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Advanced Research on Stimulating Ultra-Tight Reservoirs: Combining Nanoscale Wettability, High-Performance Acidizing, and Field Validation

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Abstract

Unconventional hydrocarbon reservoirs with low matrix permeability (<0.3 mD), high temperatures, and sour conditions present significant challenges for stimulation and production enhancement. This study examines field trials for a large oil and gas operator in the UAE, focusing on tight carbonate deposits with reservoir temperatures above 93 °C and high sour gas content. A novel multi-stage chemical stimulation workflow was created, beginning with a pre-flush phase that alters rock wettability and reduces interfacial tension at the micro-scale. This was followed by a second phase that increased near-wellbore permeability and ensured proper acid placement. The treatment's core used a thermally stable, corrosion-resistant retarded acid system designed to slow reaction rates, allow deeper acid penetration, and build prolonged conductive wormholes. Simulations revealed considerable acid penetration of the formation beyond the near-wellbore zone. The post-treatment field data showed a tenfold improvement in injectivity, which corresponded closely to the acid penetration profiles predicted by modeling. Furthermore, oil production demonstrated sustained, high oil production of 515 bpd on average for several months after the treatment, in contrast to the previously unstable and low-rate production. Finally, the findings support a reproducible and technologically advanced stimulation technique for boosting recovery in ultra-tight carbonate reservoirs using the acid retardation effect where traditional stimulation fails.

Keywords: tight formation; wettability; rock properties; stimulation; chemical treatment; injectivity test

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1. Introduction

The global demand for hydrocarbon-based energy is driving exploration and production (E&P) operations to more technically demanding and unconventional reservoirs. While conventional oil fields have long been the foundation of production portfolios, their natural decline rates and limited scope for additional primary or secondary recovery necessitate a shift to tight formations, where permeability frequently falls below 1 millidarcy (mD), and in some cases below 0.01 mD [1]. As a result, increasing output from low-permeability

reservoirs has become a strategic necessity, especially in countries such as the Middle East, North America, and portions of Asia, where these reservoirs offer unexplored assets with potential long-term value [2]. In many established oil-producing countries, the majority of relatively accessible, high-permeability reservoirs have already been tapped, forcing operators to concentrate on untapped or underperforming zones within ultra-tight formations [3]. These formations usually have permeabilities of less than 1 millidarcy (mD), with some zones dropping below 0.1 mD.

Production from such reservoirs is fundamentally limited by severely constrained flow routes and the presence of capillary forces that hamper hydrocarbon movement. These characteristics result in low recovery efficiency, particularly when using standard production and stimulation procedures. To address this, oilfield development techniques are progressively incorporating novel stimulation technologies targeted at greatly improving reservoir deliverability and overcoming flow constraints caused by tight matrix structures.

Low-permeability reservoirs are frequently distinguished by complicated mineralogy, low porosity, and extremely tight pore throats that impede fluid flow. These formations—which include tight carbonates, and tight sandstones—require advanced intervention to improve reservoir protentional to produce oil [4], and this study focuses on carbonate- and tight-reservoir challenges encountered in the UAE. Traditional stimulation methods, such as matrix acidizing, are frequently rendered ineffective due to inadequate fluid placement, insufficient acid penetration, undesirable rock–fluid interaction, and rapid reaction kinetics at high temperatures [5]. One of the key obstacles in developing these ultra-low-permeability reservoirs is the combination of poor reservoir characteristics, fluid properties, and operational logistics. The reservoirs are frequently found in geologically complicated strata with varying porosity, mineral composition, and fracture dispersion. Reservoir fluids can be viscous, acidic, or contain sour gases like hydrogen sulfide (H_2S) and carbon dioxide (CO_2), posing significant threats to personnel and infrastructure. In other circumstances, extreme surface and subsurface conditions—such as temperatures rising above 122–149 °C—and remote, logistically isolated locales hamper real-time intervention and monitoring.

To address these constraints, a shift in stimulation philosophy is required—one that focuses on changing the rock–fluid interaction at the microscopic level rather than depending only on mechanical fracture propagation or brute-force acid injection. A major component of this shift is the controlled regulation of wettability and interfacial tension inside the formation. Hydrocarbons in tight formations are frequently adsorbed onto pore surfaces due to oil-wet or mixed-wet conditions, limiting their capacity to move freely. It is feasible to mobilize these trapped hydrocarbons and encourage their migration toward the wellbore by chemically modifying the rock's surface properties to make them more water-wet [6]. Furthermore, lowering interfacial tension reduces capillary trapping and increases relative permeability, which aids in the displacement of oil from tight pore spaces.

In this environment, improved chemistry and tailored fluid systems become critical. To meet the unique problems given by high-temperature, sour, and ultra-tight reservoirs, innovative pre-flush and main acid formulations are being developed, which include nanoscale surfactants, corrosion inhibitors, and wettability modifiers. These chemical processes not only clean and dissolve formation damage (such as carbonates, scale, and silica-based clays) but they also re-engineer the reservoir matrix's surface energy. They contribute to the formation of conductive wormholes and micro-scale flow channels by allowing treatment fluids to penetrate deeper and more uniformly, considerably enhancing post-treatment productivity. The current study builds on these principles by conducting a thorough field assessment of two complicated, sour, ultra-tight formations in the gulf region. Conventional stimulation operation proved ineffective in the presence of low

permeability (<0.3 mD), high temperatures (~290 °F), and corrosive gas compositions (up to 18% H_2S and 7% CO_2). A unique multi-stage stimulation strategy was developed, combining enhanced reservoir assessment with a carefully planned chemical treatment program. This strategy encompassed nanoscale wettability modification, interfacial tension reduction, and formation-specific acidizing, resulting in considerable output increases.

This study describes the engineering workflow, the chemistry underlying the proposed steps for improved stimulation fluids, field implementation methods, and production outcomes [7]. The findings demonstrate how a thorough understanding of reservoir petrophysics, along with specialized chemical systems and operational adaptability, can reveal the untapped potential of difficult unconventional reservoirs.

The formation under study poses unusual technical challenges, including limited permeability (<0.3 mD), high bottom-hole temperatures (~144 °C), and highly sour fluid conditions (up to 18% H_2S and 7% CO_2). A new stimulation technique was developed to address the limitations of traditional acidizing technologies [8], which includes the following:

- Customized pre-flush and main acid systems with improved thermal stability and regulated reactivity;
- Advanced chemical packages with nanoscale surfactants, iron control agents, and chelating additives;
- Methods for adjusting wettability and reducing IFT to release hydrocarbons;
- Implemented corrosion mitigation measures for safe and efficient deployment in sour circumstances.

The intent was to minimize skin damage, increase matrix permeability, and restore hydrocarbon flow in vertical and deviated wellbores. Before field implementation, the approach includes extensive laboratory screening, compatibility testing, and chemical efficiency validation. Post-treatment evaluation was carried out using a well test analysis, production monitoring, and pressure transient analysis.

The findings highlight the importance of chemically tailored stimulation fluids in altering the production profile of poor wells in confined reservoirs. This study demonstrates how reservoir assessment, fluid design, and field execution work together to provide long-term production benefits from complicated geological conditions.

Real-time monitoring of injection rates and surface characteristics, together with thorough operational records kept by the customer throughout the treatment lifespan, drove the systematic evaluation and confirmation of reservoir performance. These real-time diagnostics provide instant data on fluid placement, formation response, and skin evolution before and after stimulation. Surface injection profiles, downhole pressure data, and post-job well testing were used to measure the treatment's success in reducing near-wellbore damage and increasing injectivity or productivity. Continuous flow rate monitoring enabled the observation of breakthrough behavior, formation acceptance, and fluid diversion efficiency—which is especially important in heterogeneous or laminated zones where conventional acid placement is generally ineffectual.

Across multiple field trials conducted on both producer and injector wells, the use of the newly engineered stimulation fluids consistently demonstrated measurable improvements in performance metrics, including significant increases in injection rates (up to 300% in some injectors) and stabilized oil production rates in previously stagnant wells. These improvements were not confined to a particular lithology but were detected over a wide range of reservoir characteristics, from tight carbonates with poor matrix permeability to fractured or highly permeable zones known as thief zones with complicated flow networks. Importantly, the improvements were maintained over lengthy monitoring periods, demonstrating that the treatment not only eliminated the damaged epidermis but also altered

the rock–fluid interaction in a way that retained permeability and flow conductivity over time [9]. Anchored in data-driven decision-making, this operational feedback loop proved essential in optimizing future treatments, verifying the flexibility of the chemical system, and proving the scalability of the method over several reservoir conditions.

2. Materials and Methods

Conventional matrix acidizing treatments, particularly those that use direct injection of hydrochloric acid (HCl), are traditionally carried out by bullheading acid or coiled tubing spotting across open-hole intervals in lateral wells or through perforated pay zones in vertical wells, with little regard for the actual condition of the near-wellbore environmentsuch as the presence of formation damage or complex skin layers. This one-size-fits-all method assumes homogenous acid dispersion and reactivity, depending entirely on HCl's high reactivity with carbonate deposits to provide stimulation [10]. However, this approach consistently performed poorly, particularly in damaged or low-permeability zones where acid contact with the productive formation was hampered by organic residues, asphaltenes, paraffins, fines migration, and drilling or completion-induced damage. Because HCl is extremely reactive with inorganic carbonate minerals, it quickly depletes at the initial site of contact, resulting in limited penetration and substantial acid leakage, while leaving non-reactive, insoluble organic deposits unaffected. As a result, the real productivity increase was substantially smaller than anticipated as the acid was unable to reach or efficiently dissolve the true flow-restricting components entrenched within the skin zone. These operational constraints underlined the urgent need for a more focused and preparatory treatment strategy addressing both organic and inorganic damage mechanisms prior to acid application, ensuring optimized contact between the acid and the clean, reactive rock surface and, finally, producing more efficient and uniform stimulation results [11].

The original phase of the research was primarily motivated by the inefficiencies identified in traditional matrix acidifying treatments using hydrochloric acid (HCl), particularly when applied to carbonate reservoirs. Despite the fact that HCl is the most reactive and widely used acid for carbonate dissolution due to its rapid reaction kinetics, field applications consistently produced suboptimal stimulation results, owing primarily to excessive acid leak-off into the formation matrix and non-uniform etching of the near-wellbore region. The quick reactivity of HCl frequently led to premature acid spending at or around the wellbore, inhibiting deeper penetration and even stimulation. These constraints encouraged further research into the fundamental mechanisms influencing acid–rock interactions, with a focus on reservoir wettability [12]. Due to long-term hydrocarbon exposure, the initial rock surfaces in the examined formations were largely oil-wet, limiting the acid's ability to touch and react with the carbonate matrix uniformly. To solve this, the researchers used a unique two-stage pre-treatment method to change the wettability of the formation from oil-wet to water-wet. This was accomplished by combining an organic dissolver with a customized chelating agent system designed to remove inorganic acid-insoluble contaminants while also penetrating deeply into the injured skin zone.

This conditioning phase aided in the exposure of the carbonate surface and improved the efficacy of subsequent acid treatments by lowering surface tension and enhancing aqueous phase compatibility. As a result, this pre-conditioning enabled a more controlled and efficient interaction between the main acid slug and the exposed carbonate rock, reducing acid loss to non-productive zones and increasing reactive surface area, ultimately improving overall stimulation effectiveness and matrix permeability [13]. During the well's preliminary assessment, a pre-injectivity test was performed to determine the formation's ability to absorb fluids prior to acid stimulation. The results showed extremely poor injectivity, with insignificant fluid intake and surface pressures rapidly increasing with

low pump speeds. In response, production engineers offered a standard strategy that involved injecting a 15% inhibited hydrochloric acid (HCl) solution to target suspected acid-soluble inorganic damage. Despite several efforts, this intervention was futile, with injectivity remaining critically low, indicating a more sophisticated harm mechanism than simple mineral scaling. It was determined that organic deposits, asphaltenes, paraffin, and residual chemical residues from past operations—combined with probable particle migration and water blocks—were all limiting the rock's permeability near the wellbore.

To address this multidimensional damage profile, a meticulously constructed pre-flush sequence was implemented, consisting of a three-stage chemical treatment meant to gradually disaggregate organic and inorganic deposits and prepare the rock surface for stimulation. The first phase entailed slowly injecting a customized nano-surfactant solution with extremely low interfacial tension and great wettability alteration capability. The nano-surfactants, which are colloidal micellar structures with a diameter of less than 100 nm, were designed to thoroughly enter microfractures and pore throats, mobilize hydrocarbons, and disperse trapped oil coatings that impede fluid movement. Their nanometric size allowed them to avoid formation constrictions and interact closely with the rock matrix and organic layers, changing surface energy to promote water-wet conditions and remove attached organic materials. This was immediately followed by a soaking stage with a high-strength, biodegradable organic dissolver made from a proprietary ester-based solvent blend and designed to aggressively dissolve complex organic deposits such as wax, asphaltene, and organic acid residues [14]. The soaking period was chosen to ensure continuous contact with the damaged zones, resulting in maximum breakdown and detachment of these materials from the rock surface and perforation tunnels. The wettability-altered, cleansed pore regions were then treated with a targeted slug of 10% inhibited HCl in a confined volume. This acid stage was not intended as a primary stimulation fluid but rather as a precision tool for dissolving any lingering inorganic damage—such as calcium carbonate scale and iron precipitates—that had become accessible following the earlier cleanup phases.

