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Non-acidic Iron Sulfide Scale Dissolver: from Lab Development to Field Application

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ABSTRACT

One of the major challenges encountered in the sour wells is iron sulfide scale deposition. It causes issues of well deliverability, well intervention, and production loss. Mechanical descaling is currently applied, but it is time-consuming and costly. Dissolvers based on concentrated hydrochloric (HCl) acid have high dissolving power, but they also have limited applicability due to overwhelming drawbacks such as corrosion and H₂S generation.

A non-acidic chemical dissolver was developed to remove iron sulfide deposited at downhole tubular and near wellbore region. The chemical is non-corrosive and no H₂S generation during dissolution. The standalone chemical treatment for iron sulfide removing in the downhole tubing in a sour oil well was successfully executed. Jetting, repeated treatment and longer soaking time were applied to overcome the limitation of this scale dissolver. The results demonstrated the chemical process provided desirable scale removal with significantly reduced cost compared to the conventional mechanical descaling. The multi-fingered caliper log runs pre-chemical and post-chemical treatment showed up to 90% of the scale can be removed by the chemical treatment. The dissolution efficiency is higher in the deeper section of the production tubing due to higher temperature at the bottom part of the tubular.

Keywords: iron sulfide, scale, dissolver

INTRODUCTION

Sour oil and gas wells typically contain water, carbon dioxide, and hydrogen sulfide. The production environment, along with high pressure and temperature, tends to cause severe corrosion damage including metal loss, pitting and stress corrosion cracking, and scale deposition.

One of the major challenges in the sour wells is iron sulfide deposition. It can deposit in the downhole tubular and topside pipeline, which can cause operational problems, such as restriction of downhole surveillance and intervention, and significant loss of oil and gas production.¹⁻⁴ Iron sulfide deposition in sour gas and oil wells is largely a corrosion induced scale problem.⁵ It can form during the production and acid stimulation treatment. The iron released from tubing due to corrosion during the production stage is one source of iron sulfide deposition in the tubular and surface facilities. It is initiated by the corrosion of steel tubing to generate ferrous ions (Fe^{2+}). The ferrous ions then contact the flowing oil and gas stream containing a high concentration of H_2S to form iron sulfide scale on the surface of tubular. Continuously exposing the iron sulfide scale to H_2S during the production can convert the iron sulfide into poly morphological species of Fe_xS_y scale, in which x:y ratio increases from 1:1 to 1:2. As the stoichiometric coefficient of y increases, the iron sulfide species become harder in mechanical strength and more difficult to dissolve. The final product, pyrite, is insoluble in the common strong acids used in the oil and gas industry, such as HCl. The iron released from tubing due to acid corrosion during acidizing treatment is another major source of iron sulfide deposition in the near-wellbore region and downhole tubular. A large amount of iron sulfide could form during acid treatment, which could cause severe formation damage in the near-wellbore region and be one of the major contribution to the thick layer of iron sulfide deposited in the downhole tubular.⁵ Iron sulfide scale deposition in sour gas wells differs significantly from well to well, in terms of severity, chemical composition and depth in the well³. Normally, the deposition is observed at the surface of downhole tubing below 6000 ft. Scale deposition is often negligible or only a very thin scale layer in the upper part of the tubular above 6000 ft. The deposition on the surface of downhole tubular is not evenly distributed. More severe iron sulfide formed with an increase of well depth.⁶

The iron sulfide scale is mechanically tough. Both chemical and mechanical methods have been used to remove the iron sulfide deposited in the downhole tubular.^{7,8} A milling tool is first run through the scale by cutting a pilot hole, and then a jetting and chemical soaking using HCl based acid dissolver is performed. These steps take a long time to execute operationally. Mills could be worn out due to the hardness of the iron sulfide scale, therefore multiple coiled tubing trips are needed to reach the target depth. In addition, mechanical descaling treatment cannot address the iron sulfide deposited in the near-wellbore region. HCl based scale dissolvers have been used in several previous descaling jobs. Although it is often effective in removing deposits, the harsh corrosion of the production string and casing, and the generation of H_2S , are the major concerns.⁹ Hence, the iron sulfide removal by acid-based dissolvers is rarely performed regionally. Alternative dissolvers usually have been found to have limited dissolving powers. Therefore, new chemistry development is required to overcome the long-lasting challenges of iron sulfide removal.

Recently, a non-acidic iron sulfide dissolver was developed and applied the first time in a sour oil well suffered significant blockage due to iron sulfide deposition in the downhole tubular. The descaling process using this dissolver eliminated the conventional mechanical descaling. Therefore, it significantly saved the operation cost and reduced the operation time. The standalone chemical soaking treatment was carefully designed. In order to properly evaluate the merit of this technology, multi-finger caliper log runs were conducted to measure tubing inner diameter before and after the scale dissolver soaking. It provided quantitative information on the amount of scale that was dissolved. The caliper runs showed chemical alone was capable to remove sufficient amount of the tenacious iron sulfide deposited in the production tubular.

