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Mitigation of Gas Condensate Banking Using Thermochemical Fluids and Gemini Surfactant: A Comparison Study

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Abstract

Accumulation of condensate liquid around the production well can cause a significant reduction in gas production. Several methods are used to mitigate the condensate bank and maintain the gas production. The most effective approaches are altering the rock wettability or inducing multiple fractures around the wellbore. This paper presents a comparison study for two effective approaches in mitigating the condensate bank. The performance of thermochemical fluids (**TCF**) and gemini surfactant (**GS**) in removing the condensate liquid and improve the formation productivity is studied.

In this work, several experiments were carried out including coreflooding, capillary pressure, and relative permeability measurements. The profiles of condensate saturations show that **GS** can mitigate the condensate bank by 84%, while **TCF** removed around 63% of the condensate liquid. Also, **GS** and **TCF** treatments can increase the relative permeability to condensate liquid by factors of 1.89 and 1.22 respectively, due to the wettability alteration mechanism. Capillary pressure calculations show that **GS** can reduce the capillary pressure by around 40% on average, while **TCF** leads to a 70% reduction in the capillary forces.

Overall, injection of **GS** into the condensate region can lead to changing the wettability condition due to the chemical adsorption of **GS** on the pore surface, and thereby reduce the capillary forces and improve the condensate mobility. On the other hand, **TCF** injection can improve rock permeability and reduce capillary pressure. Both treatments (**GS** and **TCF**) showed very attractive performance in mitigating the condensate bank and improving the formation production for the long term. Finally, an integrated approach is presented that can mitigate the condensate damage by around 95%, utilizing the effective mechanisms of **GS** and **TCF** chemicals.

Keywords: condensate bank, chemical treatments, thermochemical fluids, gemini surfactant, multiple-fractures, wettability alteration

Introduction

In gas condensate reservoirs, the accumulation of condensate liquid around the production well causes serious formation damage and reduces the gas productivity considerably (Sayed and Al-Muntasheri, 2016; Ahmed, 2018; Ayub and Ramadan, 2019; Hassan *et al.*, 2019). The condensate damage induces more problems in tight reservoirs; the condensate liquid will be become immobile thereby lead to blocking the hydrocarbon flow (Muskat, 1951; Fevang and Whitson, 1996; Asgari *et al.*, 2014). The accumulated liquid can reduce gas production by 84% due to the restriction of gas flow from reservoir formation to the wellbore.

Different techniques are used to mitigate the condensate banking problems and maintain or improve gas production (Sayed and Al-Muntasheri, 2016; Sayed *et al.*, 2018; Hassan *et al.*, 2019). The common methods are gas recycling, hydraulic fracturing, and chemical injection (Linderman *et al.*, 2008; Maleki *et al.*, 2012; Mahdiyar and Jamiolahmady, 2014). The pressure around the wellbore can be maintained above the dew point pressure by injecting hydrocarbon or nonhydrocarbon gases (Fevang and Whitson, 1996; Odi, 2012). The injected gas will pressurize the new wellbore region and lead to condensate re-vaporization (Odi, 2012; Meng and Sheng, 2016). However, to maintain effective performance, the gas injection would be applied every 4 to 10 months, based on the fluid's composition and reservoir conditions (Sayed and Al-Muntasheri, 2016; Hassan *et al.*, 2019). Besides the gas transportation, there exist several challenges of handling the gas injection, especially the recycling treatments need to be conducted frequently which may require some logistic such as stopping the gas production and scheduling the gas recycling (Ayub and Ramadan, 2019; Jia *et al.*, 2019).

Hydraulic fracturing presents an effective technique for mitigating the condensate bank by creating conductive paths between the reservoir formation and the wellbore (Khan *et al.*, 2010; Mahdiyar and Jamiolahmady, 2014; Jiang *et al.*, 2020). The induced channels will reduce the drawdown pressure and thereby delay the development of condensate banking (Khan *et al.*, 2010; Mahdiyar and Jamiolahmady, 2014; Hou *et al.*, 2016). However, the condensate liquid can be formed and accumulated inside or around the induced fractures which will lead to reducing the fracturing conductivity (Mahdiyar and Jamiolahmady, 2014). The accumulation of condensate liquid inside or around the generated fractures present severe damage and chemical treatment are used to remove the formation damage. Usually, solvents are injected to clean the fractures and restore their conductivity, but this will lead to an increase in the treatment cost (Sayed and Al-Muntasheri, 2016; Hassan *et al.*, 2019).