The selection of an effective nano-surfactant for wettability adjustment in carbonate reservoirs, specifically to shift the rock surface from oil-wet to water-wet, necessitates a thorough examination of various interconnected physicochemical, thermodynamic, and reservoir-specific variables. Important selection criteria include particle size distribution, surface charge (zeta potential), hydrophilic–lipophilic balance (HLB), thermal and ionic stability, interfacial tension reduction capabilities, and adsorptive behavior on reservoir rock surfaces. The nano-surfactant must be colloidally stable (zeta potential > $\pm$30 mV) to prevent aggregation under reservoir salinity and temperature conditions while maintaining a particle size range below 100 nm for deep penetration into pore throats and uniform surface coverage. Furthermore, it must displace adherent oil coatings by lowering oil–brine interfacial tension (<1 mN/m) and establishing a stable aqueous layer over the carbonate surface to assist the transition to water-wet conditions. Thermal stability at reservoir temperatures (90–130 °C) and compatibility with high-salinity brines containing divalent ions (e.g., Ca^{2+}, Mg^{2+}) are crucial for maintaining performance in downhole settings. Furthermore, the nano-surfactant should have minimal irreversible adsorption on rock surfaces to reduce chemical loss and increase efficiency. To effectively examine and screen prospective nano-surfactants, a battery of laboratory procedures was completed.

These included dynamic light scattering (DLS) and zeta potential analysis for colloidal characterization; interfacial tension (IFT) measurements with spinning or pendant drop tensiometry; and wettability alteration assessments with contact angle goniometry and Amott/USBM methods. Furthermore, core flooding and spontaneous imbibition studies are used to quantify oil recovery improvement, while thermal aging and compatibility tests

assess chemical integrity under simulated reservoir conditions. Adsorption experiments (static and dynamic) provide information on surfactant retention within the formation, whereas SEM or micro-CT imaging confirms surface cleaning and pore accessibility after treatment. These studies work together to create an integrated approach for systematically identifying and validating the most effective nano-surfactant formulation customized for increasing oil recovery through wettability adjustment in distinct reservoir situations.

2.1. Test Performed and Selection of Nano-Surfactant

The nano-surfactant formulation's selection process is crucial for ensuring its effectiveness and compatibility with the intended candidate reservoir. This approach is governed by a stringent evaluation framework that incorporates both third-party laboratory testing and internal analytical assessments. Third-party testing independently validated the nano-surfactant's physicochemical characteristics, interfacial behavior, and performance in simulated reservoir conditions. Concurrently, in-house laboratory studies are performed to determine compatibility with reservoir fluids and rock mineralogy, including emulsion stability, wettability alteration potential, thermal stability, and interactions with formation water and crude oil. The dual-layered technique ensures that the chosen nano-surfactant system is not only chemically stable but also matched to the reservoir's specific lithological and geochemical profile, optimizing its efficiency in improving hydrocarbon recovery while avoiding formation damage [15]. The following describes the tests performed to confirm the chemical effectiveness.

2.1.1. Particle Size and Zeta Potential Analysis

A qualified third-party laboratory specializing in colloidal and nanomaterial studies performed rigorous particle size and zeta potential characterization to certify the chosen nano-surfactant's appropriateness for reservoir use. The primary goal of this study was to confirm the nano-surfactant's particle size distribution and surface charge properties, which are important markers of colloidal stability, dispersion behavior, and surface reactivity under reservoir circumstances. Dynamic light scattering (DLS) was used to measure the hydrodynamic diameter of the particles in solution, revealing a narrow particle size distribution within the nanoscale range of 10 to 100 nanometers, which corresponds to the optimal range required for effective pore penetration and uniform surface coverage in carbonates [16].

Figure 1 depicts the compatibility testing carried out to evaluate the effectiveness of a customized nano-surfactant formulation when mixed with raw acid and crude oil under static conditions:

(1) Image (a): Crude oil sample before treatment, showing its natural phase behavior and look.
(2) Image (b): A raw 32% hydrochloric acid solution combined with the designed nano-surfactant. The clear, homogeneous phase found demonstrates full miscibility and chemical compatibility.
(3) Image (c) shows the result of combining the nano-surfactant/acid blend with crude oil. A distinct phase separation is visible, clearly distinguishing the oil and acid/surfactant layers, showing the nano-surfactant's stability and non-reactivity with hydrocarbons under high-temperature conditions (82 °C).

These findings highlight the nano-surfactant's strong colloidal behavior and efficacy. The efficient separation shown in (Figure 1c) between acid and crude oil phase strengthens the nano-surfactant's chemical integrity and interfacial activity, demonstrating its applicability for enhanced oil recovery (EOR) and acid stimulation applications. This behavior also

prevents the creation of stable emulsions, which is an important advantage in maintaining fluid mobility and decreasing flow assurance issues in downhole settings.



Figure 1. Performance of the sized particles of nano-surfactant ranging from 1 µm to 10 µm over sludgy crude oil and acid mixture [17]: (**a**) crude oil sample; (**b**) raw acid 32% mixed with nano-surfactant; (**c**) compatibility testing between acid and crude oil.

A zeta potential investigation was also performed by utilizing an electrophoretic light scattering apparatus to determine the electrostatic potential at the particle–fluid interface. The zeta potential exceeded ±30 mV, indicating a highly stable colloidal system with negligible particle aggregation or precipitation, even at higher temperatures and in brine salt conditions typically found in downhole environments. These data demonstrate that the nano-surfactant possesses the fundamental physicochemical properties required for efficient wettability alteration and deep formation penetration, justifying future investigation using advanced wettability, interfacial tension, and core flooding tests.

2.1.2. Interfacial Tension (IFT)

Interfacial tension (IFT) measurements were taken with a spinning drop tensiometer under reservoir-like circumstances, such as temperatures (80–120 °C) and salinity-matched synthetic brine. The test sought to determine the nano-surfactant's effectiveness in lowering oil–water interfacial tension, which is a critical factor in improving fluid mobility and oil displacement [18]. Figure 2 shows a semi-logarithmic depiction of the influence of nano-surfactant concentration on surface tension at two different temperatures: 25 °C (75 °F) and 122 °C (250 °F). As the concentration increases from 0.0001 to 10 gallons per 1000 gallons, surface tension drops dramatically at both temperatures, demonstrating effective surfactant activity. At 25 °C (75 °F), surface tension decreases dramatically from roughly 55 dynes/cm to around 25 dynes/cm as the concentration increases, with diminishing returns above 0.1 gal/1000 gal.

The results indicated a significant drop in IFT from about 56 mN/m to less than 21 mN/m at 70 F—demonstrating the nano-surfactant's robust surface activity and potential to boost oil recovery by encouraging interfacial instability and emulsification—as well as

a decrease in surface tension from 32 mN/m to 11 mN/m at 122 °C (250 °F), simulating surface reservoir performance.

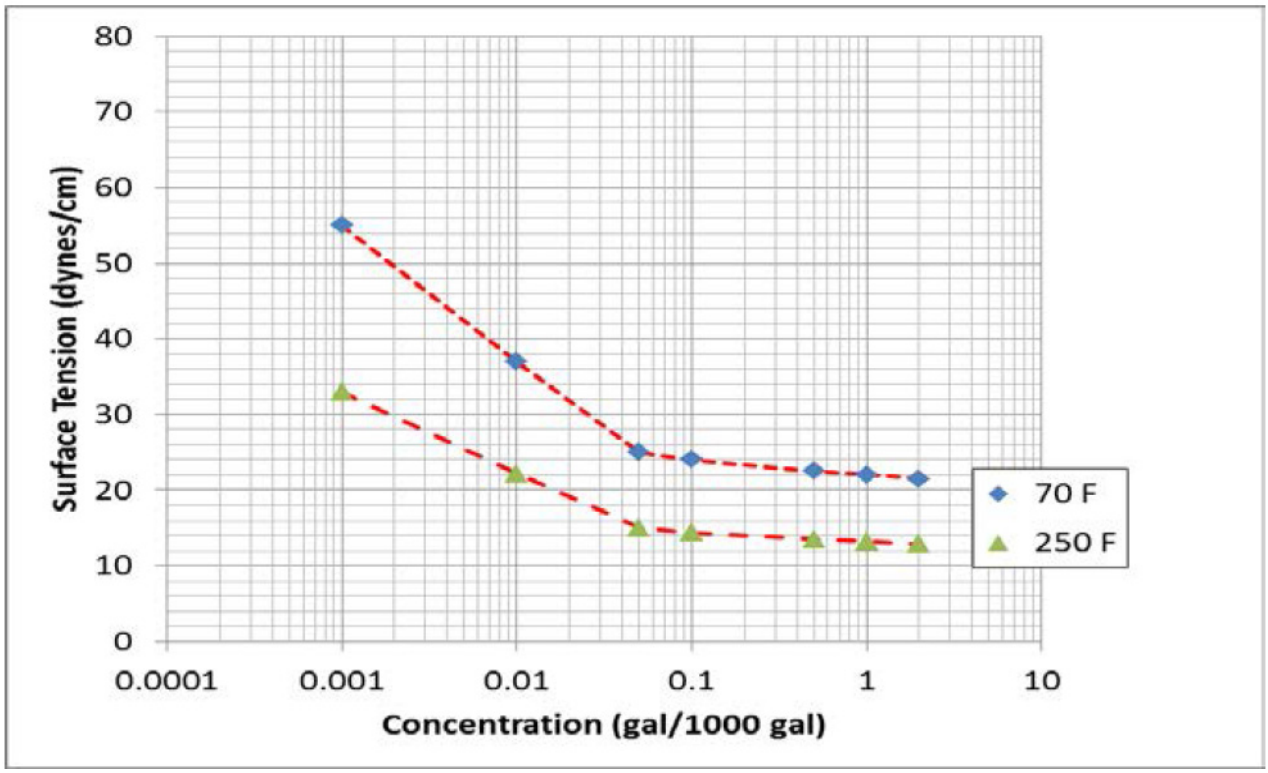


Figure 2. Describing the drop in IFT value at different temperatures.

This result verifies the nano-surfactant's temperature-responsive activity and demonstrates its greater efficiency in lowering interfacial tension, particularly at high reservoir temperatures (1 mN/m = 1 dyne/cm).

2.1.3. Wettability Alteration Test

In order to evaluate nano-surfactant performance in the laboratory—notably, for the wettability alteration and compatibility testing—representative materials and specialist equipment were required [19]. The following items were necessary for carrying out accurate and trustworthy tests:

Wettability Alteration Testing

- To imitate in situ wettability, carbonate core plugs were aged in crude oil for two weeks at reservoir temperature.
- Treatment options included crude oil samples, synthetic brine, and nano-surfactants. Visually evaluate the surface wettability before and after applying nano-surfactant.
- Use vacuum saturators, core holders, and drying ovens for core preparation and post-treatment conditioning.

Wettability testing was carried out at Superior Abu Dhabi Company's laboratory, UAE, Abu Dhabi, where aged carbonate core samples were treated with the nano-surfactant solution after two weeks of oil saturation at reservoir temperature, as shown in Figure 3. Visual examination and contact angle analysis indicated a significant transition from oil-wet to water-wet behavior, with visible changes in the surface wetting characteristics.



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

Figure 3. Wettability test performed to highlight surface wet changes: (**a**) core sample from rig; (**b**) core sample dipped in surfactant; (**c**) wettability change result.

These visual and measurable indicators confirmed the nano-surfactant's efficacy in modifying rock wettability, a fundamental mechanism for increasing oil mobilization in carbonate reservoirs.

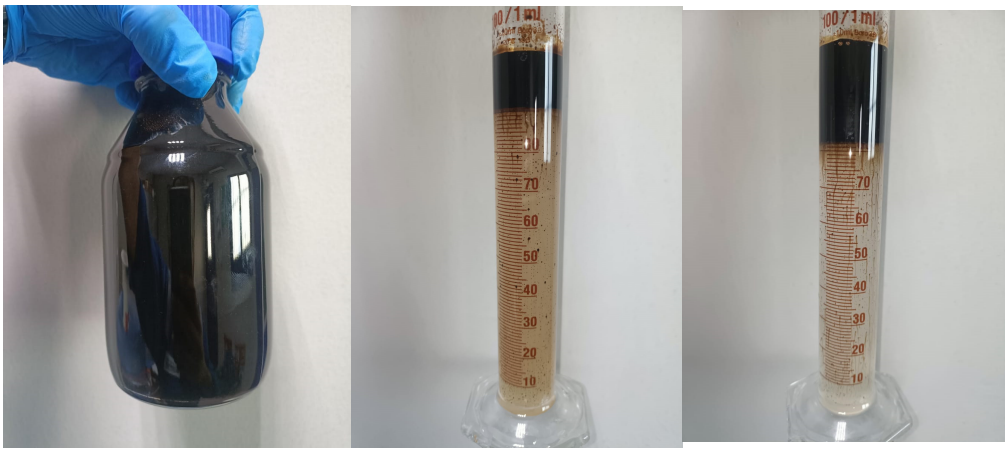
2.1.4. Compatibility Test

Compatibility and stability testing are required to guarantee that the nano-surfactant retains its chemical integrity and effectiveness when exposed to high-salinity brines and high reservoir temperatures. This evaluation confirms that no precipitation, phase separation, or deterioration occurs under operational settings, ensuring consistent field performance [20]. Below outlines testing equipment and its steps:

(1) Combine nano-surfactant formulations with synthetic brines with changing salinity and divalent ion concentrations (e.g., Ca^{2+}, Mg^{2+});
(2) Use glass beakers, magnetic stirrers, or mechanical mixers to achieve homogeneous mixing;
(3) To imitate downhole conditions, use a temperature-regulated water bath or oven set to 82 °C;
(4) Employ visual examination tools to detect phase separation, turbidity, and precipitation.

The nano-surfactant's compatibility and stability were tested in-house with a temperature-regulated water bath set to 82 °C to approximate reservoir thermal conditions as shown in Figure 4.

The nano-surfactant was combined with synthetic brines of varied salinity and divalent ion concentrations and aged for many days. Visual inspection found no evidence of precipitation, turbidity, or phase separation, indicating excellent thermal and ionic stability. These findings support the nano-surfactant's durability and suitability for use in high-temperature, high-salinity carbonate reservoirs.

