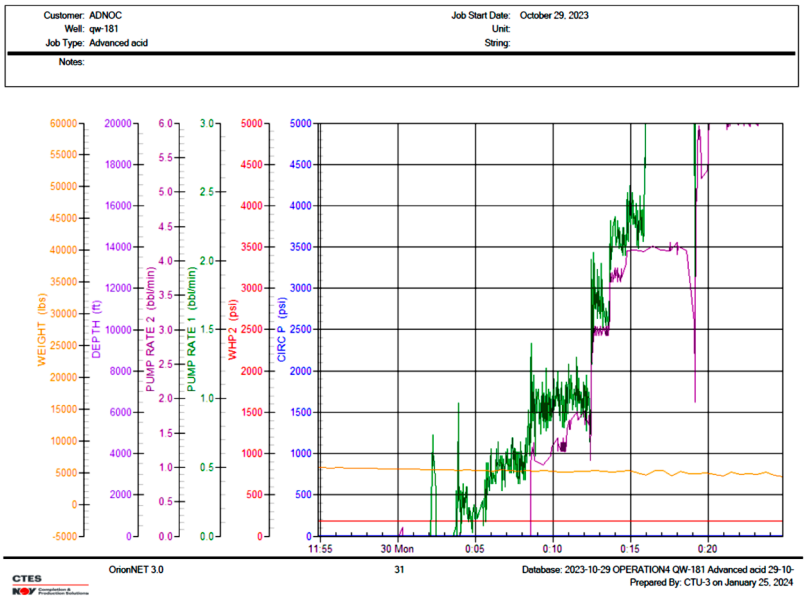


Figure 18. Real-time post-injectivity test recorded on field.

- Pumping Rate 1 in purple demonstrated an increase up to 4 barrels;
- Pumping Rate 2 in green demonstrated an increase up to 2.5 barrels.

Both injection rates sustained for a period of 30 min continuous injection at a negligeable pressure of 200 Psi.

After implementing the new acid treatment on the same well, a comparison took place between the results of both conventional 15% HCl acid treatment and emulsified acid treatment, where remarkable enhancement in terms of injection rate and decrease in wellhead pressure were recorded during and after operation. Table 9 demonstrates the variation of essential operational factors while using the new emulsified acid treatment onto rock:

Table 9. Comparison table between conventional 15% HCl and new Emulsified Acid treatment.

Conventional Acid System					Emulsified Acid System				
	QW-129		QW-133			QW-129		QW-133	
Factors for Model	**Pre-Injectivity**	**Post-Injectivity**	**Pre-Injectivity**	**Post-Injectivity**	**Factors for Model**	**Pre-Injectivity**	**Post-Injectivity**	**Pre-Injectivity**	**Post-Injectivity**
Injectivity Flow rate bpm	1.7	3	1.5	2.4	Injectivity Flow rate bpm	2	7	0.5	6.5
Circulating Pressure in coiled tubing Psi	1500	1400	4000	1250	Circulating Pressure in coiled tubing Psi	1300	1300	1100	1100
WHP Psi	1500	1400	1000	900	WHP Psi	1200	700	1200	600

As mentioned in the above Table 9, in the first case QW-129, using conventional stimulation the injection rate was enhanced from 1.7 bpm up to 3 bpm with a slight decrease in wellhead pressure of 100 psi, however, the injectivity increased from 2 bpm to 7 bpm with a drop in wellhead pressure of 500 psi when using the new emulsified acid treatment.

The second case, QW-133, showed the similar pattern, using conventional 15% HCl acid, the injectivity increased from 1.5 bpm up to 2.4 bpm although the injectivity was improved by 12 times from 0.5 up to 6.5 bpm while pumping the new emulsified acid treatment.

These data were recorded and collected by Superior Abu Dhabi during and after the stimulation operation.

5. Predictive Modeling Approach

Few research explored how machine learning can predict injectivity enhancement while stimulating a certain rock. In our investigation into the enhancement of injectivity following acid treatment, a comprehensive analysis was conducted employing three different predictive models: Support Vector Machine (SVM), Gradient Boosting Regressor (GBR), and Ridge Regression [28].

