Increase liquid oil production by huff-n-puff of produced gas in shale gas condensate reservoirs

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Abstract

Hugh shale resources available and low gas price turn the oil operators' activities to producing more liquid oil. The earlier studies from our research group and others show that huff-n-puff has the highest potential to improve oil recovery (IOR) in shale oil reservoirs, compared with common IOR methods of gas flooding and waterflooding. This paper is to extend the research to shale gas condensate reservoirs to evaluate the IOR potential. The simulation analysis approach is used.

The simulation results and discussions in this paper show that huff-n-puff injection of produced gases can produce more liquid oil in gas condensate reservoirs than gas flooding or primary depletion. This result is verified by all the simulated cases with different reservoir and fluid properties and operation conditions. The advantages of huff-n-puff over gas flooding are the early response to gas injection, high drawdown pressure, oil saturation decrease near the wellbore by evaporation, and overcoming the pressure transport problem owing to ultra-low permeability. The advantages become more important when the initial reservoir pressure is close to the dew point pressure, or the bottom-hole flowing pressure is low. The effects of injected gas composition, cycle time and soak time during the huff-n-puff process are investigated. A simple economic analysis is also conducted.

[1]Introduction

Generally, when the pressure is reduced, a liquid will vaporize to become a gas. However, in some special situation, when the pressure is reduced below a dew point pressure, a liquid forms from an initial gas phase, as shown in Fig. 1 from Point A to Point B. This phenomenon is called retrograde condensate. Such reservoir is called gas condensate reservoir where initially the fluid is in gas state in reservoir. To produce the gas condensate, the conventional practice 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). The reason is that, if the reservoir pressure is allowed to decline below the dew point, a considerable volume of valuable condensate may be lost in the reservoir because oil saturation is formed and it is more difficult for the liquid to flow to the surface compared with gas. When oil saturation is below a residual oil saturation, oil cannot be produced using a conventional producing method. In addition, gas productivity declines rapidly once the liquid is formed near the wellbore, because the liquid will block gas flow (Thomas et al., 1995).

Fig. 1 – An example of p-T diagram of a retrograde condensate

In a shale or tight gas condensate reservoir where the formation permeability is very low (nano-Darcy or micro-Darcy), if the well flowing pressure and/or the reservoir pressure is above the dew point pressure, the pressure difference between the reservoir pressure and well flowing pressure which is the drive force to produce gas condensate will be small, especially when the initial reservoir pressure is near the dew point pressure. Then the production rate will be low and the resulting total hydrocarbon recovery will be low as well.

To increase reservoir pressure, there are two methods: gas flooding and huff-n-puff. In the gas flooding, gas is injected through an injector, and fluids are produced from another producer. In the huff and puff gas injection, gas is injected to the reservoir through a well during the huff period, and fluids are produced from the same well during the puff period.

In our earlier work of huff-n-puff gas injection in shale oil reservoirs, we studied the pressure effect on oil recovery (Wan et al., 2013a, 2013b; Gamadi et al., 2013; Wan et al., 2014; Gamadi et al., 2014). By intuition, if the flowing pressure is above the minimum miscibility pressure (MMP), the injected gas will be fully miscible with the in-situ oil, then the oil viscosity will be

decreased to the minimum and the oil will swell to the maximum. The oil recovery will be high. However, the simulation results in Fig. 2 show that higher oil recovery is obtained if a lower bottom-hole flowing pressure (BHFP) is used, even though the flowing pressure is lower than the MMP. The main reason is that as the flowing pressure is lower, the pressure difference between the reservoir and this flowing pressure (drive force) will be higher, so that flow rate will be higher according to Darcy's law. Apparently, one of the dominant mechanisms is pressure maintenance. According to the discussions and definitions in Sheng (2011), if the dominant mechanism is pressure maintenance, the gas injection process belongs to improved oil recovery (IOR). If the dominant mechanism is related to miscible flooding, the gas injection process belongs to enhanced oil recovery.

Similarly, in gas condensate reservoirs, to increase gas and oil production, the pressure drop should be high. The wellbore flowing pressure will be lower than the dew point pressure. When that occurs, the liquid oil will be accumulated at the wellbore, and the resulting gas saturation will be low. Then gas condensate rate will be lower, the corresponding liquid oil rate will be low as well.

