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Research Article

Barium Sulfate Scale Removal at Low-Temperature

Hany Gamal,[1] Saad Al-Afnan,[1] Salaheldin Elkatatny ⓘ,[1] and Mohamed Bahgat[2]

[1]*Department of Petroleum Engineering, College of Petroleum & Geosciences, King Fahd University of Petroleum & Minerals, Dhahran 31261, Saudi Arabia*
[2]*Rosewell Energy Company, 327 El-Horreya Road, Cleopatra, Alexandria 21500, Egypt*

Correspondence should be addressed to Salaheldin Elkatatny; elkatatny@kfupm.edu.sa

Precipitation of the scale in the oil and gas reservoirs, surface and subsurface equipment, and processing and production facilities is a big problem as it affects petroleum production. The scale precipitations decrease the oil and gas production and cause economical loss. Solving this issue requires an engineering investigation to provide a safe, efficient, and economic solution. Consequently, this study proposed a developed dissolver for barium sulfate scales, where two field-scale samples were collected from different locations. The compositional analysis for scale samples showed that sample 1 is 100% barium sulfate where sample 2 has 97.75% barium sulfate and 2.25% of quartz. The composition of the developed dissolver has diethylenetriamine pentaacetic acid (DTPA) as a chelating agent, oxalic acid, and tannic acids as an activator, nonionic surfactant, and water as the base fluid. The new dissolver was investigated with extensive lab tests to determine the dissolution efficiency, precipitation tendency for the dissolved scale solids, corrosion rate, and fluid-rock interaction. The obtained successful results indicated that the developed dissolver had a dissolution efficiency for two real barium scale samples as the results showed 76.9 and 71.2% at 35°C and 91.3 and 78.4% at 90°C for samples 1 and 2, respectively. The new solution has a great performance compared with common scale dissolvers in the oil field as hydrochloric acid, ethylenediaminetetraacetic acid, and diethylenetriamine pentaacetic acid. The developed dissolver showed a very low precipitation tendency for the scale dissolved solids (1.9 and 3.2% for samples 1 and 2, respectively) under 35°C for 24 hours. Without any additives of corrosion inhibitors, the corrosion rate was 0.001835 g/cm^2 at 6.9 MPa and 100°C for 6 hours. Injecting the developed dissolver for damaged sandstone core sample with barite mud by flooding test showed a return permeability of 115%.

1. Introduction

The oil and gas industry suffers from the scale precipitation in the well equipment. The scale depositions will affect the internal capacity for the well equipment either downhole or at the surface as the production tubing, subsurface valves, wellhead, surface pipelines, and production and processing facilities, in addition to, the reservoir formation [1–4]. The scale precipitation causes formation damage, decreases the reservoir injectivity and productivity performance, and also changes the rock wettability [5, 6].

There are many reasons for the scale deposits and exposing many fluid streams during the production cycle was found to be the most critical factor as these streams have different ions and concentrations. These streams might include the oil, formation water, and injected water and will format

different types of scales [4]. Barium and calcium minerals are commonly found with higher concentrations in the formation water than the seawater; moreover, a higher concentration of sulfate ions is commonly existing with the seawater than the formation water [7]. Many different types of scales are prevalent with the oil and gas field from the sulfate type as barium sulfate which is commonly called barite ($BaSO_4$), calcium sulfate ($CaSO_4$), and strontium sulfate ($SrSO_4$) [8, 9].

Many operational parameters and conditions have a great impact on the scale precipitations in the field as pressure, temperature, interaction time, degree of acidity or alkalinity pH, and chemical equilibrium [10]. The location of the scale and its type will occur based on the streams' ions concentrations and the operating conditions. One of the hardest scale types is the sulfate scales that are commonly formatted due to the incompatibility between the two water streams of

production and injection water, and this scale type is a hard scale for removal as it has a low dissolution rate with acid [11]. The barium sulfate (barite) is commonly used with the drilling fluids to obtain the required mud type for well control issues [12, 13], and the incompetent practices and poor design during the drilling operations might cause formation damage by the barite solids precipitations in the drilled rock pore system [14–16]. Many sulfate scales are precipitated in the reservoir section and the well pumps of artificial lift equipment [17].

1.1. Scale Removal Solutions. The field scales removal operations are considered critical jobs due to the composite scales from different types with changing the operation conditions along the production stream. Two common methodologies are applied in the field of descaling that includes the mechanical or the chemical solutions and, in some cases, can be applied together. The descaling process should be designed from technical and economic aspects [18, 19]. The scale precipitations might lead to production reduction or shutdown [20], and hence, utilizing the scale inhibitors might be efficient for preventing the scale deposition [7, 21, 22]. The proper chemical design for the scale inhibitors has shown successful results for field applications [23].

Designing the chemical scale dissolver should investigate the scale solubility by chemical reactions and dissolution mechanisms to develop a highly efficient scale dissolver for the field descale operations [4]. The solution pH is a critical parameter that affects the scale solubility with the developed dissolver [24]. The pH of the developed chemical solution for scale removal will have a great impact on the equipment integrity due to the corrosive effect [25, 26]. Recently, many studies in the literature are targeting high pH solutions [27–30]. The high pH scale dissolvers will not damage the well tubular and equipment as the corrosion rate is low. At the same time, high pH solutions will save the additional cost that is commonly applied for the scale inhibitors and intensifiers [31, 32]. A study was performed to provide a scale dissolver with a 12.5 pH value for removing sulfate and/or sulfide scale types by employing specific concentrations of ethylenediamine, nitrilotriacetic acid (NTA), and chloroacetic acid [33].

