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Emulsified oil foam for improving the flowability of heavy oil in wellbore under high salinity environments

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ABSTRACT

Emulsified oil foam was investigated to improve the flowability of heavy oil under high salinity environment of 23×10^4 mg/L. Sixteen foaming agents were used to determine an applicable formulation. The factors affecting the formation and stability of the emulsified oil foam were evaluated, including oil viscosity, oil–water ratio, foaming agent concentration, stirring rate and time, and temperature. The microgram of emulsified oil foam was analyzed by polarizing microscope. The results showed that stable pseudo-emulsion film was built. The considerable dynamic viscosity-reducing rates in different depth in wellbore were obtained according to pressure differential method in long tube physical simulation experiments.

Introduction

The production difficulty caused by high viscosity has always been a major issue facing the development of heavy oil reservoirs. Conventional heavy reservoirs usually have relative shallow buried depth. The heavy oil has bad fluidity in the formation. For these heavy oil reservoirs, generally, the thermal recovery methods, such as the steam flooding, cyclic steam stimulation, in situ combustion, etc., were implemented to achieve in situ oil upgrade or physically improve the fluidity of the heavy oil in the formation [1]. However, these thermal techniques are not feasible for those deep or extra deep heavy oil reservoirs, such as Tahe oilfield (Tarim Basin, China) because of the faced issues of operation, economy or effectiveness [1]. Fortunately, for these reservoirs with deep buried depth, the reservoir temperature is high and the heavy oil has a good fluidity in the formation. The heavy oil becomes immovable or hardly movable in wellbore with the reduction of the temperature. Therefore, if the flowability of the heavy oil in the wellbore can be improved, the operation difficulty facing these deep heavy oil reservoirs can be solved. For now, these reservoirs maintain the operation by mixing light oil to lower the viscosity of the heavy oil. The high rate of the mixed light oil make it uneconomic with the current low oil price and the lack of the light oil in this field. There are some other viscosity reduction methods in the wellbore for heavy oils, such as heating [2], chemical method (emulsifying, oil-soluble viscosity reducers), and microbial method, etc. [3]. However, the heating method was uneconomic because of high energy consumption at this low oil price. The chemical method has strong pertinence and requires special research and development of different chemicals for different heavy oils. The microorganisms method is still in research stage because the microbes at high temperature has low survival rate and is difficult to control [4].

In this study, we attempted to introduce the emulsified oil foam for viscosity reduction in the wellbore. The idea of emulsified oil foam was derived from the foamy oil. The foamy oil is often used to describe the observed obvious foaminess in the heavy oil samples in wellhead [5]. The term foamy oil was the earliest founded by Sarma and Maini [6]. The foamy oil is produced by solution gas drive. During the production of heavy oils, gas is separated from the crude oil and dispersive in the form of bubbles in the heavy oil. These bubbles can keep steady in the open container for a few hours [5]. Smith believed that the fluidity of the foamy oil are several times higher than the single phase flow of heavy oil [7]. The foamy oil flow in porous media [8], the foamy oil mechanism [9], and the factors affecting the formation and stability including crude oil viscosity [10–12], crude oil composition [13], the pressure drop rate [14], the solution gas–oil ratio [15,16], etc.,

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have been studied. The formation of the foamy oil in the reservoir requires three necessary conditions: high solution gas–oil ratio, enough pressure drop rate and high fluid viscosity [17]. For Tahe oilfield, the dissolved gas content is too low to form the foamy oil. Therefore, we attempted to form emulsified oil foam in the wellbore to improve the fluidity of the heavy oil based on the idea that foamy oil could reduce the viscosity of heavy oil. Once the emulsified oil foam was generated in wellbore, the heavy oil will have a good flowability. This method will be another alternative and promising method for viscosity reduction in wellbore with its low cost and easy operation.

In this study, 16 foaming agents were used to obtain an applicable formulation to improve the flowability of the heavy oil. The factors affecting the formation and stability of the emulsified oil foam were investigated, and the microgram of the formed emulsified oil foam was analyzed. The long tube physical simulation experiments were carried out and the pressure differential method was used to help to evaluate the dynamic viscosity-reducing rate in pipe flow.

Experimental

Materials

Sixteen foaming agents were used for determining a suitable foam formulation to form the emulsified oil foam. The 16 foaming agents were listed in Supporting Information (Table 1). The target block is a carbonate reservoir with a formation temperature of 120 °C. The viscosity–temperature curve of the heavy oil was measured using high temperature high pressure rheometer (MCR30, Anton Paar) as shown in Supporting Information (Fig. 1). The salinity of the reservoir injection was 23×10^4 mg/L.

