

Kinetic Approach to Predict Iron Carbonate Precipitation During Acid Stimulation

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ABSTRACT

In this work, an advanced numerical geochemical method, reactive transport modeling (RTM), is applied to simulate the iron carbonate formation during and post-acid stimulation. The code Toughreact is used for the prediction of the dynamic processes of reservoir fluid composition, and porosity and permeability alteration during and after stimulation treatment. This allows an insight into the spatial and temporal distribution of iron carbonate precipitation. Results of an acid treatment scenario in a sweet carbonate reservoir demonstrate that iron carbonate formation is a corrosion induced scale issue. High concentration of iron can release from tubular due to corrosion during acid injection stage, especially for high temperature reservoirs. The injected acid influenced an area of about 5 meters radial distance from the wellbore. The acid selectively dissolves limestone while leaving the dolomite component largely undissolved. A significant increase in porosity was observed in area of about 1 meter from the well due to the dissolution of limestone. Iron carbonate will not deposit at the initial stage of acid injection due to low pH environment. A significant amount of iron carbonate scale was observed in the acid-influenced area due to mixing of spent acid with the formation water.

This paper presents the mechanisms of iron carbonate deposition during acid stimulation in sweet carbonate reservoirs. It will contribute to applying iron carbonate scale prevention strategy and optimizing acid treatment design.

Keywords: iron carbonate, oilfield scale, acid stimulation, numerical modeling

INTRODUCTION

Acid stimulation is a frequently used technology to enhance the production rate of hydrocarbons from a reservoir. Depends on the reservoir types (carbonate or clastic) and mineralogical compositions of the formation rocks, different types of fluids and injection schemes are selected to ensure the optimal treatment results. The injected acid will dissolve some damaged materials accumulated during the drilling or production operations and high reactivity minerals (e.g., calcite) near wellbore, and thus increase the permeability and decrease the skin value in the vicinity of the production well.

Carbonate reservoir demonstrates significant heterogeneity at different scales both temporally and geographically in the field. Vertical carbonate facies variations controlled by sequence stratigraphy are dominated heterogeneity at meter-scale. Smaller scale heterogeneity may present because of (1) sorting, texture, and chemical composition of grains; (2) diagenesis (e.g., cementation, dissolution and dolomitization) and biological effects (e.g., bioturbation), and; (3) geomechanical effects (e.g., fractures and faults). Due to these heterogeneities, some dissolution features such as wormholes may form due to the differential dissolution of reservoir rock and formation of selective pathways.

Iron carbonate scaling may be a problem in the sweet carbonate gas wells, which impose a significant threat to economic and efficient field operations. The source of iron may come from corrosion of carbon steel pipes and well completion materials during the stimulation operations. The reaction of iron carbonate formation in sweet gas wells is shown in Equation 1.



Iron carbonate deposited on downhole tubulars decreased well deliverability and restricted wellbore surveillance. Iron carbonate were also accumulated at wellhead manifold to cause flowline blockage. In addition, it is suspected that during acidizing jobs, iron carbonate could be formed in the near wellbore reservoir, which renders the effectiveness of acid stimulation and also contribute to the scale problem on tubulars. Due to their thermodynamic metastability, iron carbonate can form at different times and well depths. Mechanical descaling and chemical dissolution are currently applied to mitigate the scale buildup on downhole tubing, but it is time consuming and costly. When precipitated inside the near wellbore formation, scaling is very difficult to be mitigated effectively.

Though extensive research has been carried out to understand iron carbonate scale deposition in sweet gas wells, knowledge of its temporal transformation and spatial distribution is still poor, making the formulation of a cost-effective mitigation strategy difficult. To make a suitable management strategy, it is essential to understand the mechanisms of iron carbonate deposition. In the present study, we constructed a 3D reactive transport modeling to simulate the iron carbonate scale formation near production wellbore during a hypothetical well stimulation process and to understand the mechanisms of iron carbonate formation in near wellbore during acid stimulation. The impact of scale formation on the reservoir and well properties during the stimulation process was evaluated.