Tetrakis hydroxymethyl phosphonium salt (THPS) was studied to be added to the ethylenediaminetetraacetic acid (EDTA) to develop a chemical scale dissolver with a pH of 8 to enhance the alkalinity base for the solution [28]. Organic and inorganic acids are commonly utilized in the oil and gas field for scale removal purposes [34]. Commonly, a surfactant is added to the chemical solution to remove the hydrocarbon layer from the scale solids to increase the interaction between the scale body and the chemical solution to provide a higher dissolution rate. Hydrochloric acid (HCl) is one of the most common acids for scale removal applications in the petroleum industry [35]. Among the undesirable side effects of hydrochloric acid, the corrosive impact and producing hydrogen sulfide toxic gas. Therefore, specific chemical additions need to be added to control these impacts during the scale removal jobs [5, 36–38]. In addition to that, the performance of HCl was found efficient in specific scale

types as zinc sulfides [39], pyrrhotite, and troilite of iron sulfides. However, the results did not show great solubility with sulfate scales as strontium, calcium, and barium [20, 21]. Organic acids as citric acid, maleic acid, formic acid, and acetic acid were employed for the scale removal at high-pressure high-temperature reservoirs [40–42]. The organic acids have a low corrosive impact on the equipment and have along-time chemical reactions; however, the scale dissolution rate is relatively low [41].

The chelating agents were studied for scale dissolution as an alternative for the organic and inorganic acids. The chelating agents have many advantages as they have a small corrosive rate, are safely handled, and environmentally friendly [43]. Among these chelating agents ethylenediaminetetraacetic acid (EDTA), hydroxyethyl ethylene diamine triacetic acid (HEDTA), hydroxyethyl iminodiacetic acid (HIDA), diethylenetriamine pentaacetic acid (DTPA), and methylglycinediacetic acid (MGDA) showed successful applications for scale removal in the oil and gas field. However, the high cost, pH optimization, effective concentration, descale exposure time, and thermal stability are considered the most common disadvantages for employing the chelating agents for the scale removal operations [29, 44, 45].

The barium sulfate scale was found to decrease the reservoir rock permeability, and the temperature is a critical parameter for the barium sulfate scale deposition as the precipitation decreases at the higher temperature [7]. The chelating agents were studied for removing the barium sulfate scale; Bageri et al. [13] developed a novel solution by employing the diethylenetriamine pentaacetic acid with a special catalyst, and the study results showed an enhancement of the dissolution efficiency for the barium sulfate scale removal.

The current study proposed a developed scale dissolver for removing the barium sulfate scale precipitations. The study provides new contributions in terms of the high dissolution rates for the developed dissolver for two real field samples of barium sulfate scale type, high efficiency at low-temperature conditions (35°C) for the surface scale treatment, low corrosive rate to maintain the well equipment and field facilities integrity, high pH for the developed dissolver of 9.78, low precipitation tendency for the dissolved solids after the solubility process, and the developed chemical solution provided a great permeability enhancement throughout the core flooding test for a damaged core sample with barite-weighted mud. In addition, the dissolution performance for the developed dissolver was compared with the common dissolvers in the oil industry named HCl acid (15 wt.%), EDTA (20 wt.%), and DTPA (20 wt.%), and the results showed the highest performance for the developed scale dissolver over the other dissolvers under the same condition. Through the study, extensive lab analysis was performed for the field produced water, injected water, and collected field scale samples to design an efficient scale dissolver.

2. Materials and Experimental Work

Figure 1 shows the proposed layout for the study, starting from the field scale samples collection, followed by the routine chemical analysis for the scale samples and the water
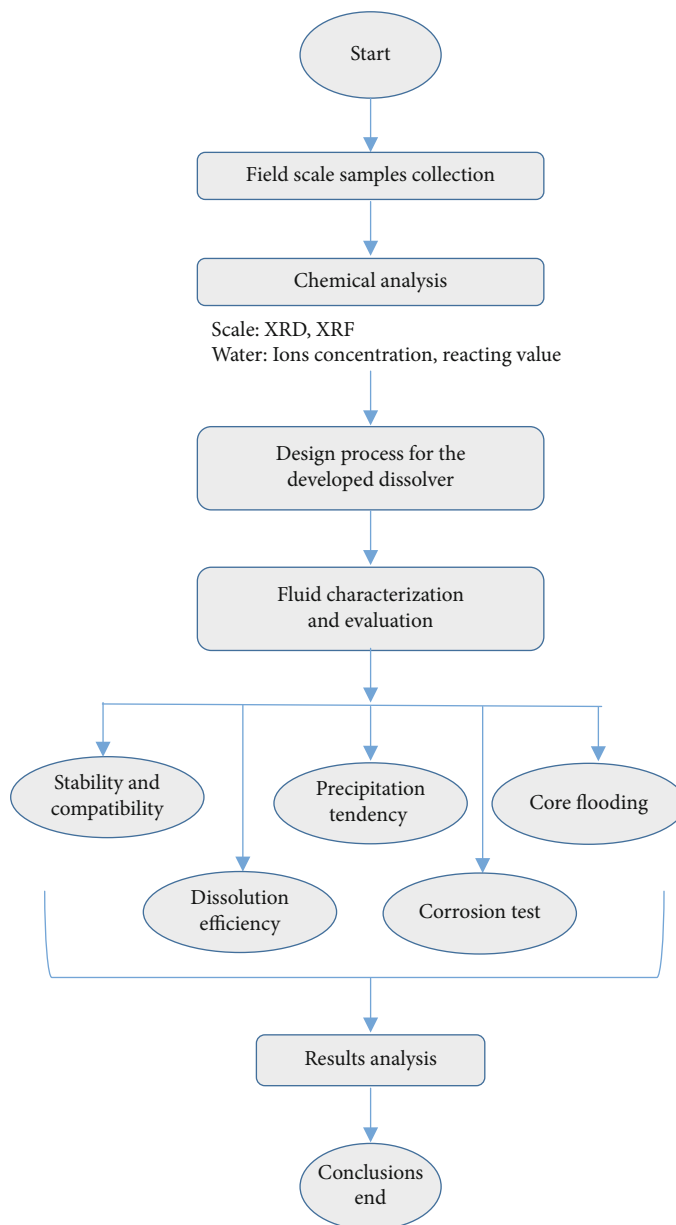
FIGURE 1: The methodology layout for the study.