Chemical techniques present an encouraging technique for solving the formation damage associated with condensate banking (Al-Anazi *et al.*, 2007; Bang *et al.*, 2009; Al-Yami *et al.*, 2013; Ajagbe and Fahes, 2020). Solvents can be injected to dissolve the condensate liquid and reduce its viscosity, thereby it can be recovered easily. Also, the interfacial tension at gas/condensate contact can be reduce utilizing solvent injection which will enhance the condensate mobility (Karandish *et al.*, 2015; Sharifzadeh *et al.*, 2015). However, the solvent injection is a temporary solution and should be repeated every few months (Schultz *et al.*, 2003). Wettability alteration fluids can be used to mitigate the condensate banking by changing the rock wettability toward less liquid wet, and therefore, prevent the condensate accumulation around the wellbore (Al-Anazi *et al.*, 2007; Karandish *et al.*, 2015; Liu *et al.*, 2015). Numerical studies and laboratory measurements were carried out to determine the effectiveness of chemical treatment in solving the condensate damage problems (Bang *et al.*, 2009; Maleki *et al.*, 2012; Asgari *etal.,* 2014). Chemicals such as fluorochemical, fluorocarbon, anionic surfactants, and fluorinated silica were used to mitigate the condensate banking by altering the rock wettability to a weak liquid state (Li *et al.*, 2011; Zheng and Rao, 2011; Aminnaji *et al.*, 2015; Safaei *et al.*, 2020).

Most of the condensate removal techniques are either temporary or expensive treatments. The industry is always looking for new techniques that can solve the condensate banking damage efficiently for a long-term application while reducing the treatment cost. Many studies have been conducted to prolong the effective duration of condensate removal as well as minimize the operational cost and risk. Among different techniques, wettability alteration showed an effective solution for reducing condensate damage. Also, the in-situ generation of pressure and temperature at reservoir conditions is a newly developed technique that can effectively recover the condensate liquid and improve the reservoir productivity for the long term. The generated heat and pressure change the condensate behavior and induce multiple fractures around the production well thereby remove the condensate damage.

This work aims to examine the performance of two effective chemicals that can combat the condensate damage challenges. In this study, thermochemical fluids (**TCF**) and gemini surfactant (**GS**) were used to reduce the formation damage associated with condensate accumulation. **TCF** can be injected to react at the reservoir conditions and generate pressure pulses in situ and induce multiple fractures around the production well. Also, the near-wellbore region can be flushed by **GS** to alter the wettability and capillary conditions, hence, mitigate the condensate bank damage. In this work, different techniques were utilized to determine the performance of **GS** and **TCF;** laboratory measurements such as coreflood, capillary pressure, and relative permeability were conducted. The influence of **TCF** and **GS** injection on the fluid's mobility, capillary pressure, relative permeability, and condensate removal were studied.

Experimental Approach

Materials

Tight sandstone samples were used in this work; Table 1 lists the mineralogical composition of the used samples. High percentages of quartz (71%) and illite (18%) minerals were observed in used samples. Also, the rock samples have low percentages of feldspars and chlorite minerals. Moreover, petrophysical measurements indicate that average rock permeability is 0.47 mD and the porosity is 14.2%, Table 2 lists the rock properties.

Table 1—Rock mineralogical compositions.

Mineral	Percentage (%)
Quartz	71
Calcium Feldspar	5
Potassium Feldspar	2
Chlorite	4
Illite	18
Total	**100**

Table 2—Petrophysical properties.

Sample	Diameter (in)	Length (in)	Pore Volume (ml)	Porosity (%)	Permeability (mD)
Core 1	1.5	6	21.72	12.5	0.24
Core 2	1.5	3	14.29	17.1	0.89
Core 3	1.5	6	22.59	13	0.27

In addition, an actual condensate liquid of 1.8 cP and 46 °API (American Petroleum Institute) was used in this work. All rock samples were saturated with the condensate liquid, and high-pressure conditions were applied to ensure representative results. The used chemicals are synthesized gemini surfactant (**GS**) and thermochemical fluids (**TCF**). Figure 1 shows the chemical structure of the gemini surfactant, and **Equation 1** represents the thermochemical reaction. More details about thermochemical fluids and gemini surfactants are reported previously (Hassan *et al.*, 2018; Hussain *et al.*, 2019). The surfactant CMC (critical micelle concentration) is 0.00887 mmol/L at 30 °C, while the thermochemical reaction can generate pressure up to 5000 psi and temperature up to 700 °F. Moreover, KCl brine of 3wt.% was used to prepare the surfactant solutions at the desired concentrations as well as measuring the absolute permeability for the used rock samples.

