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Condensate Banking Removal Using Slow Release of In-Situ Energized Fluid

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Abstract

Condensate banking represent a persistent challenge during gas production from tight reservoir. The accumulation of condensate around the wellbore can rapidly diminish gas production. When reservoir pressure drop below dew point, condensate start to dropout from gas phase, filling pores and permeable fractures, and block gas production. There are several strategies to mitigate condensate banking, however, these strategies are either demonstrate limited results or are economically not viable.

In this study, a novel method to mitigate condensate was developed using thermochemical reactants. Slow-release of thermochemical reactants inside different core samples was studied. The effect of in-situ generation of gas on the petrophysical properties of the rock was reported. Thermochemical treatment was applied to recover condensate on sandstone and carbonate, where the reported recoveries were around 70%. However, when shale sample was used, the recovery was only 43%.

Advanced Equation-of-State (EoS) compositional and unconventional simulator (GEM) from CMG (Computer Modelling Group) software was used to simulate thermochemical treatment and gas injection. The simulation study showed that thermochemical stimulation had increased production period from 3.5 to 22.7 months, compared to gas injection.

Introduction

Natural gas gains more value day by day which makes its production more profitable. As the production of gas increases, several challenges should be addressed to maintain cost-effective production, especially from tight reservoirs. Condensate banking is one of the most critical reasons for decreasing production rates in gas fields around the world. When the reservoir pressure decreases below the dew point, liquid starts to drop out from gas(1). The condensate liquid then accumulates in the pores, and decrease permeability around the wellbore, therefore, limits gas production.

When the reservoir pressure drop below dew point, accumulation of liquid condensate around the wellbore can form three mobility regions(2), as shown in Figure 1. Near wellbore area, will be the first region of mobile gas and mobile condensate, where both liquid and gas phase are flowing to the wellbore. The second region, there are also two phases of gas and liquid condensate. However, in this region the condensate is below saturation point, which makes it immobile and do not flow to wellbore. The faraway region, there is only a gas phase, as the reservoir pressure would be above dew point.

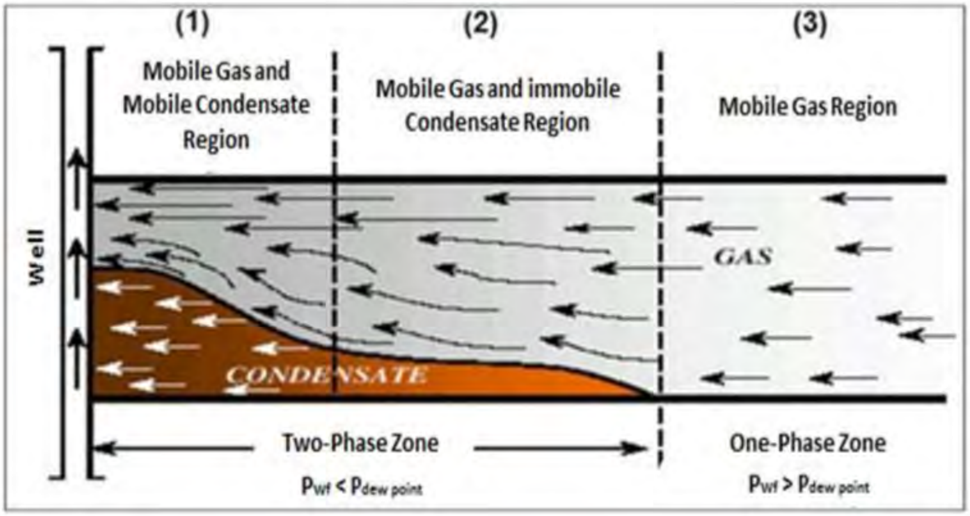

Figure 1— Condensate Saturation below the Dew Point Pressure Flow Behavior in the Three Known Regions [2]

Well testing can be applied to evaluate condensate banking in the reservoir, where buildup and drawdown tests can show the change in fluid type, rate variations, and fluid dynamics(3). Analytical solution can be applied to model the three-mobility region around the wellbore, as worked out by Wilson(4). He developed the model based on the relationship between reservoir radios and all of gas mobility and condensate saturation, using equation 1, as illustrated in Figures 2 & 3.

$$k = k_{\min} + \left(k_{\max} - k_{\min}\right)\left[1 - \exp\left(\frac{-1}{\alpha}\frac{r2}{t}\right)\right] \tag{1}$$