samples from the production and injection streams, and then, the design process for the developed dissolver for the barium sulfate scale. The fluid characterization and evaluation were performed by extensive lab work in terms of the fluid compatibility and stability, solution efficiency, precipitation tendency, corrosion test, and the core flooding experiment. The test results were analyzed and conclusions were provided based on these results analysis.

2.1. Materials Description. The main objective of this study is to provide a solution for removing the field barium sulfate scales. In this study, two scale samples of barium sulfate type were collected from a real production field that has scale precipitation issues. The first scale was collected from an offshore producing platform, whereas the second one was collected from a pipeline that is used for petroleum transpor-

tation in the oil field. Figure 2 shows the collected scale samples to be prepared for the chemical and physical analysis to study their properties and compositions. Scale sample 1 (Figure 2(a)) was collected from a producing oil well that has wellhead pressure of 5.86 MPa and downhole pressure of 14.96 MPa, associated water cut of 85%, reservoir depth of 2,050 m, and average surface temperature of 35°C. The second scale sample (Figure 2(b)) was collected from a surface pipeline network that has a temperature of 35°C.

The collected scale samples were investigated employing X-ray diffraction (XRD) and X-ray fluorescence (XRF) to determine the mineralogical and elemental compositions of the scale samples [46]. Table 1 listed the XRD results for the two samples, sample 1 had 100% barium sulfate ($BaSO_4$), while sample 2 had barium sulfate of 97.75% and 2.25% quartz (SiO_2). The elemental composition of the scale
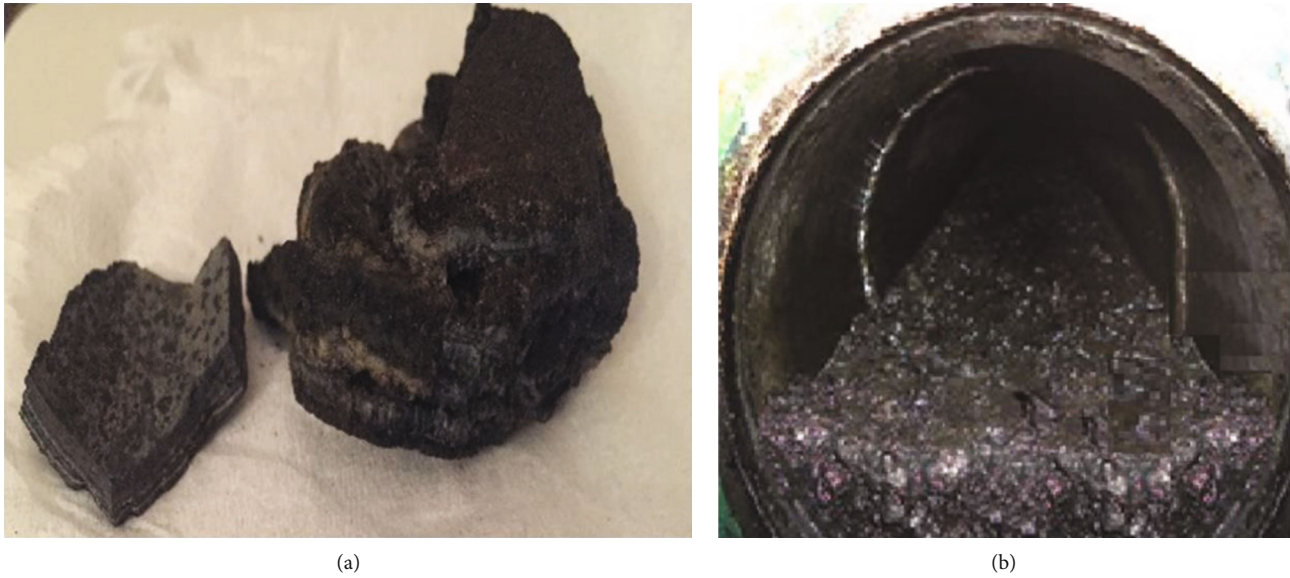
(a)

(b)

FIGURE 2: Barium sulfate samples from the field. (a) Collected from a platform. (b) Collected from a transportation pipeline.

TABLE 1: XRD results for the collected barium scale samples.

