Optimization of Huff-n-Puff Gas Injection in a Shale Gas Condensate Reservoir

Xingbang Meng, James J. Sheng^{*}, Texas Tech University

^{*}Corresponding author, james.sheng@ttu.edu, phone: 806 834 8477

Abstract

Condensate blockage is a serious problem in shale gas condensate reservoirs. As the pressure decreases lower than dew point pressure, condensate forms. This condensate reduces the relative permeability of gas and the productivity of shale gas condensate reservoirs.

Huff-n-puff gas injection is an EOR method in which a well alternates between injection, soaking, and production. Based on the laboratory study conducted by Meng et al. (2015), huff-n-puff gas injection was proven as an effective method to enhance condensate recovery for Eagle Ford shale cores. In this paper, a numerical reservoir simulation study is conducted to optimize the application of huff-n-puff gas injection in an Eagle Ford shale gas condensate reservoir. During the injection and soaking process, the pressure of the reservoir is built up, the condensate was revaporized to gas, and then was produced during the production process. Different parameters were investigated including injection time, soaking time, production time, and cycle numbers.

The results show that huff-n-puff gas injection is an effective method to enhance condensate recovery in the Eagle Ford shale gas condensate reservoir. It was found that the optimum injection time is the time during which the pressure of the main condensate region can be increased higher than dew point pressure. Also, shorter or even no soaking is more effective. The production time depends on the production decline rate. It is more profitable to start another cycle of huff-n-puff gas injection when the production rate is decreased to a low value.

1. Introduction

Kuenen (1892) used the term “retrograde condensation” to describe the anomalous behavior of a mixture that forms a liquid by an isothermal decrease in pressure, or by an isobaric increase in temperature. Kurata and Katz (1942) gave the most concise and relevant discussion of retrograde phenomena related to petroleum engineering. Retrograde vaporization can be used to describe the formation of vapor by an isothermal increase in pressure or by an isobaric decrease in temperature. Neither form of retrograde behavior occurs in single component systems. Gas condensate reservoirs typically exhibit GOR's between 3000 and 150000 scf/STB and liquid gravities between 40 and 60° API (Standing, 1977; Moses, 1986).

For a gas condensate reservoir only gas normally exists in the reservoir, as the pressure is higher than the dew point pressure. When the pressure is decreased lower than the dew point pressure, the heavy components of reservoir fluids could be condensed, and a liquid phase could be formed in the reservoir. This formed liquid is named condensate. Liquid dropout will continue to increase until the pressure reaches a specific value. At this pressure, the maximum liquid dropout has accumulated in the reservoir. After this occurs, further pressure reduction will revaporize most of the condensed liquid-condensate.

These conclusions assume that the overall composition of the reservoir mixture remains constant during depletion. In reality, the behavior of liquid dropout differs from that suggested by constant composition analysis. The condensate saturation is usually less than the saturation needed to mobilize the liquid phase. This is because the heavier components in the original mixture constitute most of the immobile condensate saturation and the overall molecular weight of the remaining reservoir fluid increases during depletion. This also makes the condensate accumulate in the formation, and reduces the relative permeability of gas. The productivities of gas and liquid in gas condensate reservoirs are reduced due to this condensate accumulation-condensate blockage.

Generally, gas injection is applied to improve condensate recovery in gas condensate reservoirs by increasing or maintaining the pressure above dew point pressure. In different gas injection methods such as gas cycling, CO₂ injection, and N₂ injection, the aim is to keep the pressure in the reservoir higher than the dew point to prevent condensate formation. Gas injection also helps to revaporize the liquid condensate to the gas phase again and let the condensate be recovered.

Abel et al. (1970) described two schemes of gas cycling: full pressure maintenance and partial pressure maintenance. In full pressure maintenance, gas is continuously injected into the reservoir while at the same time condensate is produced from the reservoir. In partial pressure maintenance, gas is injected into the reservoir after primary depletion below the dew point in an attempt to slow further pressure decline and re-vaporize the condensate. Luo et al. (2002) conducted experiments on a real rich gas condensate fluid to investigate condensate recovery based on the two schemes mentioned above. Their results showed that the condensate recovery is higher when injection is done above the saturation pressure. Al-Wadhahi et al. (2006) did simulation work to examine the cyclic gas injection to revaporize liquid dropout in an Omani gas field. In this study, a compositional simulation model was used to confirm the theory of condensate revaporization. The results indicated that cyclic gas injection is a viable production method. This method could improve gas deliverability and enhanced condensate recovery.