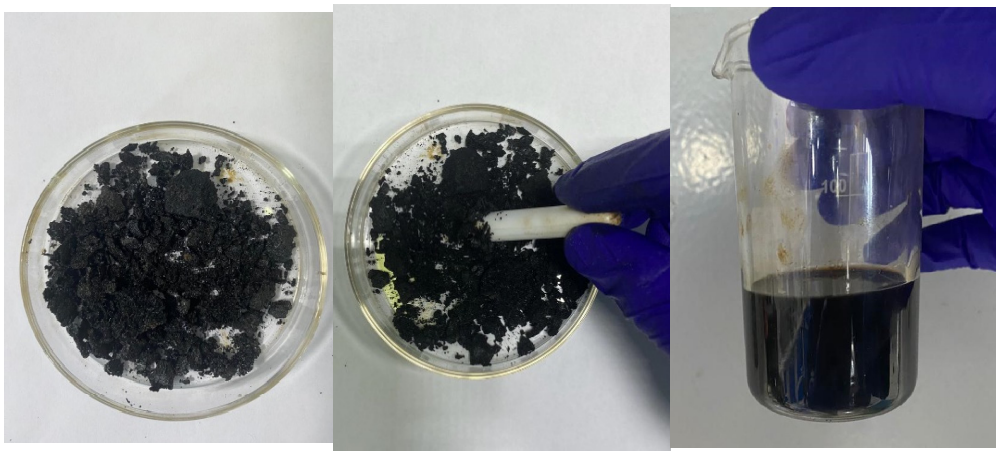


(**a**) (**b**) (**c**)

Figure 4. Compatibility test performed in laboratory leading to complete separation between crude-oil-associated water droplets and nano-surfactant solution: (**a**) crude oil sample; (**b**) compatibility test at 10 min; (**c**) compatibility test at 20 min.

2.2. Organic Dissolver

A complete dissolving performance test was carried out at Superior's laboratory, Abu Dhabi, to determine the effectiveness of the chosen solvent system in breaking down organic deposits commonly found in reservoirs. The test was specifically designed to recreate field-representative circumstances by using actual organic deposit samples from the same or geologically related strata (Figure 5a), ensuring a high level of relevance to the intended application. Moreover, Figure 5b highlights the importance of measuring iron content within the scale to estimate the solvent's capacity for dissolving. The technique entailed exposing pre-weighed amounts of these organic deposits to the solvent under static circumstances, with continuous contact maintained for a predetermined time. Importantly, the experiments were conducted at ambient (room) temperature rather than increased thermal conditions in order to assess the solvent's intrinsic chemical dissolving capacity without regard for heat amplification. This low-temperature testing method provides a more conservative and rigorous assessment of the solvent's effectiveness by demonstrating the system's capacity to dissolve resistant organic materials even in suboptimal heat settings, as demonstrated in Figure 5c. Figure 5c shows a quick and easy dissolution of scale via the solvent's active molecule.



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

Figure 5. Solubility test to estimate the efficiency of solvent to dissolve organic deposits: (**a**) scale deposit in a glass Petri; (**b**) iron content captured through magnet; (**c**) scale dissolution via solvent.

After treatment, the leftover particles were filtered, dried, and re-weighed to determine the percentage of dissolution, and ocular observations indicated that the asphaltenic and paraffinic components were completely or nearly completely dissolved [21]. The results not only confirmed the solvent's high reactivity and solvation strength but also provided a competitive advantage in solvent selection by validating its performance under less favorable conditions than those found in actual reservoir environments, ensuring robust and reliable field applicability.

2.3. Dissolution Testing Methodology

A consistent laboratory approach was developed to assess the dissolution effectiveness of several solvents on organic scale deposits using representative field samples as demonstrated in Figure 6. The materials and equipment used were as follows:

- Organic scale deposits (2 g per test);
- Glass beakers for containing test mixtures;
- Multiple solvents for comparison based on their chemical makeup;
- Pre-weighed filter paper mesh;
- Oven with the temperature set to 138 °C (280 °F) for drying.



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

Figure 6. Steps of filtering and drying the dissolved organic deposits into the organic dissolver solution: (**a**) mixture of dissolved deposits; (**b**) dissolved deposits in a Petri dish; (**c**) filter paper with undissolved deposits, dried in oven at 138 °C.

The test procedure included the following steps:

1. Sample Preparation: A total of 2 g of organic deposit was placed in a glass beaker and mixed with 50 mL of the different solvents.
2. Soaking Phase: The combination was left to soak at room temperature for 6 h, providing enough contact time for dissolution without thermal enhancement;
3. Filtration: After soaking, the solution was filtered using pre-weighed filter paper to remove undissolved residue;
4. Drying: The filter paper with residual solids was dried in an Emmet oven at 138 °C for 6 h to remove moisture and accurately measure the weight;
5. The filter paper was weighed after drying to determine the non-dissolved material mass;

6. Calculating Dissolution Efficiency: The non-dissolved residue mass was subtracted from the original deposit of 2 g to obtain the mass of dissolved material.

The dissolution results are represented as a percentage of the total dissolved mass, allowing for a quantitative comparison of solvent performance in Table 1. The table shows the results of an organic deposit solubility test for ten distinct chemical formulations at a 100% (pure) concentration for a period of a 6-hour soaking time at 25 °C. The solubility performance of the studied compounds differed greatly, showing variances in their effectiveness at dissolving organic deposits. SUP-Asphalt 01 had the maximum solubility (99.20%), indicating exceptional dissolution power and significant competence in treating heavy organic deposits such as asphaltenes. In contrast, Paraffin 02 had the lowest solubility (26.50%), indicating poor efficiency for organic deposit removal.

Table 1. Summary of experimental solubility and dissolution test.

S/N	Chemical Code	Concentration	Soaking Time	Test Temperature	Solubility
1	SUP-Asphalt 01	Pure (100%)	6 hrs	75 °F (25 °C)	99.20%
2	Paraffin 02	Pure (100%)	6 hrs	75 °F (25 °C)	26.50%
3	Organic dissolver	Pure (100%)	6 hrs	75 °F (25 °C)	73.70%
4	Solvent—01	Pure (100%)	6 hrs	75 °F (25 °C)	54.40%
5	Solvent—02	Pure (100%)	6 hrs	75 °F (25 °C)	62.80%
6	Solv—01	Pure (100%)	6 hrs	75 °F (25 °C)	82.20%
7	Solv—07	Pure (100%)	6 hrs	75 °F (25 °C)	71.50%
8	LX 120	Pure (100%)	6 hrs	75 °F (25 °C)	63.36%
9	Paraffin—102	Pure (100%)	6 hrs	75 °F (25 °C)	64.50%
10	Orange Solv	Pure (100%)	6 hrs	75 °F (25 °C)	86%

Organic Dissolver demonstrated a significant solubility of 73.70%, making it a viable option for dissolving organic compounds. Among the solvents examined, Solv-01 had the highest solubility (82.20%), followed by Orange Solv (86%), indicating that they are very effective and adaptable in dissolving a variety of organic pollutants. Solv-07, LX120, and Paraffin-102 demonstrated intermediate performance, with solubility values of 71.50%, 63.36%, and 64.50%, respectively, suggesting good but not exceptional dissolution capabilities. Meanwhile, Solvent-02 and Solvent-01 had 62.80% and 54.40% solubility, indicating moderate effectiveness. Importantly, solubility was assessed with great accuracy: after the soaking time, each solution was filtered through a 100-micron filter paper to separate undissolved residues, and the filtrates were then dried in an oven at 280 °F to ensure total solvent removal.

The final weight of the remaining solids allowed for exact calculation of the solubility percentage. Overall, the test results clearly show that SUP-Asphalt 01, Solv-01, and Orange Solv are the most promising candidates for efficient organic deposit dissolution under the specified test conditions, whereas formulations such as Paraffin 02 may require further optimization or are better suited to specific lighter-deposit challenges.

This room-temperature dissolution testing method takes a conservative and field-representative approach to solvent screening, ensuring that only solvents with high inherent chemical reactivity are chosen for further use in organic scale remediation.

3. Results

Extensive laboratory testing on the selected nano-surfactant—including wettability changes, compatibility with downhole fluids and formation minerals, and organic deposit dissolution efficiency—has resulted in a highly successful field implementation, demonstrating the treatment's technical viability and impact. The nano-surfactant displayed exceptional wettability alteration characteristics, evidenced by the contact angle reductions and Amott index changes, effectively transforming the reservoir rock from oil-wet to water-wet, which is required for increased fluid displacement and acid accessibility. Compatibility tests conducted under simulated reservoir conditions (high salinity, divalent ion concentrations, and increased temperatures) revealed no phase separation, precipitation, or loss of functionality, demonstrating the chemical's thermal and ionic durability. Dissolution studies using real field-derived organic deposits at ambient temperature revealed near-complete solubilization, which is crucial for pre-cleaning the pore surfaces before major acid injection. These technical advantages were visible during deployment [22].

The first field example featured a severely damaged injector well with no injectivity, despite previous acidization with 15% HCl, a high-reactivity acid commonly utilized in carbonate reservoirs. Even after a full-volume matrix treatment, the well failed to absorb fluids, indicating serious formation damage or chronic oil-wet conditions. Based on the optimistic lab results, my technical team and I proposed using a pre-flush slug of nano-surfactant that had been designed and dosed to achieve maximal wettability change. When applied, the nano-surfactant reacted with the near-wellbore rock surface, changing the wettability from oil-wet to water-wet and efficiently eliminating remaining hydrocarbon coatings and deposits. This pre-conditioning stage significantly increased injectivity, allowing the subsequent acid stage to penetrate deeper and react more efficiently with the formation, resulting in a sustainable injectivity enhancement.

In the second scenario, a producer well that had previously performed an acid stimulation operation, continued to produce in an unstable and unsustainable manner, most likely due to poor initial acid placement and permeability obstacles created by oil-wet conditions and surface clogs. A similar nano-surfactant-based pre-flush method was used to improve pore–scale connectivity and permeability to the primary treatment. In both cases, the essential operational parameters included the following:

(1) Injection pressure (Psi);
(2) Rate (barrels per minute);
(3) Skin behavior;
(4) Post-treatment injectivity/productivity indicators.

These operation factors were carefully monitored and recorded in real time. The findings confirmed a significant increase in injectivity, and the same pattern was found in several consecutive wells, emphasizing the need for applying nano-surfactant pre-flush treatments prior to any acid stimulation operation. The overall field experience confirms the lab-to-field link and establishes the nano-surfactant as a game-changing addition for improving stimulation success in complex carbonate reservoirs. Table 2 demonstrates ten real field cases where the injection was improved after soaking the nano-surfactant. Additionally, reservoir data including permeability and porosity are mentioned in Table 2, highlighting the nature of tight formations and proving the effectiveness of the treatment for very-low permeable rock and tight formations.

Table 2. Real field case studies.

Cases	Well Type	Res. Temp	Res. Pr	Reservoir Permeability	Reservoir Porosity	Damaged Skin
Case 1	Water Injector	200 °F	2200 Psi	0.5 mD	23.5%	3.26
Case 2	Water Injector	200 °F	1900 Psi	0.4 mD	22%	5.8
Case 3	Oil Producer	200 °F	2300 Psi	0.9 mD	21%	2.78
Case 4	Oil Producer	200 °F	2700 Psi	0.95 mD	28%	3.32
Case 5	Oil Producer	200 °F	2800 Psi	0.35 mD	32%	3.00
Case 6	Oil Producer	250 °F	2100 Psi	0.25 mD	26%	3.18
Case 7	Oil Producer	250 °F	3000 Psi	0.78 mD	25%	3.44
Case 8	Gas Producer	280 °F	4200 Psi	0.3 mD	18%	6.56
Case 9	Gas Producer	290 °F	4600 Psi	0.35 mD	23%	4.6
Case 10	Gas Producer	290 °F	5000 Psi	0.8 mD	21.5%	3.7

The result was a remarkable improvement in injectivity, evidenced by the post-treatment injectivity test that revealed a more than tenfold increase in fluid intake capacity while maintaining the same surface pressure limitations. The successful restoration of injectivity confirmed the pre-flush system's synergistic action with nano-surfactants, organic dissolvers, and acids. This preparation phase was crucial for subsequent matrix acid stimulation as it ensured uniform acid application and deep penetration into the reservoir.

Finally, comprehensive damage removal and rock reconditioning resulted in a considerable and sustained increase in oil production, demonstrating the technical efficiency of the phased chemical treatment technique in badly damaged, low-permeability wells.

The field data show that the pre-flush treatment plays a critical role in improving the effectiveness of acid stimulation operations. In the ten cases in Table 3, injection rates significantly improved after pumping the specifically formulated pre-flush solution, which was meant to target and minimize damaged skin effects by addressing scale deposition, organic matter accumulation, and unstable wettability conditions. Initial injection rates across the wells were modest, ranging from 0.5 to 1.4 bpm (Table 3), indicating the formation's thick skin and poor permeability of less than 1 mD. However, following the pre-flush application, final injection rates considerably increased, often doubling, tripling, or even reaching up to 19 times higher—as in Case 10, where the injection rate jumped from 0.1 bpm to 1.95 bpm, and Case 5, where it climbed from 1.25 bpm to 2.25 bpm. This result clearly demonstrates that the pre-flush efficiently prepared the reservoir by eliminating obstructions and changing surface qualities prior to acid injection. The real-field statistics clearly demonstrate that the pre-flush phase is required for any reservoir stimulation program. It inhibits the premature reaction and expenditure of acid near the wellbore, which is frequent when acid is delivered directly into a damaged formation without first conditioning. Wells where the pre-flush was implemented not only had greater and more steady injection rates but also had deeper acid penetration, resulting in more successful and long-lasting stimulation effects. Without this pre-flush, conventional acidizing would have likely led to high

amounts of acid being, restricted formation cleaning, and unstable production performance. Thus, the findings confirm that a well-designed and well-conducted pre-flush is critical for increasing the efficiency and long-term effects of acid stimulation treatments, improving production and optimizing waste costs.