Compound	Chemical formula	Sample 1, wt.%	Sample 2, wt.%
Barium sulfate	$BaSO_4$	100	97.75
Quartz	SiO_2	0	2.25
Total		100	100

samples showed that they are mainly composed of sulfur (S) and barium (Ba) elements as samples 1 and 2 had a barium content of 48.4 and 44.6% and a sulfur element of 17.7 and 14.1 wt.%, respectively (Table 2). The composition included an additional small amount of silicon, chloride, and strontium elements.

The chemical analysis of the water is very critical as the formation of scales is highly dictated by its composition. The analysis for the produced water sample from the field was performed, and Table 3 shows the ions concentrations and the relevant reacting value for each ion. The reacting value is important from a chemical point of view to predict the scale type [30]. The results showed that chloride, barium, and sodium have the highest ion concentrations by 61,900, 38,500, and 31,400 milligrams/liter (mg/L), respectively, and these ions have the highest percentages for the reacting values by 49.3, 48.04, and 38.6%, respectively. Sulfate (SO_4) concentration is 926 mg/L in the produced water sample. The specific gravity for the developed solution was 1.048. The chemical analysis was also performed on the injected water that was used for the enhanced recovery. Table 4 shows the chemical analysis of the water sample that was used for the injection operations in the field. The results show that chloride, sodium, and sulfate represent the highest ions concentration in the injected water with concentrations of 19,162, 10,679, and 2,680 mg/L, respectively. The total dis-

solved solids were found to be 35,556.5 mg/L (ppm) for the injected water sample, while it was 101,843 ppm for the produced water sample.

The study proposed a newly developed barium sulfate scale dissolver at a low-temperature scale. Table 5 shows the chemical composition for the proposed dissolver. Diethylenetriamine pentaacetic acid (DTPA) with 15 to 30 weight percentage was employed as a chelating agent, oxalic acid and tannic acids as an activator for the new chemical dissolver with concentrations of (5 to 15) and (1 to 5) wt.%, respectively, less than 1 wt.% of nonionic surfactant, and water as the base fluid constituting the remaining weight percentage. The developed barium sulfate scale dissolver had a pH of 9.78 and 1.17 specific gravity at ambient conditions.

3. Experimental Lab Work

The experimental lab work was designed to investigate the developed dissolver for application aspects in terms of compatibility and stability, dissolution performance at specific conditions of temperature and time, precipitation tendency of the dissolved solids, and core flooding test. The following section will discuss in detail the procedures for each lab test.

3.1. Fluid Stability and Compatibility. The fluid stability might change with the ambient conditions, and therefore, testing fluid stability is very critical as it represents the fluid resistance to change with changing the conditions. The test was conducted as follows:

  (i) A fluid amount (100 ml) was put into a flask, and stirring the fluid for 10 min

  (ii) Cover the fluid flask and put it into a static oven or on a Hot-plate at 150°C for 24 hours

  (iii) Examine the fluid for any color changes and/or precipitations

TABLE 2: XRF results for the collected barium scale samples.

Element	Chemical formula	Sample 1 (wt.%)	Sample 2 (wt.%)
Silicon	Si	0.0	2.82
Sulfur	S	17.7	14.1
Chloride	Cl	0.7	0.2
Barium	Ba	48.4	44.6
Strontium	Sr	0.0	0.35

TABLE 3: Chemical analysis results for the field produced water.

Ions	Chemical formula	mg/L	Reacting value	% reacting value
Sodium	Na	31,400	1,366.72	38.60
Calcium	Ca	6,030	300.90	50
Barium	Ba	38,500	1,085.70	48.04
Magnesium	Mg	1,250	102.75	2.90
Sulfate	SO_4	926	19.26	0.54
Chloride	Cl	61,900	1,745.58	49.30
Carbonate	CO_3	0.00	0.00	0.00
Bicarbonate	HCO_3	337	5.53	0.16
Hydroxide	OH	0.00	0.00	0.00
Total dissolved solids		101,843		

TABLE 4: Chemical analysis results for the field injected water.

Ions	Chemical formula	mg/L
Chloride	Cl	19,162
Sodium	Na	10,679
Magnesium	Mg	1,278
Sulfate	SO_4	2,680
Calcium	Ca	409.6
Potassium	K	395.3
Carbon (inorganic)	C	276
Bromide	Br	663
Boron	B	4.4
Strontium	Sr	7.9
Fluoride	F	1.3
Total dissolved solids		35,556.5

(iv) Record photos before and after the test in a clear glass tube

Also, the fluid compatibility was tested by two processes of mixing the developed scale dissolver with samples of the formation water and crude oil individually for each sample. The mixing was performed by 50 to 50% of the developed dissolver and the field sample (formation water for test 1 and crude oil for test 2). After that, the mixed solution was kept at 150°C for 24 hours and the solution was investigated for any physical changes in color, precipitation, or phase separation.

TABLE 5: The chemical composition of the new scale dissolver.