MODELING APPROACH

Reactive transport modeling (RTM) is an emerging tool for understanding the dynamics of physical and chemical processes in the subsurface. It rigorously couples fluid flow and geochemical reactions to predict the spatial and temporal distributions of fluid and rock properties. The change in concentration

over time is treated as a product of the sum of all transport processes (advection, dispersion and diffusion) and the geochemical reactions.

The simulations of the scale formation during acid stimulation for the carbonate formation are conducted with the computer code TOUGHREACT, a numerical simulation program for chemically reactive nonisothermal, density-dependent flows of multiphase fluids in porous and fractured media,¹ facilitated by an interactive graphical interface pre-processor and post-processor (PetraSim v2015).

A 3D grid model of 10 x 10 x 20 m (X x Y x Z) is set up in this study and the injection production well is placed at the lower right corner in the horizontal view (Figure 1). The modeling domain can be viewed as a quarter of the complete near-well region. The horizontal layer is defined as nonuniform polygonal (Voronoi) meshes with maximum cell area of 0.012 m² and minimal refinement angle of 30°. A higher resolution mesh is used near the well with the maximum cell area of 0.005 m² near the well. The grid system comprises 6707 active cells. A no-gradient boundary condition is utilized at the upper and right boundaries of the domain in the horizontal view (Figure 1). This no-gradient boundary is implemented by assigning a very large (infinite) volume to the boundary grid block.¹ Consequently, any influence from the influx becomes negligible compared to the large volume of the formation brine. The aqueous chemical composition of the boundary element, as well as its thermodynamic conditions, such as temperature and pressure, is therefore kept essentially unchanged from the original formation brine.¹ For the acid treatment, the hypothetical injection and flow back scheme includes a 0.5 h injection phase at a rate of 19.2 kg/s with 28 wt% HCl, a 0.5-6 h setting phase, and a 6-18 h flow back phase (designed by pumping at a rate of 1.6 kg/s) (Table 2). If considering the complete near-well region, the injection rate would be 76.8 kg/s (or ~ 1200 gpm) and the flow back rate would be 6.4 kg/s (or ~ 100 gpm). Based on field data, the dissolved Fe concentration in the stimulation fluid is assumed to be 0.2 mol/kg (11169 ppm) due to acid corrosion of tubulars, coiled tubing, and surface equipment.

Reservoir matrix is defined as dolomitic limestone (50% calcite and 50% dolomite) with 12% porosity and 10 millidarcy permeability. The high reactive channels (prone to form wormholes) are defined as pure limestone (100% calcite) with 56% porosity and 3 Darcy permeability. Calcite and dolomite are considered as the primary minerals that originally exist in the formation, while goethite, hematite, mackinawite, pyrrhotite, troilite and siderite are considered as the secondary minerals to be potential iron-bearing scales. Transition State Theory²⁻⁴ type rate law is used for calcite dissolution, but Burton-Cabrera-Frank theory⁵ for crystal growth type rate law is used for calcite and iron-bearing scale precipitation. The kinetic parameters employed in this study are taken directly from Palandri and Kharaka.⁶ Reactive surface areas of calcite and dolomite are assumed to be 1000 cm²/g and iron-bearing scales to be 2500 cm²/g.

An initial pressure of 300 bars (or 30 MPa) and temperature of 137 °C are assigned to the formation. The flow domain is initially filled with 90% of gas and 10% of water (gas saturation of 0.9) to represent gas reservoirs. Geochemical calculations include 11 primary aqueous species (Na⁺, Ca²⁺, Fe²⁺, Mg²⁺, K⁺, H⁺, Cl⁻, SO₄²⁻, HCO₃⁻, H₂O, and Sr²⁺). A representative formation water composition was selected (Table 1). The injecting fluid has a pH of -0.22 and 0.2 mol/kg (11169 ppm) Fe to represent the Fe contaminated acid.⁷