Potential to Increase Condensate Oil Production by Huff-n-Puff Gas Injection in a Shale Condensate Reservoir

Abstract

This paper presents a huff-n-puff gas injection method to increase condensate production in an Eagle Ford gas condensate reservoir using a simulation approach. The simulation study suggests that the huff time and puff time should be the same. Because of higher compressibility of a gas condensate fluid, either huff or puff time required will be longer than that for a shale oil reservoir. For the studied reservoir, an optimum huff or puff time is about 600 days. However, a shorter time of 300 days is preferable for recouping the cost for facilities. To improve the overall liquid condensate recovery performance, during the last half of the development period, the huff-n-puff may be changed to pressure depletion so that the energy injected earlier can be fully utilized. Other effects such as those of initial water saturation, injection pressure, and gas composition, are also investigated in this paper. The methodology presented in this paper is applicable to other gas condensate reservoirs, and some of results or conclusions may be typical of gas condensate reservoirs.

Introduction

In a gas condensate reservoir, when the pressure is decreased below the upper dew point, liquid condensate forms. Even when the overall reservoir pressure is above the dew point, most often, the pressure near a producer will be below the dew point. Thus, liquid condensate will accumulate near the wellbore. The liquid condensate blocks gas flow, reducing the gas production rate. Thus, less liquid oil can be obtained at the surface (Thomas et al., 1995). Bang et al. (2008) found that condensate buildup in the fractures can significantly reduce the productivity of fractured wells. The steady-state relative permeability even in propped fractures is typically on the order of 0.1. When oil saturation is below a residual oil saturation, oil cannot be produced using a conventional production method. To solve this problem, several techniques have been used, including gas cycling, drilling horizontal wells, hydraulic fracturing, injection of super-critical CO₂, use of surfactant, use of solvents and the use of wettability alteration chemicals. Gas cycling is to keep the reservoir pressure above the dew-point pressure. Drilling horizontal wells and hydraulic fracturing are to reduce the pressure drop. Injection of super-critical CO₂ is to reduce the dew-point pressure (Uchenna, 2012). Use of surfactant is to reduce interfacial tension or alter wettability so that the capillary number is increased and the well productivity is increased (Kumar et al., 2006; Ahmed et al., 2011). One common practice in conventional reservoirs is to maintain the reservoir pressure or even the bottom-hole well pressure of the production well above the dew point pressure by gas and/or water flooding (Hernandez et al., 1999). Use of

chemical stimulation to alter the wettability to non-liquid wetting to remediate the blocking problem was proposed by Kumar et al. (2006), Ahmadi et al. (2011), and Ganjdanesh et al. (2015). Use of solvents to mitigate the impact of liquid blockage has shown positive treatment outcomes in conventional gas condensate reservoirs (Al-Anazi et al., 2005; Sayed and Al-Munstasher, 2014). Recently, Meng et al. (2015) have verified in the laboratory that huff-n-puff gas injection can enhance liquid oil production in shale gas condensate cores.

This paper is to investigate the potential of huff-n-puff gas injection to increase liquid oil production in an Eagle Ford gas-condensate reservoir using a simulation approach.

Setup of a base simulation model

The current technology to develop shale resources uses horizontal wells with multistage fracturing. To conduct a simulation study, we need to build a model including this technology, and this model needs to be validated. Several authors (Kurtoglu, 2013; Yu et al., 2014) have built models using the Middle Bakken data, but their detailed models are not publically available, and there are no data in the literature that are more complete than the Bakken data. Thus, we will use the Bakken data to build a base model.

In this paper, the compositional simulator, GEM, developed by Computer Modeling Group (CMG) (2014), is used. Because of flow symmetry, a half-fracture connected through a vertical well is simulated. In the Middle Bakken case, a horizontal well is fractured with 15 fracturing stages. It is assumed that only one fracture is generated at one stage, so the production data from this model represents one-thirtieth of the actual production.

The simulation model (reservoir volume) includes two regions: the stimulated reservoir volume and the un-stimulated reservoir volume. The schematic is shown in Figure 1. The model area is 296.25 ft wide in the I direction, 4724 ft in the J direction with 724 ft in the SRV area, and 50 ft in the K direction (not shown in the figure). In this model, the half-fracture spacing is 296.25 ft in the I direction, the fracture length is 724 ft in the J direction, and the fracture height is 50 ft in the K direction. The half-hydraulic fracture width is 0.5 ft. One block is used in the K direction of 50 feet.