Component	wt.%	Function
DTPA	15~30	Chelating agent
Oxalic acid	5~15	Activator
Tannic acid	1~5	Activator
Nonionic surfactant	<1	Penetrant
Water	60~68	Base fluid

3.2. Solubility Test. The solubility test is commonly studied to report the dissolution efficiency of the developed chemical dissolver for the scale sample by calculating the weight decrease of the scale before and after the exposure to the developed dissolver. The test was conducted several times to determine the optimum scale mass to dissolver volume ratio for the assessment of the economic and technical aspects [19, 47]. The high efficient dissolver should provide a high dissolution rate with lesser dissolver volume 5. The prospected mass of the precipitated scale is typically calculated by the reduction in the inner diameter of the equipment that has a precipitated scale and the scale density value [14, 48]. The test procedures were conducted under two temperature levels of 35 and 90°C at atmospheric pressure for 24 hours as follows:

(i) 100 ml of the developed scale dissolver was placed in an oven at the required temperature for 10 min

(ii) 10 g $[W_1]$ of the scale sample was measured

(iii) The solid scale was added to the dissolver solution in the test tube

(iv) Once the test period was up, commence removing the test bottle to cool down in a water bath

(v) The weight of the filter paper $[W_f]$ was measured and then filtered using a vacuum filter

(vi) The remaining solid was dried in a static oven at 90°C for 2.5 hours

(vii) The weight after the drying process (weight of filter paper with the remaining solids) $[W_2]$ was measured

(viii) The weight of the remaining solids was calculated $[W_3 = W_2 - W_f]$

(ix) The dissolution capacity was calculated as $[[W_1 - W_3]/W_1] * 100$

3.3. Precipitation Tendency for Dissolved Solids. The term precipitation tendency for dissolved solids represents the tendency of the dissolver scale solids to precipitate after the dissolution impact of the scale dissolver during the descale treatment operation. During the solubility test, some scale solids dissolved in the chemical solution of the dissolver. Such dissolved solids can precipitate due to the change in conditions of pressure, temperature, and/or time. The precipitation of dissolved solids is a critical issue that can lead

to equipment plugging or generating another scale type. The test simulates the real-field environment for the descale jobs and reports how much of the dissolved scale solids will precipitate after the treatment. The precipitation tendency test of the dissolved solids was performed to check for that. The test was conducted at a low temperature of 35°C for 24 hours on the two collected scale samples.

3.4. Corrosion Test. Corrosion is considered a big issue in field operations that is partially or completely damages the field or well equipment. The corrosion test was conducted to calculate the corrosion rate of the dissolver at 50°C for 6 hours (which is adequate for descale operation) [19] using an autoclave cell at a pressure of 6.9 MPa. The developed dissolver solution was tested for corrosion without any corrosion inhibitors by using a casing coupon of T95 grade. The weight reduction of the coupon was measured after the corrosion test to determine the corrosion rate as follow [49]:

$$\text{CR} = \frac{W_l}{A * T} \tag{1}$$

where CR is the corrosion rate [mg/(cm² hr.)], W_l is the loss of coupon weight (mg), A is the initial surface area of the coupon (cm²), and T is the exposure time (hr.).

3.5. Core Flooding Experiment. In order to determine the efficiency of the newly developed dissolver, a core sample was initially flooded with oil-based mud (OBM) that was weighted by barite (barium sulfate) as a weighting material. Table 6 shows the OBM composition with the mud additives and their quantities to prepare one barrel for the mud. Diesel is the base fluid for the mud with 93.8 liters and barite represents the mud weighting material with 72.6 kg to control the mud density, and the other compositions were commonly added for adjusting the mud rheology and filtration properties. Table 7 shows the mud rheological properties in terms of yield point and plastic viscosity and the filtration properties of the mud. The mud density was 1.68 grams per cubic centimeter (g/cm³), the mud yield point was 7.182 Pascal, and the viscosity was 0.063 Pascal second (Pa.s). The measurements were under a temperature of 50°C, while the mud filtration was 3.2 cubic centimeters per 30 minutes at a temperature of 180°C.

The developed scale dissolver was investigated for the core flooding test by employing a core sample of Berea sandstone rock type. Figure 3 showed a schematic diagram for the core flooding apparatus. Table 8 shows the core properties and the flooding experiment conditions. The core sample had 12.29% porosity and 78.88 mD permeability. The core flooding was conducted at 90°C with net overburden pressure of 3.45 MPa.

The test was conducted as per the following procedures:

(1) The core initial permeability was determined

(2) 200 ml of the prepared OBM to simulate the real formation damage by the barite was injected

TABLE 6: OBM composition (one barrel).

Material	Quantity
Diesel	93.8 L
Barite	72.6 kg
Lime	550 g
Calcium chloride 98%	1.93
Caustic soda	240 g
Salt	380 g
Soda ash	68 g
Sodium bicarbonate	228 g
XC polymer	437 g

TABLE 7: OBM mud properties.

Density	1.68 g/cm³ @ 50°C
Yield point	7.182 Pascal (Pa) @ 50°C
Viscosity	0.063 Pascal second (Pa.s) @ 50
Filtration	3.2 cm³/30 min @ 180°C

(3) The core was displaced by 200 ml of 5% NH₄Cl (preflush stage)

(4) The permeability was measured at the same injection rates (1-2 ml/min)

(5) The core was displaced by 100 ml of the developed scale dissolver and left to soak for 3 hours (main treatment)

(6) The plug was displaced by 200 ml of 5% NH₄Cl (postflush stage)

(7) The permeability was measured at the same injection rates (1-2 ml/min)

The return permeability was determined from steps 3 and 6 to get the core permeability before and after the treatment using the developed scale dissolver.

$$\text{return K} = \frac{k_f}{K_i}, \tag{2}$$

where return K is the return permeability value in (%), k_f is the final permeability (mD), and k_i is the initial permeability (mD).