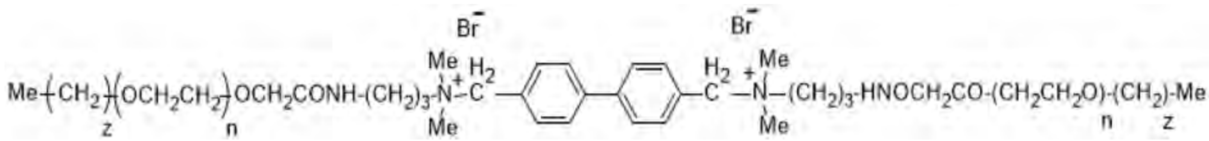

Figure 1—Chemical structure of the gemini surfactant used in this work.

$$NH_4Cl + NaNO_2 \rightarrow NaCl + 2H_2O + N_2(gas) + \Delta H(heat) \tag{1}$$

Experiments

Several techniques were employed to evaluate the performance of **GS** and **TCF** including coreflood, capillary pressure, and relative permeability experiments. During the flooding tests, **GS** and **TCF** were injected into the tight cores at high pressure. Overburden pressure of 1500 and backpressure of 500 psi were applied. A flooding system was used to perform the chemical injections as well as to measure the relative permeability using the unsteady-state approach. The relative permeabilities were estimated using the JBN (Johnson, Bossler, and Neumann) method (Johnson *et al.*, 1959; Ramstad *et al.*, 2012). Furthermore, the capillary pressure was determined for the rock samples before and after the condensate removal treatments. The impact of chemical injections on reducing the capillary forces and improving the flow condition was estimated. The uncertainty of the experimental measurements was minimized by preparing the samples and conducting the measurements using the same experimental conditions.

Results and Discussion

The accumulation of condensate liquid can block the gas flow into the wellbore and reduce the formation productivity. The chemical injection can reduce the liquid accumulation by altering the rock wettability or inducing conductivity paths around the wellbore, allowing the condensate liquid to be produced. This study investigates the efficacy of thermochemical fluids and gemini surfactants in mitigating condensate damage. First, the condensate recovery from tight rocks due to **TCF** and **GS** injection is examined. Next, the enhancements in condensate permeability after the chemical treatments are analyzed using the JBN method (Ramstad *et al.*, 2012). Additionally, the decrease in capillary forces and the increase in condensate mobility after the chemical injections are estimated. Finally, the influence of **TCF** and **GS** techniques on the pore system is examined. Results of condensate removal, fluids mobility, capillary forces, and pores network are discussed.

Condensate Mitigations

Gemini surfactant and thermochemical fluids were injected into tight rock samples to mitigate the condensate banking. Figure 2 shows the profiles of remaining condensate saturations during **TCF** and **GS** treatments. Around 84% of the condensate liquid was removed using gemini surfactant, and the remaining condensate saturation is around 16%. While **TCF** removed around 63% of the condensate liquid and yielded a liquid saturation of 37%. In these experiments, the used rock samples have almost similar properties which will minimize the experimental uncertainty. The rock samples have absolute permeability of less than 1 mD and porosity around 13%. The main recovery mechanism during **GS** flooding is the wettability alteration induced by the injected surfactant. The injected fluids covered the rock surface and change the wettability condition toward a less liquid wet state, therefore increasing the condensate mobility. In this study, the change in rock wettability due to **GS** flooding was evaluated using relative permeability, fluid mobility, and capillary pressure techniques, as will be discussed in the coming sections of this paper.