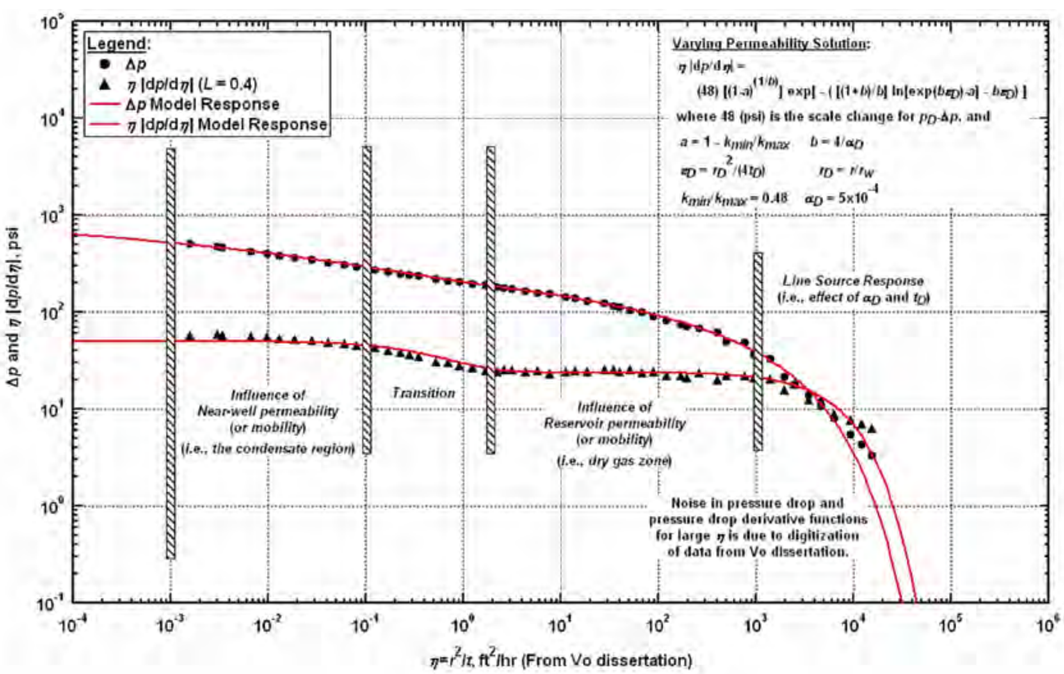

Figure 2— Pressure curves for a typical gas condensate well [4].

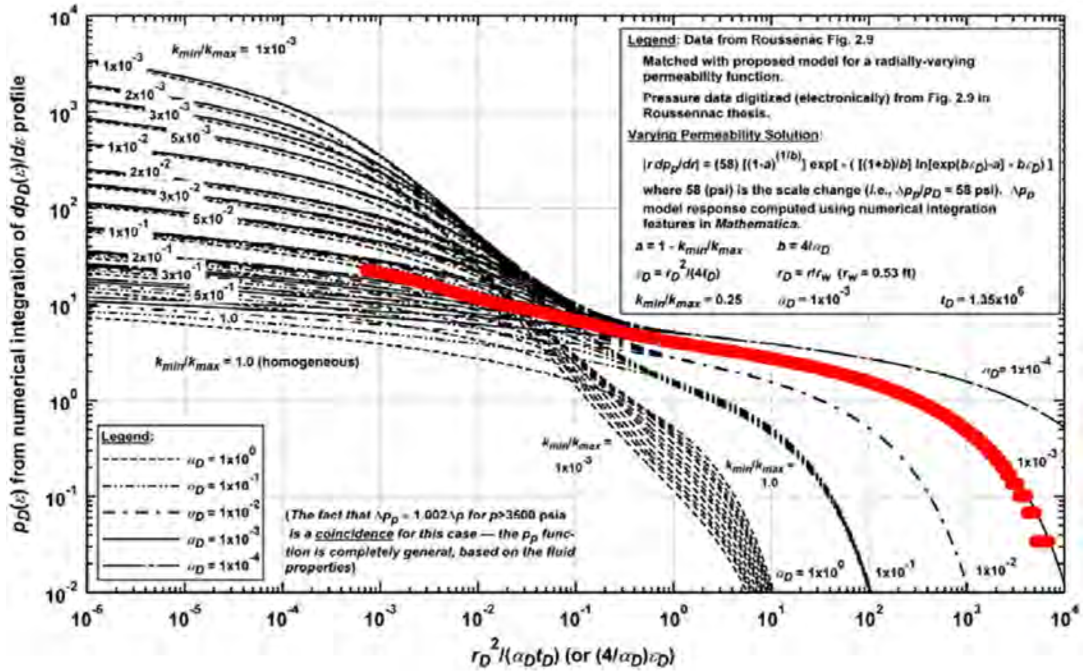

Figure 1—. Pressure derivative curves for gas condensate reservoir [4].