4. Results and Discussion

4.1. Fluid Stability and Compatibility. The developed dissolver was tested for fluid stability and compatibility under conditions of 150°C for 24 hours. The results showed no color change and no precipitation as showed in Figure 4.

4.2. Solubility Results. The dissolution rate was investigated to determine the scale removal efficiency for the field descale operations. The results are presented in Figure 5. They revealed a high efficiency of 76.9 and 71.2% for sample 1
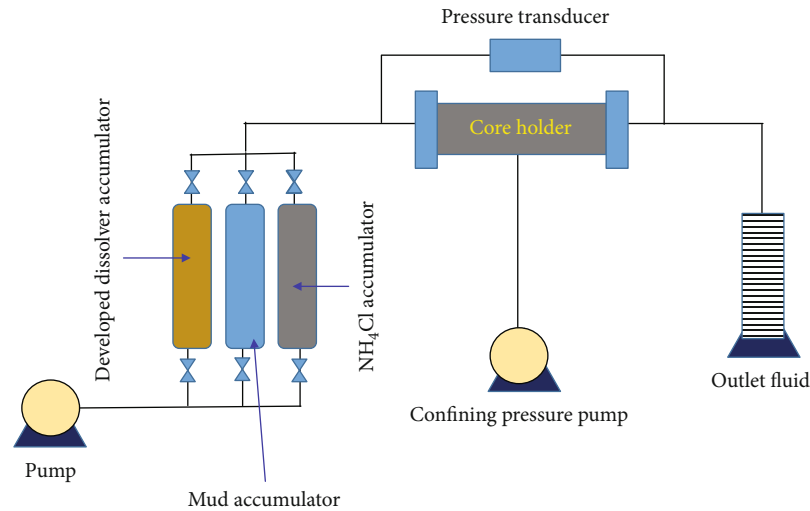
Figure 3: Flooding apparatus schematic.

Table 8: Core flooding experiment conditions.

Core type	Berea sandstone
Core porosity	12.29%
Core permeability (mD, 9.869E^{-12} cm^2)	7.78E-10 cm^2 (78.88 mD)
Core dimensions (inches, 2.54 cm)	7.62 cm length (3 inches) 3.81 cm diameter (1.5 inches)
Temperature	90°C
Net overburden pressure	3.45 MPa
Back pressure	6.9 MPa

and 91.3 and 78.4% for sample 2 at 35°C and 90°C, respectively. As shown the solubility test was conducted at two levels for temperatures at 35°C and 90°C to account for the surface (low temperature) and downhole (high temperature) conditions for the scale precipitations.

Also, the dissolution efficiency was compared with other dissolver solutions to show the relative improvement in the performance. HCl acid (15 wt.%), EDTA (20 wt.%), and DTPA (20 wt.%) were employed for this comparison, and the results showed that the developed dissolver showed a significant improvement of dissolution efficiency for the two samples. As presented in Figure 6, HCl (15 wt.%) showed a weak dissolution for the two scale samples by 1.3 and 1% for samples 1 and 2, respectively. EDTA (20 wt.%), and DTPA (20 wt.%) had a close performance; however, it is not strong dissolution as the results were 21.2 and 12.9% for EDTA (20 wt.%) and 27.8 and 15.6% for DTPA (20 wt.%) for samples 1 and 2, respectively. The developed dissolver outperformed the EDTA (20 wt.%) and DTPA (20 wt.%) with an average factor of 3.2 and 5 for the dissolution rates, respectively.

4.3. Precipitation Tendency for Dissolved Solids. Figure 7 shows the results of the precipitation tendency test for dissolved solids for 24 hours at 35°C. The results indicated that
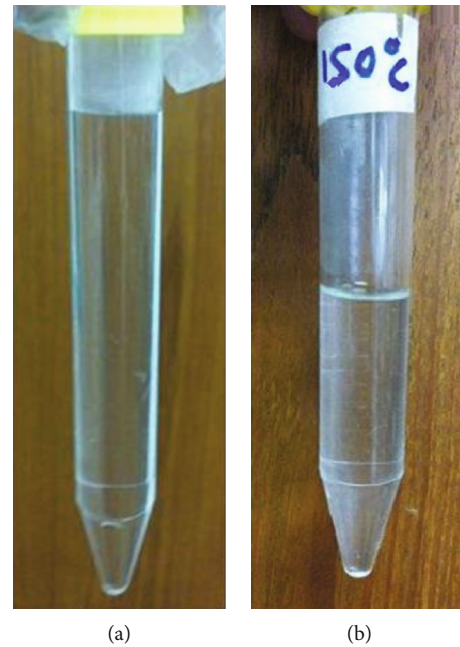

Figure 4: Stability performance. (a) At room temperature. (b) After 24 hours at 150°C.

for scale sample 1, the precipitation tendency test for dissolved solids was 1.9% and 3.2% for scale sample 2. The low precipitation tendency for the dissolved solids showed a good dissolution performance without the precipitates of the dissolved solids again after the treatment operations.