Table 3. Summary of recorded injection rates after pre-flush soaking.

Cases	Well Type	Res. Temp	Initial Inj. Pr	Initial Inj. Rate	Final Inj. Pr	Final Inj. Rate
Case 1	Water Injector	290 °F	1200 Psi	1.2 bpm	200 Psi	3.8 bpm
Case 2	Water Injector	200 °F	1150 Psi	1.2 bpm	350 Psi	6 bpm
Case 3	Oil Producer	200 °F	1200 Psi	0.85 bpm	460 Psi	1.7 bpm
Case 4	Oil Producer	200 °F	1100 Psi	1.4 bpm	800 Psi	1.98 bpm
Case 5	Oil Producer	200 °F	1150 Psi	1.25 bpm	720 Psi	2.25 bpm
Case 6	Oil Producer	250 °F	900 Psi	1.1 bpm	630 Psi	2.05 bpm
Case 7	Oil Producer	250 °F	1120 Psi	0.5 bpm	550 Psi	1.2 bpm
Case 8	Gas Producer	280 °F	1200 Psi	0.5 bpm	830 Psi	1.05 bpm
Case 9	Gas Producer	290 °F	1230 Psi	0.3 bpm	400 Psi	0.8 bpm
Case 10	Gas Producer	290 °F	1680 Psi	0.1 bpm	1170 Psi	1.95 bpm

The stimulation program was designed as a comprehensive multi-stage strategy that addressed the challenges of tight and low-permeability carbonate reservoirs found in mature Middle Eastern fields. The treatment workflow was designed to first address near-wellbore damage, both organic and inorganic in nature, using a carefully sequenced deployment of advanced fluid systems, including a nano-modified surfactant pre-flush, a targeted organic dissolver, and an emulsified acid system as the primary stimulation fluid [23].

3.1. Pre-Flush Field Implementation for Gas Producer Well (Case Study 1)

In carbonate reservoirs, particularly those with complex near-wellbore damage and oil-wet surface characteristics, traditional matrix acidizing—typically including direct injection of 15% hydrochloric acid (HCl)—is frequently insufficient. This is especially true in reservoirs with organic-based damaged skin, heterogeneous deposits, and poor permeability intervals where acid cannot efficiently react with targeted surfaces. A noticeable case study was a well that remained non-injective despite several attempts to inject straight hydrochloric acid (HCl). The main cause of this failure was identified as considerable surface alteration caused by high hydrocarbon saturation and organic scale deposition, which together hindered effective acid penetration and limited reaction at the mineral interface. To address this issue, a structured pre-flush sequence was implemented to change the near-wellbore environment and increase acid accessibility. Following the start of the pre-flush therapy, injection rates gradually increased—from 0.5 barrels per minute (bpm) to 1 bpm, and finally to 2 bpm. Following completion of the three-stage pre-flush cycle, the

overall injection capacity increased significantly, from 0.1 bpm to 2 bpm—a nearly 20-fold increase. This gradual increase in injectivity allowed the subsequent main acid treatment to be successfully pumped at an average rate of 2.7 bpm, showing that the formation had grown sufficiently responsive. As a result, the reservoir was successfully stimulated, allowing for the cleaning of pore spaces and the removal of damage along the wellbore.

3.1.1. Nano-Surfactant Performance

To address this issue, a nano-engineered surfactant system was implemented as a pre-flush step prior to the primary acid treatment. The chosen nano-surfactant was particularly intended to target the nanoscale morphology of the rock surface, accelerating the transition from oil-wet to water-wet conditions. This change is crucial because it decreases capillary forces, allowing aqueous treatment fluids (such as acid and solvents) to have direct and homogenous contact with the rock matrix. All laboratory findings were validated on a field scale, with the pre-flush step using the nano-surfactant system resulting in significant improvements in rock–fluid interaction and near-wellbore permeability. This pre-conditioning treatment brought the rock surface back to a wet state, eliminated organic and oil-based skin, and allowed the acid stage to penetrate successfully. The injectivity improvement was substantial, with post-treatment rates increasing by 6 to 7 times the baseline values.

The nano-surfactant was injected as a slug under controlled flow conditions, enabling enough time for surface conditioning to occur. Laboratory research had previously shown that the surfactant could dramatically lower interfacial tension (IFT), shift contact angles to hydrophilic states, and remain chemically compatible with downhole fluids. In the field, this method resulted in a significant increase in injectivity, allowing future acid and solvent treatments to penetrate deeper into the formation and efficiently react with the damaged zones. The use of this nano-surfactant pre-conditioning method not only aided in the removal of previously unremovable organic deposits but also improved fluid placement and matrix contact for the primary stimulation fluid. As a result, the stimulation outcome was significantly enhanced, suggesting that including nanoscale surface chemistry into stimulation procedures can be a critical component in unlocking productivity from previously unresponsive wells [24].

3.1.2. Organic Dissolver Dissolution

In many carbonate reservoir stimulation conditions, particularly in mature or hydrocarbon-laden formations, limited injectivity is frequently attributed to the existence of persistent organic deposits that do not react with ordinary hydrochloric acid (HCl). These deposits produce a permanent exterior layer made up mostly of acid-insoluble elements such as asphaltenes, waxes, and resinous substances. This organic barrier binds closely to pore walls and scale surfaces, effectively protecting the underlying inorganic and carbonate elements from acid exposure. In a representative low-injectivity case, direct application of 15% HCl resulted in no increase in injection rates due to the acid's inability to penetrate and react. A specific organic dissolver was consequently introduced as a vital pre-flush step.

This dissolution process not only restored access to acid-soluble material but also reinforced the nano-surfactant-induced wettability change, which had previously moved the rock surface from oil-wet to water-wet conditions. The combined impact of the surface chemistry alteration and organic scale removal allowed the succeeding acid stage to engage directly with the formation matrix, resulting in effective mineral dissolution and significant increases in injectivity. This sequential method indicated that successful stimulation in such complex reservoirs necessitates the use of both organic dissolvers and wettability modifiers to increase formation permeability and acid efficacy [25].

3.1.3. Acid Pickling Treatment

After successfully dissolving the exterior organic shell with a specialized organic solvent system, a targeted acid pickle treatment—also known as an acid wash—was used to remove any remaining acid-soluble contaminants and carbonate-based near-wellbore damage. This step was critical to improving injectivity and preparing the reservoir for the major stimulation stage. The acid wash was a carefully formulated 15% HCl solution that was designed to react selectively with the exposed carbonate surfaces and inorganic scale that had previously been protected by organic fouling. After removing the organic barrier and making the rock surface more water-wet using nano-surfactant conditioning, the acid was able to penetrate deeper and make more homogeneous contact with the formation matrix. This enabled the effective dissolution of calcite-based scale, cement filtrate residues, and other fine-scale carbonate deposits that had reduced pore throat connection. The acid pickle not only cleaned the near-wellbore region but also removed micro-blockages inside pore structures, restoring permeability and allowing for better flow routes during the later main acid treatment. This step-by-step strategy emphasizes the importance of thorough formation conditioning for overcoming complicated damage pathways and achieving optimal stimulation outcomes [26]. Operational monitoring revealed a measurable increase in injectivity following the acid wash step, confirming its critical significance as a transition period between organic scale cleanup and full-scale matrix stimulation [27,28].

The yellow curve on the presented plot in Figure 7 reflects the pumping rate. The first noticeable increase in the yellow curve corresponds to the first pumping stage of the pre-flush. This pre-flush contains a nano-surfactant solution designed to change the wettability of the rock formation. The nano-surfactant improves injectivity by converting the rock surface from oil-wet to water-wet, allowing fluids to infiltrate the formation more efficiently during future acidizing or major treatment stages.

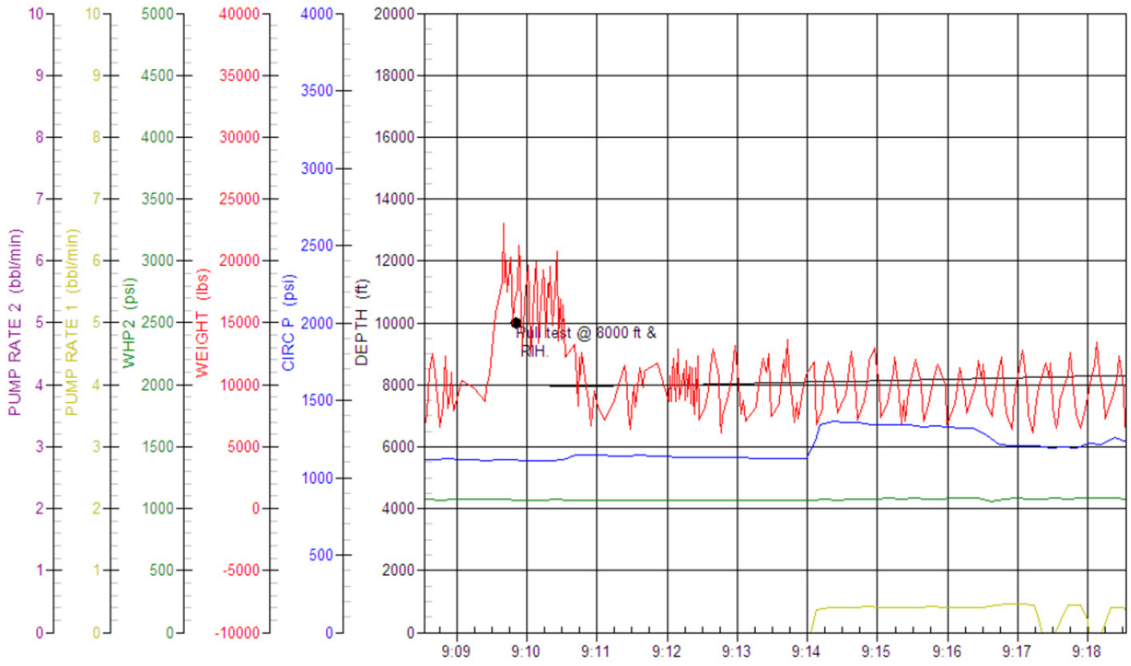


Figure 7. Recorded pumping rate while pumping pre-flush at a rate of 0.5 bpm during first slug of nano-surfactant [29].

The second significant increase in the yellow curve corresponds to the pre-flush's second pumping stage, which includes the injection of the organic dissolver demonstrated in Figure 8.

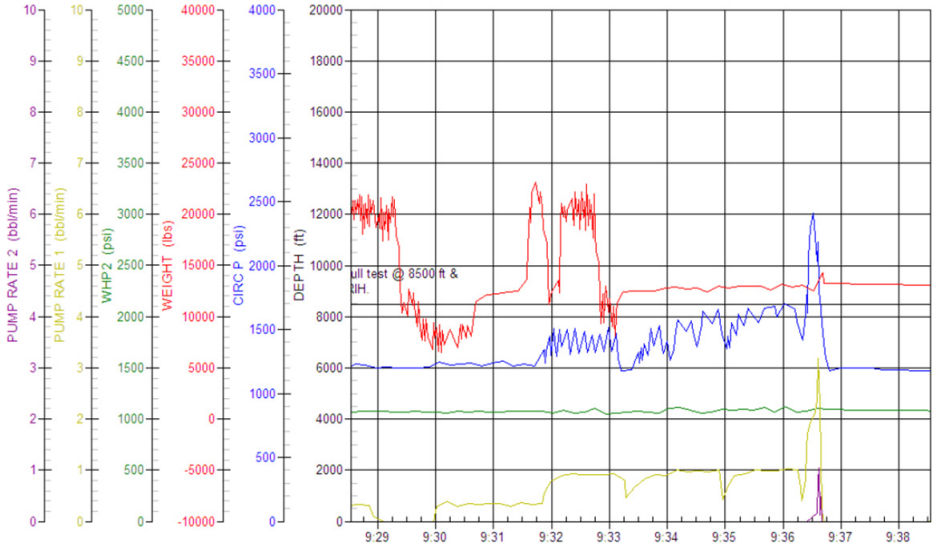


Figure 8. Recorded flow rate data while pumping organic dissolver in the pre-flush stage at a rate of 1 bpm.

The organic dissolver's principal role is to dissolve organic compounds (such as asphaltenes and other organic deposits) that clog the reservoir's natural pore network. Breaking down these organic barriers is very important because it increases the efficiency of acid placement by allowing the acid to penetrate deeper into the formation rather than being inhibited at the wellbore. This improves stimulation coverage and avoids acid leakage or early acid spending near the wellbore, maximizing acid treatment efficiency. During this phase, the pumping rate steadily increases until it reaches approximately 1 bpm, ensuring enough contact time and dissolver penetration into the formation.

The yellow curve on the plot (Figure 9) depicts the pumping rate during the pre-flush stages. The third significant increase in pumping rate corresponds to the third stage of the pre-flush, known as the acid pickling phase. During this stage, a precisely determined volume of acid is poured into the formation, taking into account the open hole capacity and lateral section geometry. The major goal of this acid pickling is to enter the pore structure and dissolve mineral and acid-soluble contaminants such as carbonates, fines, and scale, which can impede fluid routes and reduce reservoir permeability. Importantly, the data show a steady increase in the injection rate, eventually reaching around 2 barrels per minute (bpm). This progressive growth is extremely important since it immediately demonstrates the efficacy of the previous chemical sequence. Initially, the nano-surfactant injection during the first stage changed the rock surface wettability from oil-wet to water-wet, increasing fluid mobility. In the second stage, the organic dissolver efficiently dissolved organic deposits that had previously clogged pore spaces, increasing injectivity. Finally, during the acid pickling process, mineral and acid-soluble impurities were efficiently removed, removing additional obstacles to liquid movement. The gradual increase in injection rate to 2 bpm without any signs of considerable pressure increase or instability demonstrates that the formation has been successfully conditioned. It shows that the sequential chemical treatments reduced formation damage, increased pore connectivity, reduced acid leakage, and ensured more uniform and deeper acid penetration during the main treatment phase. This complete pre-flush method considerably increases the likelihood of meeting the targeted stimulation goals while maximizing acid efficiency and treatment costs.