Gas injection

Historically, condensate banking was resolved by gas cycling where in the condensate-gas fields the produced gas was reinjected in the well to maintain the reservoir pressure and that will ensure it is above the dew point and hence decrease the possibility of liquid drops and condensate banking(5). Nowadays, with the high economical value, it is not profitable to recycle natural gas. Almuntashiry and sayed(6) summarized different methods for condensate banking mitigation where these can be categorized as pressure maintenance methods, chemicals injections and productivity improvement. Pressure maintenance include gas cycling and CO_2 and N_2 gases injection. While Chemical solutions includes wettability alternation and solvent injection. Finally, productivity improvement includes horizontal wells, hydraulic fracturing and acidizing. In this study thermochemical reaction is utilized in condensate banking mitigation where this reaction produces both high temperature and pressure.

Pressure maintenance

Maintaining reservoir pressure is one of the practices to keep production rates high. When the pressure is maintained at levels higher than dew point, the condensate accumulation decreases. In the past, it was practical to inject lean-gas into the reservoir to maintain pressure. However, as the gas price increased, this process became less beneficial. Besides increasing the pressure, injected gas can also reevaporate the condensate which mean it can play a vital role by preventing the formation and mitigating the already formed banking(7). The injection is not exclusive for lean gas where different gases can be used as CO_2, Nitrogen and mixture of gases. Ahmed et al.(5) studied the effectiveness of lean gas, N_2, and CO_2 Huff 'n' Puff operation on three different Gas-Condensate system and concluded that the process is viable option to mitigate condensate banking in the near wellbore region. Choosing the type of gas to be injected in the reservoir depends on phase behavior of the fluid and flow characteristic of the reservoir(6).

Donohoe and Buchanan(8) did a comparison between lean-gas injection and Nitrogen for three hypothetical fluids. They found that recovery factors of nitrogen injection were comparable with lean-gas injection. They also concluded that reservoirs having Condensate to Gas Ratio (CGR) richer than 100 bbl/

MMcf should be considered for N_2 injection. Introducing N_2 to the field could requires building several facilities as air separation unit (ASU) and nitrogen rejection unit (NRU)(9).

Huff n Puff injecting CO_2 in depleted gas reservoirs can be useful where Ayub et al.(10) did a simulation study and showed that the process can mitigate condensate banking through three aspects, dissolving the condensate due to low MMP between condensate and CO_2, condensate re-vaporization and increasing near well pore pressure. Dissolved CO_2 in water generate carbonic acid, which could be corrosive to mild steel (11-13). Another possible damage is the precipitation of Calcium bicarbonate when CO_2 is injected in carbonate reservoir, which could plug the channels and decrease the production eventually (14 and 15).

Chemical injection

Another type of injection is chemical injection. Methanol and dimethyl ether (DME) can be injected in the impacted well since they are miscible with the condensate. Al-Anazi et al(16) discussed the effect of methanol on condensate banking where they found out that methanol injection increased production by a factor of two, before it declines again after 4 months. Liu et al.(17) used DME as a solvent to remove the liquid blockage that includes both hydrocarbons and water. The treatment showed an increase in relative permeability. However, this treatment is temporary when it comes to condensate removing.

Injection of wettability alternation chemical can be applied to change rock from being liquid wet to gas wet(18). Al-Yami et al.(2) reported a field trial of using polymeric fluorinated surfactant to enhance gas flow and remove condensate blockage. The treatment showed an increase of gas and condensate production by 83% and 313% respectively, which lasted for more than 2 years. However, fluorochemicals and their degradation could be hazardous and harmful for humans and the environment (19-21).