Figure 1 – Schematic of the base model

In this paper, we tried to use the data of the Middle Bakken formation presented by Kurtoglu (2013). Table 1 summarizes the input matrix and fracture properties in the Non-SRV and SRV regions in the Middle Bakken shale. The dual permeability model is used to simulate the naturally and hydraulically fractured shale reservoirs. The shale matrix permeability is 0.0003 mD. The natural fracture effective permeability in the SRV is 0.0313 mD. The natural fracture permeability in the un-stimulated reservoir region is 0.00216 mD; that is much lower than the stimulated region.

Table 1 – Matrix and Fracture properties		
	Non-SRV	SRV
Thickness, ft	50	50
Matrix Permeability, mD	3.0E-04	3.0E-04
Matrix Porosity, fraction	0.056	0.056
Fracture Porosity, fraction	0.0022	0.0056
Fracture Permeability, mD	2.16E-03	3.13E-02
Fracture Spacing, ft	2.27	0.77
Hydraulic fracture porosity, fraction		0.9
Hydraulic fracture permeability, mD		100

The reservoir fluid composition, the Peng-Robinson EOS parameters, and relative permeabilities are from Yu et al. (2014). Use these data and parameters, 1.2 years of production history is able

to be matched. During the history-match,, the stock-tank oil rate is imposed and the effort is made to match the well bottom-hole pressure. Figure 2 compares the simulated well bottom-hole pressure (line) with the actual data (dotted points). It can be seen that the well bottom-hole pressure is reasonably matched.

Figure 2 – Well bottom-hole pressure (dot points are actual data, and line is simulated data)

Next, the above calibrated, hydraulically fractured model is used to conduct a simulation study of gas condensate recovery in this paper. The grids, reservoir rock properties, matrix and fracture properties, etc. are unchanged. But gas condensate properties and some of reservoir properties for a gas condensate reservoir in the Eagle Ford formation are used in the model as described next.

For this gas condensate reservoir, the initial reservoir pressure is 9985 psig, the measured upper dew point pressure is 4184 psig, and the reservoir temperature is 270 °F. The reservoir fluid composition and the Peng-Robinson EOS parameters are presented in Table 2, and the binary interaction coefficients are shown in Table 3. In Table 2, P_c , T_c and V_c are critical pressure, critical temperature and critical volume, respectively, and MW is molecular weight.

Comp.	Initial mole fraction	P_c (atm.)	T_c (K)	V_c , L/mol)	Acentric Factor	MW g/mole	Parachor coeff.
CO ₂	0.0188	72.80	304.2	0.0940	0.225	44.01	78.0
N ₂	0.0036	33.5	126.2	0.0895	0.04	28.01	41
CH ₄	0.5695	45.4	190.6	0.099	0.008	16.04	77

C ₂ H ₆	0.1431	48.2	305.4	0.148	0.098	30.07	108
C ₃ H ₈	0.0637	41.9	369.8	0.203	0.154	44.10	150.3
IC ₄	0.0145	36.0	408.1	0.263	0.176	58.12	181.5
NC ₄	0.0244	37.5	425.2	0.255	0.193	58.12	189.9
IC ₅	0.0143	33.4	460.4	0.306	0.227	72.15	225
NC ₅	0.011	33.3	469.6	0.304	0.251	72.15	231.5
FC6	0.0177	25.97	483.1	0.344	0.330	86	250.11
FC7	0.1194	37.16	651.8	0.381	0.36996	168	278.405

Table 3 - Binary interaction coefficients for Eagle Ford gas condensate											
	CO ₂	N ₂	CH ₄	C ₂ H ₆	C ₃ H ₈	IC ₄	NC ₄	IC ₅	NC ₅	FC6	FC7
CO ₂	0										
N ₂	0	0									
CH ₄	1.05E-01	2.50E-02	0								
C ₂ H ₆	1.30E-01	1.00E-02	2.69E-03	0							
C ₃ H ₈	1.25E-01	9.00E-02	8.54E-03	1.66E-03	0						
IC ₄	1.20E-01	9.50E-02	1.57E-02	5.49E-03	1.12E-03	0					
NC ₄	1.15E-01	9.50E-02	1.47E-02	4.91E-03	8.66E-04	1.59E-05	0				
IC ₅	1.15E-01	1.00E-01	2.09E-02	8.73E-03	2.80E-03	3.82E-04	5.54E-04	0			
NC ₅	1.15E-01	1.10E-01	2.06E-02	8.58E-03	2.71E-03	3.50E-04	5.15E-04	7.17E-07	0		
FC6	1.15E-01	1.10E-01	2.53E-02	1.17E-02	4.62E-03	1.20E-03	1.49E-03	2.28E-04	2.55E-04	0	
FC7	1.15E-01	1.10E-01	2.96E-02	1.47E-02	6.57E-03	2.29E-03	2.68E-03	8.00E-04	8.49E-04	0	0