Huff-n-puff gas injection is an EOR method normally used in the steam injection in conventional reservoirs. The well is used as both injection well and production well. Meng et al. (2015) conducted experiments on shale cores. Their experiment results show good EOR potential for huff-n-puff gas injection, but field scale study is necessary. In this study, the application and operation of huff-n-puff in the Eagle Ford shale gas condensate reservoir was simulated.

2. Reservoir Model Description

Ultra-low permeability shale reservoirs require a large fracture network to maximize well performance. Actually, for shale reservoirs, the large scale fracture network formed by hydraulic fracturing-stimulated reservoir volume (SRV) is required to achieve profitability (Cipolla et al. 2008; Mayerhofer et al. 2008). Those authors discussed about using numerical simulations of explicit fracture networks created in a stimulated reservoir volume to model the physics of flow within a fractured shale reservoir. They added the SRV to obtain reasonable results. In actuality, the mechanism of SRV is not well known. In our simulation model, SRV is also added. Thus, the simulation model includes two regions: the stimulated reservoir region and the un-stimulated reservoir volume.

The whole shale reservoir is stimulated with 9 transverse fractures. In this simulation work, only one hydraulic fractured reservoir region was simulated on the basis of flow symmetry. Thus, the cumulative condensate and gas production could be obtained simply by multiplying by the number of effective fractures. The simulation model is shown in Fig.1.

Fig.1. Schematic of simulation model

The reservoir simulation work for the application of huff-n-puff gas injection was performed by using the compositional simulator, GEM in Computer Modeling Group. The dimensions of the shale gas condensate reservoir were 592 ft wide in the I direction, 2724 ft in the J direction with 724 ft in the SRV area as shown in Fig. 1, and 50 ft in the K direction. In this reservoir model, the half fracture spacing was 296.25 ft in the I direction, the fracture length was 724 ft in the J direction, and the fracture height was 50 ft in the K direction. The half-hydraulic fracture width was 0.5 ft. Symmetric flow geometry allows the results to be extrapolated to a larger scale. The reservoir was also modeled as a $21 \times 31 \times 1$ Cartesian grid. For this model, increasing the number of grid blocks has no effect on the simulation results, but the more grid blocks required, the longer the computation times. Thus, these grid blocks were selected to simulate the huff-n-puff gas injection project.

Also, the reservoir rock properties used in this model were based on the published data in Eagle Ford shale (Wan et al, 2013). The properties of the reservoir are shown in Table 1.

Table 1: Reservoir properties

Parameters	value	unit
Initial reservoir pressure	5000	psi
Reservoir Temperature	200	°F
Thickness	50	ft
Matrix Permeability	0.0001	mD
Matrix Porosity	0.06	
Rock Compressibility	5.0E-06	
Hydraulic Fracture Permeability	100	mD
Permeability of Matrix	0.0001	mD

PVT and compositional data for an Eagle Ford shale gas condensate reservoir fluid sample was obtained from published data (Seo and Anderson, 2012; Li et al. 2015). The fluid model was generated using CMG WinProp. The sample was taken at a depth of 9800 ft, the initial pressure was 5000 psi, and the temperature was 200 °F. The components of the reservoir fluid were lumped into 14 pseudo-components. Table 2 lists the pseudo-components descriptions used in this model, and the input for the Peng-Robinson equation of state calculations.

As it can be seen from Fig. 2, condensate starts to form when the pressure is lower than the dew point pressure 2750 psi. Then, the condensate volume continues to increase until the pressure reduces to 2500 psi when the maximum amount of condensate liquid is reached. After that, as the pressure continues to decrease, the liquid is revaporized and the condensate volume is reduced.

The simulation work was used to determine the application of huff-n-puff gas injection in the field, thus, there was only one well in this model and this well was used as both an injection well and a production well. The producer was subjected to the minimum bottom-hole pressure constraint of 1500 psi, and the injection well was subjected to the maximum injection pressure constraint of 4000 psi. The injection and production times are discussed in a later section.