These methodologies were utilized on a dataset containing diverse well characteristics, including Permeability, Porosity, Water Saturation, and Skin Factor, alongside metrics associated with reservoir and treatment pressures.

5.1. Standardization Process

Prior to modeling, data was standardized to have zero mean and unit variance, crucial for the performance of the predictive algorithms.

The standardization process, also known as z-score normalization. This process transforms the features of the dataset to have a mean (μ) of zero and a standard deviation (σ) of one. The transformation is given by the formula:

$$z = \sigma(x - \mu) \tag{6}$$

In the provided Python code, the "StandardScaler" from Scikit-learn's preprocessing module is used to perform this standardization. The scaler is first fitted to the training data, calculating the mean and standard deviation for each feature in the training dataset. These statistics are then used to transform both the training and testing datasets without biasing the model with information from the testing data.

The means and standard deviations computed during scaling are crucial when interpreting model coefficients, especially when scaling back to the original feature space. This ensures that interpretations and predictions remain relevant to the original context of the data.

5.2. Predictive Models and Their Configuration

Three different models were used: Support Vector Regression (SVR), Gradient Boosting Regressor (GBR), and Ridge Regression.

1. Support Vector Regression (SVR):

SVR applies the principles of support vector machines to regression problems. It attempts to fit the error within a certain threshold and is robust against outliers.

In the code, the SVR model is trained with a set of hyperparameters that define the margin of tolerance (C) and the kernel type. The "GridSearchCV" is utilized to find the optimal hyperparameters by searching through a predefined space of values and evaluating model performance using cross-validation.

5.2.1. Detailed Derivates and Rationale Behind Parameters Selected Related to SVR

Mathematical Derivation: The central concept of Support Vector Regression is to identify a function f(x) that does not differ from the true values y by more than a margin, and at the same time function's complexity is minimized, causing a shift from one hyper plane.

The functions that constitute SVR are as follows: min(w, b, epsilon)(1/2||w||^2 + C∑_(i = 1)^n xi_i), Where: w is the weight vector perpendicular to the hyperplane, b is the bias term, xi_i are the slack variables allowing for some margin violations for the data that is not linear, and C is a parameter of regularization that controls balance between reducing the error term and the complexity of the model.

The optimization problem is in determining how to minimize the error while at the same time maximizing the distance between the support vectors and the decision boundary. For problems heterogeneous in data that is non linear the kernel trick is used which allows the input data to be represented in a higher dimension space where linear separation is possible.

Rationale Behind Parameter Selection:

C (Regularization Parameter): a small C encourages a more gentle model by allowing errors while big C increases the focus on minimizing errors hence the possibility of overfitting such a model weakens. C = 0.1, C = 1, C = 5, C = 10, provide an optimal grid search ensuring appropriate bias-variance trade off.

Gamma: Regulates the significance of each point in the data set. A high value for gamma may lead to the model being over-parameterized while lower values for gamma ensures better generalization of the model.

Kernel: The RBF kernel is used because it can accommodate more complex, non-linear relationships, while the linear kernel is more appropriate in less complex problems.

2. Gradient Boosting Regressor (GBR):

GBR builds an ensemble of weak prediction models, typically decision trees, in a stage-wise fashion. It optimizes for a loss function, enhancing the model where it is not performing well.

In this case, the GBR is configured with a default setup, but typically, parameters like the number of estimators, learning rate, and max depth can be adjusted. The randomness is controlled via the random state parameter to ensure reproducible results.

5.2.2. Detailed Derivates and Rationale Behind Parameters Selected Related to GBR

Gradient Boosting Regression follows the approach of minimizing past models' residual errors by the construction of an additive model, Gradient Boosting proceeds in a forward stage-wise manner. The model can be expressed with the formula below:

$$f(x) = \Sigma(m = 1 \text{ to } M)\ \text{Gamma__m} \times h_m\ (x)$$

where:

h_m(x) describes the m-weak learner (which is usually a decision tree),

Gamma_m is the weight of the m-th tree that minimizes the residual sums of squares.