The values of the above tables are obtained by regression to match relative volumes (Figure 3) and liquid dropouts during a constant composition expansion test (Figure 4) at different pressures. The experimental data were measured by a service company.

Figure 3 – Relative volume at different pressure

Figure 4 – Liquid dropout at different pressures

Simulation results and discussion

The reference case is the primary depletion. The reservoir is produced for 10,950 days (30 years). The maximum gas production rate is 300 MSCF/day for a half fracture that is equivalent to 9 MMSCF/day for the whole horizontal well. The minimum bottom-hole pressure is 500 psi. The oil recovery after 30 years is 28.195%, and the gas recovery is 66.164%. Next, we will investigate the effects of huff and puff time, the combination of huff-n-puff and pressure depletion, initial water saturation, and gas composition. Before any huff-n-puff injection, 1,800 days of primary depletion is carried out. At the end of this primary depletion, the average reservoir pressure becomes 4065 psi and the well bottom-hole-pressure is 513 psi.

Effect of huff and puff time

Next, we need to simulate huff-n-puff gas injection. The maximum injection pressure is set at the initial reservoir pressure of 9985 psi. The maximum gas injection rate for the half-fracture model is 300 MSCF/day, which is equivalent to 9 MMSCF/day for a whole horizontal well with 15 stages (fractures). The maximum gas production rate is the same as the maximum injection rate. The gas injected is methane (lean gas). No soaking time is added in the simulation, as the purpose of the soaking time is not to improve liquid oil recovery (Meng et al., 2015). The huff time and puff time are set the same. The huff or puff time is then changed from 100 days to 1,200 days. The results are shown in Table 4. In the table, the case “Primary” is for primary depletion, for H100P100, the huff time or puff time is 100 days, and the rest of cases are self-explanatory.

Table 4 - Effect of huff or puff time									
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF	Oil revenue, MM\$	Gas revenue, MM\$	Total revenue, MM\$
Primary	28.195	66.164	26.630	346.330	0.000	346.330	2.663	1.385	4.048
H100P100	35.738	33.214	33.755	1553.900	1380.000	173.900	3.376	0.696	4.071
H300P300	42.130	27.055	39.793	1536.600	1395.000	141.600	3.979	0.566	4.546
H600P600	49.106	5.999	46.382	1468.600	1437.200	31.400	4.638	0.126	4.764
H900P900	51.925	27.845	49.044	1270.700	1124.900	145.800	4.904	0.583	5.488
H1200P1200	51.435	31.524	48.582	1100.200	935.200	165.000	4.858	0.660	5.518
H1500P1500	49.837	32.186	47.073	841.480	773.000	68.480	4.707	0.274	4.981
H1800P1800	44.145	-1.786	41.696	754.280	763.630	-9.350	4.170	-0.037	4.132

Table 4 shows that as the huff or puff time is increased up to 900 days, liquid oil recovery is increased, then it is decreased with the huff or puff time. When the huff or puff time is over 900 days, oil recovery decreases. This is because the production rate is high in the beginning of the

puff period and then sharply decreases. Thus, a too-long puff time will result in a lower oil recovery. The trend for gas recovery to change with huff or puff time does not follow that for oil recovery. As the huff or puff time is increased from 100 to 1,500 days, gas recovery decreases then increases. At 1,800 days, the gas recovery factor is even negative. That means more gas is injected than produced. In the table, the gas recovery is calculated by the net gas produced, divided by the original gas in place. The net gas produced is the produced gas minus the injected gas. If the oil and gas prices are assumed to be \$100/STB and \$4/MSCF, respectively, the oil and gas revenues and their total revenue are shown in Table 4. Here, lower oil and gas prices are not used, because shale resources will most likely not be developed if the prices are lower. Table 4 shows that the total revenue increases with the huff or puff time less than 1,200 days. In practice, a shorter huff time is preferable for a quicker return on the investment. Therefore, from a practical point of view, we may choose the huff or puff time of 300 days.

