Advances in Geo-Energy Research

Vol. 3, No. 1, p. 29-42, 2019
www.astp-agr.com

Original article

Productions of volatile oil and gas-condensate from liquid rich shales

Palash Panja[1,2]*, Manas Pathak[2], Milind Deo[2]

[1]Energy & Geoscience Institute, University of Utah, 432 Wakara Way, Suite 300, Salt Lake City, UT 84108, USA

[2]Department of Chemical Engineering, University of Utah, 50 Central Campus Dr., Salt Lake City, UT 84112, USA

(Received August 22, 2018; revised August 28, 2018; accepted August 29, 2018; available online September 5, 2018)

Citation:
Panja, P., Pathak, M., Deo, M. Productions of volatile oil and gas-condensate from liquid rich shales. *Advances in Geo-Energy Research*, 2019, 3(1): 29-42, doi: 10.26804/ager.2019.01.02.

Corresponding author:
*E-mail: ppanja@egi.utah.edu

Keywords:
Volatile oil
gas-condensate
critical temperature
liquid recovery
production optimization

Abstract:
The growth in productions of liquid hydrocarbons from tight formations (shales) has been phenomenal in recent years. During the production of liquids (oil and condensate), large amounts of associated gas are also produced. The economic viability of a producing well depends on maintaining a reasonable proportion of liquid. The compositions and state of reservoir fluid play an important role in producing liquids from tight formations or shales in the USA such as Eagle Ford in Texas, Niobrara in Wyoming-Colorado, and Bakken in North Dakota. Small deviation in reservoir temperature around the critical point changes the state of the fluid (volatile oil or condensate) and as a result, the production of liquid is affected. Impacts of the state of the fluid (volatile oil or condensate), reservoir permeability and operating conditions on ultimate recoveries and produced gas liquid ratio are studied here. Five different reservoir fluids representing low to high liquid hydrocarbon contents are considered. Around 2% increment in condensate recovery after 10 years of production is observed from 100 nD permeability reservoir filled with the richest fluid (fluid 5) when the well is operated at 3000 psia compared to 1000 psia. At the same conditions, 9.3% more condensate is recovered for the leanest fluid (fluid 1). Therefore, operating the well at higher flowing bottom hole pressure (BHP) maximized the liquid recoveries of volatile oils and condensates in case of low permeability reservoirs (100 nD). However, in case of higher permeability (1000 nD) reservoir, lower operating pressure was preferable to increase the recovery. Conclusively, bottom hole pressure has less impact on the richer fluids and higher permeability reservoir. Operating well at higher BHP (3000 psia) also suppresses the production of gas and relatively enhances the production of liquid. Liquid to gas ratio (LGR) declines more rapidly for 100 nD permeability reservoirs compared to 1000 nD at BHP of 1000 psia. High fracture permeability (1000mD and above) appeared to negatively affect liquid recoveries at higher BHP resulting in reduction of recovery by around 2%. An optimum fracture permeability may be necessary based on reservoir permeability, operating pressure and type of fluid.

1. Introduction

It has been recognized that oil recovery greatly depends on reservoir fluid properties such as initial gas-oil ratio (GOR), API gravity, saturation pressure etc. For conventional reservoirs (Orangi et al., 2011; Whitson and Sunjerga, 2012). Initial gas oil ratio which is dependent on the compositions of fluid affects (positively or negatively) the recovery factor mainly in three ways. Firstly, gas dissolved in liquid phase makes the liquid more mobile thus increases the liquid recovery. Secondly, free gas (below saturation pressure) sustains the reservoir pressure which in turns helps to produce more liquid. Thirdly, free gas being highly mobile compared to liquid phase suppresses the liquid production. Therefore, the initial gas oil ratio affects recovery of liquid in a complex manner. Similar behavior of multiphase fluid flow is also observed in unconventional reservoirs like shales. Geologic properties are also the key parameters in the production of liquids from many prolific tight and shale formations such as the Bakken, Niobrara and Eagle Ford in the United States (Pathak et al., 2014).