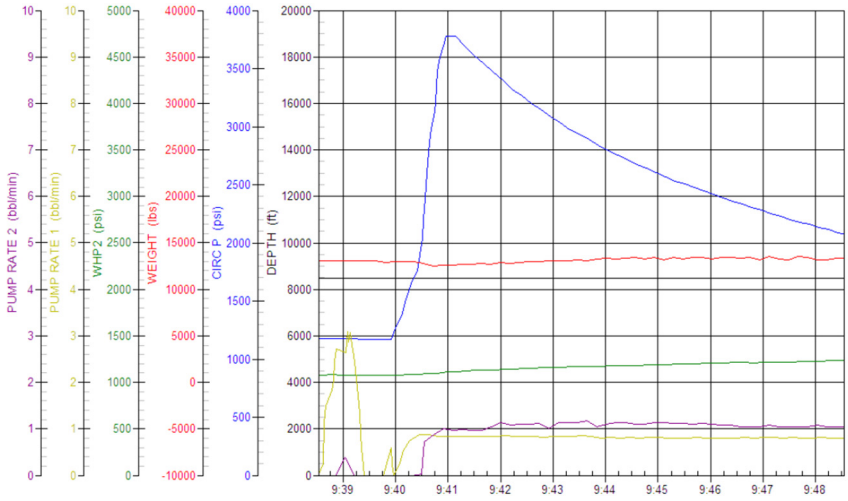


Figure 9. Recorded data while pumping the acid pickle treatment, third slug of the pre-flush stage at a rate of 0.5 bpm [29].

In Figure 10, Pumping Rate 1 (in yellow) and Pumping Rate 2 (in purple) depict the fluid injection progression during and after the pre-flush phase, respectively. During the final stage of the pre-flush, the injection rate is initially set at 2 barrels per minute to ensure sufficient dynamic pressure to force fluids into the near-wellbore region and lateral portions. Following the completion of the pre-flush slugs, the Pumping Rate 2 (purple curve) shows that the flow remains stable, with a discharge rate of roughly 2 barrels per minute, indicating consistent injectivity conditions. The pre-flush phase, which includes wettability modification with nano-surfactants, organic deposit removal, and mineral dissolution, is an important and necessary step in the overall stimulation design. It prepares the formation for proper cleaning by gradually removing damaged skin and clearing obstructions at many layers (organic-, mineral-, and wettability-induced). This preparation improves fluid access to the deeper pore structure. The pre-flush's efficiency is plainly demonstrated by the stable injection behavior observed after completion, indicating an open, cleaned, and more conductive formation.

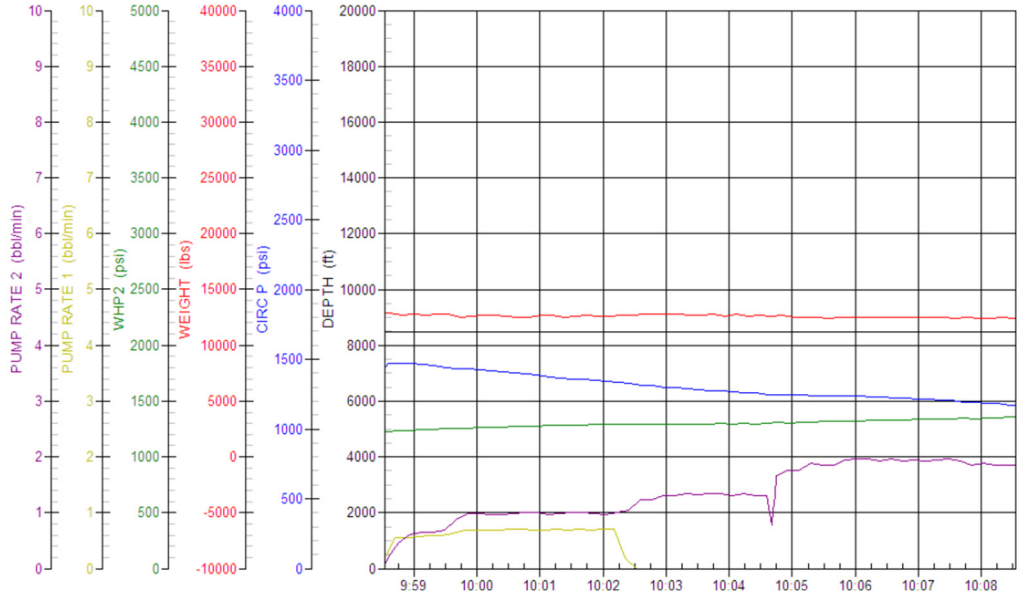


Figure 10. Final recorded pumping rate after completing the pre-flush stage demonstrating a stable rate of 2 bpm.

Furthermore, the pre-flush treatment increases the efficacy of subsequent acidification by reducing acid loss around the wellbore and boosting deeper acid penetration into the reservoir matrix. This ultimately leads to permeability augmentation, which is the primary goal of stimulation procedures. In Figure 11, the smooth transition from Pumping Rate 1 to Pumping Rate 2 indicates that the formation has been successfully conditioned, resulting in more effective stimulation outcomes, where one pump is able to reach 2 bpm—easily overcoming back pressure in the reservoir.

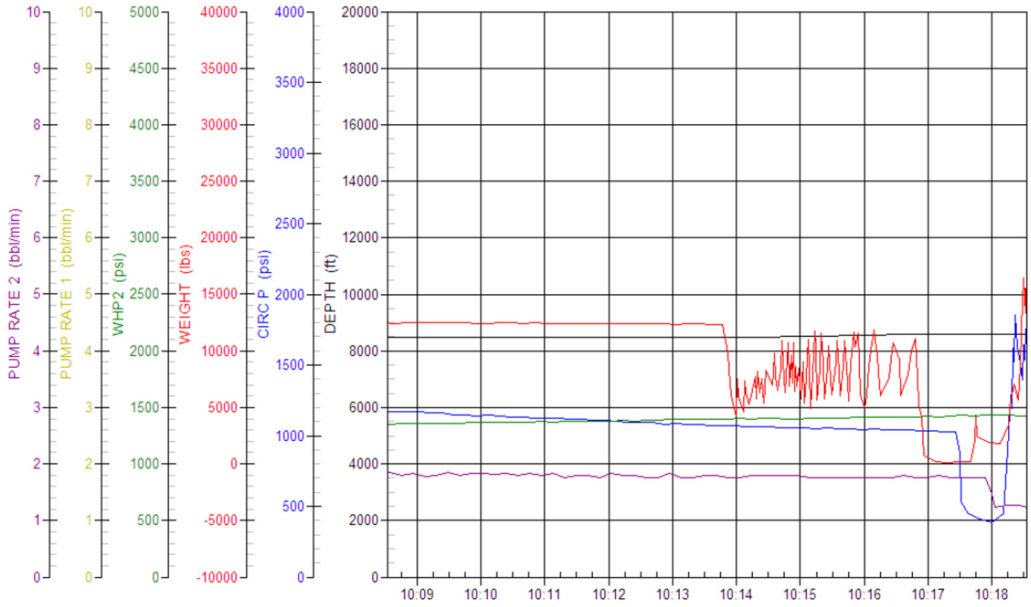


Figure 11. Recorded pumping data during main acid treatment.

After the soaking time of the pre-flush stage for 24 h, the main treatment was introduced with a progressive injection rate of 2.7 bpm during acidizing, as shown in Figure 12, leading to tremendously improved production after acid stimulation, where the acid was able to bypass damaged skin and reach deep into the formation to clean and effectively create wormholes in the reservoir.

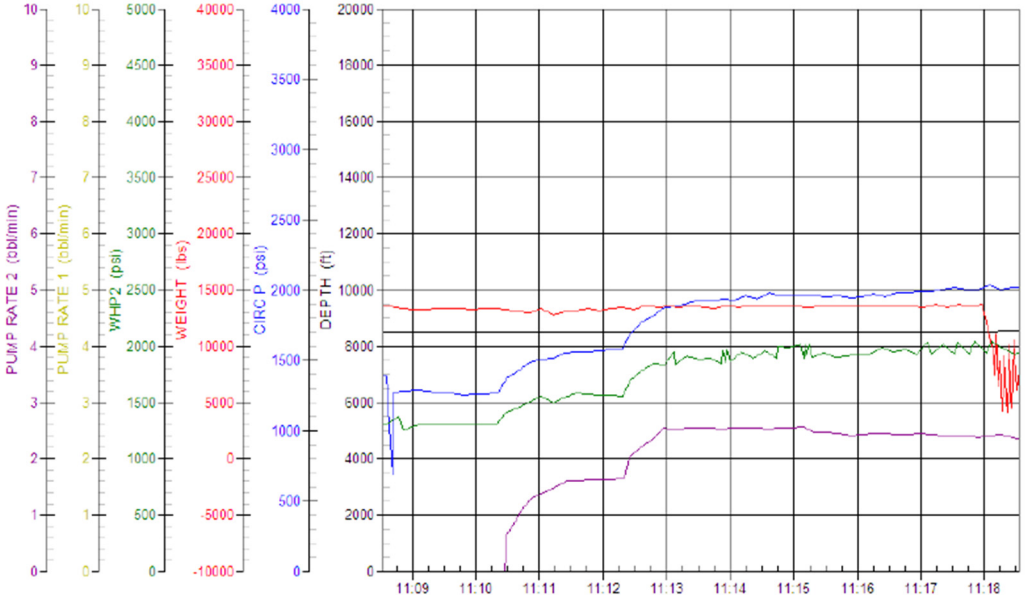


Figure 12. Final recorded fluid rate after completion of main acid stimulation.

3.2. Pre-Flush Steps Implemented for Oil Well (Case Study 2)

The same three-stage chemical pre-flush methodology—which included the nano-surfactant treatment, organic dissolver injection, and acid pickling—was successfully used in a second case study involving a challenging oil-producing well, where the major scale composition was recognized as organic in origin. In this case, the formation was thought to be coated with a heterogeneous layer of complex organic substances, primarily paraffins, asphaltenes, resinous hydrocarbon leftovers, and inorganic deposits that form a mixed scale. These deposits lay close to the pore surfaces, thereby limiting permeability and impeding flow. The process began with the injection of a nano-surfactant slug designed particularly to change the reservoir rock's wettability from oil-wet to water-wet and minimize fluid interfacial tension.

This critical first step increased surface accessibility and fluid mobility by breaking the adhesion forces that held the organic layer to the formation. The exposed organic matrix was then targeted and broken down using an organic dissolver with high solvency efficiency. The dissolver's activity resulted in the progressive elimination of hydrocarbon fouling, restoring pore connectivity and exposing previously shielded components. Following the removal of the organic phase, a hydrochloric acid pickling stage was used to react with any remaining acid-soluble components, such as embedded carbonate particles or drilling-induced damage.

The cumulative effect of this sequential approach resulted in a significant alteration of the near-wellbore environment. Following treatment, injectivity increased fourfold but wellhead pressure decreased significantly, indicating improved formation permeability and efficient fluid placement. This study demonstrates how a targeted and disciplined application of stepwise chemical pre-flushing can release flow potential in wells hampered by complicated organic scaling, ensuring long-term productivity and operational efficiency.

3.3. Pre-Flush Three Stages Performed on WAG Well

As part of an enhanced oil recovery (EOR) strategy, the operator implemented a water-alternating-gas (WAG) injection scheme in a number of peripheral injector wells strategically located around major production wells. These injector wells were operated on a cyclic basis, with six months of high-pressure water injection followed by six months of processed gas injection, resulting in a dynamic displacement front that optimized sweep efficiency and sustained oil production rates in the targeted formation. However, due to the cyclical nature of fluid injection and the shifting physicochemical properties of the injected phases, these wells sustained severe near-wellbore damage over time, principally from alternate scaling mechanisms, wettability changes, and variable pressure regimes.

To address these difficulties, the same novel three-stage pre-flush treatment—which included nano-surfactant injection, organic dissolver application, and acid pickling—was strategically used in the WAG injector wells. The pre-flush procedure was carefully designed to condition the damaged near-wellbore zone prior to acid stimulation. The nano-surfactant altered the rock surface characteristics, lowering interfacial tension and moving wettability toward water-wet conditions, allowing the following fluids to penetrate more deeply. This was followed by the injection of an organic dissolver to eliminate complex organic accumulations, such as hydrocarbon residues and biofilms that accumulate during alternating injection phases. Finally, the acid pickle phase effectively removed inorganic scale and carbonate-based deposits from the damaged skin.

The graph in Figure 13 depicts the reservoir's initial injectivity behavior during the stimulation operation, measured by the coiled tubing data and surface pumping parameters:

- At the commencement of the operation (about 11:07), the injection rate is roughly 1.6 barrels per minute (bpm), as shown on the second scale from the left;
- This flow rate is maintained while pumping the three proposed pre-flush steps, which are intended to condition the wellbore and start the breakdown of deposits;
- Wellhead pressure (WHP2) remains steady, indicating limited flow into the formation and reflecting the low injectivity condition at the time;
- Pump pressure, rate, and CT depth are recorded continuously, indicating controlled operation with no substantial changes, supporting the inference that fluid input into the reservoir is limited.