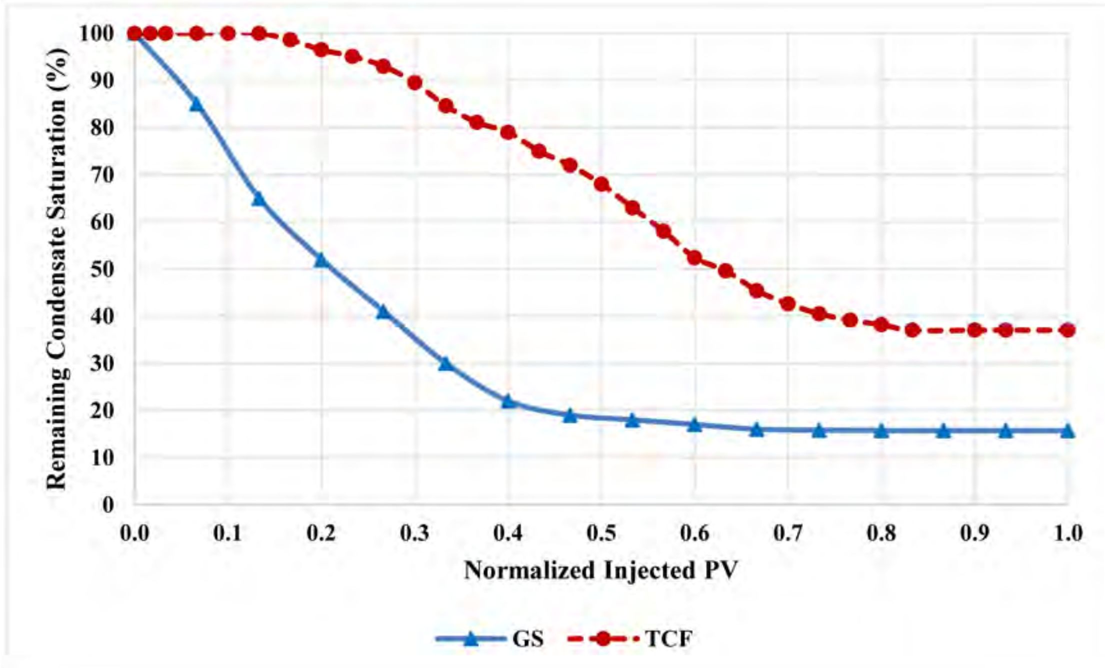

Figure 2—Profiles of remaining condensate saturation during the injections of gemini surfactant (GS) and thermochemical (TCF) fluids.

On the other hand, during **TCF** treatment, the injected fluids reacted inside the pore space and revaporized a portion of the condensate liquid due to the in-situ generated heat and pressure. Analyzing the phase behavior of the condensate liquid indicates that **TCF** injection can convert around 70% of the condensate liquid into a gaseous state. Consequently, the fluid viscosity will be reduced by 17 folds, the viscosity was decreased from 0.34 to 0.02 cP at reservoir conditions. Hence, the overall mobility will be increased by more than 80%. Ultimately, **GS** and **TCF** treatment showed effective performance in mitigating the condensate banking for tight rocks. **GS** showed higher condensate recovery compared to **TCF**, an increase of 21% in the condensate recovery was obtained using **GS**, the removal mechanisms will be discussed in the coming sections.

Relative Permeability

The relative permeability to condensate liquid is one of the key parameters that can contribute to the condensate removal process. Chemical injections usually aim to increase the condensate relative permeability and thereby the condensate liquid can easily flow to the wellbore, as a result, the condensate accumulation will be minimized. In this work, the impact of **GS** and **TCF** injections on the relative permeability curves was investigated utilizing the unsteady state approach. Figure 3 shows the change in relative permeability for water and condensate due to the injection of gemini surfactant and thermochemical fluids. Injection of gemini surfactant into the tight formations can change the wettability status to less oil-wet condition and hence increase the relative permeability to condensate liquid (Salehi *et al.*, 2010; Kamal, 2016; Hassan *et al.*, 2020). Therefore, in this study, gemini surfactant was injected to increase condensate mobility by reducing the oil-wetness. Relative permeability measurements were used to evaluate the changes in rock wettability after applying **GS** treatment. An oil-water system was used to assess the wettability conditions, which will reduce the complexity associated with introducing the gas phase and the impact of **GS** and **TCF** treatments on the condensate relative permeability can be captured. **GS** treatment reduces the relative permeability to the water phase by 63% and increased the condensate relative permeability by a factor of 1.89. While **TCF** injection led to reducing the water relative permeability by around 68% and the condensate permeability was increased by a factor of 1.22 after the treatment. The improvement in condensate permeability can lead to reduce the residual condensate saturation and thereby minimizing the liquid accumulation around the wellbore and avoid the development of condensate banking. Overall, **GS** and **TCF** treatments can increase the relative permeability to condensate liquid by changing the rock wettability toward less condensate wetness. **GS** showed better performance compared to **TCF** in increasing the condensate relative permeability.