Table 2: Peng-Robinson EOS Fluid Description of Eagle Ford Condensate Lumping

	Fraction	Pc(atm)	Tc(K)	Acentric Factor	MW
CO2	0.18	72.8	304.2	0.225	44.01
N2	0.13	33.5	126.2	0.04	28.013
CH4	61.92	45.4	190.6	0.008	16.043
C2H6	14.08	48.2	305.4	0.098	30.07
C3H8	8.35	41.9	369.8	0.152	44.097
IC4	0.97	36	408.1	0.176	58.124

NC4	3.41	37.5	425.2	0.193	58.124
IC5	0.84	33.4	460.4	0.227	72.151
NC5	1.48	33.3	469.6	0.251	72.151
NC6	1.79	29.3	507.4	0.296	86.178
NC7	1.58	27	540.2	0.351	100.205
NC8	1.22	24.5	568.8	0.394	114.232
NC9	0.94	22.8	594.6	0.444	128.259
C10+	3.11	20.686	617.7	0.4902	142.3

Fig. 2. The liquid dropout curve for CCE experiment at 200 °F on the gas condensate mixture

The hydraulic fracture was modeled as a 2-ft wide pseudo fracture in order to increase numerical stability (Sanchez-Rivera et al. 2015). The effective fracture grid block permeability was calculated from Equation 1:

$$K_{eff} = \frac{K_f W_f}{W_{eff}} \quad (1)$$

K_f is the actual fracture permeability, W_f is the actual fracture width, and W_{eff} is the width of the grid blocks representing the fracture.

In this simulation, a fracture with a permeability of 100 mD and a width of 0.5 ft was modeled as a 2 ft wide fracture with a permeability of 25 mD. This was done to improve the stability of the model.

3. Results

3.1 Start of huff-n-puff

The life expectancy of an Eagle Ford shale well could be as long as thirty years, production of 40% of an Eagle Ford shale well can come in the first five years, then followed by a long decline curve as long as thirty years. This means in later years, the wells produce oil and gas at very low volume. Thus, the beginning of huff-n-puff gas injection is an important time for the exploration of the shale gas condensate reservoir.

One cycle of huff-n-puff gas injection was applied in the simulation model at different start times: 5 years, 10 years, and 15 years. The total production time in this work was 25 years. The results of different cases were compared with 25 years of primary depletion. For this single cycle the injection time was 200 days, and the rest time in 25 years was the production period. The results are shown in Fig. 3.

Fig. 3. Condensate recovery for different cases

Compared with the 25 year primary depletion case, the application of huff-n-puff gas injection could increase the condensate recovery. Starting the single cycle of huff-n-puff gas injection after 15 years had an incremental recovery of 1.9% compared with case without huff-n-puff gas injection. Meanwhile, starting huff-n-puff after 5 years had an incremental recovery factor of 1.5.

Fig. 4 shows the gas production rate from the primary depletion period. As Fig. 4 indicates, the production decreased very fast in the first 5 years and in the following 20 years the production rate was very slow. In the first year, the gas production rate was 158950 ft³/day and after 15 years the rate decreased to 11767.18 ft³/day. The production rate declined almost 92%, which is a very high value. At 10 years, the rate declined about 85%. The high decline rate is also not only due to the ultra-low permeability, but also due to the accumulation of condensate in the formation. Thus at 15 years both the heavy and light hydrocarbon components were left in the reservoir.

Combined with the gas production decline rate and the effect of the starting time of huff-n-puff, it can be seen that huff-n-puff gas injection is more effective when starting at the later period of primary depletion (when the production rate was decreased around 90% in this case). If the huff-n-puff is applied too early, the primary production rate is not that low and comparing the incremental recovery with the cost of injection process, it is unnecessary. When the huff-n-puff gas injection is applied in the later time, since the production rate is so low, the application of huff-n-puff gas injection can effectively enhance the recovery and increase profits.

Fig. 4. Gas production rate for 25 years primary depletion

3.2 Injection Period

Based on the investigation of huff-n-puff application on other kinds of reservoirs (Sheng, 2015; Yu et al. 2014), injection time has a very large impact on incremental recovery. The longer injection time means a longer time for pressure to build up in the reservoir. For shale gas condensate reservoirs, the longer pressure build time means more condensate can be revaporized to gas phase, and then more condensate can be recovered during the production period. Though a

longer injection has greater recovery, the longer injection time also indicates more is gas needed to be injected into the reservoir. This means there can be more costs during the injection. If the costs of injection cannot achieve more profits, the application of huff-n-puff gas injection would fail.

In this section, a series of cases were conducted simulating three cycles of huff-n-puff gas injection after primary depletion. The injection time was varied from case to case while the production time remained same: 200 days. Based on the study of previous section, soaking time was not applied. The three injection times were: 10 days, 50 days, and 100 days. Fig. 5 shows the condensate recovery for the different cases. The condensate recovery increased. It is obvious that when the injection time was increased, the increment of pressure in the reservoir increased. Thus, more condensate was recovered. Fig. 6 shows the condensate saturation after three cycles of huff-n-puff, and it can be seen that the condensate which remained in the reservoir or remained near the fracture in the 100 day injection time case was less than the 10 day injection time case and the 50 day injection time case.