LAB DEVELOPMENT

A non-acidic iron sulfide dissolver had been developed as an efficient and cost-effective alternative for removing iron sulfide deposited in the downhole tubular and near wellbore region.⁴ This non-acidic scale dissolver showed better performance on iron sulfide dissolution than typical conventional non-acidic iron sulfide dissolvers, such as Tetrakis(hydroxymethyl)phosphonium Sulfate (THPS) and traditional chelate-based dissolvers. Compared with the traditional HCl based iron sulfide dissolver, this non-acidic iron sulfide dissolver is low corrosive and no H₂S generation during dissolution.

The laboratory development and iron sulfide dissolution results were reported in Chen's previous study.⁴ The dissolution performance results are referred to this paper, as was shown in Figure 1, to summarize the lab development.

The non-acidic based iron sulfide dissolver SD-D performed much better in term of iron sulfide dissolution capacity over 24 hours test than the pH neutralized chelate scale dissolver SD-B, the traditional THPS based SD-C and the chelate based iron sulfide scale dissolver SD-A, as shown in Figure 1. In addition, different from the traditional HCl acid-based iron sulfide dissolver, this non-acidic iron sulfide dissolver SD-D is low corrosive and no H₂S generation during dissolution. It will significantly improve the safe operations.

Balanced the dissolution capability of iron sulfide and the safe operation, the non-acidic iron sulfide dissolver SD-D was recommended for field test as one of the promising alternative iron sulfide dissolvers.

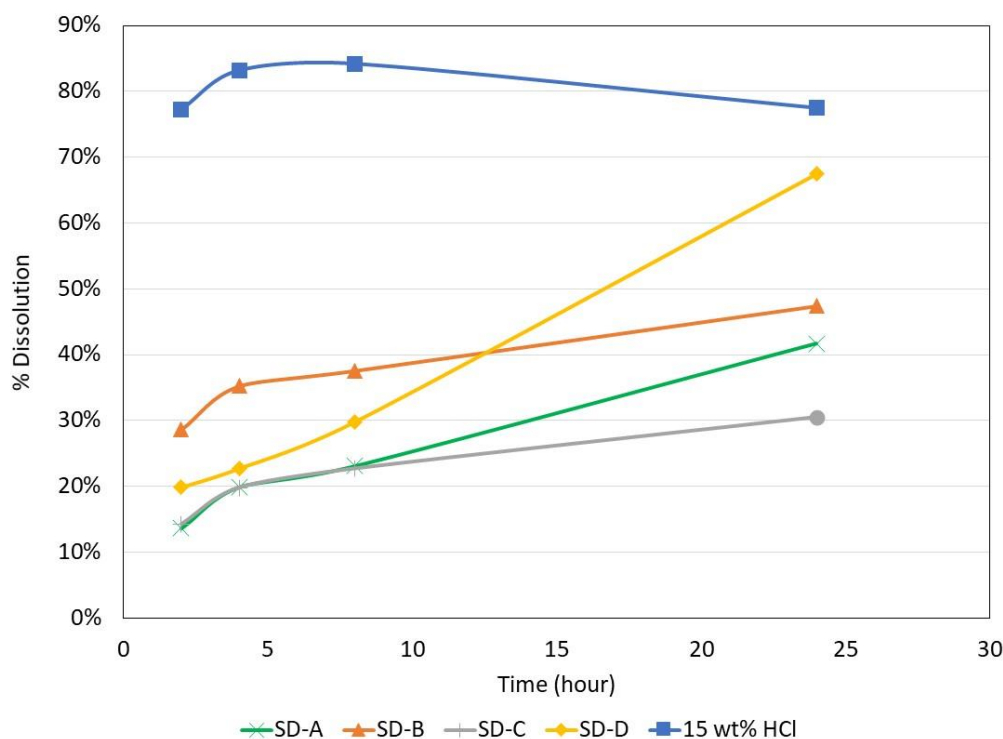


Figure 1. Rate of dissolution of scale in the presence of field scale dissolvers at 125°C over 24 hours.⁴

FIELD APPLICATION

A sour oil well with ~4 mole% H₂S in gas phase has suffered severe corrosion and scale blockage in the downhole tubing. The inner diameter (ID) of the downhole tubing measured by the caliper log before the scale removal treatment is shown in Figure 2. Figure 2 shows a joint-by-joint plot, 30 feet for each joint, from the surface to the bottom of the tubing. The body penetration marked in red is predominantly due to the corrosion, which is induced the wall loss. The scale deposit is marked in green, which causes reduction of tubing ID and tubing blockage. The wall penetration and the thickness of the scale deposit are calculated as a percentage of the original wall thickness. For example, the original wall thickness is 0.271" for the 4.5" downhole completion tubular. The thickness loss of 0.1355" in the tubing is calculated as 50% of body penetration ($0.1355/0.271 \times 100\% = 50\%$). The thickness of 0.1355" scale surface deposition is calculated as -50% ($-0.1355/0.271 \times 100\% = -50\%$) due to the reduced tubing ID.

Harsh surface scale deposition was detected, especially at the bottom section of the downhole tubular. The scale samples, as shown in Figure 3, were collected from the downhole tubular for composition analysis.