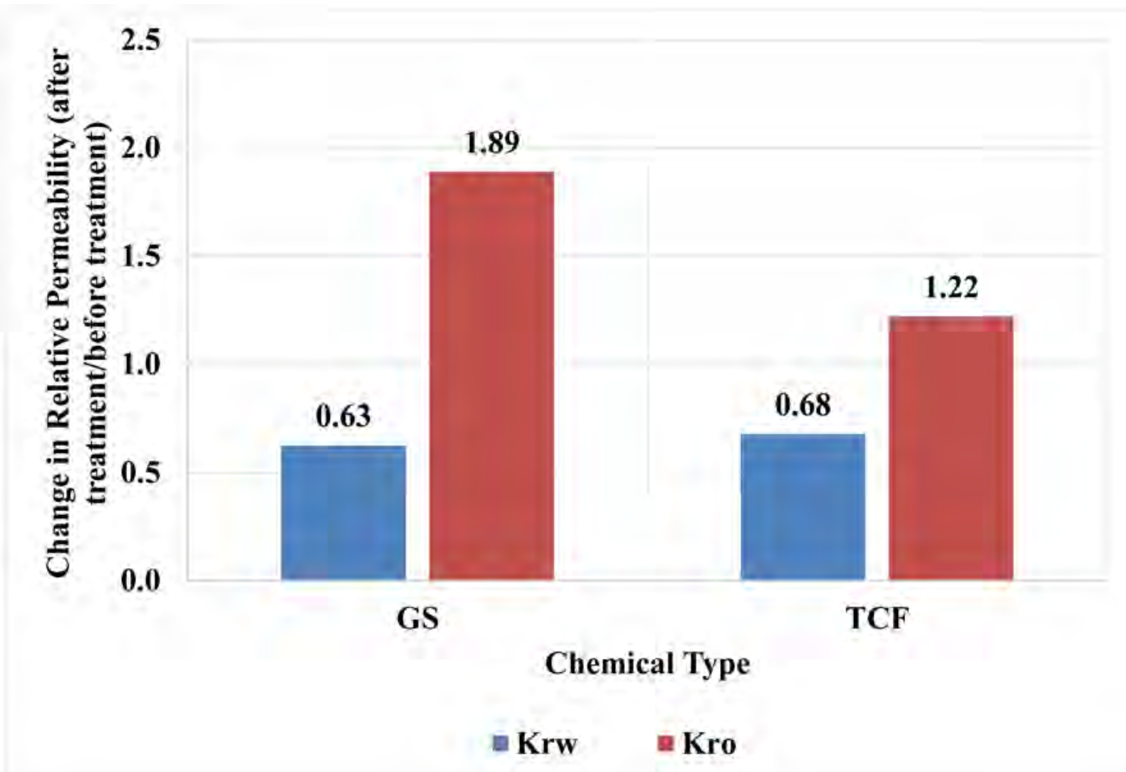

Figure 3—The change in relative permeability for water (krw) and condensate (kro) due to the injectionof gemini surfactant (GS) and thermochemical fluids (TCF).

Condensate Mobility

Condensate banking can be prevented by increasing the mobility of condensate liquid (Sayed and Al-Muntasheri, 2016; Hassan *et al.*, 2019a; Panja *et al.*, 2020). The hydrocarbon mobility can be raised by improving the relative permeability or decreasing the fluid viscosity, as indicated by **Equation 2**. In the previous section, the impact of **GS** and **TCF** injections on the relative permeability was discussed. However, in this section, more discussion about the increase of condensate mobility after the **GS** and **TCF** treatments is provided utilizing the results of relative permeability and the changes of fluid properties during the treatments. Figure 4 shows the change in condensate mobility before and after injection of gemini surfactant (**GS**) and thermochemical fluids (**TCF**). **Equation 2** was utilized to estimate condensate mobility. Injection of **GS** led to an increase in the condensate mobility from 0.14 to 0.27. The increase in condensate mobility is attributed mainly to the alteration of rock surface toward less condensate-wetness after the **GS** injection. On the other hand, the thermochemical treatment led to increasing the condensate mobility from 0.36 to 0.58. The improvement in condensate mobility is attributed to the generated heat during **TCF** treatment. The thermochemical reaction can increase the temperature by around 55% (Hassan *et al.*, 2018), and hence the condensate viscosity will be reduced significantly. Also, a thermochemical reaction can re-vaporize a portion of the condensate liquid to a gaseous phase which will reduce the viscosity as well (Hassan *et al.*, 2019a). Ultimately, **GS** and **TCF** treatments can improve condensate mobility due to the wettability alteration or the changes in condensate properties. **GS** treatment showed better performance compared to **TCF** injection, and the condensate mobility was increased by a factor of 2 on average.