Fig. 2 – Oil rate and recovery at different bottom-hole flowing pressures (marked in the figure) (Sheng and Chen, 2014)

The current available technique to produce gas condensate shale reservoirs is through primary depletion using horizontal wells with multiple transverse fractures. No IOR or EOR methods have been implemented in shale reservoirs. Juell and Whitson (2013) did simulation work to find optimal operation conditions for gas condensate shale reservoirs is in the depletion mode. They found that the optimal production strategy for wells producing from highly undersaturated gas condensate reservoirs is likely to have an initial period where the flowing pressure equals the

saturation pressure, followed by a gradual increase in drawdown, towards the minimum bottom-hole pressure that is operationally possible. When that occurs, the liquid oil will be accumulated at the wellbore, and the resulting gas saturation will be low. Then gas condensate rate will be lower, and the corresponding liquid oil rate will be low as well. To solve this problem, the condensate in conventional condensate reservoirs is re-vaporized by lean *gas flooding* (Standing et al., 1948; Weinaug and Cordell, 1949; Smith and Yarborough, 1968), nitrogen (Aziz, 1982) or CO₂ (Chaback and Williams, 1994; Goricnik et al., 1995).

However, in shale and tight reservoirs, formation permeability is so low that any flooding (gas flooding and waterflooding) may not be feasible because the pressure drop from an injector to a producer is large and thus it is very difficult for the pressure to transport from the injector to the producer. For the huff-n-puff, a quick response from gas injection is expected. The injected gas will increase the pressure near the producer thus the drive energy is boosted. The increased pressure may vaporize the liquid dropout near the producer. However, there was a concern that the injected gas during the huff period will be re-produced during the puff period. This is a hypothesis.

To solve the low-permeability problem, to increase the production drawdown (production rate), and to increase liquid oil offtake, the following preferred scheme to produce gas condensate reservoirs is proposed:

- Huff-n-puff gas injection mode,
- Flowing bottom-hole pressure lower than the dew point pressure.

In this paper, simulation approach is used to test the hypothesis first. Then detailed simulation results and analysis are presented to support the above new idea.

[2]Set up of simulation model

Sheng and Chen (2014) compared the potentials of gas flooding and huff-n-puff gas injection to enhance oil recovery in shale oil reservoirs. In this simulation work, the same grid model in the earlier study is used, except that gas condensate compositions are used to replace the black oil model. The compositional simulator, GEM, developed by CMG is used. By doing so, the base model used in this paper is justified. The gas condensate composition is from Orangi et al. (2011) as re-presented in Table 1, and the simulated related reservoir and fluid parameters are presented in Table 2. The model grid set up is shown in Fig. 3. In Table 1, P_c , T_c and V_c are critical pressure, critical temperature and critical volume, respectively, and MW is molecular weight. Because of flow symmetry, two half-fractures along the left and right boundaries are simulated. These two half-fractures are equivalent one fracture. One half-fracture is connected to the injector, while the other is connected to the producer. A fracture of 2-ft width is used to represent the real fracture of 0.001 ft but the fracture permeability is reduced from 83,000 mD to 46.5 mD based on the concept of equivalent fracture conductivity ($k_f w_f$) (Rubin 2010). The concept of equivalent fracture conductivity is that the fracture conductivity ($k_f w_f$) in the model of $46.5 \times 2 = 83 \text{ mD}\cdot\text{ft}$ is equal to the conductivity of real fracture which is $83000 \times 0.001 = 83 \text{ mD}\cdot\text{ft}$. The fracture length is 1000 ft. represented by 55 blocks in the J direction of the simulation grid. The formation height and the fracture height are the same, 200 ft., represented by 7 blocks in the K direction. The fracture spacing is 200 ft. The locations of two half-fractures in the gas flooding

mode are in the most-left and most-right blocks in the I direction as shown in Fig. 1 and Fig. 9. The location of a single fracture in the huff-n-puff mode is in the middle of the model, as schematically shown in Fig. 9. Total 22 blocks are used in the I direction in the gas flooding mode and 21 blocks in the I direction for the huff-n-puff mode. For the gas flooding, the injector is located at $I = 1$ and the producer at $I = 22$. For the huff-n-puff, the injector and producer (same well) is located at $I = 11$. The well locations in the XY plan are schematically shown in Fig. 9. All the wells are perforated at the bottom layer ($K = 7$) and in the middle in the J direction ($J = 28$). The detailed block sizes are as follows.

