A comparative study of huff-n-puff gas and solvent injection in a shale gas condensate core

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A compositional modeling study is conducted to compare huff-n-puff solvent injection with gas injection in improving oil recovery from shale gas-condensate reservoirs. The solvents used are methanol and isopropanol, and gases are methane and ethane. The model represents a simple 8″X1″ lab scale core model based on a published experimental work. The phase behavior data and relative permeability data are tuned to match the published lab data.

Simulation results are analyzed to compare the performance of four injection fluids — methane, ethane, methanol and isopropanol (IPA) based on the recovery of fluids in place in terms of barrel of oil equivalent within the same operation time. Comparisons were made for two reservoir fluids, Fluid A and Fluid B, with the latter having a higher liquid dropout. Recovery mechanisms are also studied for gases and solvents.

Ethane injection is a novel idea in this paper and proved to be the best injection fluid on accounts of higher as well as much faster recovery as compared to methane, methanol or isopropanol. This is attributed to ethane being a lighter fluid and aiding in revaporizing the condensate. While this is also true for methane, the most significant difference between the two is that ethane is also able to reduce overall dew point pressure of the mixture, ensuring lower injection volume and time for the same recovery factor.

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1. Introduction

The phenomena of retrograde condensation can cause severe reduction in productivity of a gas-condensate reservoirs. This occurs when the reservoir pressure falls below the dew-point pressure of the gas-condensate fluid system. Heavier and valuable hydrocarbon components condense from the gas phase causing blockage in the pores, restricting the gas flow path. This reduces both the productivity of the gas as well as the oil phase. The most important defining parameter in reduction of reservoir productivity is a critical condensate saturation (Bennion et al., 2001); if the saturation of the condensed hydrocarbon phase is less than this critical value it remains immobile and reduces the relative permeability of the flowing gas.

Reduction of gas productivity has also been reported to be severe for lean gas condensate reservoirs, specifically in the Arun field where productivity reduced by 50% for a 1.1% liquid dropout fluid

system (Afidick et al., 1994). Coreflood experiments have demonstrated severe condensate blocking for both low and high permeability cores (Al-Anazi et al., 2002), however, this problem is compounded in low permeability formations (Zhang and Wheaton, 2000).

While in conventional reservoirs a bank of condensate forms around the well, with condensate saturations decreasing away from the well as pressures increases further into the reservoir, for shale reservoirs we may expect condensate buildup in the fractures with condensate saturations reducing as we move into the stimulated rock volume area, and reservoir matrix adjacent to the fractures. This is where the immobile condensate phase maybe expected. Lab experiments showed a 90% decrease in gas relative permeability for propped fractures in conventional reservoir cores (Bang et al., 2008b).

Several mitigation methods have been practiced and researched for recovering gas and condensate from the reservoir. The most common is dry gas injection (Abel et al., 1970; Sheng, 2015; Sheng et al., 2016) which helps maintain reservoir pressure above the dew point pressure of the reservoir and additionally, re-evaporate any

condensate that has accumulated in the reservoir (Meng and Sheng, 2016a,b; Meng et al., 2016). Other alternatives such as methane (Al-Anazi et al., 2004), CO$_2$ (Amini et al., 2011) and, nitrogen injection (Siregar et al., 1992) have been successfully tried. Methane huff-n-puff experiments have also shown good EOR potential in shale cores where condensate recovery was 52.7% after 8 cycles of methane huff-n-puff (Meng et al., 2016).

Apart from gas injection, chemical treatment for improving recovery from gas condensate reservoirs has been extensively researched. This can be broadly categorized into two parts — solvent injection and surfactant application. Methanol flooding experiments have been conducted on both high permeability sandstone and low permeability limestone cores to treat condensate blockage where the relative permeability of gas improved significantly and condensate banking phenomena was delayed for some time (Al-Anazi et al., 2002). Methanol injection was also tried in the Hatter's Pond Field where enhanced flow period was observed for up to four months after the treatment increasing recovery by up to 50% for both gas and condensate (Al-Anazi et al., 2003). Extensive phase behavior experiments were done to understand the addition of methanol and isopropanol to synthetic gas-condensate mixtures (Bang et al., 2010). Isopropanol can solubilize more hydrocarbons compared to methanol and it does not partition into water unlike methanol. Addition of a solvent shifts the phase behavior of the fluid from the gas condensate region to a volatile region and the fluid thus exhibits a bubble point instead of a dew point pressure. This mechanism helps extract the liquid dropped-out as the entire system exits as a single phase liquid (Ayyalasomayajula et al., 2002).