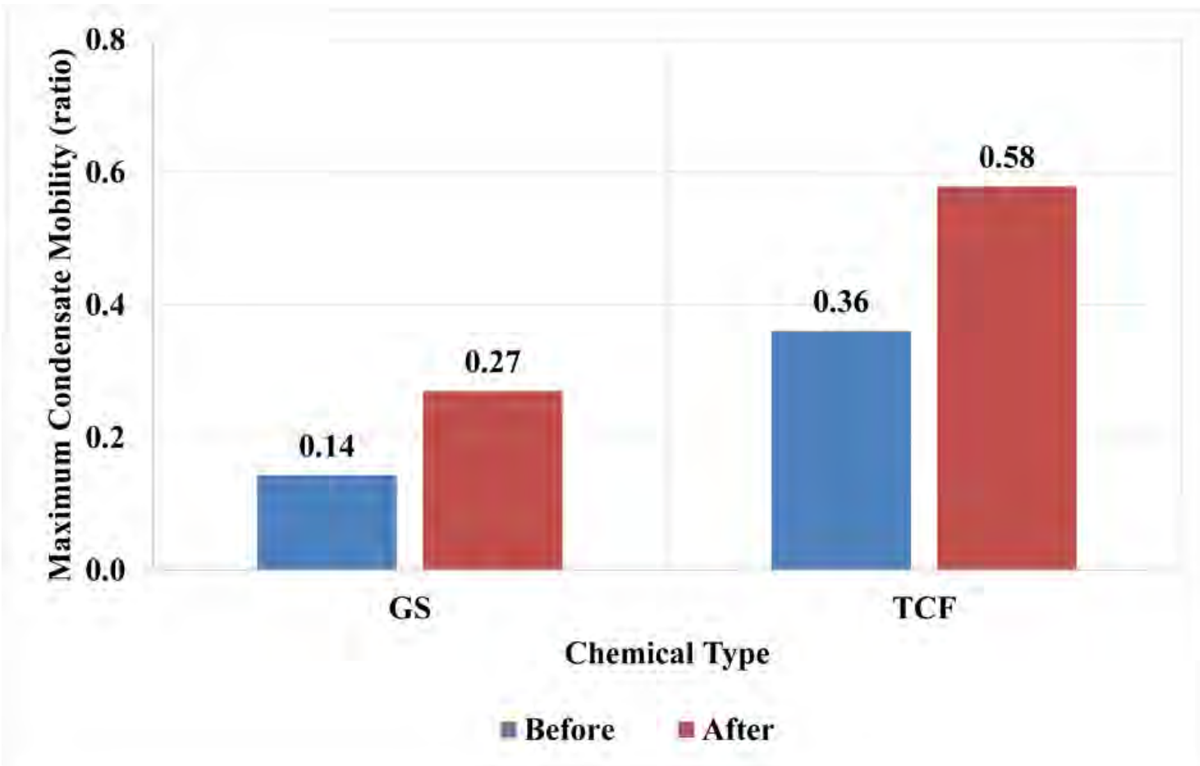

Figure 4—Condensate mobility before and after injection of gemini surfactant (GS) and thermochemicalfluids (TCF).

$$M = \frac{kk_r}{\mu} \tag{2}$$

Where M is the condensate mobility, μ is the condensate viscosity (cP), and k and kr are the absolute permeability (mD) and relative permeability to condensate, respectively.

Capillary Pressure

Chemical injections can reduce the capillary pressure (Pc) of tight formations by altering the rock properties such as pore throat size or adjusting the fluid properties such as interfacial tension. The capillary pressure can be determined using **Equations 3** or **5** (Brooks and Corey, 1964; Tiab and Donaldson, 2015; Xu *et al.*, 2019). In this work, the capillary pressure was estimated before and after applying **GS** and **TCF** treatments, as shown in Figure 5. The capillary force was reduced from 55.5 to 39.8 psi using **GS** injection, indicating that less pressure will be required to recover the condensate liquid. Also, the reduction in capillary pressure can lead to reducing the condensate saturation by around 30%, revealing that the accumulation of condensate liquid will be minimized using **GS** treatment. On the other hand, injection of thermochemical fluids showed more reductions in the capillary pressure compared to **GS** treatment. The capillary pressure was reduced from 55.5 to 31.6 psi after injecting **TCF** into the tight rock samples. Gemini surfactant reduces the capillary pressure mainly by decreasing the residual condensate saturation, refer to **Equations 3** and **4.** However, thermochemical fluids reduce the capillary forces by enlarging the average pore sizes (refer to **Equation 5**) due to the generation of multiple fractures after **TCF** treatment. Overall, thermochemical treatment outperforms the gemini surfactant approach in reducing capillary pressure. Reductions of 40 to 70% can be obtained using **GS** and **TCF** injections, respectively.