At every step, residual errors are evaluated by the following equation:

$$r_i = y_i - f(x_i)$$

Learning Rate: Determines the influence of each tree. It must be lowered to avoid overfitting which means requiring and using more trees.

Number of Estimators: Limits the overall quantity of trees in a model. An insufficient number may result in the model being too simple while an excessive number may lead to the model being too complex. Cross-validation is ideal for determining the value.

Max Depth of Trees: Capturing varying degrees of complexity requires varying degrees of depth. However too deep may result in the model overfitting but depths of 3 to 5 are ideal.

3. Ridge Regression:

Ridge Regression introduces a regularization term (alpha) to the ordinary least squares equation to reduce model complexity and prevent overfitting.

The model is configured with alpha = 5, influencing the strength of the regularization. A higher alpha value means more regularization, leading to smaller coefficients, but too high a value can lead to underfitting [29].

5.2.3. Detailed Derivates and Rationale Behind Parameters Selected Related to RR

Ridge regression seeks to minimize the positive coefficients in limited information problems by embedding self-normalization. The optimization equation is expressed as:

$$\text{hat(beta)} = \text{argmin(beta) sat } (((y) - (X \times \text{beta}))\text{^2} + \text{lambda (eta)}\text{^\{2\}}$$

where:

- y is the target value vector
- X is the design matrix for multiple dimensions
- (beta) β is the vector containing the regression coefficients
- (lambda) λ is the value enforcing the penalty.

This formulation helps alleviate problems of multicollinearity by contracting the values of the coefficients of correlated predictors.

Rationale Behind Specification of Parameters:

- Alpha (lambda): Moderates the regularization intensity. An increase in lambda would try to reduce the over-fitting.
- A value of 5 was selected to moderate model overfitting and allows sufficient flexibility for the model.

Concerning the three vectors used to build a model able to predict the targeted injection rate using reservoir data where Support Vector Machines (SVM) perform nicely, in particularly high-dimension space, as well as limitation that involve complex non-linear decision boundaries, particularly when using the Gaussian RBF kernel. By selecting C, gamma, and kernel type the model learning a representative generalization to fit the data.

Gradient Boosting performs great with non-linear correlations because it optimizes successive weak learners. It can refine residuals to challenging level with good performance but necessitates careful parameters selection.

Ridge Regression is used in linear models when regularization is necessary to avoid overfitting, especially in situations with multicollinearity or when the number of features is significantly larger than the number of observations but has limitations when the input and output variables interact.

5.3. Application of Ridge Coefficients to Generate Formulas

After training, Ridge Regression provides coefficients (weights) for each feature (Table 10). These coefficients represent the relationship between each feature and the target variable, adjusted for the scale of the feature. The formula used to predict the target variable from the features can be written as:

$$y = \beta_0 + \beta_1 \times x_1 + \beta_2 \times x_2 + \ldots + \beta_n \times x_n \quad (7)$$

Table 10. Exploratory Analysis data and coefficients.

Description	Predicted Values								
Ridge Scaled coefficients	−0.1	0.03	−0.03	0.07	−0.11	0.07	0.08	0.1	0.1
Ridge Scaled intercept	6.23								
Standard Scaler st_dev	0.12	1.7	7.86	0	0.91	195.16	0.62	362.86	449.69
Standard Scaler means	0.73	23	70.13	−0.12	4.81	2545.33	1.17	950	766.67
Descaled coefs	−0.81	0.02	0	14.11	−0.12	0	0.13	0	0

Here, β0 is the intercept, and β_1, β_2, …, β_n are the feature coefficients. However, because we use standardized data for training, the coefficients correspond to the standardized features, not the original scales.