The block sizes in feet in the I direction from $I = 1$ to $I = 22$ in the order (gas flooding mode) are:

1, 4, 6, 8, 8, 9, 10, 12, 12, 14, 16,
16, 14, 12, 12, 10, 9, 8, 8, 6, 4, **1**

The block sizes in feet in the I direction from $I = 1$ to $I = 21$ in the order (primary and huff-n-puff modes) are:

16, 14, 12, 12, 10, 9, 8, 8, 6, 4, **2,**
4, 6, 8, 8, 9, 10, 12, 12, 14, 16

The block sizes in feet in the J direction with total 55 blocks (all modes) are:

35, 21 blocks at 20 ft each, 16, 10, 8, 6, 4, 2, 4, 6, 8, 10, 16, 21 blocks at 20 ft each, 35

The block sizes in feet in the K direction from $K = 1$ to $K = 7$ in the order (all modes) are:

52.8, 26.4, 14.2, 13.2, 14.2, 26.4, 52.8

In this study, a single well and a single fracture are built in the model for the huff-n-puff and primary modes. In principle, their block sizes in the I direction could be the same as those in the gas flooding mode, if two half-wells and two half-fractures are used. The results are unchanged because of the flow symmetry (Chen, 2013).

Table 1 – Peng-Robinson EOS Fluid Description of Eagle Ford Condensate (Orangi et al., 2011)

Components	Initial Composition, mole fraction	Pc (atm.)	Tc (deg. K)	Acentric Factor, dimensionless	MW g/mole	Vc (l/mol)
C1	0.65882	45.4	190.6	0.013	16.04	0.099
N2	0.00154	33.5	126.0	0.04	28.01	0.089
C2	0.08337	48.2	305.4	0.0986	30.07	0.148
C3	0.0467	41.9	369.8	0.1524	44.09	0.203
CO2	0.02686	72.8	304.2	0.225	44.01	0.094
IC4	0.01045	36.0	408.1	0.1848	58.12	0.263
NC4	0.01825	37.5	425.2	0.201	58.12	0.255
IC5	0.00825	33.4	460.4	0.2223	72.15	0.306
NC5	0.00791	33.3	469.6	0.2539	72.15	0.304
NC6	0.01194	32.46	507.5	0.3007	86.18	0.344
C7+	0.07627	27.8	584.1	0.3673	112	0.446

C11+	0.04551	20.2	692.1	0.5491	175	0.685
C15+	0.00278	17.62	737.5	0.6435	210	0.809
C20+	0.00135	15.39	781.0	0.7527	250	0.942

Fig. 3 – Model grid set up

Table 2 – Reservoir and fluid properties used in the model

Initial Reservoir Pressure	9088 psi
Porosity of Shale Matrix	0.06
Initial Water Saturation	0.2
Compressibility of Shale	$5 \times 10^{-6} \text{ psi}^{-1}$
Shale Matrix Permeability	0.0001 md
Reservoir Temperature	310 °F
Reservoir Thickness	200 ft.
Dew Point pressure	3988 psi

[3]Simulation results and discussion

Basically, three scenarios are compared: primary production, gas flooding and huff-n-puff gas injection. In each scenario, primary production is implemented in the first 5 years, followed by 25 years of continued production. In the gas injection and gas huff-n-puff scenarios, the injected gas or recycled gas is methane C_1 . The minimum bottom hole flowing pressure for the producer is 500 psi, and the maximum bottom hole injection pressure for the injector is 9500 psi. This injection pressure is a conveniently chosen value and close to the initial reservoir pressure 9088 psi. It is assumed to be below the fracture pressure. For the huff-n-puff mode, the injection and production cycle is 100 days, and there is no soaking time. Table 3 shows the simulation results for these base cases. The ratios of each parameter for the huff-n-puff scenario to that for the gas flooding scenario are also shown in this table.