More condensate was recovered from the reservoir when the injection time was longer. However, as mentioned before, longer injection time means higher costs. Thus, the profits of every case were investigated, excluding Taxes and OPEX. In this investigation of profits, we used a low oil price of 40 USD/bbl, and a gas price of 2 USD/Mscf. The purpose of profit analysis in this study is to compare the efficiency of different cases, so an optimized parameter such as injection time can be determined.

Fig. 5. Condensate recovery for different injection time cases

Fig. 6. Condensate saturation distribution for different injection time cases

Table 3: Profits for different injection time cases

Injection time, days	Condensate RF, %	Produced oil, bbl	Injected gas, ft ³	Produced gas, ft ³	Profit, \$USD
10	13.3	12933.2	30000000	315000000	1087328
50	14.5	14113.4	117000000	381000000	1092536
100	15.1	14678.5	164000000	407000000	1073140

As it can be seen from Table 3, the 100 day injection time case had the highest condensate recovery of 15.1%. However, the profits of 100 days injection time case were the lowest. Compared with the 10 day injection time case and the 50 day injection time case, the 100 day injection time case had a much larger volume of injected gas, and the cost of the injection period was much higher. Compared with the 10 day injection time case, the 50 day injection time case had a higher condensate recovery and the profit was also higher.

It can be concluded that longer injection time does not mean higher profits. Though longer injection time can increase condensate recovery, the costs are much higher and the profits are lower. During the design of the injection period of huff-n-puff gas injection, it is very important to choose the best injection time. As it mentioned before, the condensate saturation is mainly in the near fracture region, as shown in Fig.7. From Fig. 8, it can be seen for the 50 day injection time case, the condensate saturation near the fracture region was lower. This means that during the 50 day injection, the pressure of this near fracture region increased, and the condensate was revaporized.

Fig. 7. Condensate saturation after 15 years primary depletion

Fig. 8. Pressure distribution after 1st cycle of injection for different injection time cases

Thus, the optimized injection time is that during the injection time, the pressure of the main condensate region in the reservoir can be increased higher than dew point pressure. The condensate can be revaporized to gas phase, and both condensate production and gas production can be increased.

3.3 Soaking time

The effect of soaking period on condensate recovery is investigated in this section for the application of huff-n-puff in a shale oil reservoir. A series of simulations was conducted using different soaking periods: 0, 50 days, and 100 days. In these three cases, two cycles were simulated: 100 days of injection and 200 days of production. It can be seen from Fig. 9 that all three cases had the similar condensate recovery, but the simulation without a soaking period had the largest condensate recovery (14.5%). The simulation with the longest soaking time (100 days) had the smallest recovery (14.23%).

The results from the three simulations indicate that there are no benefits to applying a longer soaking time. Longer soaking time means the longer waiting time, and this reduces the production period. Also, longer soaking time had the smallest recovery in these three simulation cases. This means that for the application of huff-n-puff gas injection in shale gas condensate reservoir, short soaking time or even no soaking time would be better.

The reason why soaking time has a negative effect in this case is related to the gas condensate fluid property. In these three simulation cases, the injection pressure was already set to a high value: 4000 psi. When the gas was injected into the formation, the pressure of the region near the fracture increased rapidly. The pressure increased to higher than dew point pressure, the condensate was revaporized to gas phase, and the oil (condensate) saturation decreased.

Though the injected gas could flow further into the reservoir and increase the further region pressure when the well was shut in and the soaking period was applied, the pressure of the region near the fracture decreased compared to the value when the well was just shut in. This is because the pressure in this near fracture region transferred to the further region in the reservoir. When the pressure decreased, the revaporized condensate could be formed into liquid again. The condensate saturation also increased again in the near fracture region, as shown in Fig. 10.

With this in mind, it is clear that for the application of huff-n-puff in shale gas condensate reservoirs, shorter injection or even no soaking time is preferred. If injection pressure is much higher than dew point pressure, then adding a short soaking time will be better because even if the near fracture region pressure transfers to the further region, the pressure will still be higher than dew point pressure, and the condensate will be revaporized to gas phase. However if the injection pressure is not that much higher than dew point pressure, the soaking time could have a negative effect.

Also, in a large scale shale gas condensate reservoir, the condensate is mainly accumulated near the fracture region, thus, for the purpose of increasing condensate recovery, increase of this region's pressure is the main objective.

The study in this section indicates that shorter or no soaking time is needed during a huff-n-puff operation in shale gas condensate reservoirs.