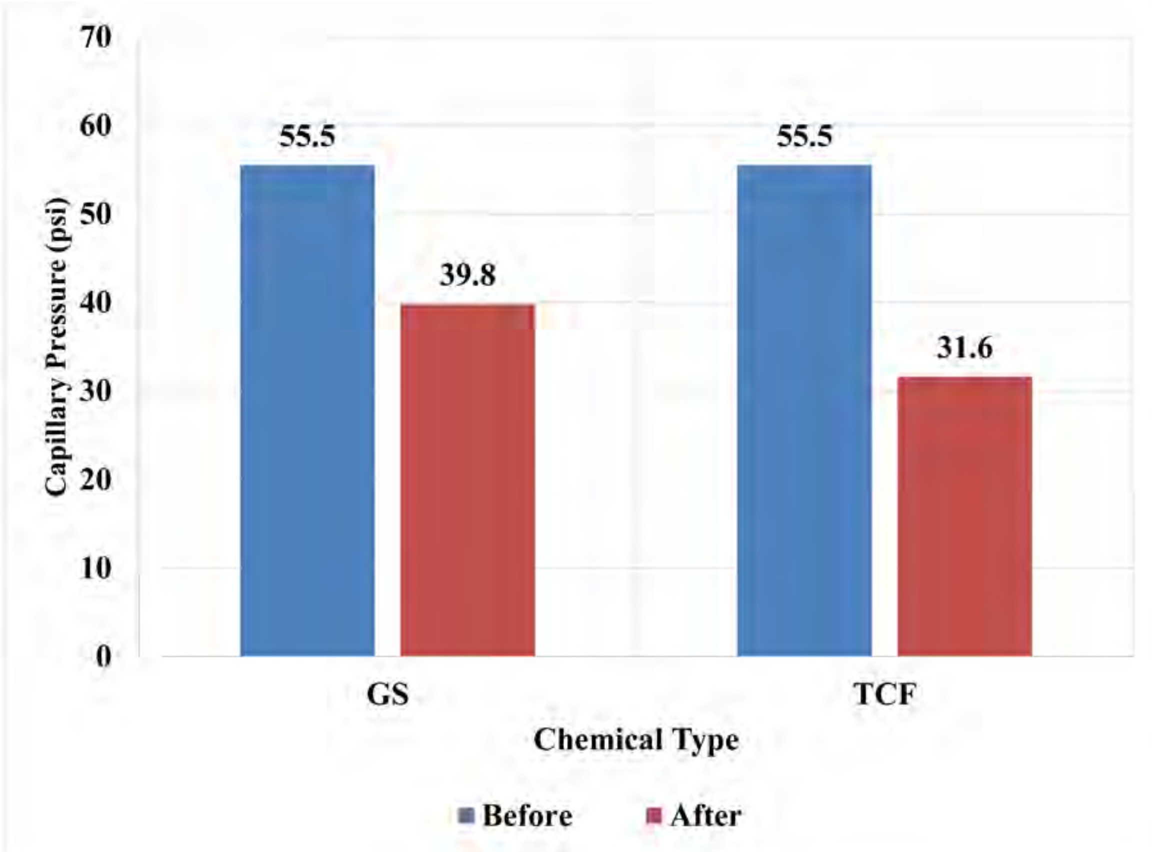

Figure 5—Capillary pressure before and after applying gemini surfactant (GS) and thermochemical(TCF) treatments.

$$P_c = P_d S_e^{-\frac{1}{\lambda}} \tag{3}$$

$$S_e = \frac{S - S_r}{1 - S_r} \tag{4}$$

$$P_c = \frac{2\sigma cos\theta}{r} \tag{5}$$

Where Pc is the capillary pressure (psi), Pd is the displacement or threshold pressure (psi), Se is the effective fluid saturation estimated based on the residual saturation (S_r), Lambda (λ) is the pore size factor, a is the interfacial tension (mN/m), θ is the contact angle, and r is the pore throat size (µm).

An Integrated Approach

Thermochemical fluid and gemini surfactant can be injected sequentially to eliminate the condensate banking damage as well as improve the formation conductivity for the long term. First, thermochemical fluids can be injected to react downhole and induce fractures around the wellbore, leading to improve conductivity in the near-wellbore region. Thereafter, gemini surfactant can be injected to alter the wettability of the rock matrix as well as the surface of the induced fractures. This approach will lead to integrating the benefits of both GS and TCF treatments. Efficient removal of condensate liquid can be obtained by applying this approach, as shown in Figure 6. Based on the remaining condensate saturation, a liquid removal of 94% can be achieved using **TCF**+**GS** injections, compared to 84 and 63% removals using individual injections of **GS** and **TCF** fluids, respectively. Applying the integrated approach showed a higher removal because more removal mechanisms will be involved. **TCF** will reduce the capillary pressure and increase the overall permeability around the wellbore, and **GS** injection will alter the rock wettability and reduce the residual condensate saturation.