Table 3 – Performance comparison of different scenarios (100 nD)

	Primary	Gas flooding (A)	Huff-n-puff (B)	Ratio (B/A)
Total gas produced (MMSCF)	357.01	275.43	3133.7	11.38
Gas injected (MMSCF)	0	216.36	3008.3	13.90
Net gas produced (MMSCF)	357.01	59.07	125.4	2.12
Oil produced (MSTB)	30.385	36.5	46.666	1.28
Oil recovery factor (%)	26	31.23	39.93	1.28
Value of produced oil and gas (MM\$)	4.46654	3.88628	5.1682	1.33

From Table 3, it can be seen that the liquid oil recovery from gas huff-n-puff is 39.93%, almost 14% higher than that from the primary depletion, and about 8% higher than the gas flooding scenario. If the oil price is assumed to \$100/STB, and the gas selling price is \$4/MSCF, the huff-n-puff scenario also shows the highest revenue. Although the primary depletion has a higher revenue than the gas flooding, the liquid oil recovery is lower. In the economic calculation, the difference in capital investment and facility and operation costs are not included. A discount rate is not included either. If a discount rate is considered, the performance of huff-n-puff will look even better than gas flooding because the former responds to gas injection earlier, as Fig. 4 shows that the cumulative oil produced in the huff-n-puff scenario at the earlier days is higher than that in the gas flooding scenario. The simple economic analysis is conducted to compare the liquid oil production potentials between the huff-n-puff mode and gas flooding mode. A detailed economic analysis should be conducted in a real project.

In the current North American market, the gas supply is higher than the demand. Increasing liquid oil production is operators' interest. The results in Table 3 show that huff-n-puff gas injection can meet the operators' goal.

Fig. 4 – Cumulative oil production in the base cases of gas flooding and huff-n-puff

Fig. 5 shows the oil saturations near the producing fractures at Block (21,28,4) for the gas flooding case as marked in Fig. 9, and at Block (10,28,4) in the middle of the model also schematically marked in Fig. 9, but the grids are not correct because the grids in Fig. 9 are for the gas flooding mode not for the huff-n-puff mode. It shows that the oil saturation in the gas huff-n-puff case quickly decreases to very low values. At the end, the oil saturation is almost zero. In the primary and gas flooding cases, the oil saturations remain high. Note the oil saturation in the gas flooding case builds up because the oil bank reaches the producing fracture. In the gas huff-n-puff case, the oil saturation suddenly shoots up because some oil in the producing fracture is displaced to the block near the fracture during the gas injection period, as shown in Fig. 6.

Fig. 7 shows the pressures near the producing fracture. It clearly shows that the pressure in the gas huff-n-puff case fluctuates at high and low values following the huff and puff cycles. The pressures in the primary and gas flooding cases remain low. When the flowing bottom-hole pressure is below the dew point pressure, some liquid will drop out during the puff period. But the liquid will be “picked” up by injected dry gas (less heavy components) or mixed with dry gas during huff period. Fig. 8 shows the pressure and oil saturation near the producing fracture in the case of gas huff-n-puff. It clearly shows that as the pressure declines during the puff period, the oil saturation builds up; as the pressure is increased during the huff period, the oil saturation is decreased.

Fig. 5 – Oil saturations near fractures

Fig. 6 – oil saturation near (I=10) and at the producing fracture (I=11).

Fig. 7 – Pressure near the fractures

Fig. 8 – Pressure and oil saturation near the producing fracture in the gas huff-n-puff case