Productivity improvement

Another approach to overcome condensate-banking challenge is horizontal drilling. Miller et al.(22) conducted a study to simulate the role of horizontal wells on reducing condensate banking. They found that the horizontal well showed less drawdown pressure and reached the dew point after 1880 days compared with 396 days for the vertical. Another finding, at below dew point conditions, oil saturation was 0.27 for vertical well, where it was only 0.20 for a horizontal well. Acidizing and hydraulic fracturing were applied sometime to increase permeability, remove blockage, and increase gas production.

Thermochemical treatment approach

A new approach was developed to mitigate condensate banking by using slow-release of thermochemical reactors. The new treatment can mitigate condensate by three factors. The first factor is by increasing reservoir pressure, as nitrogen gas is generated in-situ. The second factor is generation of heat and gas, which can not only evaporate condensate, but also dilute the liquid phase, therefore reduce viscosity. One of the critical factor that contribute to condensate banking is liquid loading. When, there is a significant amount of condensate and/or water in the near-wellbore area and in the wellbore itself, high hydrostatic pressure will be created, which will chock the well and result in a total loss of gas production. When chemical fluids, such as solvents and acids, are pumped in the wellbore, they will also create extra chocking material in the reservoir that requires lifting.

A novel treatment, based on pumping thermochemical fluid, was developed to mitigate condensate. The advantage of pumping thermochemical fluid over other solvents or acid injection that thermochemical reactants can be designed for slow-release of nitrogen gas. The release of in-situ nitrogen gas will energize the fluid in the reservoir, and greatly support flowing back liquid condensate and water not only from the well, but also from the reservoir. The new slow-release recipe of thermochemical was tested in the lab, using autoclave system, as shown in Figure 4. Fluid was pumped inside the reactor at room pressure and temperature. The slow-release of nitrogen gas was monitored by the reactor gage pressure. The reactor pressure increased from zero to 15,400 psi after 10 days, as illustrated in Figure 5. Then the reaction was quiet. The duration of nitrogen gas release can be predesigned in the lab. The slow release of nitrogen gas, will allow the fluid to be pumped deep into the reservoir and slowly energize liquid condensate, which is chocking the well. Furthermore, the flowback of this reactive chemical will in-situ energize wellbore fluid for effective deliquification of the wellbore.

Figure. 4— Autoclave system rated up to 20,000 psi and 500º C.