5. Corrosion Test

The results for the corrosion test revealed an additional advantage of the developed dissolver. Table 9 listed the corrosion test results for the steel coupon before and after the exposure to the new dissolver at a pressure of 6.9 MPa under
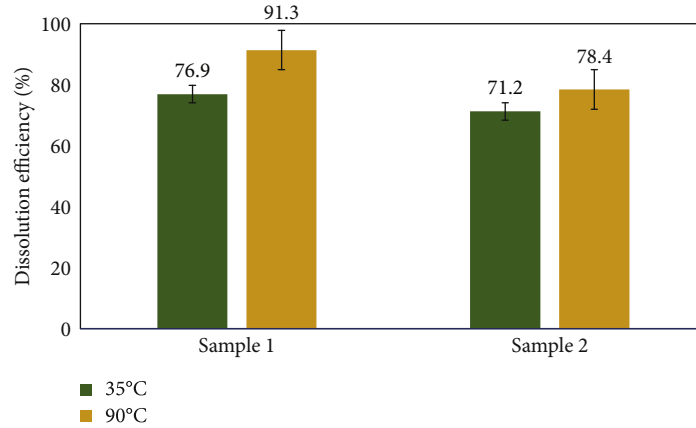
FIGURE 5: Dissolution efficiency for the developed dissolver at different temperatures (35°C and 90°C for 24 hours).
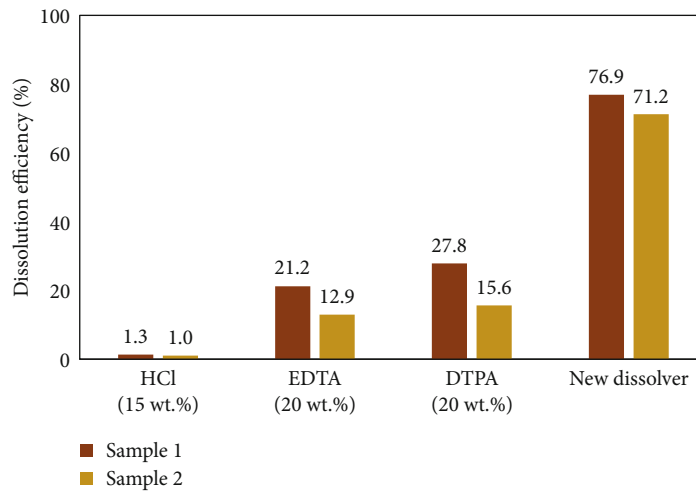

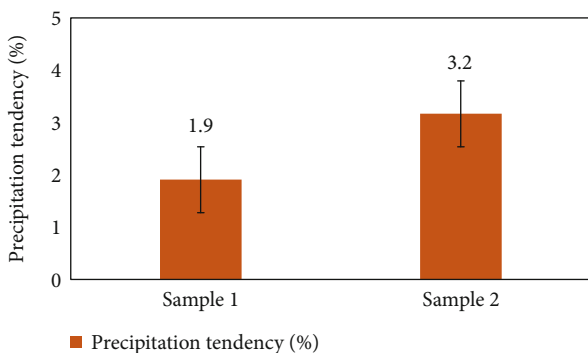FIGURE 6: Dissolution efficiency for the developed dissolver versus commercial ones at 35°C for 24 hours.

FIGURE 7: Results of precipitation tendency for dissolved solids for the two scale samples.

TABLE 9: Corrosion test results.

Condition	Weight, g	Surface area, cm^2	Thickness, cm	Corrosion rate, g/cm^2
Before	51.726	50.73457	0.30198	0.001835
After	47.323	50.68792	0.29946	

50°C for 6 hours. The results showed that the surface area reduced by only 0.0919% after the exposure while there was a thickness reduction by 0.834% to provide a corrosion rate of 0.001835 g/cm^2 which is very low and indicates the safe use of the developed dissolver for removing the barium sulfate scales.

5.1. Core Flooding. Flooding the damaged sandstone core sample with the developed scale dissolver was executed as per the test procedures and the results are presented in Figure 8. The core flooding experiment started by pumping the developed dissolver into the damaged sandstone core plug at 36 kPa, and the pressure started to increase by the pumping force action into the pore system of the damaged core sample until the wormholes were initiated by the chemical reaction impact between the rock-dissolver at 48 kPa after injecting 5.25 ml of the dissolver solution. The initiated wormholes were then propagated, and the differential pressure started to decrease due to increasing the reaction rate between the rock matrix and the scale dissolver. Figure 9 shows the generated wormholes in the flooded core sample after pumping the dissolver fluid.
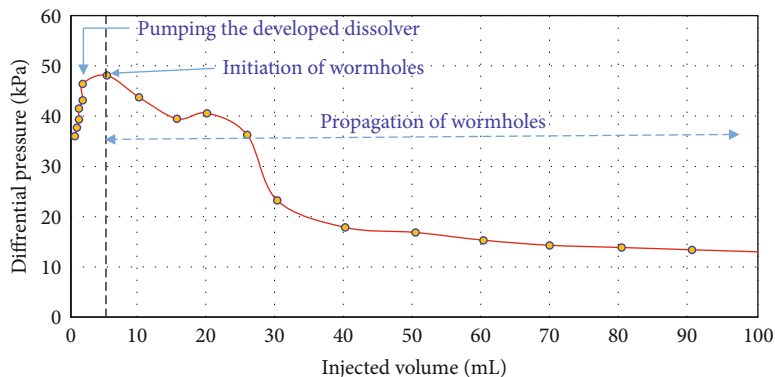
Figure 8: Pressure drop versus injected volume during injecting with the developed dissolver.