In the conventional or tight reservoirs, gas flooding is used to maintain high pressure so that liquid oil and gas production can be achieved (Thomas et al., 1995). In these cases of shale gas condensate reservoir (matrix permeability of 100 nD), gas flooding does not result in higher liquid production. This is because the pressure near the injection well is very high, but this pressure cannot propagate to the production end owing to very low permeability. The pressure near the producing fracture (Block (21,28,4) as marked in Fig. 9) in the gas flooding case is very low (about 1000 psi as shown in Fig. 7), but the pressure near the injection fracture (Block (1,28,4) as marked in Fig. 9) is very high (9500 psi). It is clear in the pressure map at the end of 10 years of gas flooding, as shown in the left side in Fig. 9. The pressure at the injection side is at 9500 psi, while the pressure at the production side is 500 psi. And there is a large area in between where the pressure is 4000–6000 psi. To further validate this point, the gas flooding case is re-simulated by simply increasing the matrix permeability by 1000 times from 100 nD to 0.1 mD. The pressure map at the end of 10 years of gas flooding is shown in the right side of Fig. 9. Fig. 9 at the right side shows that the pressure at the injection side is about 2481 psi, and the pressure at the production side is 500 psi. And the pressure gradually propagates from the injector to the producer. Note that in the case of 0.1 mD, the pressure near the injector cannot be built up to 9500 psi like the case of 100 nD, because the pressure is able to dissipate to the production end.

Pressure maps at end 10 yrs injection (k=100 nD)

Pressure maps at end 10 yrs injection (k=0.1 mD)

Fig. 9 – Pressure distributions at the end of 10 year injection for two permeability reservoirs

To further understand the difference between a conventional or tight reservoir and a shale reservoir, three scenarios of primary, gas flooding and huff-n-puff are re-simulated for a tight formation of 0.1 mD. The results for these three cases are shown in Table 4. It shows that the oil recovery factor is the highest in the gas flooding case, twice that from the primary case. The oil recovery factor in the gas huff-n-puff case is lower than that in the gas flooding case. The revenues from produced oil and gas are in line with the oil recovery factors from these three scenarios. The performance difference in Table 3 and Table 4 shows that gas huff-n-puff is a preferred method to increase liquid oil production in shale gas condensate reservoirs, but may not in conventional or tight gas condensate reservoirs. The ratios of each parameter for the huff-n-puff scenario to that for the gas flooding scenario in Table 4 are all lower than one except for the net gas produced, compared with the ratios in Table 3 for a shale reservoir which are all greater than one.

Table 4 – Performance comparison of different scenarios (0.1 mD)

	Primary	Gas flooding (A)	Gas huff-n-puff (B)	Ratio (B/A)
Total gas produced (MMSCF)	427.22	7491.5	3989.4	0.53
Gas injected (MMSCF)	0	7200	3600	0.50
Net gas produced (MMSCF)	427.22	291.5	389.4	1.34
Oil produced (MSTB)	55.046	111.36	83.167	0.75
Oil recovery factor (%)	47.1	95.28	71.16	0.75
Value of produced oil and gas (MM\$)	7.21348	12.302	9.8743	0.80

[4]Further parametric study

To further verify this new idea to increase liquid oil production from gas condensate reservoirs, a series of parametric studies are conducted. The parameters studied include initial reservoir pressure, bottom-hole flowing pressure (BHFP), cycle time, soak time, gas compositions, and CO₂ injection.

[4.1]Initial reservoir pressure

The dew point of the gas condensate in the base model is 3988 psi, and the initial reservoir pressure is 9088 psi. It is expected that if the initial reservoir pressure is close to the dew point, the huff-n-puff method should be more effective compared to gas flooding and primary depletion. A lower reservoir pressure of 5000 psi is tested while keep the dew point pressure unchanged. The results for the three scenarios are presented in Table 5. The ratios of oil recovery factors and values of produced oil and gas for the huff-n-puff scenario to those for the gas flooding scenario are all 1.52. These ratios at the initial reservoir pressure of 9088 psi (performance results in Table 3) are 1.28 and 1.33, respectively. Comparing these ratios at these two initial reservoir pressures, it can be seen that with lower initial reservoir pressure, the huff-n-puff shows higher potential of improved oil recovery (IOR) compared with gas flooding.