To convert these back, we use the original means and standard deviations of the features:

Original Coefficient = Standard Deviation Coefficient

And the intercept is adjusted accordingly:

Original Intercept = Ridge Intercept − ∑ (Original Coefficients × Feature Means)

This re-scaling allows for the interpretation and application of the model in the original data space selected twelve factors), making predictions and insights directly applicable to real-world infectivity rate into the reservoir [30].

Integrating the specific results from the research study, the coefficients provided by the Ridge model (including their scaled forms), along with the performance metrics (MAPE, RMSE, R^2) for each models demonstrated in Tables 11 and 12, provide a comprehensive understanding of model performance and the influence of each feature on the predicted outcome of injectivity after using emulsified acid treatment in reservoirs and helps in decision-making for future operations [31]. This detailed analysis aids in the practical understanding and application of new acid treatments to improve reservoir injectivity, aligned with the overarching goals of the research article.

Table 11. Results of Ridge model.

Results	QW-181	QW-133	QW-138	QW-129
Predicted Injectivity (bpm)	5.45	6.35	6.37	6.88
Error (%)	5	−2	−2	−2

Table 12. Statistical characteristics for the used data according to each predictive model.

Models Errors	MAPE	RMSE	R^2
SVM	1.73	0.11	0.97
Gradient Boosting Regression	2.4	0.31	0.78
Ridge	2.73	0.17	0.93

Figure 19 presents the pair plots and correlations matrix that were generated using Ridge model. In the correlation, twelve operational factors were chosen to conduct and train the models paper [16]. A nearly linear relationship was obtained while running the three models as shown in the below Figures 20–22. The predicted results were similar to the actual one where the error obtained in the three models was acceptable and very low.

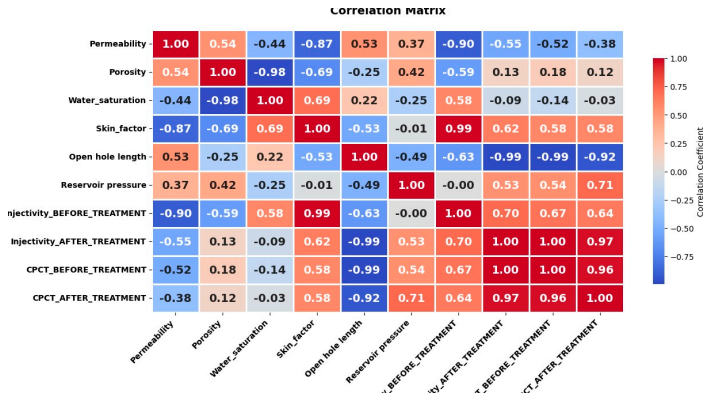


Figure 19. Pair plots and correlation matrix using the input data.

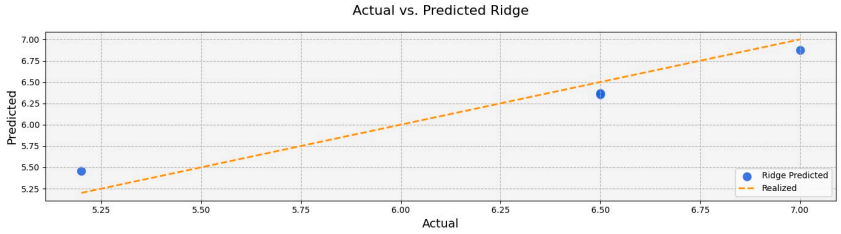


Figure 20. Prediction result using SVM in comparison with actual.

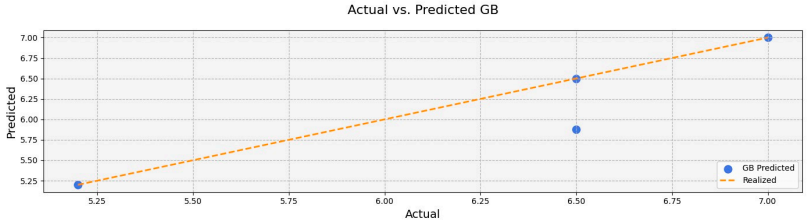


Figure 21. Prediction result using GB in comparison with actual.