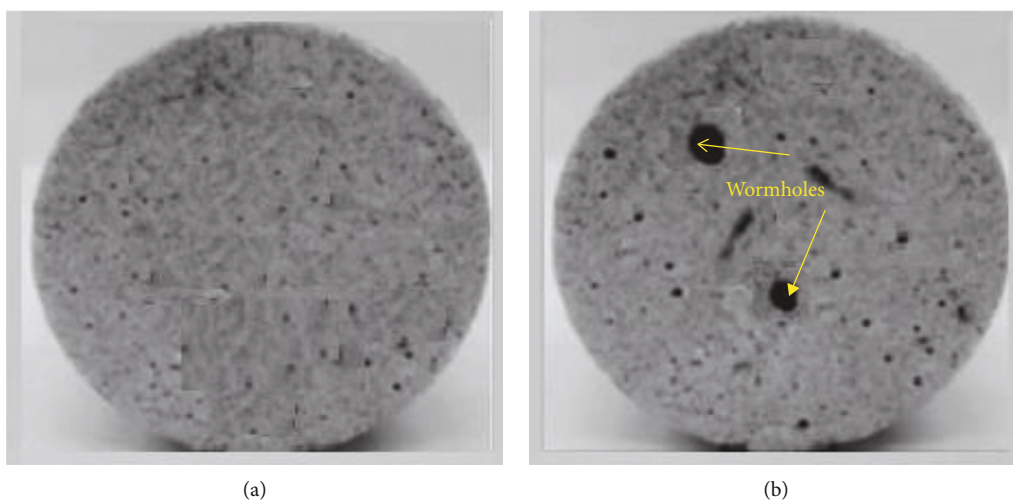(a)   (b)

Figure 9: Core sample for core flooding. (a) Sample before flooding. (b) Wormholes after injecting the new dissolver.

The permeability of the core sample was determined before and after the core flooding experiment using the developed dissolver. The results showed that the permeability value was improved from 47.75 mD to 54.68 mD after injecting the new solution of the developed barium sulfate scale dissolver (i.e., the return permeability was 115%). The results indicated a satisfactory performance of the newly developed dissolver to remove the damage that was caused by the barrier OBM and returned the original rock permeability with enhancement, and therefore, the results provide a promising potential of the dissolver for the field treatment application.

5.2. Dissolution Mechanism. The newly developed scale dissolver has diethylenetriamine pentaacetic acid (DTPA) as a chelating agent, oxalic acid and tannic acids as an activator, and nonionic surfactant. The developed composition was designed to provide the high dissolution performance of barium sulfate scales that was achieved as follows:

(i) DTPA: is a chelation agent complexing the barium and silicon compounds in the scale and the core plug

(ii) Oxalic Acid: classified as the simplest dicarboxylic acid. Its acid strength is much greater than that of acetic acid [48]. Oxalic acid is a reducing agent and

its conjugate base is a chelating agent for metal cations

(iii) Tannic Acid: works as an activator, cleaning agent as a surfactant, reacts with corrosion products, and reacts as a corrosion inhibitor

(iv) Nonionic Surfactant: nonionic surfactants contain no charge, they are the second most widely used surfactants after anionic surfactant, these molecules have no charge and so they are less likely to create foam, nonionic surfactant can work on both carbonate and sandstone formations

6. Conclusions

This study proposed a newly developed dissolver that showed a promising potential for removing barium sulfate scale with high dissolution efficiency, low precipitation tendency, low corrosion rate, and permeability enhancement for sandstone core flooding experiment. The following findings summarize the lab investigation of the developed dissolver:

(i) The fluid showed good stability and compatibility under temperature conditions of 150°C for 24 hours

(ii) The dissolution efficiency was high for the two barium sulfate scale samples, at 35°C, the dissolution was 76.9 and 71.2%, while at 90°C, the results were 91.3 and 78.4% for sample 1 and 2, respectively

(iii) The solubility efficiency for the developed dissolver outperformed the other common chemical dissolvers for scale removal as HCl acid (15 wt.%), EDTA (20 wt.%), and DTPA (20 wt.%).

(iv) The precipitation tendency test for the dissolved solids showed that dissolved solids were 1.9 and 3.2% for the scale samples 1 and 2, respectively, under 35°C for 24 hours

(v) The developed scale dissolver had a safe corrosion rate (0.001835 g/cm^2) without any corrosion inhibitor additives

(vi) The core flooding test provided a 115% return permeability of the damaged sandstone sample

The limitations beyond this study can be summarized in the scale mineralogy, pressure and temperature environment, solubility static condition, and sandstone as a rock type for core flooding experiment. The obtained results from this study indicated a safe use and a great performance for field descale applications to remove the barium sulfate scale.

Abbreviations

XRD: X-ray diffraction
XRF: X-ray fluorescence
HCl: Hydrochloric acid
EDTA: Ethylenediaminetetraacetic acid
DTPA: Diethylenetriamine pentaacetic acid
HEDTA: Hydroxyethyl ethylene diamine triacetic acid
HIDA: Hydroxyethyl iminodiacetic acid
NTA: Nitrilotriacetic acid
MGDA: Methylglycinediacetic acid
mD: Millidarcy
THPS: Tetrakis hydroxymethyl phosphonium salts
HPHT: High-pressure high-temperature
T95: Casing grade
CR: Corrosion rate [mg/(cm^2 hr.)]
W_l: Weight loss (mg)
A: Initial surface area of the coupon (cm^2)
T: Exposure time (hr.)
MPa: Mega Pascal
kPa: Kilo Pascal
mg/l: Milligrams per liter
ml: Milliliter
g: Gram.

Data Availability

The data is already included in the manuscript.

Conflicts of Interest

The authors declare no conflicts of interest.

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