Table 5 – Performance at the initial reservoir pressure of 5000 psi

	Primary	Gas flooding (A)	Huff-n-puff (B)	Ratio (B/A)
Total gas produced (MMSCF)	286.62	158.78	2125.8	13.39
Gas injected (MMSCF)	0	225.51	2010.1	8.91
Net gas produced (MMSCF)	286.62	-66.73	115.7	-1.73
Oil produced (MSTB)	17.832	15.446	23.418	1.52
Oil recovery factor (%)	18.969	16.43	24.911	1.52
Value of produced oil and gas (MM\$)	2.92968	1.2777	2.8046	2.20

[4.2]Effect of bottom-hole flowing pressure (BHFP)

As mentioned earlier (see Fig. 2), the oil recovery in shale oil reservoirs should be increased as BHFP is lowered because of larger driving energy. However, Table 6 shows that although the gas produced during the primary depletion is increased in shale gas condensate reservoirs, the oil recovery in both primary depletion and gas flooding increases with BHFP before reaching the dew point pressure (3988 psi in this studied reservoir), and decreases after the dew point. This is because more liquid will drop out when the BHFP is farther below the dew point; and the drawdown will be reduced when the BHFP is increased above the dew point. So the oil recovery factor decreases with BHFP. The ratio oil recovery factors of the huff-n-puff and flooding reaches the lowest point at the dew point pressure (close to 1).

Table 6 – Oil recovery factors (%) at different BHFPs and different injection modes

BHFP, psi	Primary gas, MMSCF	Primary oil	Gas flooding (A)	Huff-n- puff (B)	Ratio (B/A)
500	357.01	26	31.23	39.93	1.28

1000	337.87	26.427	31.757	39.328	1.24
2000	285.84	27.97	33.813	38.805	1.15
4000	167.85	28.903	35.1	34.683	0.99
6000	85.132	15.272	19.972	25.322	1.27

Fig. 10 – Values of produced oil and gas change with BHFP in the different production modes

Fig. 10 shows the values of oil and gas produced in MM\$ at different BHFPs. The value decreases with BHFP in the primary depletion and the huff-n-puff. The value is at the highest at the dew point pressure, and the value increases in the huff-n-puff mode.

[4.3] Cycle time effect

Fig. 7 shows that the pressure quickly decreases when the well is put in production, and quickly increases when the well is put in injection. After a short time of production or injection, either production or injection rate must quickly decrease. Therefore, reducing cycle time should accelerate production. Table 7 shows the results for different cycle times. Interestingly, the total gas produced follows this expectation, but the total oil produced does not. The data shows that the maximum oil is produced when the cycle time is at 100 days.

Table 7 – Effect of cycle time

	200 d	100 d	50 d	25 d
Total gas produced (MMSCF)	2232.2	3133.7	3783.1	3814.4
Gas injected (MMSCF)	2161.6	3008.3	3621.5	3572
Net gas produced (MMSCF)	70.6	125.4	161.6	242.4
Oil produced (MSTB)	43.816	46.666	44.668	40.891
Oil recovery factor (%)	37.49	39.93	38.22	34.99
Value of produced oil and gas (MM\$)	4.664	5.1682	5.1132	5.0587

[4.4]Soak time effect

In most of the cases, the puff period immediately follows the huff period. There is no soak time imposed because it is expected that miscibility or diffusion between the injected gas and in situ gas and condensate is fast. To test this hypothesis, the huff time of 100 days in the base case is split into 50 days of soak time and 50 days of injection time. In other words, during the 100 days, the first 50 days are used to inject gas, then the well is shut-in in the next 50 days. The case is “50 d shut-in, 100 d open” in Table 8. The results in the table show that all the parameters are lower in this case compared to the base case without 50 days of soak time (the case “100 d” in the table), except the net gas produced. When the diffusion effect is added (in the case of “50 d shut-in, 100 d open, diffusion”), all the parameters are higher than those in the corresponding case without diffusion. However, the effect is minor, and those parameters are all lower than those in the base case. In the simulation model, only the molecular diffusion is considered in this paper. The molecular binary diffusion coefficients between components in the mixture are calculated by using Sigmund (1976) method.

