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How to select the right solvent for solvent-aided steam injection processes

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ABSTRACT

Solvent-steam processes gained popularity in recent years in the extraction of high-asphaltenes-content heavy hydrocarbons. However, while solvent selection is key for the success of these processes, the criteria for solvent selection are still not fully established. In this study, three asphaltenes insoluble (propane, n-hexane, carbon dioxide) and one asphaltenes soluble (toluene) solvents were tested on solvent-aided steam processes to extract a bitumen sample from Alberta, Canada. Both steam flooding and SAGD performances were analyzed. The impact of clay presence was investigated by conducting experiments with and without the addition of clays, consisting of an illite-kaolinite mixture. The results of this study suggest that the produced oil samples from steam injection processes are in the form of water-in-oil emulsions. It has been observed that the amount of asphaltenes in produced oil determines the amount of water trapped in the form of emulsions. Co-injection of solvent with steam decreases the interfacial film between water and asphaltenes. However, asphaltenes insoluble solvents were found to be more effective to eliminate the forces at the oil-water interface. Presence of clays also reduced the water content of emulsions. The results of this study suggest that carbon dioxide, which is a non-hydrocarbon asphaltenes-insoluble solvent, yields the greatest quality oil with the lowest amount of water and clay in produced oil and provides high oil recovery. Hence, it is recommended to use asphaltenes-insoluble, non-hydrocarbon solvents for the extraction of low API gravity, high viscosity, and high asphaltenes content reservoirs.

1. Introduction

The effective recovery of high viscosity hydrocarbons like heavy oil, extra-heavy oil, and bitumen requires the application of thermal enhanced oil recovery (thermal EOR) methods due to the poor mobility of these oils (Prats, 1982). While steam flooding is one of the most reliable methods to enhance the mobility of oil (Sarathi and Olsen, 1992), environmental footprint and operational constraints of steam generation entail to investigate the alternatives to steam injection processes (Mukhametshina et al., 2016).

To reduce scale formation and corrosion in a steam generator; in other words, to increase the life of the steam generator in order to reduce operational costs, it is necessary to use fresh water during steam generation (Burns, 1965; Fanaritis et al., 1965). However, excessive use of fresh water resources and greenhouse gases emitted during steam generation due to the burning of fossil fuels raise environmental concerns (Kovscek, 2012). To mitigate the environmental problems associated with steam generation, solvent aided-steam injection processes were proposed with the intent to minimize steam use and maximize oil recovery (Farouq Ali and Abad, 1976; Nasr et al., 1991; Stape and Hascakir, 2016). Oil recovery is maximized by enhancing oil mobility (decreasing the oil viscosity) in two ways in solvent-steam processes; through dilution of oil with solvent, and increasing the temperature of reservoir with steam (Nasr and Ayodele, 2006; Nasr et al., 2003). Therefore, developing a better understanding of the interactions between solvent and oil at steam temperatures is key for the success of solvent-aided steam-injection processes (Stape and Hascakir, 2016; Stape et al., 2016; Kar et al., 2016; Coelho and Hascakir, 2015).

Solvent-steam processes are generally applied to high viscosity and low API gravity crudes, which have high asphaltenes content (Speight, 1991). Most of the solvents used in solvent aided-steam injection processes are asphaltenes insoluble solvents. Hence, asphaltenes deposition onto the reservoir rock during solvent-aided steam processes is expected (Zhao, 2007; Ardali, et al. 2012). Furthermore, water-asphaltenes interactions are inevitable during any EOR method in which water in any form is injected, as water is a polar molecule and asphaltenes represent polar fractions of

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crude oil (Punase et al., 2016; Kar and Hascakir, 2015). A consequence of this interaction is the formation of water-in-oil emulsions (Hall and Bowman, 1973). It is not only the crude oil components that contribute to emulsion formation, but also the reservoir fines due to their polar nature and high cation exchange capacity (Kokal et al., 1995; Kokal, 2005; Kar et al., 2015; Coelho et al., 2016; Unal et al., 2015; Demir et al., 2016). Emulsion is a surface phenomenon which occurs at the interface of the polar components forming emulsions (Clementz, 1976; Nguyen et al., 2013). To avoid the formation of emulsions or decrease the severity of emulsions, surfactants and solvents can be utilized (Bertness, 1965; Pacheco et al., 2011). Hence, solvent-aided steam injection processes may also increase the produced oil quality by inhibiting the formation of severe emulsions, provided that the solvents are selected properly.

This study addresses these issues by providing solvent selection criteria to minimize the water-oil interaction and also discuss the role of clays in this interaction for several solvent, steam, and solvent-steam injection processes.