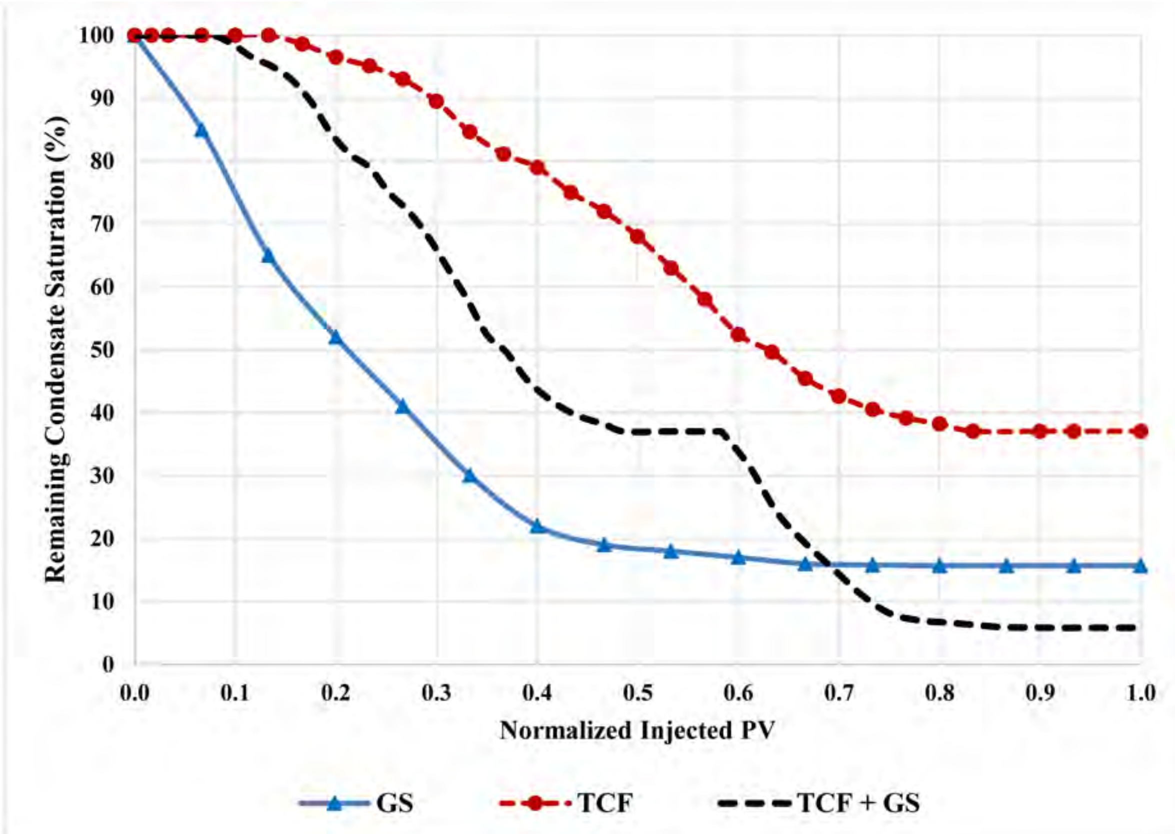

Figure 6—Profiles of remaining condensate saturations during GS, TCF, and TCF+GS treatments.

In summary, both fluids **TCF** and **GS** showed very attractive performance in mitigating the condensate bank, and several removal mechanisms are contributed to removing the condensate liquid. **TCF** treatment induces multiple fractures around the wellbore which will improve the formation conductivity and minimize problems associated with condensate accumulation for the long term. On the other hand, **GS** injection can alter the rock wettability and thereby reduce the residual condensate saturation. Integrating **TCF** and **GS** showed better performance and mitigated the condensate banking with an efficiency of 95%, and remaining condensate saturation of less than 6% can be achieved. However, more investigation can be performed to optimize the performance of (**TCF+GS**) treatment, such as finding the optimum chemical volumes and treatment time. Also, large-scale simulations can be conducted to assess the condensate removal efficiency using these chemicals.

Conclusions

This work presents a comparison study for two effective chemicals in mitigating the condensate bank for tight gas condensate reservoirs. The performance of thermochemical fluids (TCF) and gemini surfactant (GS) in removing the condensate liquid and improve the formation productivity is studied. Several experiments were carried out including coreflooding, capillary pressure, and relative permeability measurements. The following conclusions can be drawn based on this work;

- Injections of gemini surfactant and thermochemical fluids can remove 84% and 63% of the condensate liquid, respectively.
- **GS** and **TCF** treatments can increase the relative permeability to condensate liquid by factors of 1.89 and 1.22 respectively, due to the wettability alteration mechanism.

- The condensate mobility was increased by a factor of 2, and the capillary pressure was reduced by 40% and 70% using **GS** and **TCF** treatments, respectively.
- Thermochemical treatment outperforms gemini surfactant approach in reducing the capillary pressure and improving condensate flow.
- Finally, an integrated approach is presented that can mitigate the condensate damage by more than 90%, utilizing the effective mechanism of **GS** and **TCF** chemicals.

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