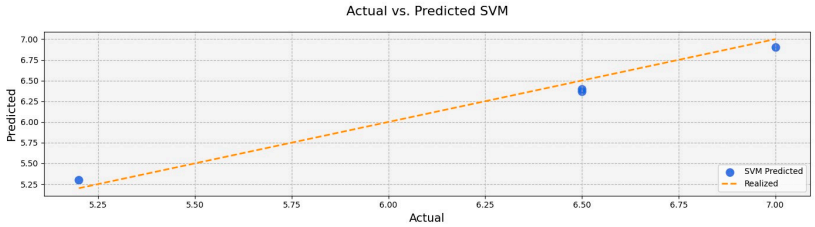


Figure 22. Prediction result using Ridge in comparison with actual.

6. Conclusions

The flow of new approach treatment through carbonate reservoirs in the gulf region delivered impressive outcomes, where the injectivity of four injection wells increased by a factor of 6 to 10 times due to the wormholes formed while injecting the emulsified acid via high velocity jetting tool. Formulated 20% Emulsified acid recipe is a good alternative to 15% HCl. The retardation nature of the mixture allows it to penetrate deep into the formation and stimulate the formation (as proven by increasing the injection rate). According to the novel stationary pumping system with the abrasive jetting tool, the low injection rate with high viscosity overcomes damaged skin within the reservoir, dissolving it, creating mini fractures and long warmholes. Furthermore, three models were trained after selecting twelve factors that were able to build a prediction scenario of the new emulsified acid into the formation and its impressive effect in enhancing the injectivity rate.

Finally, the main purpose of the thesis is to prove that the formulated emulsified acid treatment with a 70:30 acid–diesel ratio that demonstrated previously good performance in sandstone reservoir, demonstrated even better result on pure limestone formation and challenging tight reservoir, where it was the best option to enhance the injectivity and affect reservoir productivity. The treatment formulation retards reaction kinetics, allowing for extensive penetration into the unconventional formations where limited pores and low permeability make standard 15% HCl or 28% HCl ineffective.

On the basis of the results obtained, the following conclusions can be drawn:

- Emulsified acid treatment is compatible with diesel using superior Acid Emulsifier (SUP-AE-03) and not compatible with water, resulting in a snake shape when in contact with hydrophilic solution.
- Acid–diesel ratio of 70:30 ensures a consistent emulsion, average viscosity, and maximum acid concentration for effective retardation and deep acid penetration into carbonate reservoir.
- Emulsified acid low injection rate and high viscosity were addressed by designing an acid injection via high velocity abrasive jetting tool.
- Emulsified acid demonstrated deep live acid injection resulting in drop in pressure and increase in rate after pumping the treatment within the formation.
- Injectivity enhancement from 6 to 10 times due to emulsified acid treatment retardation effect.
- Injectivity results demonstrated that emulsified acid treatment is cost effective alternative to HCl which didn't show any improvement after stimulating the abovementioned wells.
- At low injection rate, emulsified acid provides deeper wormhole penetration with lower injected volumes compared to plain acid. This high efficiency is confirmed by the absence of an optimum injection rate as shown in the post injectivity tests in four cases of injector wells.
- Correlation succeeded, where twelve operational factors were selected to conduct and train the models that predict similar result versus the actual and real results.
- the built model can be used to estimate the output of selecting emulsified acid treatment on any new well.

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Conflicts of Interest: The authors declare no conflict of interest.

Abbreviations

HCl	Hydrochloric acid
NPV	Net profit value
CTM	Coal-to-Methanol
CCUS	Carbon Capture, utilization and storage

EOR	Enhance Oil Recovery
BPM	Barrel per minute
PSI	Pounds per square inch
BBL	Barel
STB	Stock tank barrel
OOIP	Original Oil in Place
HTHP	High Temperature high pressure
SVM	Support Vector Machine
SVR	Support Vector Regression
GBR	Gradient Boosting Regressor
RR	Ridge Regression

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