2. Experimental

In total, 16 experiments were conducted to investigate the impact of solvent type, clay presence, and well configuration on the performance of steam, solvent, and solvent-steam injection processes. Two steam flooding, five solvent flooding, five solvent-aided steam flooding, one steam assisted gravity drainage (SAGD), and three solvent-aided SAGD experiments were performed at identical experimental and initial conditions. While flooding experiments were conducted in a one-dimensional (1D) sample holder, a two-dimensional (2D) sample holder was used to conduct SAGD experiments. Experimental set-up and pictures of the 1D and 2D sample holders are shown in Fig. 1.

This paper will briefly comment on the experimental procedure, however, readers who are interested in learning more about the experimental procedure and apparatus for flooding and SAGD experiments are encouraged to examine previously published work (Coelho and Hascakir, 2015; Mukhametshina and Hascakir, 2014; Stape and Hascakir, 2016; Stape et al., 2016).

To investigate the effect of clay presence in the reservoir rock on produced oil quality, all reservoir rock samples were prepared by either mixing 85 wt% Ottawa Sand with 15 wt% clay (90 wt% kaolinite and 10 wt% illite) or by using just 100 wt% Ottawa Sand. Corresponding pore volume (~32% porosity) was filled with 16 vol% distilled water and 84 vol% bitumen at 8.8° API gravity and 54,000 cP viscosity.

All 16 experiments were conducted at 89.7 psi [0.62 MPa] back pressure. In all experiments that involved steam injection (steam flooding, solvent aided-steam flooding, SAGD, and solvent aided-SAGD), steam was injected at 165 °C [329 °F] with 18 mL/min cold water equivalent (CWE) rate, which provided 100% steam quality.

The solvent injection experiments (solvent flooding solvent-aided steam flooding, and solvent-aided SAGD) were achieved at a constant solvent injection rate; 2 mL/min (liquid volume at standard conditions). As solvents, carbon dioxide, propane, n-hexane, and toluene were tested (Mukhametshina et al., 2016; Coelho and Hascakir, 2015; Stape et al., 2016; Coelho et al., 2016). These four solvents were selected according to their following features;

- while carbon dioxide is a non-hydrocarbon solvent; propane, n-hexane, and toluene are hydrocarbon solvents,
- while carbon dioxide, propane and n-hexane are in the gas phase at 89.7 psi and 165 °C during solvent-steam injection processes; toluene is in liquid phase,
- while carbon dioxide, propane, and n-hexane are asphaltenes insoluble solvents; toluene is an asphaltenes solvent (Speight, 1991).

Hence, the experiments presented in this study are useful to understand the response of the solvent-steam injection processes for different types of solvents with distinctive features.

The experimental conditions for all 16 experiments along with the oil recovery results are summarized in Table 1.

It has been observed that due to pore lining and pore bridging features of clays used in this study (illite and kaolinite), clays reduced the permeability of the system significantly (Neasham, 1977; Kar et al., 2016; Coelho et al., 2016). Thus, among all flooding experiments (E1 through E12), the best oil recoveries were consistently obtained with the experiments conducted without clays (Table 1). The impact of clays is observed more significantly in solvent flooding experiments. For solvent-steam injection, this impact is still significant, but is reduced considerably when compared to solvent flooding experiments. The most noteworthy impact of clays on oil recovery has been observed in propane injection cases (E7 through E10). Based on these findings, it is

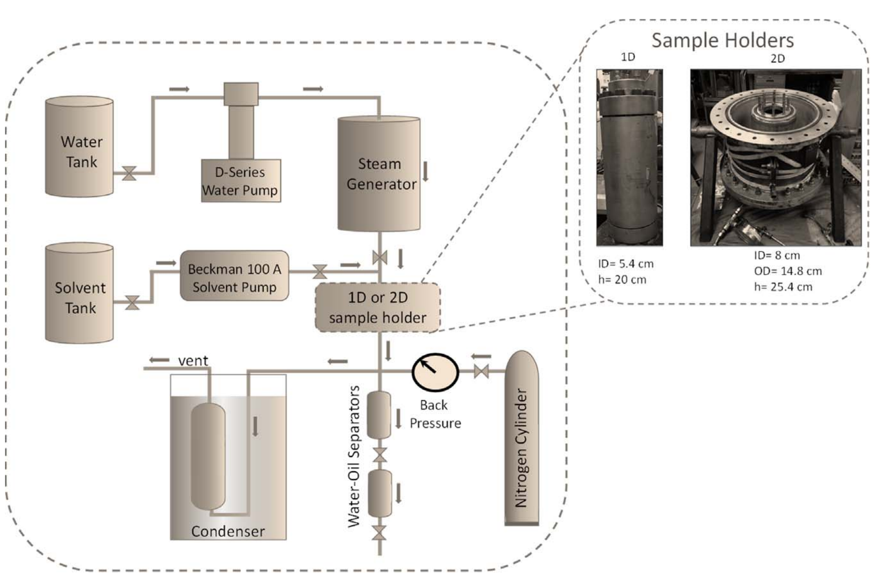

Fig. 1. Experimental set-up (left) and sample holders (right). (ID: Inner Diameter, OD: Outer Diameter, and h: height of the sample holder).

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