Comparing the huff-n-puff case, H300P300, with the primary case, the total incremental revenue is only 0.497 MM\$. But this is only from a half fracture. For the whole well of 15 fractures (stages), the total incremental revenue is 14.92 MM\$. This shows that the huff-n-puff gas injection could be economical.

Combination of huff-n-puff and pressure depletion

From Table 4, we can see that one third of the total revenue for the primary case is the produced gas revenue, while the gas revenue for the huff-n-puff cases are marginal. This is because produced gas from huff-n-puff cases is re-injected into the reservoir, maintaining a high reservoir pressure. To make a huff-n-puff project more economical, the reservoir may be depleted after some huff-n-puff cycles.

To prove the above hypothesis, half of the huff-n-puff period (after 6,300 days) of H300P300 case is changed to the pressure depletion period during which no gas is injected. The new case is H300P300-half-dp. The results are shown in Table 5. It can be seen that the oil recovery factor becomes lower, but the gas recovery factor is higher. The total revenue from H300P300-half-dp is a little higher than that from H300P300. We further compare the case H600P600 and H600P600-half-dp in which gas injection (huff) is stopped after 7,200 days. The oil recovery from H600P600-half-dp is a little higher, but the gas recovery is higher than that from H600P600. H600P600-dp4800 is a case with a longer period of depletion (gas injection is stopped after 4800 days). Less oil, and thus less total revenue, is generated from this case compared with those in H600P600-half-dp.

Table 5 - Combination of huff-n-puff and pressure depletion									
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF	Oil revenue, MM\$	Gas revenue, MM\$	Total revenue, MM\$

Primary	28.195	66.164	26.630	346.330	0.000	346.330	2.663	1.385	4.048
H300P300	42.130	27.055	39.793	1536.600	1395.000	141.600	3.979	0.566	4.546
H300P300-half-dp	39.842	60.317	37.632	1035.700	820.000	215.700	3.763	0.863	4.626
H600P600	49.106	5.999	46.382	1468.600	1437.200	31.400	4.638	0.126	4.764
H600P600-half-dp	50.491	54.630	47.690	1183.200	897.220	285.980	4.769	1.144	5.913
H600P600-dp4800	45.721	60.777	43.184	855.350	537.220	318.130	4.318	1.273	5.591

Effect of different huff and puff times

The huff and puff times in the proceeding cases are the same. To optimize a production scheme, one may want to see whether different huff and puff times could improve the performance. Taking H300P300 as a base case, the puff time is changed to 600 days and 150 days in H300P600 and H300P150, respectively. Their results are shown in Table 6. It seems that the performance is best if the huff and puff times are the same.

Table 6 - Different huff and puff times									
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF	Oil revenue, MM\$	Gas revenue, MM\$	Total revenue, MM\$
H300P300	42.130	27.055	39.793	1536.600	1395.000	141.600	3.979	0.566	4.546
H300P600	37.300	47.589	35.230	1149.100	900.000	249.100	3.523	0.996	4.519
H300P150	37.210	-5.701	35.146	1105.300	1135.100	-29.800	3.515	-0.119	3.395

Effect of maximum injection pressure

Here, we take the case of huff-n-puff time of 300 days as an example to investigate the effect of injection pressure and rate. For the Primary case and the H300P300-9985psi case, which is the same case as H300P300 listed earlier, the maximum injection pressure is 9,985 psi, and the maximum injection and production gas rate is 300 MSCF/d for the half-fracture model. In the case of H300P300-7,000 psi, the maximum injection pressure is 7,000 psi and the maximum rate is 200 MSCF/d (correspondingly reduced as well). Table 7 shows that the oil recovery and the total revenue are reduced. The total revenue is close to that in the Primary case. When the injection pressure is reduced to 3,500 psi (with maximum rate being 100 MSCF/d), the oil recovery factor and the total revenue are further reduced, being even lower than those from the Primary case. The results here suggest that the injection pressure should be higher to benefit huff-n-puff gas injection.