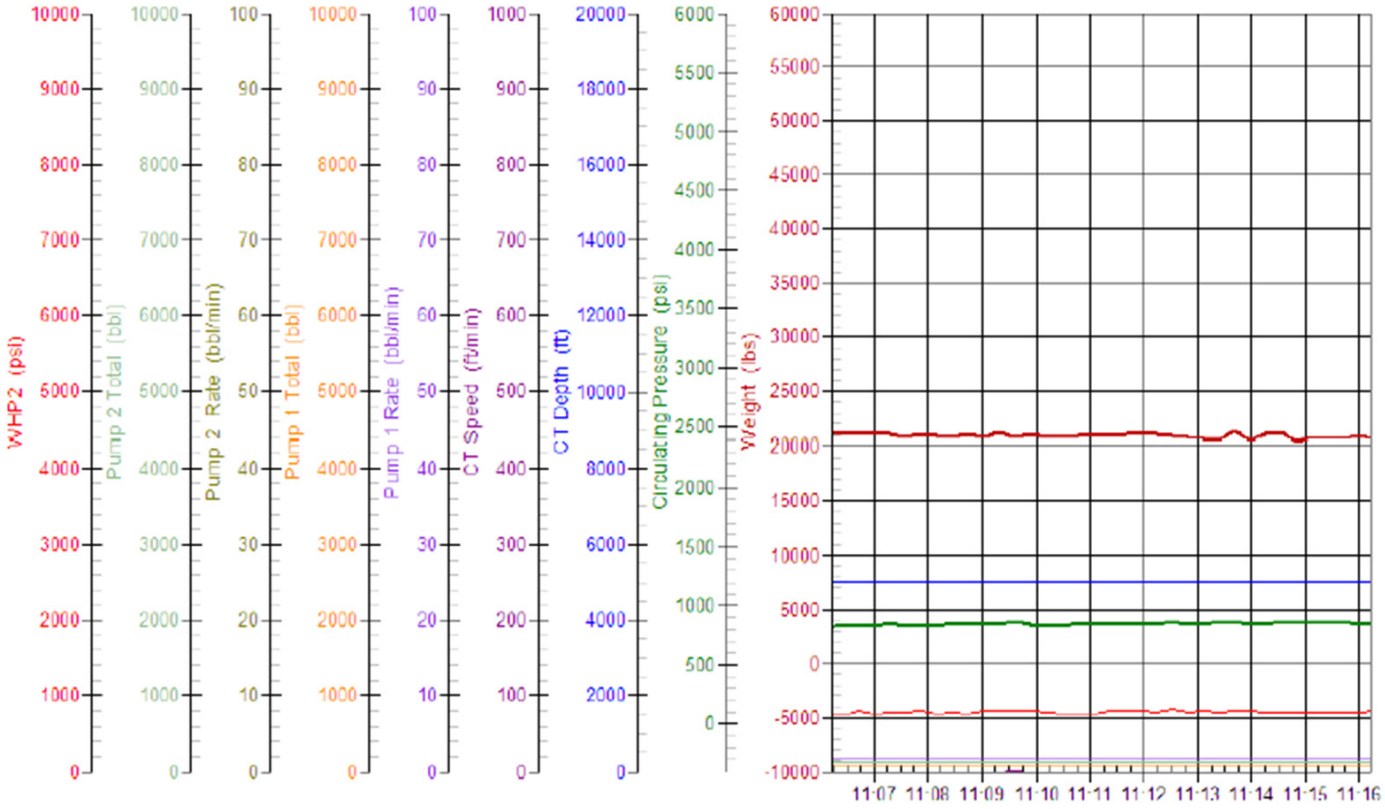


Figure 13. Recorded data during pre-flush treatment.

The graph in Figure 14 shows the increase in Pumping Rate 1 (indicated in purple) after the pre-flush stages. Initially, the injection rate was reduced, indicating a low formation injectivity. Pumping Rate 1 increased gradually during the pre-flush treatment. This pattern shows a gradual reduction in near-wellbore limitations. Finally, the treatment increased the injection rate to 6.2 barrels per minute (bpm), demonstrating the efficacy of the pre-flush in improving formation acceptance.

The incorporation of this pre-flush sequence had a measurable positive impact on well performance, enhancing acid distribution and formation reactivity during the main treatment phase. Field results revealed a significant improvement in injectivity following treatment, with lower surface injection pressure and improved acid placement efficiency. This finding not only confirmed the efficacy of the pre-flush technique in WAG injector wells but also emphasized its value as a pre-treatment step in minimizing injection-related damage and maximizing EOR success.

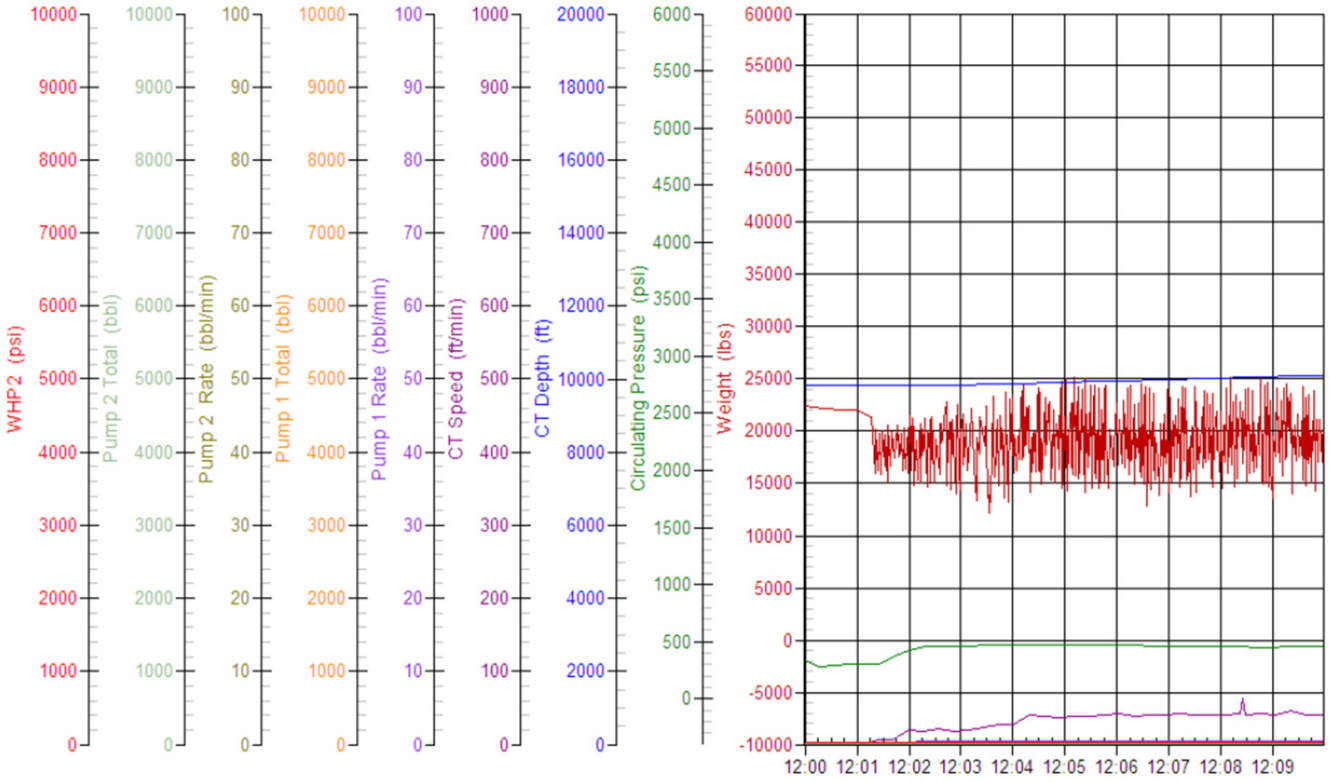


Figure 14. Recorded fluid rate after completion of pre-flush treatment for an injection at 6.2 bpm.

3.4. Pre-Flush Treatment for Water Injector Well

In this enhanced oil recovery (EOR) scenario, a strategic design of water injector wells surrounding producer wells allows for continuous water injection, which is crucial for maintaining appropriate reservoir pressure and, as a result, increasing hydrocarbon recovery at the surface. This pressure maintenance immediately counteracts the reduction in reservoir energy by sustaining driving mechanisms and increasing volumetric sweep efficiency. A new pre-flush technique, with a distinct positive "fingerprint" in injector wells, was applied to effectively minimize near-wellbore damaged skin, enhancing the conditions for following acid stimulation and increasing formation reactivity. While the original pre-flush greatly increased injectivity, a focused approach to inorganic acid-insoluble compounds resulted in a doubled improvement. The formation damage was distinguished by the presence of calcium and magnesium precipitates, which resulted from the interaction of formation water with the barium sulfide-containing well-killing fluid.

The graph in Figure 15 describes the improvement in injection performance during the pre-flush stage. Initially, the pumping rate—shown in purple at 0.5 bpm and light yellow at 1 bpm—suggested limited formation acceptance. These rates gradually increased throughout the pre-flush, indicating that near-wellbore limitations had been eliminated. Finally, the combined effect of the pre-flush treatments increased the injection rate to 3.2 bpm, suggesting improved formation injectivity and the efficacy of the chemical preparation phase.

The graph in Figure 16 highlights the improvement in pumping rates during the main treatment stage. Initially, the injection rate was 3.2 bpm, with pumping shown in purple and light yellow. As the treatment progressed, the rates steadily increased, indicating enhanced fluid placement and improved formation permeability. By the end of the main treatment, the injection rate reached 6.2 bpm, demonstrating the effectiveness of the chemical treatment in significantly improving injectivity and overcoming formation resistance.

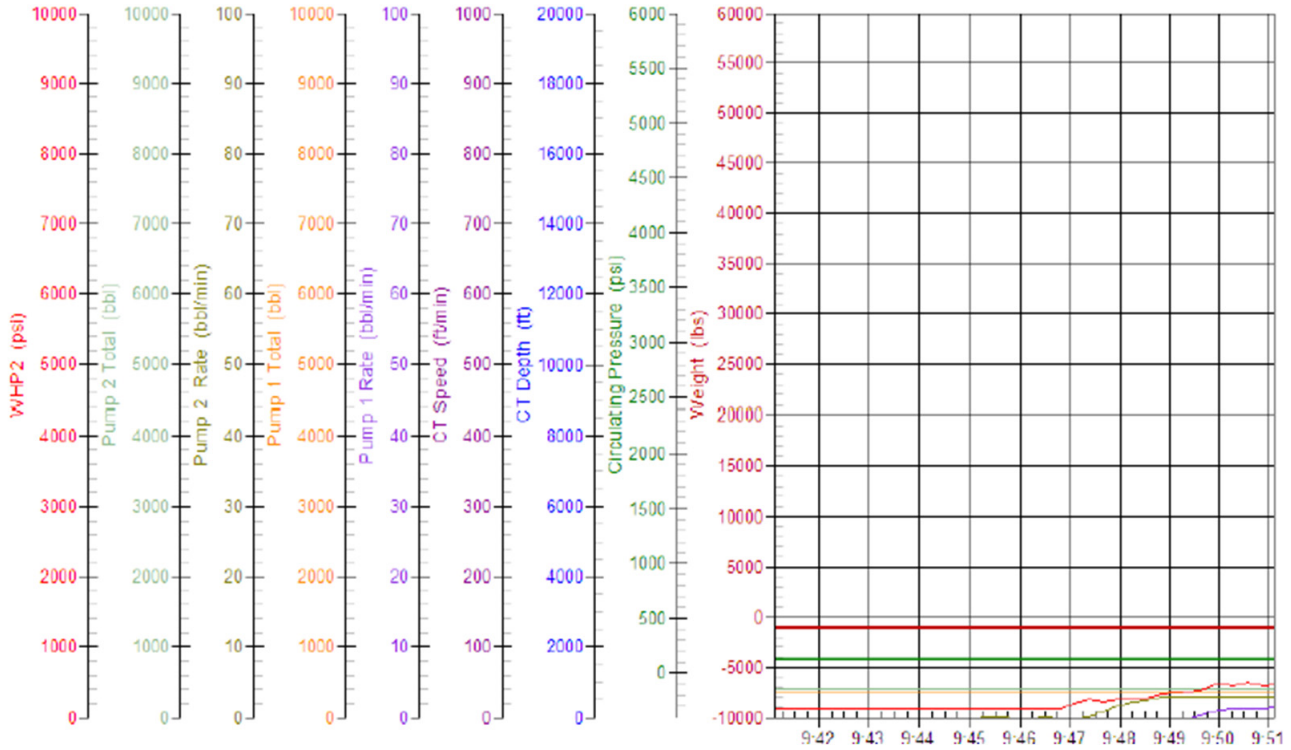


Figure 15. Initial recorded operational data during pre-flush treatment.