Fig. 9. Soaking time effect on condensate recovery

Fig. 10. Pressure and condensate saturation comparison between no soaking case and 100 days soaking time case

3.4 Number of huff-n-puff cycles and production period

The huff-n-puff cycle number is also a very important parameter that needs to be seriously taken into account during the application of the huff-n-puff gas injection method in shale gas condensate reservoirs. 11 cycles of huff-n-puff were simulated to investigate the efficiency of huff-n-puff over multiple cycles. Every cycle consisted of 50 days of injection and 200 days of production. Based on the previous study, soaking time was not used in this model. Fig. 11 shows the condensate recovery and the pressure.

Fig. 11. Condensate recovery and average pressure for 11-cycles huff-n-puff gas injection

It can be seen in Fig. 11 that the condensate recovery increased to 16.12% after 11-cycles of huff-n-puff gas injection. The total production time, including primary depletion time and huff-n-puff gas injection time, was 8225 days. The comparison of this 11-cycle gas injection after 15 years of primary depletion and 8225 days of primary depletion is shown in Fig. 12. The incremental condensate recovery by the application of huff-n-puff gas injection was 3%.

Fig. 12. Condensate recovery comparison between huff-n-puff gas injection and primary depletion

Fig. 13 shows the gas production rate, and it can be seen that during the production period of every cycle, the production rate was actually high at the end of the production period. According to the previous study, it is better to start huff-n-puff gas injection when the production rate decreases to a low value. In these 11-cycles of huff-n-puff, the rate decreased about 65% at the end of every production period. Thus, the period of this production should be increased. In a fixed operation time, the increased production time means the fewer cycles of huff-n-puff gas injection, the less cost. According to this production rate, if we want the production rate in the production period to be decreased about 90%, then the production time should be increased to 400 days.

Based on this relationship between decline rate and production time, another huff-n-puff gas injection project was conducted. In this simulation, the injection time was the same as the previous one: 50 days, and based on the previous study, soaking time was also not taken into account. The production time was increased from 200 days to 400 days. The total exploration time of this case was same as the 11-cycles of huff-n-puff gas injection: 8825 days. Based on this different time, only 6 cycles were run in this new huff-n-puff gas injection project. Fig. 14 shows the condensate recovery comparison between 11-cycles of huff-n-puff and 6-cycles of huff-n-puff.

Fig. 13. Production rate in 11-cycles huff-n-puff simulation work

Fig. 14. Condensate recovery comparison between 11-cycles huff-n-puff and 6-cycles huff-n-puff

The condensate recovery was 16% in 6-cycles of huff-n-puff gas injection, and for 11-cycles of huff-n-puff gas injection, the condensate recovery was only 0.12% higher than that in 6-cycles of huff-n-puff. This indicates that the start of production time in huff-n-puff gas injection should follow the same optimization principle for the end time of primary depletion. By following this principle, fewer huff-n-puff cycles are needed to increase the condensate recovery. Also, fewer cycle numbers means less gas is needed to be injected into reservoir. This means lower costs for huff-n-puff gas injection projects. Table 4 shows the profits analysis for different cycle numbers of huff-n-puff gas injection and primary depletion. 6 cycles of huff-n-puff with 400 days production time had higher profits.

Table 4: Profits analysis for different cycle numbers of huff-n-puff gas injection and primary depletion.

	Condensate RF, %	Produced oil, bbl	Produced gas, ft ³	Injected gas, ft ³	Cumulative Profits, \$USD	Profits incremental, \$USD
Primary	13.5	13136.2	300000000.0	N/A	1125448.0	N/A
11 cycles, 200 days production	16.1	15675.5	678226112.0	412651936.0	1158168.8	32720.8
6 cycles, 400 days production	16.0	15453.5	234300000.0	526000000.0	1201540.0	76092.0

7. Conclusions

- Huff-n-puff is an effective method to enhance condensate recovery in shale gas condensate reservoir.
- Huff-n-puff gas injection is more effective when started at the later time. If huff-n-puff is applied too early, the production rate is not too low, and by comparing the profits of incremental recovery with the cost of injection process, it is not practical.
- An optimized injection time should be selected so that during this injection time, the pressure of the main condensate region in the reservoir can be increased higher than dew point pressure.
- There is no benefit to applying a long soaking time. For the application of huff-n-puff gas injection in the shale gas condensate reservoir, a short soaking time or even no soaking time would be better.
- The cycle number of huff-n-puff is combined with the injection time, soaking time, and production time. For a fixed time of exploitation, more cycles of huff-n-puff gas injection do not mean higher profits. The cycle number should depend on the optimized injection time and optimized production time.

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