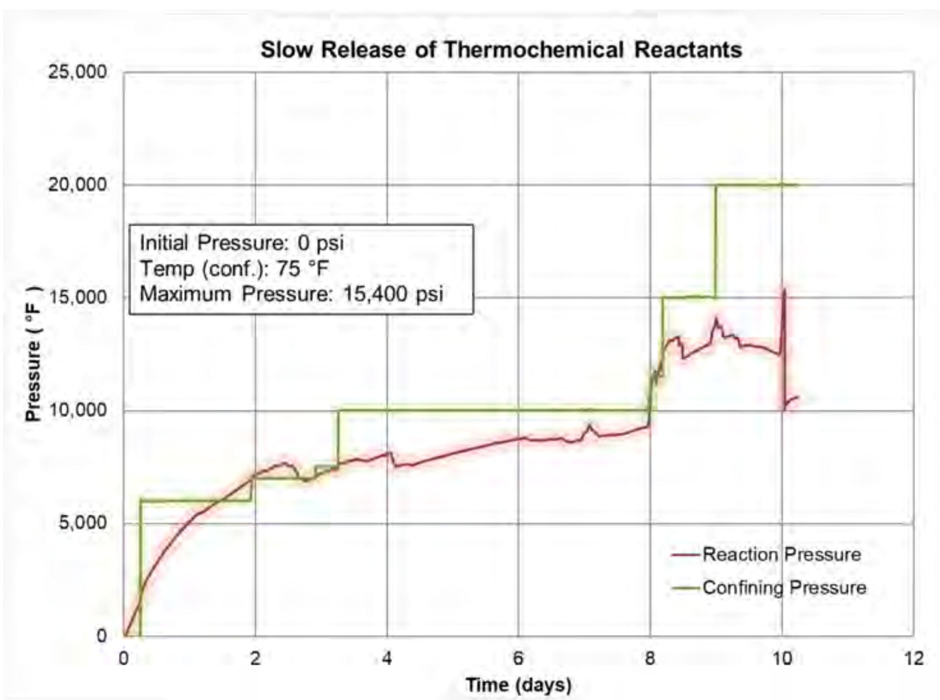

Figure. 5— Autoclave system test of slow-release of thermochemical reactants

Condensate Recovery using Thermochemical Fluid

Three different types of rocks (sandstone, carbonate, and shale) were used to evaluate condensate removal using the new slow-release system of thermochemical reactants. Table 1 shows the petrophysical properties of the three rock types used in this study. The rock samples were placed in coreflood system and saturated with condensate. Then, several cycles of thermochemical system was pumped to recovery condensate. During each cycle, the fluid was lift for socking time until equilibrium was achieved. The strategy of cyclic flooding was selected to reduce treatment fluid volume by 50%, compared to single stage flooding(23). Around 70% of condensate fluid was recovered from sandstone and carbonate rocks in three cycles of injection. However, for shale, 43% of condensate was recovered after five cycles of injection, as depicted in Figure 6.

Table 1—Petrophysical properties of the core samples used in this work.

Sample ID	Sample Type	Diameter (cm)	Length (cm)	Bulk Volume (ml)	Pore Volume (ml)	Porosity (%)	Absolute Permeability (mD)
SS	Sandstone	3.81	5.33	60.81	12.67	20.83	13.12
LS	Limestone	3.81	5.46	62.20	9.84	15.82	7.39
SH	Shale	3.81	5.40	61.54	1.96	3.19	0.012

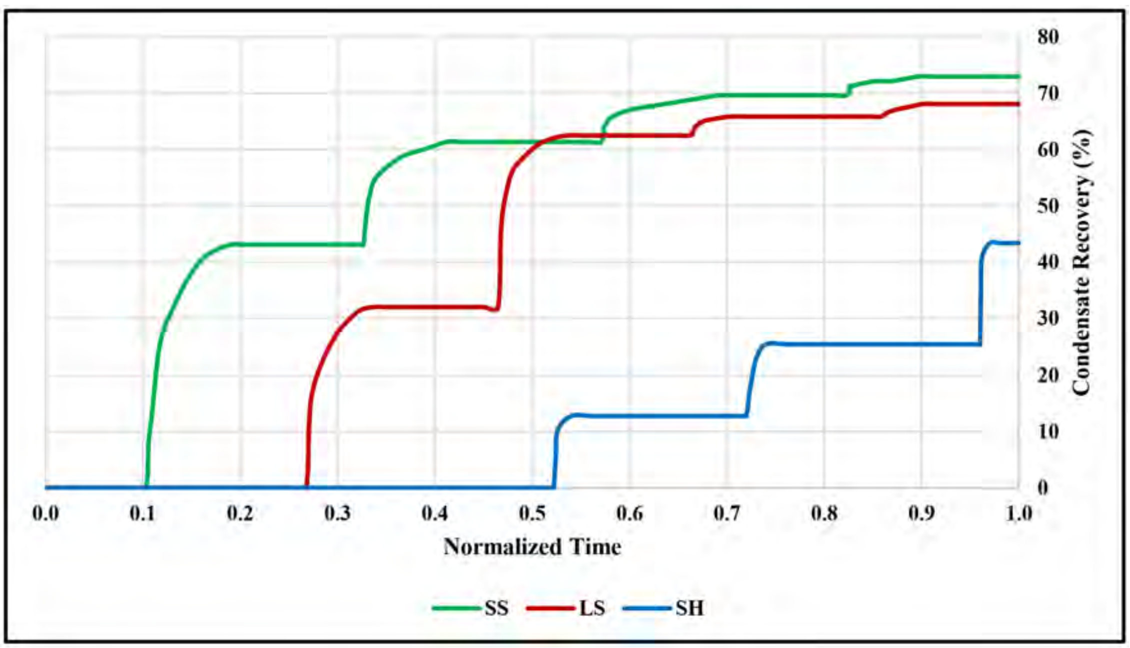

Figure 6—Cumulative condensate recovery during thermochemical injection into sandstone (SS), limestone (LS) and shale (SH) rocks(23).

The slow release of in-situ energized fluid within the reservoir not only help to energize condensate, but also creates microfracturing in tight rocks, so, increase permeability and reduce capillary forces. Tight core samples were used to evaluate the effect of slow-release of thermochemical treatment on capillary forces and productivity index. The treatment showed that capillary pressure was reduced by 56% due to thermochemical treatment. Productivity index (PI) was calculated during coreflood treatment from pressure drop and found to be increased by 79%.(23)

Field Scale Simulation

In order to evaluate the effect of thermochemical treatment, for condensate banking removal, an advanced Equation-of-State (EoS) compositional and unconventional simulator (GEM) from CMG (Computer Modelling Group) software was used. Table 2 shows initial reservoir conditions that were used in this simulation. Thermochemical treatment was compared with gas injection using the same reservoir and production conditions. 1 km X 1 km rectangular Cartesian model, with a single well in the center, was used during the study, as shown in Figure 7. Four different permeability-layers, ranging from 10 to 315 mD, were used with 0.15 porosity. Reservoir temperature was set to 275 °F.