Table 7 - Effect of maximum injection pressure and rate									
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF	Oil revenue, MM\$	Gas revenue, MM\$	Total revenue, MM\$
Primary	28.195	66.164	26.630	346.330	0.000	346.330	2.663	1.385	4.048
H300P300-9985psi	42.130	27.055	39.793	1536.600	1395.000	141.600	3.979	0.566	4.546
H300P300-7000psi	36.251	31.352	34.240	1094.100	930.000	164.100	3.424	0.656	4.080
H300P300-3500psi	27.956	38.149	26.405	627.310	427.620	199.690	2.641	0.799	3.439

Effect of initial water saturation

In Table 4, the initial water saturation, which is the connate water saturation, is 0.2. Those cases are repeated with the initial water saturation being 0.4, and their results are shown in Table 8. Comparing the results in Table 8 with those in Table 4, we can see that the total revenues are reduced, case-by-case, although the oil recovery factors are higher when the initial water saturation is increased to 0.4. The higher oil recovery factors are due to the lower initial oil in place. The results from Tables 4 and 8 show that the gas injected case-by-case is similar.

Table 8 – Effect of huff or puff time ($S_{wi} = 0.4$)									
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF	Oil revenue, MM\$	Gas revenue, MM\$	Total revenue, MM\$
Primary	31.927	67.944	22.617	266.617	0.000	266.617	2.262	1.066	3.328
H100P100	38.617	32.625	27.356	1508.100	1380.000	128.100	2.736	0.512	3.248
H300P300	44.788	23.492	31.728	1487.200	1395.000	92.200	3.173	0.369	3.542
H600P600	49.075	-2.599	46.353	1423.600	1437.200	-13.600	4.635	-0.054	4.581
H900P900	54.479	25.003	38.593	1078.200	980.060	98.140	3.859	0.393	4.252
H1200P1200	53.629	31.983	37.991	925.910	800.350	125.560	3.799	0.502	4.301

Effect of injected gases

Table 9 presents the performance when methane, CO₂, and nitrogen are separately injected. The gases produced from different cases are close to each other. The oil recovery from CO₂ injection is little higher than that from the methane injection, but is much higher than that from nitrogen injection. The lower oil recovery in the nitrogen injection case is that it is much more difficult for nitrogen to be miscible with liquid oil (high minimum miscible pressure). However, in comparing the liquid oil recovery by CO₂ injection with that by methane injection in a gas condensate reservoir, Sheng's (2015) simulation results show that the former is lower. Further

investigation of the simulation data reveals that the total volume of injected CO₂ from the former case is 15% lower than that from the latter case, because the CO₂ injectivity is lower than methane's. In other words, liquid oil recovery will be lower with less gas injected. For shale oil reservoirs, the oil recovery by CO₂ injection is observed to be higher than that by methane injection from several of our simulation studies (e.g., Wan et al., 2014). From these data, we can see that the effect of gas composition in gas condensate reservoirs is more complex than that in shale oil reservoirs, which depends on gas injectivity and gas miscibility with liquid drop out.

Table 9 - Effect of injected gases						
Case	Oil RF, %	Gas RF, %	Oil produced, MSTB	Gas Produced, MMSCF	Gas injected, MMSCF	Net Gas produced, MMSCF
H300P300-C1	42.130	27.055	39.793	1536.600	1395.000	141.600
H300P300-CO2	42.263	24.720	39.918	1524.400	1395.000	129.400
H300P300-N2	29.007	26.183	27.398	1532.100	1395.000	137.100

Conclusions

Based on this simulation study, the huff time and puff time should be the same for a gas condensate reservoir. For the studied gas condensate reservoir, although a better huff or puff time should be about 900 days, from a practical operation point of view, a shorter time is preferred. Therefore, it is suggested that a huff or puff time of 300 days be used in the studied reservoir. To improve the performance, during the last half of development period, the huff-n-puff may be changed to pressure depletion so that the energy injected during the proceeding gas injection can be fully utilized. Because of higher compressibility of a gas condensate fluid, either huff or puff time is longer than that for a shale oil reservoir.

The maximum injection pressure must be higher than the upper dew point pressure so that the liquid dropout can be re-vaporized.

When the initial water saturation is higher, the revenue generated from huff-n-puff gas injection will be lower, even though the gas injected is similar.

The effect of gas composition in gas condensate reservoirs is more complex than that in shale oil reservoirs, which depends on gas injectivity and gas miscibility with liquid drop out.

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