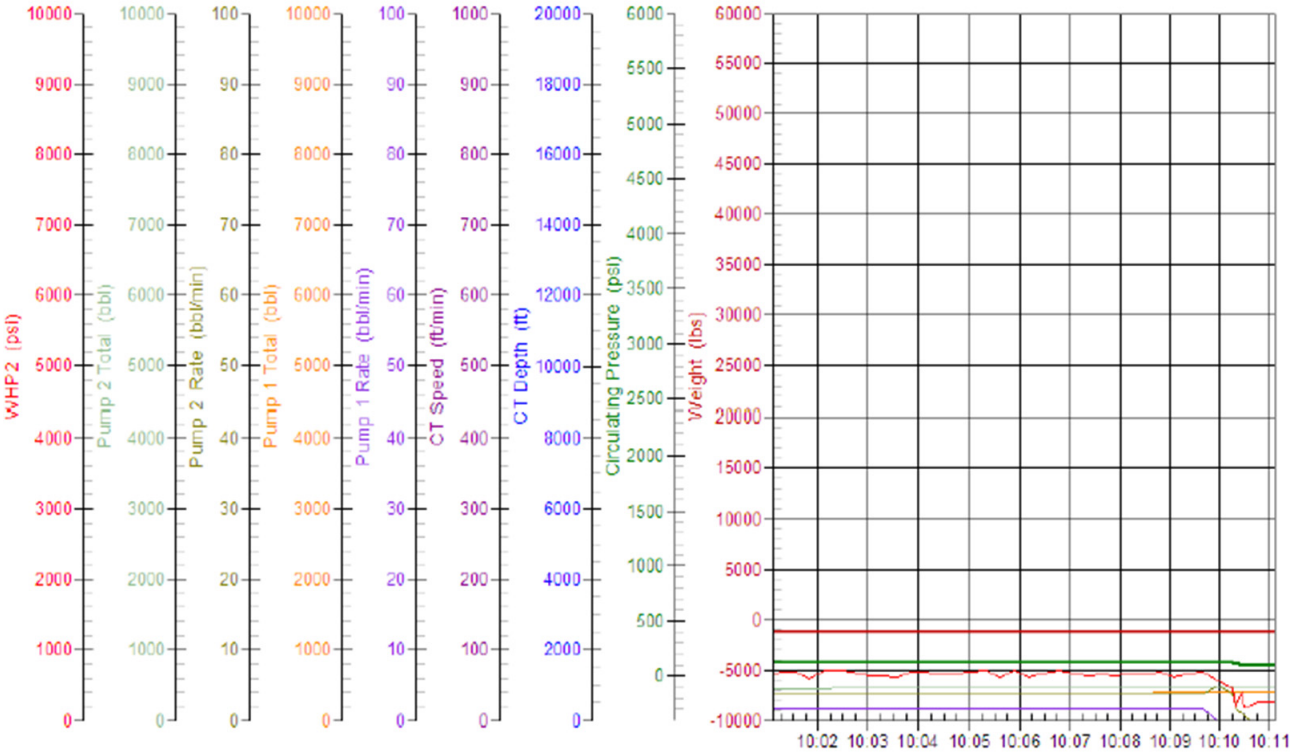


Figure 16. Recorded pumping rate after acidizing treatment reaching 6.2 bpm.

These precipitates, along with barium sulfate, generated a complex, solid particle scale that was resistant to standard hydrochloric acid (HCl) treatments. To address this issue, comprehensive laboratory studies and field testing were carried out to develop and deploy a particular chelating agent designed to successfully dissolve and sequester these specific inorganic scales, considerably increasing injectivity and overall oil recovery.

As a result, the pre-flush ahead of the main acid treatment led to improved reservoir permeability and enhanced its capacity for acid diffusion.

3.5. Main Acid Treatment

The treatment portfolio includes a variety of acid stimulation procedures designed to alleviate formation damage and increase well productivity, extending beyond traditional acidizing with 15% and 28% hydrochloric acid (HCl). Conventional acid treatments primarily involve the circulation of dilute acid solutions—15% HCl for matrix acidizing in carbonate formations and 28% HCl for more aggressive stimulation in severely damaged zones to dissolve carbonate mineral scale, remove fines, and restore near-wellbore permeability. In addition, emulsified acid treatments use surfactant-stabilized emulsions, which typically consist of a hydrocarbon phase that is diesel encapsulating concentrated acid (20% or 28% HCl) and allow for deeper penetration into formation pores due to lower interfacial tension and increased mobility. The emulsified acids are engineered to withstand premature reaction with formation minerals, thereby increasing their effective treatment radius and improving acid distribution. The 20% emulsified acid provides a balanced approach between aggression and control, making it suited for intermediate damage zones, whereas the 28% emulsified acid stimulates more strongly in badly damaged or high-permeability zones. Furthermore, the use of a single-phase acid retarder entails injecting a specifically formulated acid-inhibited mixture, which slows acid reaction rates and allows the acid to reach deeper into the formation before reacting. These retarders typically use chemical or inorganic inhibitors to temporarily limit acid–mineral interactions, allowing for controlled dissolution over a greater distance.

When various treatment types are combined, they allow for a more comprehensive approach to formation damage mitigation, maximizing the balance between acid reactivity, penetration depth, and damage elimination, resulting in increased well productivity and stimulation efficacy.

Following the above-mentioned main treatment performed after the introduced pre-flush treatment, good results were recorded in the field, as outlined below:

(1) For 15% Conventional HCl: The stimulation operation, which used 15% conventional hydrochloric acid (HCl), was evaluated by comparing it to previous acidizing procedures on the same well. The results showed a remarkable improvement, with post-injectivity testing revealing an almost sixfold rise in the injectivity index. This significant improvement indicates that the treatment substantially restored and maybe enhanced near-wellbore permeability, enhancing reservoir capacity for more efficient fluid flow. As a result, the successful deployment of this acid treatment not only maximized reservoir stimulation benefits but also contributed to a positive return on investment by balancing the acidizing operational expenses through increased well productivity and decreased formation damage. The comparison demonstrates the efficacy of the 15% HCl treatment in improving well performance and supports its continued use in the field's stimulation plan through the implemented pre-flush treatment ahead of acidizing.

The graph in Figure 17 shows how Pumping Rates 1 and 2 in purple and light yellow improved after the pre-flush and acidizing treatments. Initially, both pumping rates were limited, indicating low injectivity into the formation. However, after completing the pre-flush and acid steps, the injection performance improved noticeably. The injection rate gradually increased, eventually stabilizing at 8 barrels per minute (bpm). This illustrates the treatment's efficiency in minimizing formation damage and increasing permeability, which allows for greater fluid acceptance and injectivity.

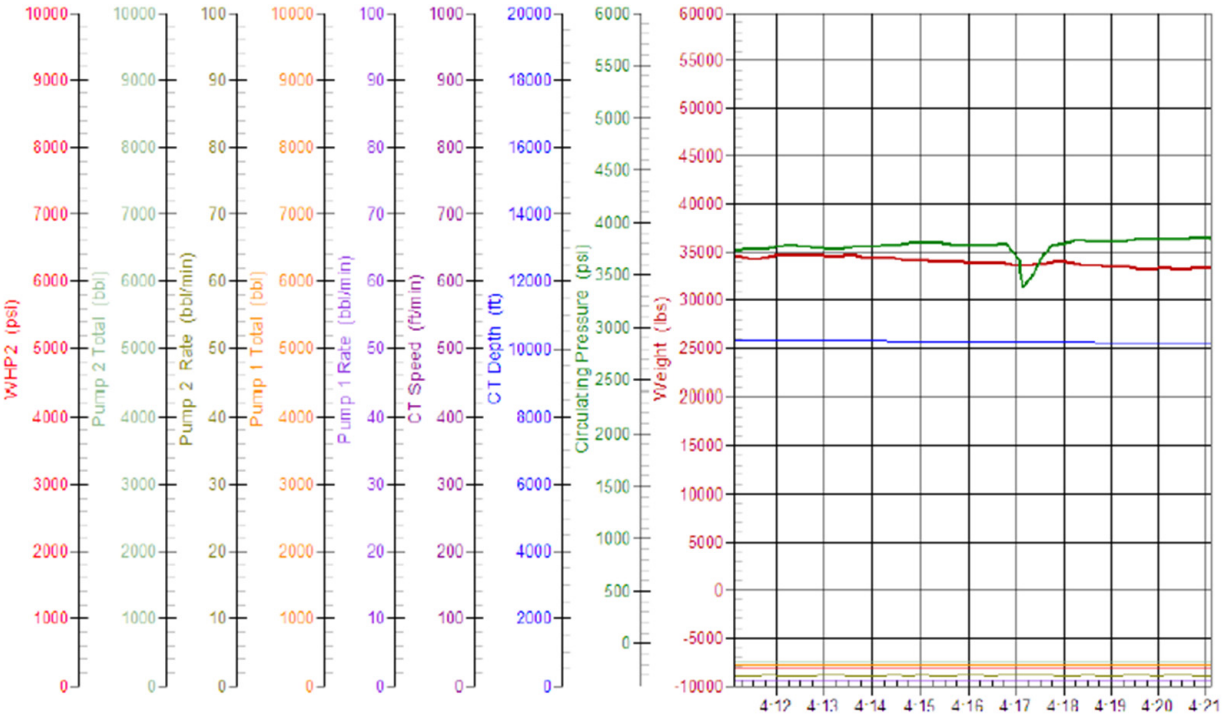


Figure 17. Recorded pumping rate during acidizing treatment.

(2) For 28% Conventional HCl: The stimulation operation employing a 28% hydrochloric acid (HCl) system was examined by comparing it to previous acidizing treatments on the same well, including earlier attempts using typical 15% HCl. The 15% HCl treatment had been ineffectual, exhibiting modest interaction with the formation and producing negligible increases in injectivity. In response, the operator suggested using a more concentrated acid to increase reactivity and produce the desired stimulating effect.

Before the main acid treatment, a pre-flush phase was carefully carried out to prepare the formation for the application of such a high acid concentration. This phase was crucial for preparing the near-wellbore environment, removing any obstructions, and ensuring proper acid penetration and effectiveness. Following the pre-flush, the 28% HCl system was successfully implemented, significantly improving well performance. Following injectivity tests, the injectivity index increased by almost eightfold. This large improvement suggests that the greater acid content, together with the pre-flush, increased near-wellbore permeability by successfully dissolving formation damage and improving pore connectivity.

As a result, the treatment restored and improved the reservoir's ability to handle fluid flow as demonstrated in Figure 12. The success of the 28% HCl system not only maximized stimulation outcomes but also provided a positive return on investment as higher well productivity offset the additional operational costs associated with utilizing a more concentrated acid. This scenario emphasizes the necessity of both good formation preparation and customizing acid concentration to specific reservoir properties, allowing for the strategic deployment of high-concentration acid systems when traditional treatments fail.

(3) Emulsified Acid Treatment for Tight Formations: The stimulation operation with a 28% emulsified hydrochloric acid (HCl) treatment was evaluated by comparing it to previous acidizing treatments on the same well, including earlier attempts with standard 15% HCl. The 15% HCl treatment had proven ineffectual, with low interaction

with the formation and modest increases in injectivity. In response, and taking into account the reservoir's tightness and limited permeability, the operator suggested using a 28% emulsified acid system to increase acid reactivity and ensure deeper penetration with controlled acid spending. Prior to the primary treatment, a pre-flush phase was carefully performed to prepare the formation for the administration of this high-concentration emulsified acid. This essential phase helped to prepare the near-wellbore environment, increase acid distribution, and allow for optimal interaction between the emulsified acid and the formation. Following the pre-flush, the 28% emulsified acid system was successfully applied, significantly improving well performance. Following injectivity tests, the injectivity index increased by almost fivefold. This improvement indicated the treatment's capacity to dramatically increase near-wellbore permeability by removing formation damage and improving pore connectivity, especially in a reservoir with low permeability. The graph Figure 18 depicts the improvement in pumping rate during the primary treatment stage. The injection began at 0.4 bpm, with flow rates shown in purple and light orange. As the treatment progressed, the rates significantly increased, indicating improved formation response and fluid uptake. By the end of the stage, the injection rate had reached 1.7 bpm, demonstrating the treatment's efficiency in improving injectivity in a previously tight formation.

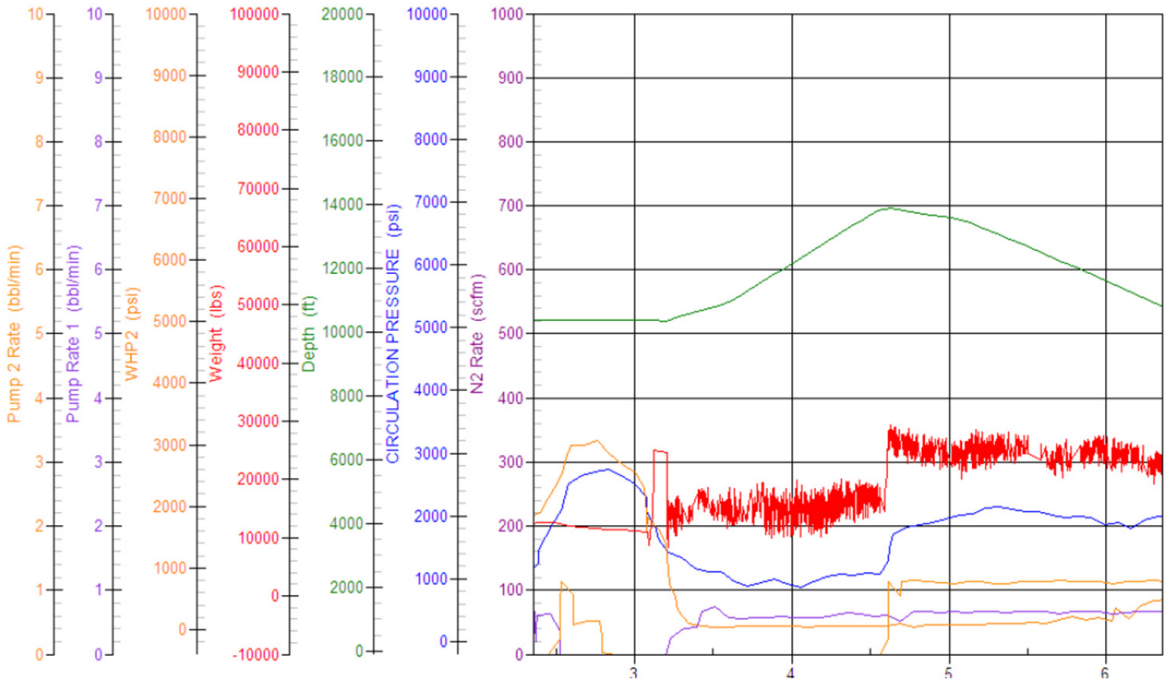


Figure 18. Data records during acid pumping.