Table 2— Initial reservoir conditions

Parameter	Value
Total bulk reservoir volume (ft^3)	9.00E+08
Total pore volume (ft^3)	1.17E+08
Total hydrocarbon pore Volume (ft^3)	9.83E+07
Original oil in place, OOIP (STB)	1.79E+06
Original gas in place, OGIP (SCF)	2.77E+10

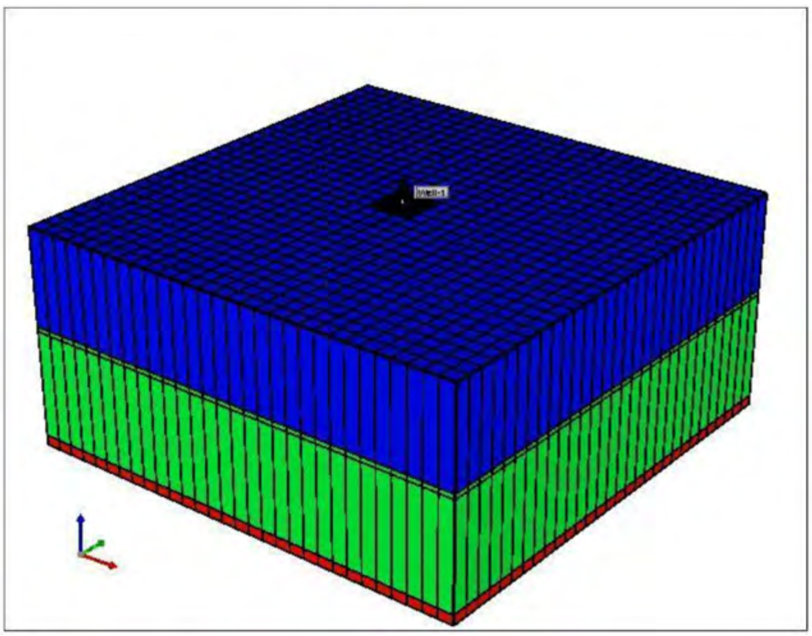

Figure 7—A 3D view of the rectangular model used in the simulation.

Gas Injection

During the simulation of gas injection, to remove condensate banking, the well was allowed to produce at a rate of 30 MMSCFD, with downhole pressure of 7,000 psi, as depicted in Figure 8. Due to condensate accumulation, downhole pressure was reduced to 1,500 psi, and production was stopped after 668. Then, three cycles of gas injection was applied, with constant rate for one month. After gas injection treatment, the well was opened for production at the same initial production rate. The well managed to produce for 104 days, before downhole pressure dropped to the preset lower limit of 1,500 psi, where the production was stopped.