This work presents a comparative study for application of four injection fluids to remediate condensate blockage— methane, ethane, methanol and isopropanol based on recovery factors of total barrel of equivalent (BOE) from a core-scale model.

2. Methodology

2.1. Model description and validation

Published core flood experiments for a synthetic four component gas condensate fluid (Al-Anazi et al., 2003) were regenerated using Computer Modeling Group's (CMG) GEM simulations. This reservoir fluid is called Fluid A in this paper and its description is given in Table 1. Al-Anazi conducted several experiments on high permeability sandstone and low permeability limestone cores to capture the dynamic accumulation of condensate buildup in a core, as the core pressure was reduced below the dew point pressure of the gas-condensate fluid. The inlet pressure was maintained at 3000 psi, which was above the dew point pressure of the gas, while the outlet pressure was maintain at 1200 psi. Single phase gas was injected at a constant flow rate. The gas flashed out into two phase gas and condensate upon entering the core. Al-Anazi measured the pressure drop across the core to determine the condensate buildup

Table 1
Core model properties from Al-Anazi et al. (2002, 2003).

Fluid A	
Component	Mole fraction
C1	0.8
C4	0.15
C7	0.038
C10	0.012
Initial Water Saturation, %	0
Reservoir Pressure, psi	3000
Reservoir Temperature, °F	145

and plotted this as a function of the pore volume of hydrocarbons injected into the core.

A low flow rate experiment from Al-Anazi's work was used to history match our model. In this experiment, gas was injected at a constant flow rate of 2 cc/hr. The pressure drop vs. pore volume injected plot is shown in Fig. 1. The figure shows two sets of data — Al-Anazi's experimental data and a simulation match of his experiment as generated by Rai (2003). Rai and Al-Anazi concluded in their work that simulating high flow rate experiments was difficult due to non-equilibrium effects. As the flow rate increased, more pore volume of gas had to be injected to achieve steady state flow in experiments. This was attributed to a stripping effect of the condensate by gas and more pore volumes required for condensate to accumulate and reach its moveable critical condensate saturation. Contrariwise, simulations of high flow rate experiments showed that less pore volume was required to reach the same steady state pressure drop. For this reason, we chose the low flow rate experiment to validate our model.

Core properties and operating conditions were unchanged and are shown in Table 2. Relative permeability data was generated using a Corey type function, and is shown in Figs. 2 and 3. This was the main parameter tuned to obtain a history match.

Tuned parameters of the relative permeability curve are given in Table 3:

In Table 3, S_{wr}, S_{gr} and S_{or} are the residual water, gas and oil phase saturations, k_{ro}^o, k_{rg}^o, k_{rw}^o are the end point relative permeability for oil, gas and water phases, while n_o, n_g and, n_w are the Corey function exponents for the oil, gas and water phases, respectively.

The number of grids in the model were sensitized and varied in the I-direction to eliminate errors caused by numerical dispersion. The final grid model is a 1-D 24 × 1 × 1 model depicting an 8″X1″ core. The producer is at the block (1,1,1) and the flowing bottom-hole pressure was 1200 psi. The injector is at the block (24,1,1) and the injection rate is 2 cc/hr at the injection pressure of 3000 psi.

Our simulation result was overlaid over the original plot to obtain a history match. This is shown in Fig. 4. The red data points are the regenerated simulation results. Al-Anazi's work obtained a steady state pressure drop after injecting 5.5 PV of single phase gas. Rai (2003) simulated this data and obtained a match at 6.2 PV of injected gas and we obtained a history match at 5.5 PV. The hump in pressure drop seen in the experimental results at low injected pore volume was exclusive to this experiment in Al-Anazi's work and this trend was not seen for other experiments. Neither Rai's work nor our work was able to capture this detail.

2.2. Reservoir fluid model

In order to correctly model interaction of the solvent phase with the hydrocarbons, phase behavior properties of binary interaction coefficients (BIC) between the solvent and reservoir fluid components need to be modeled (Bang et al., 2010; Ganjdanesh et al., 2015). This takes into account the polar interaction of the alcohol solvent with the hydrocarbon components. Bang et al. (2010) have done extensive work on generating a linear function of binary interaction coefficients and volume shift parameters with temperature for use with the Peng Robinson Equation of State (Peng and Robinson, 1976). This data is available for Fluid A, but only for methanol not isopropanol. Thus, Fluid A was used when comparing results between all injection fluids except isopropanol.

A second fluid mixture termed as Fluid B in this paper was also tuned by Bang et al., 2010 for interactions with both methanol and isopropanol solvents. Fluid A and Fluid B differ only in the mole fraction of the components and consist of the same four synthetic components — methane, butane, heptane and decane. This second