(4) For 15% Single-Phase Acid Retarder Treatment: The intervention used a single-phase retarded acid (SPRA) device, which was specifically designed to provide controlled acid reactivity for better stimulation under difficult reservoir circumstances. The process began with a meticulous pre-flush phase designed to clean the near-wellbore region and prepare the formation for the upcoming acid treatment. This initial step alone led to a ninefold increase in injection rate, showing that initial formation damage had been successfully removed and fluid mobility improved. Following the pre-flush, the major acid treatment was performed utilizing the SPRA system. The acid's delayed nature allowed for greater penetration into the formation before reacting, resulting in more uniform and long-lasting stimulation along the reservoir

face. As a result, the post-treatment injectivity index increased by a staggering sixfold over pre-treatment levels. The combined effect of the pre-flush and SPRA system confirmed the efficacy of this approach in increasing near-wellbore permeability and reservoir deliverability, making it a beneficial method for improving well performance in low-permeability formations. Figure 19 depicts key surface and downhole metrics measured during a stimulation operation, demonstrating the efficacy of the pre-flush and major acid treatment steps. The green and yellow curves, indicating Pumping Rate 1 and Pumping Rate 2, show a distinct increase from an initial 1.2 bpm to around 3.5 bpm and 3.6 bpm, respectively, for a total rate of 7.1 bpm.

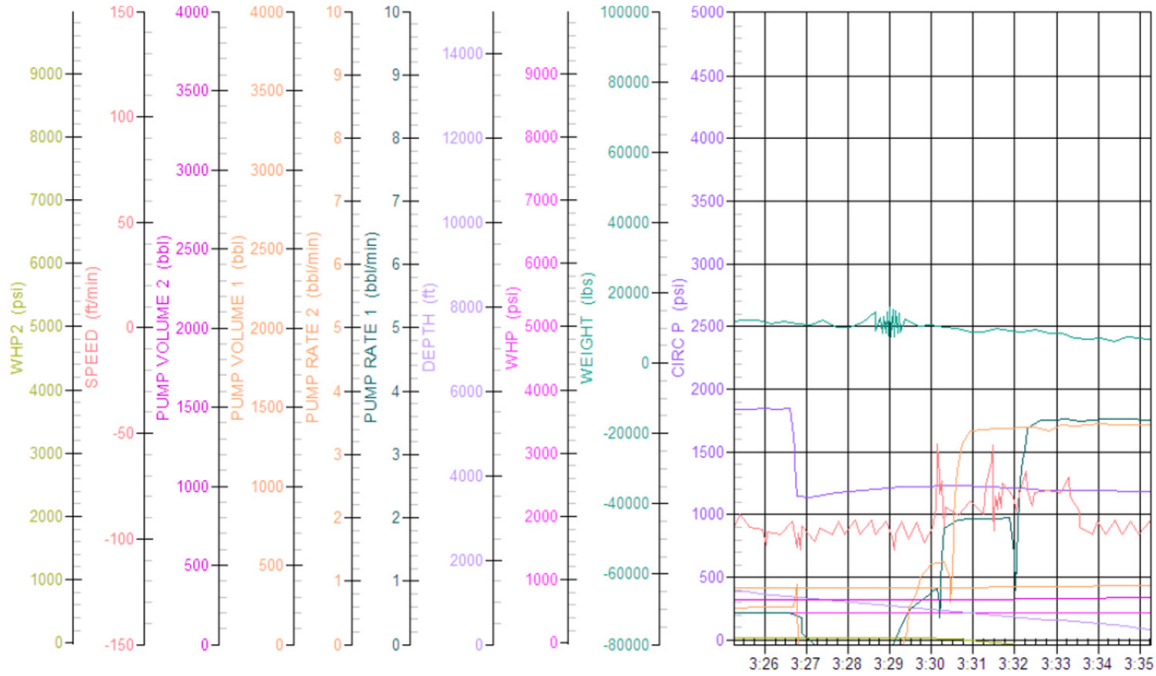


Figure 19. Recorded parameters during over displacement after acid treatment.

During the pre-flush period, the overall injection rate hits 3.5 bpm, showing that injectivity has improved initially. As the operation progresses to the single-phase retarded acid stage, the system reaches a peak rate of 7.2 bpm, showing improved permeability and efficient fluid placement in the formation. This performance trend clearly illustrates the treatment's effectiveness in decreasing near-wellbore constraints and allowing for higher pumping rates without exceeding pressure limits.

To summarize, the pre-flush phase was a critical component that was consistently implemented across all types of acid treatments, including traditional 15% HCl, high-concentration 28% HCl, emulsified acid systems, and single-phase retarded acid (SPRA) formulations. Its major function was to target and eliminate near-wellbore damage and formation deposits, essentially preparing the reservoir for the main acid stage. By removing obstructions and boosting initial injectivity, the pre-flush allowed the main acid to penetrate deeper into the formation, maximizing contact with the reservoir rock and greatly increasing treatment effectiveness. This preparatory step was critical in realizing the full potential of the subsequent acid systems, allowing each to perform at its peak efficiency whether the goal was rapid reaction (as with 15% HCl), deep penetration with controlled reactivity (as with 28% or emulsified acid), or uniform stimulation over extended contact time (as with SPRA). Finally, the inclusion of the pre-flush phase not only improved the overall stimulation outcome but also boosted the value and return on investment of the acidizing

process, guaranteeing that each acid system delivered its intended benefits in the most effective manner.

4. Discussion

The data collected from several wells clearly illustrate the importance of the pre-flush phase in improving the overall efficiency of acid stimulation operations. When compared to conventional acid treatments, particularly the standard 15% HCl system used without a pre-flush, the improvements in injectivity were significant and constant. The pre-flush is designed to target near-wellbore damage, including scale deposits, fines migration, and leftover drilling or completion fluids, which frequently decrease permeability. This initial stage successfully clears the flow pathways, allowing for better acid placement. In all cases studied, injection rates increased significantly after the pre-flush, with some wells increasing thrice even before the main acid was added. These findings highlight an important finding: the pre-flush is not only preparatory, it directly contributes to the increase in injectivity. Following the pre-flush, the use of several acid systems—including 28% standard HCl, emulsified acid, and single-phase retarded acid (SPRA)—resulted in additional increases, with post-treatment injectivity indices increasing up to sixfold compared to initial baseline levels. The comparison with treatments that used simply standard 15% HCl without a pre-flush clearly demonstrates the advantages of the combination method. This is consistent with previous research in tight, low-permeability formations, where deep acid penetration and effective damage clearance are critical for considerable productivity gains. Furthermore, the field data consistently supported our premise that good near-wellbore preparation might considerably increase acid effectiveness. In a larger sense, these findings have significant implications for stimulation procedures in confined or damaged reservoirs. The systematic application of a designed pre-flush phase optimizes acid dispersion and reactivity, regardless of the acid system used. This method not only improves operating efficiency and treatment effectiveness but also increases cost-effectiveness by optimizing the return on acid investment. Furthermore, this study emphasizes the need for developing stimulation programs holistically, which includes chemical formulation, reservoir characteristics, and operational sequencing.

The data provided in ten field examples clearly show that the pre-flush treatment greatly improves well injectivity and reservoir permeability prior to acid stimulation as highlighted in Table 4. Initially, several wells had significantly low injection rates, with some as low as 0.1 barrels per minute (bpm), as seen in Cases 9 and 10. These poor injectivity readings indicated severe formation degradation, pore obstruction, or changed wettability, most likely due to hydrocarbon saturation, scale deposition, or organic debris. The pre-flush treatment was a vital conditioning step that efficiently prepared the formation by eliminating impurities around the wellbore and improving acid accessibility. Following the pre-flush, injection rates increased significantly in all cases, allowing the main acidizing steps to proceed under more favorable conditions. For example, in Case 10, the injection rate increased from 0.1 bpm to 3.6 bpm following acidification—a 36-fold increase. Similarly, Case 1 began with an injection rate of 1.2 bpm and ended at 6.8 bpm. Case 2 (from 0.7 bpm to 8.8 bpm) and Case 5 (from 1.25 bpm to 5.56 bpm) showed particularly significant gains, highlighting the pre-flush's cumulative impact on restoring and improving reservoir permeability. This transition from low injectivity to high post-treatment flow rates indicates that the pre-flush stage not only improves acid propagation but also allows for deeper penetration and more uniform stimulation throughout the formation. As a result, this strategy is critical for overcoming initial flow constraints, optimizing acidification efficacy, and ensuring long-term productivity or injectivity gains.

Table 4. Final post-injection rate after acidizing.

Cases	Well Type	Res. Temp	Initial Inj. Pr	Initial Inj. Rate Before Pre-Flush	Final Inj. Pr	Inj. Rate After Acidizing
Case 1	Water Injector	200 °F	1200 Psi	1.2 bpm	200	6.8 bpm
Case 2	Water Injector	200 °F	1150 Psi	0.7 bpm	350	8.8 bpm
Case 3	Oil Producer	200 °F	1200 Psi	0.85 bpm	460	4.2 bpm
Case 4	Oil Producer	200 °F	1100 Psi	1.4 bpm	800	3.8 bpm
Case 5	Oil Producer	200 °F	1150 Psi	1.25 bpm	720	5.56 bpm
Case 6	Oil Producer	250 °F	900 Psi	1.1 bpm	630	5 bpm
Case 7	Oil Producer	250 °F	1120 Psi	0.5 bpm	550	4.4 bpm
Case 8	Gas Producer	280 °F	1200 Psi	0.5 bpm	830	2.6 bpm
Case 9	Gas Producer	290 °F	1230 Psi	0.3 bpm	400	3.2 bpm
Case 10	Gas Producer	290 °F	1170 Psi	0.1 bpm	710	3.6 bpm

Future study into modifying pre-flush compositions based on mineralogical and damage-specific characteristics could improve this process even further. Furthermore, using prediction models that link formation characteristics to pre-flush and acid performance could aid in determining the most effective treatment plan. Extending this concept to horizontal wells and multi-zone treatments, as well as including real-time diagnostics, could broaden its applicability and increase its utility in complex reservoir environments.

5. Conclusions

The success of chemical stimulation in complicated carbonate formations is strongly dependent on the precise sequencing of pre-treatment phases to address the multi-layered nature of near-well bore degradation. A three-step chemical slug strategy has shown effective in improving fluid placement, rock–fluid interaction, and overall stimulation efficiency. The procedure begins with the injection of a high-performance nano-surfactant designed to change the wettability of the rock surface from oil-wet to water-wet while also reducing interfacial tension (IFT) between injected fluids and hydrocarbon reservoirs. This wettability alteration makes treatment fluids more accessible to pore surfaces, promoting deeper penetration by reducing capillary forces. After the rock surface has been conditioned, an organic dissolver is used to dissolve the exterior layer of acid-insoluble organic matter—which is mostly made up of paraffins, asphaltenes, and resinous compounds and frequently wraps inorganic deposits—preventing effective acid contact. The removal of this organic coating reveals the underlying mineral matrix and opens pore channels that were previously blocked by organic waste. The third and last stage is the acid pickle (or acid wash) phase, which uses hydrochloric acid to dissolve carbonate-based scale, drilling damage, and other acid-soluble elements that make up the damaged skin. This stage ensures a clean and reactive surface prior to the major acid stimulation, allowing for homogeneous acid propagation and deeper matrix penetration. Adhering to this particular chemical sequence is critical to fully restoring formation injectivity and permeability, as each step works together to condition the reservoir for optimal stimulation performance.

In conclusion, the incorporation of a strategically designed pre-flush phase has proven to be a key and non-negotiable component in the performance of current acid stimulation treatments, particularly in difficult reservoirs with tight formations and low permeability. The pre-flush formulation's compatibility, stability, and performance under realistic field settings were ensured by the use of specific chemicals, which were chosen after rigorous laboratory testing and several trial iterations. The lab results, which demonstrated consistent

and dependable performance in dissolving and dispersing typical damage mechanisms, transferred immediately into outstanding field results across several wells. These results were characterized by considerable increases in injectivity, indicating a direct link between laboratory validation and field performance. The field results confirm the following:

Pre-flush as a Critical Component: This study demonstrates that the pre-flush phase is a necessary and fundamental stage in acid stimulation operations, especially in tight and low-permeability reservoirs.

Effective Damage Removal: The chosen pre-flush formulation was highly effective in dissolving organic deposits, acid-soluble scales, and acid-insoluble minerals, resulting in skin damage removal and wettability changes.

Extensive lab testing supported the chemical selection, and positive findings were constant in the field, resulting in up to a sixfold increase in injectivity following the completion of treatments.

Enabler for Main Acid Penetration: The pre-flush served as an activation phase, increasing the depth of acid penetration by avoiding near-wellbore damage and allowing for greater reservoir contact for all acid systems (15% HCl, 28% HCl, emulsified acid, and SPRA).

Stimulation Efficiency and Economic Value: Adding a pre-flush not only increased the effectiveness of the main acid treatment but also maximized the return on investment by ensuring deeper stimulation, better reservoir coverage, and overall improved well performance.

Recommendation for Future Operations: Given its demonstrated benefits, the pre-flush step should be considered standard practice in stimulation design, with additional study focusing on refining its composition based on reservoir-specific damage profiles.

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Abbreviations

The following abbreviations are used in this manuscript:

mD	Millidarcies
IFT	Interfacial tension
H_2S	Hydrogen sufide
CO_2	Carbon dioxide

E&P	Exploration and production
HCl	Hydrochloric acid
HLB	Hydrophilic–lipophilic balance
Ca^{2+}	Calcium
Mg^{2+}	Magnesium
bpm	Barrels per minute
WAG	Water alternative gas
EOR	Enhanced oil recovery
CT	Coiled tubing
SPRA	Single-phase acid retarder

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