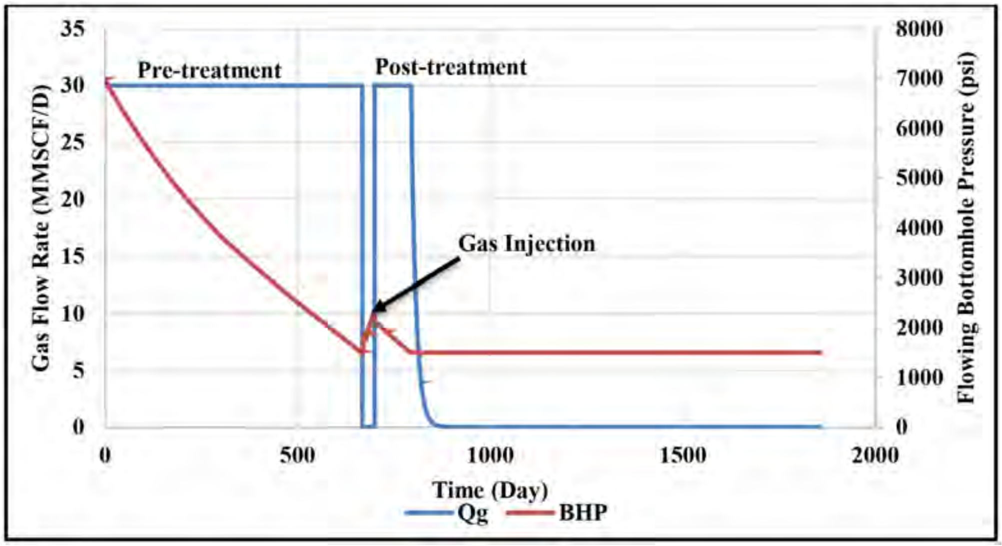

Figure 8—Profiles of gas production and the flowing downhole pressure before and after gas injection treatment.

Thermochemical Treatment

Slow-release of thermochemical treatment has three impact factors on the reservoir. In-situ generated pressure will positively affect the reservoir pressure. Moreover, the in-situ generated N2 gas will reduce condensate viscosity. The third factor is the creation of microfractures in the reservoir rock. During the simulation, and prior to thermochemical treatment, gas production was started at 30 MMSCFD, with 7,000 psi downhole pressure. Downhole pressure dropped, due to condensate banking to 1500 psi, and production was stopped after 668 days. Then, three cycles of thermochemical treatment was applied with one-week soaking time. Then, the well was open to production with 30 MMSCFD and lasted for 680 days. This shows that thermochemical treatment was able to restore initial reservoir conditions, as illustrated in Figure 9. The simulation study showed that thermochemical stimulation had increased production period from 3.5 to 22.7 months, compared to gas injection. In another word, production plateau was increased by a factor of 6.5, compared to gas injection.

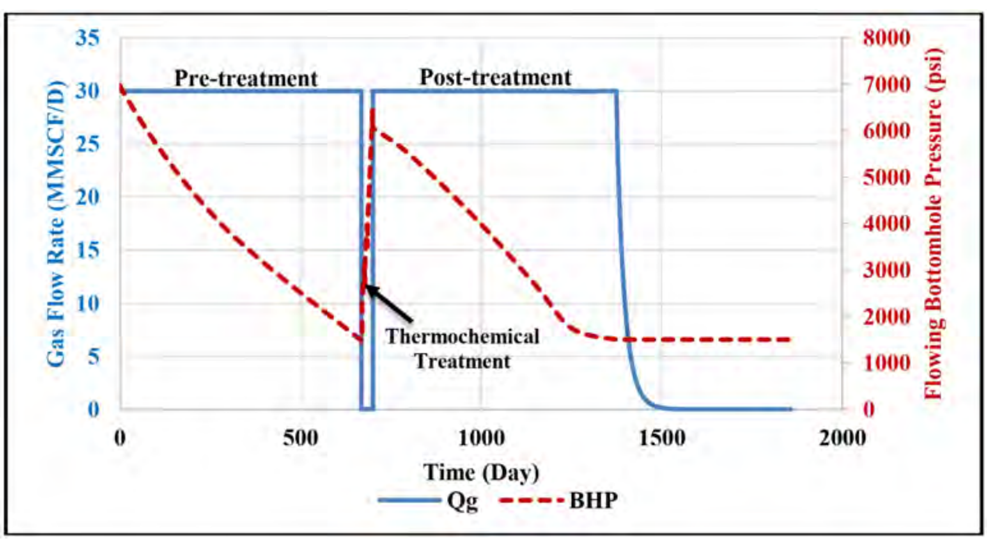

Figure 9—Profiles of gas flow rate and flowing downhole pressure before and after thermochemical treatment.

Conclusions

In this study, the impact of slow release of thermochemical treatment was studied. Based on the results achieved, the following conclusions can be drawn:

- A novel thermochemical treatment was developed to mitigate condensate bnking in gas reservoirs.
- Laboratory testing showed that slow release of thermochemical reactants can be achieved and delay reaction up to 10 days. The reaction delay will help to squeeze the treatment deeply in the reservoir to treat far-reaching areas.
- Thermochemical treatment provides pressure support, condensate viscosity reduction, and induced fracturing, which overall increase condensate recovery.
- Advanced Equation-of-State (EoS) compositional and unconventional simulator (GEM) from CMG (Computer Modelling Group) software was used to simulate thermochemical treatment and gas injection.
- The simulation study showed that thermochemical stimulation had increased production period from 3.5 to 22.7 months, compared to gas injection.

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