Determination of foam formulations

Sixteen different types of foaming agents and their compounded formulations were evaluated by bulk foam test, where the foam solution (200 ml) was stirred for 1 min with a Waring Blender at a stirring rate of 3000 r/min. The foam volume was measured with a measuring cylinder, and the drainage volume of the foam (the liquid volume below the foam column) was monitored to give the foam drainage half-life which is the time when the drainage volume reached to 100 ml (the half of the original foam solutions (200 ml)). The foam volume reflects the foaming ability of the foam agent. The bigger the foam volume, the stronger the foaming ability. The foam drainage half-life reflects the stability of the foam. The longer the foam drainage half-life, the more stable the generated foam. The foam volume and the foam drainage half-life reflect the different performance indicators of the foaming agents. The foam composite index (FCI) was introduced to give a comprehensive assessment of the foaming agents. The FCI was expressed as follow:

$$\mathrm{FCI}\,(\mathrm{ml\,min}) = \text{foam volume}\ (\mathrm{ml}) \times \text{foam drainage half-life}\ (\mathrm{min})$$

Evaluation of the factors affecting the formation of the emulsified oil foam

The effects of oil viscosity, oil–water ratio, foaming agent concentration, stirring time, stirring rate and temperature were investigated by Waring Blender method. The experiments were carried out at atmospheric conditions and ambient temperature (26 °C) except for evaluating the effect of the temperature. The compounded formulation 0.3% IAS + AES (the effective concentration ratio was 7:3) was used under the salinity of 23×10^4 mg/L. If oil and foam solution could fully form uniform emulsified oil foam by stirring, the FCI index was employed to evaluate these factors. If oil and foam solution partly formed foam, the following evaluation indexes were used: the oil volume in the foam (carrying oil volume) or the volume ratio of the oil in the foam to the original oil volume (carrying oil volume ratio) and the time when clear oil–water–foam interface appeared (separating time). The bigger the volume ratio the oil in the foam to the original oil volume, the

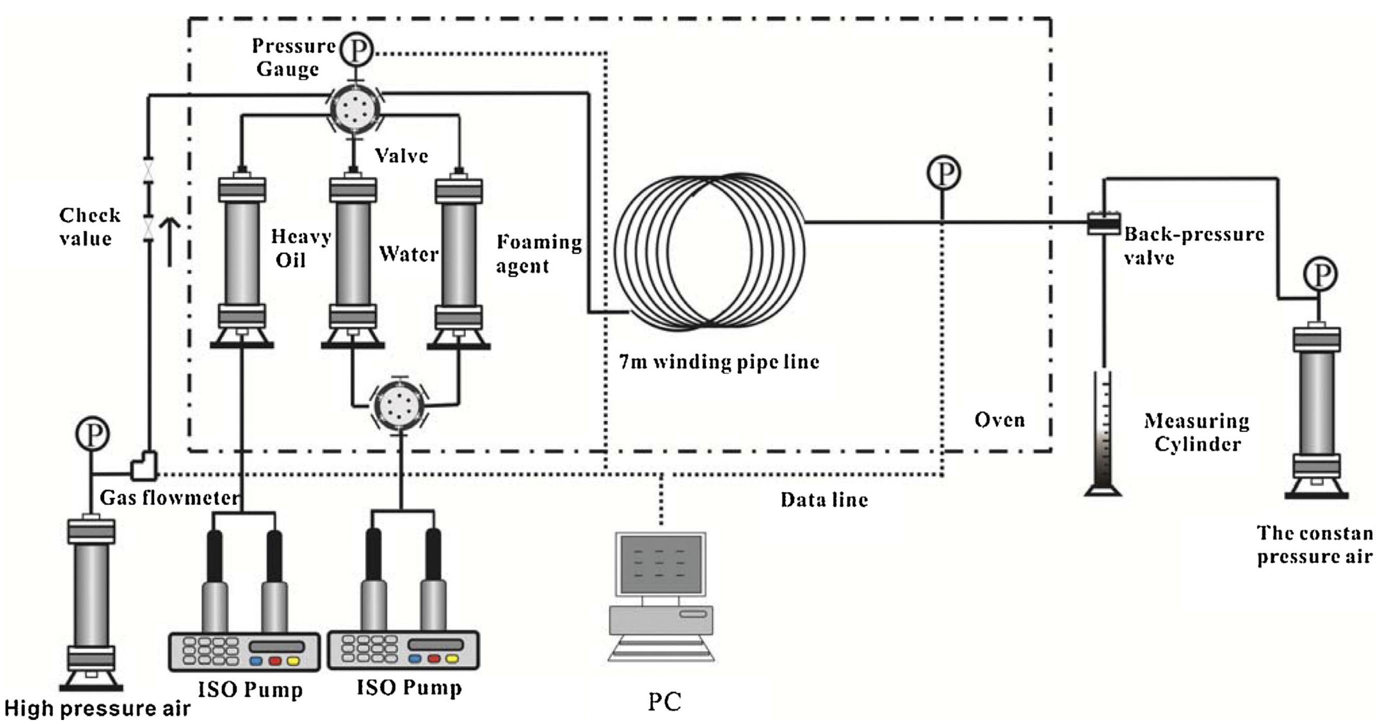

Fig. 1. Flow chart of the long slim tube experiments.