Oil & Gas Research

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content (Acetic acid and EDTA). erefore, it might be corrosive to the injection system. We used standard SY/T 5405-1996 [30], related to petroleum products corrosion test in Chinese oil elds to estimate its corrosion rates and speed at di erent temperatures using N80 steel. Temperatures were set using a static water bath.

e corrosion rate (C) and corrosion speed (vi) are given by:

Where, mo is the initial steel mass, Δmi masses di erence, Ai the steel surface area and Δt the time di erence. Figure 1 below, shows the used steel to test the corrosivity.

Corrosion inhibitors screening: To reduce the proven corrosivity of the removal solution, we used standard SY/T 5756-1995, related to corrosion inhibitors testing for chinses oil elds, to screen two corrosion inhibitors used in the oil eld and an ammonium salt ($C_3N_2H_4$).

S a b a a a : Turbidity is the measure of relative clarity of a liquid. It is an optical characteristic of water and is a measurement of the amount of light that is scattered by material in the water when a light is shined through the water sample. e higher the intensity of scattered light, the higher the turbidity [31].

To calculate the turbidity, formation and injected waters based on the ions compositions (Table 4) sheets received from the oil eld [32], were synthetized. A digital turbidity meter SGZ-2 to was used and temperatures were set in a static water bath.

S b a a : e main objective of the solution is to decrease the injection pressure on the oil eld during water ooding by removing the plugging within the formation; we decided to simulate the reservoir and plugging conditions in the lab by running a sand pack ooding experiment [33,34]. e experiment was ran using the oil eld sand at 60°C, which is the reservoir temperature. Figure 2 below, represents the scheme of the core.

e experiment was ran in four steps:

- Determine the initial sand permeability: e formation water was injected at 1 mL/min until the pressure got stable for at least 1 PV injection volume.

- Create an arti cial plugging to increase the pressure, which will represent the plugging pressure: Mix the injected and formation waters at 50/50 ratio and inject the mixture at 1 mL/min to create an inorganic sale within the pack so to reach the highest pressure of the system.

- Test the injectivity of the solution at the plugging pressure: Inject the solution at 2mL/min for 3 PV and record the pressures.

- Restore the sand permeability: Inject the formation water at 1 mL/min until stability of the pressure system.

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S a : A er ltration, the plug was found to be 38.74 Wt.% organic and 61.26 Wt.% inorganic: Images of the plugging of Images of the plugging material are shown in Figure 3 below.

SEM &XRD: Results of SEM & XRD analysis are below in Figures 4 and 5.

From SEM images, the structure of the scale is a dispersed group of spherical balls around a middle one bigger and more compact. Which makes it easy to be disengaged and hence dissolvable in weak acids.

A er ZAF correction, the diagram tells that, the scale is oxygen 45.12 At%, carbone 22.54 At%, aluminum 15.99 At%, Silica 15.52 At% and iron 00.83 At%. at makes it an aluminum silicate scale of formula SiOX AlOy

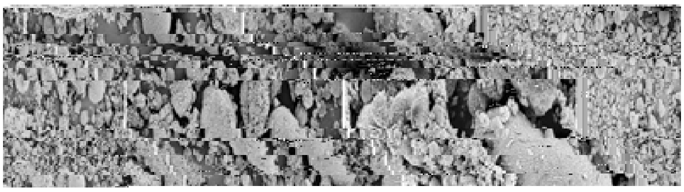

Figure 4: Images of the scale at 100, 40.0 and 10.0 εm resolutions.

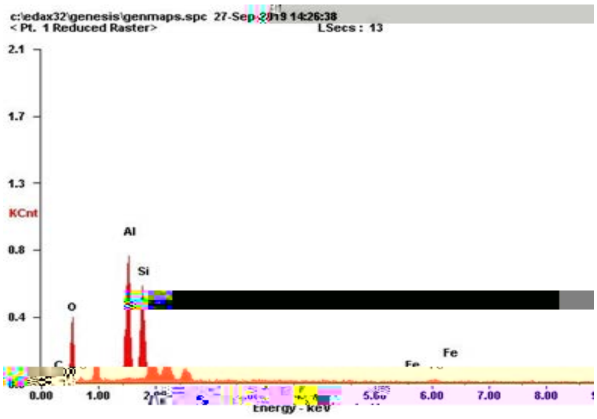

Figure 5: XRD diagram of the scale elements.

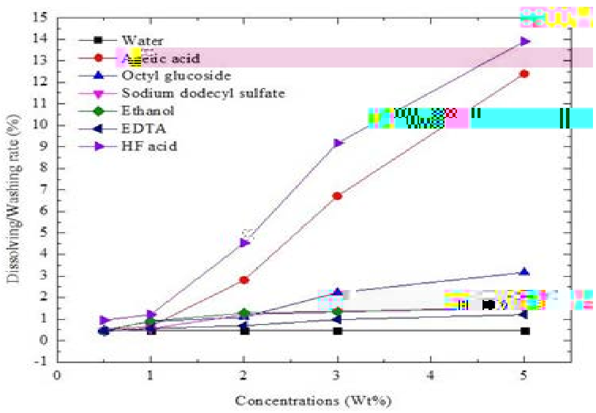

Figure 6: Chemicals dissolving/washing rates.

At low concentrations, acetic acid has shown the highest dissolve rate to the plug compared to the reference of HF acid. en the glucoside surfactant and EDTA are the second and third respectively.

[illegible]: e Dissolving/Washing rates of the ve formulas are given in Figure 7 below.

From the diagram, the best combination to dissolve the scale was the Surfactant-Based Solution (SBS) with 63% of scale dissolved; it contains 5% Octyl glucoside, 2% acetic acid, 3% ethanol, 2% EDTA, and 3% sodium dodecyl sulfate.

[illegible]

[illegible]: e pH values with temperature change are given in Figure 8 below.

At room temperature, the solution had 6.34 pH, almost basic solution. en with temperature increasing the pH decreased to 5.86 from 60°C to 70°C. at makes it indeed an acid solution at reservoir temperatures but still in the range of the oil eld requirements [5].

[illegible]: Dissolution rates with temperature changes are in Figure 9 below.

As expected, change in temperatures a ects the dissolving process as it increases gradually to reach 72% of scale dissolved at 120°C, while

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injection wells on platform B of Bohai oil eld is due mostly to injected water suspended solids content, reservoir sensitivity to pro le control agents, incompatibility between injected and formation waters and acidizing operations. From this present work, we retained:

- e studied plugging sample is an inorganic scale of Aluminum silicate family.
- e new removal solution has good compatibility with formation and injected waters (9.8 NTU), good acid pH (5.8), low corrosion rate (2.12%) and dissolves until 72% of the scale plug.
- e solution has perfect injectivity to the formation sand and decreases the injection pressures of the system of 0.426 MPa within 3 PV of injected volume. It helps as well to restore permeability bigger to the initial permeability of the sand.
- From its characteristics and performances; the solution is good enough for immediate use on site for unplugging the formation during water ooding.

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A project submitted to our laboratory, the key laboratory of unconventional oil and gas development (China University of Petroleum (East China)), Qingdao 266580, PR China.

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e authors declare that they have no con ict of interest.

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