Table 8 - Effect of soak time

Scenario	100 d	50 d shut-in, 100 d open	50 d shut-in, 100 d open, diffusion
Total gas produced (MMSCF)	3133.7	2017.9	2028.2
Gas injected (MMSCF)	3008.3	1798.2	1790.3
Net gas produced (MMSCF)	125.4	219.7	237.9
Oil produced (MSTB)	46.666	40.582	40.92
Oil recovery factor (%)	39.93	34.72	35.012
Value of produced oil and gas (MM\$)	5.1682	4.937	5.0436

[4.5]Gas composition effect

The gas flooding and huff-n-puff are simulated with the injected gas composition of 85% C_1 and 15% C_2 . The results are shown in Table 9. For the ease of comparison, the oil recovery factor and value of produced oil and gas for the base case (100% C_1) are also listed. It can be understood that as the injection gas composition is closer to the reservoir gas, the recovery will be higher, as shown in this table for the huff-n-puff and gas flooding scenarios. Note the oil recovery factor for the gas mixture injection is slightly lower than that from 100% C_1 . The ratios of oil recovery factors and values of produced oil and gas for the mixture of C_1 and C_2 are higher than those for the C_1 only.

Table 9 - Gas composition effect (85% C_1 , 15% C_2)

	Primary	Gas flooding (A)	Huff-n-puff (B)	Ratio (B/A)
Total gas produced (MMSCF)	357.01	273.680	3091.000	11.29
Gas injected (MMSCF)	0	211.290	2917.600	13.81
Net gas produced (MMSCF)	357.01	62.390	173.400	2.78
Oil produced (MSTB)	30.385	35.504	49.297	1.39
Oil recovery factor (%)	26	30.377	42.180	1.39

Value of produced oil and gas (MM\$)	4.467	3.800	5.623	1.48
Base case (100% C ₁)				
Oil recovery factor (%)	26.000	31.230	39.93	1.28
Value of produced oil and gas (MM\$)	4.467	3.886	5.17	1.33

[4.6]CO₂ injection performance

Several attempts have been made to evaluate CO₂ EOR potential in shale and tight oil reservoirs (Shoaib and Hoffman, 2009; Wang et al., 2010; Chen et al., 2013; Want et al., 2013; Wan et al., 2014; Gamadi et al., 2014; Yu and Sepehrnoori, 2014). To the best of the author's knowledge, evaluation of CO₂ potential to improve liquid oil recovery from shale oil gas condensate reservoirs has not been seen in the literature. Shale reservoirs may serve as good CO₂ storage reservoirs. Therefore, it is interesting to see the performance of CO₂ injection. Table 10 shows the oil recovery factors for CO₂ and C₁ injection. The oil recovery factor from the CO₂ huff-n-puff is higher than that from the CO₂ flooding. Interestingly, the oil recovery factor from C₁ flooding is higher than that from CO₂ flooding; and this observation is also true for the huff-n-puff cases.

Table 10 - CO₂ vs. C₁ injection

	Gas flooding (A)	Huff-n-puff (B)	Ratio (B/A)
C ₁ oil recovery factor (%)	30.890	39.93	1.29
CO ₂ oil recovery factor (%)	24.533	37.092	1.51

It may be easier to understand these observations by comparing the flooding cases. Figs. 11 and 12 shows the oil saturation and pressure near the producing fractures. They indicate that the pressure wave and the oil bank arrive later in the CO₂ flooding than in the C₁ flooding. Therefore, the cumulative oil produced in the CO₂ flooding is delayed. By the way, there is a concern of formation damage owing to asphaltene deposition in shale reservoirs (Shahriar, 2014).

Fig. 11 – Oil saturation near the producing fractures in the C₁ flooding and CO₂ flooding

Fig. 12 – Pressure near the producing fractures in the C₁ flooding and CO₂ flooding

[5]Conclusions

Based on this simulation study, the following conclusions or observations may be made.

1. Huff-n-puff injection of produced gases can produce more liquid oil in gas condensate reservoirs than gas flooding or primary depletion. All the cases with different reservoir and fluid properties and operation conditions show this result.
2. The advantages of huff-n-puff over gas flooding are early response to gas injection, high drawdown pressure, oil saturation decrease by evaporation, and overcoming the pressure transport problem owing to ultra-low permeability.
3. The advantages of huff-n-puff over gas flooding become more important when the initial reservoir pressure is close to the dew point pressure, or the bottom-hole flowing pressure is low.
4. CO₂ injection may not be superior to lean gases in terms of oil recovery in gas condensate reservoirs.
5. Apparently there is an optimum cycle time for oil recovery; and it may not be necessary to have a soak period.

[6]Acknowledgements

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