It is important to note that various fluids such as dry gas, gas-condensate and oil have been produced from a single play such as Eagle Ford shale (at depths between 4,000 and 14,000 feet) which is located in South Texas as shown in Fig. 1.

The amount of liquid hydrocarbons changes from North-West to South-East in the Eagle Ford formation. The wells towards South-East direction produce more natural gas than wells located towards North-West side. Wet gas and condensate reservoirs are the intermediate zones between oil and

https://doi.org/10.26804/ager.2019.01.02.

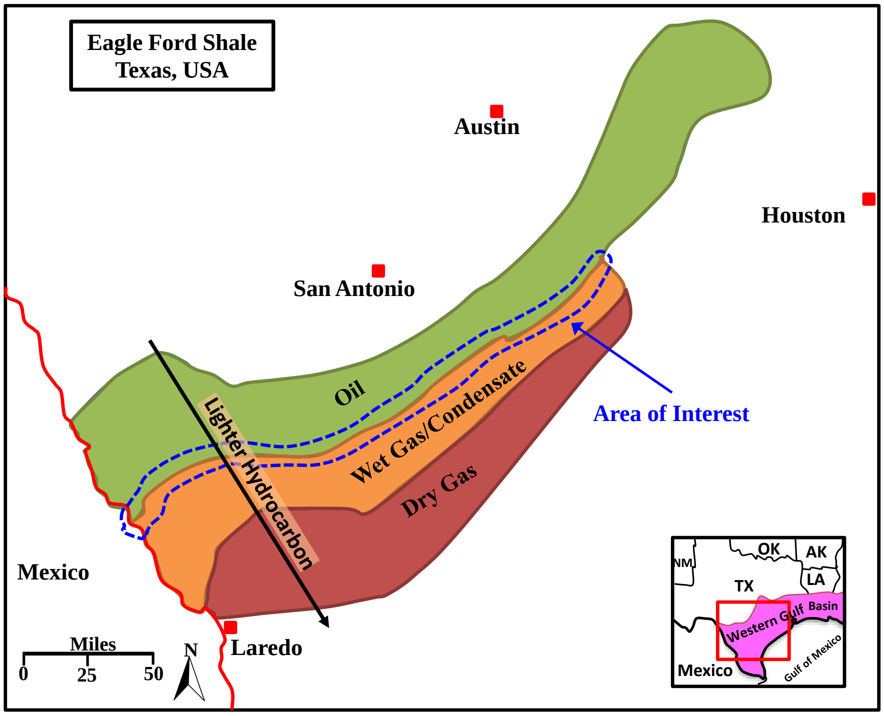


Fig. 1. Hydrocarbons fluid windows namely oil, condensate, wet gas and dry gas in Eagle Ford Shale, Texas.

dry gas windows. Reservoir performances were compared between East and West windows by varying fluid and reservoir properties (Gherabati et al., 2016). It was also shown that higher oil recovery was estimated in the East window due to higher reservoir pressure. Oil production from Eagle Ford was about a 935,000 barrels per day while the condensate production was about 232,000 barrels per day (Texas, 2016) in 2016. This study is applied to the regions of Eagle Ford where the transition from oil to condensate occurs as marked by dotted line (blue) in Fig. 1. In these regions, the reservoir temperature plays an important role to determine the state of the fluid (volatile oil or condensate) inside the reservoir. At two different initial reservoir temperature, two different fluids can be produced from the same initial reservoir fluid compositions at near-by regions. The fluids can be characterized thermodynamically from Pressure-Temperature diagram (PT diagram) as shown in Fig. 2.

Initial gas liquid ratio and saturation pressure are dependent on the initial fluid composition and reservoir temperature or state of fluid (volatile oil or condensate). Reservoir temperature greater than the critical point temperature results in condensates production, on the other conditions, reservoir temperatures less than the critical point temperature yield volatile oil production. This effect of changing temperature in the reservoir around the critical point is the primary focus of this study. This study is intended to investigate the production performance of near critical fluids such as volatile oil and condensate from ultra-low permeability reservoirs (100 nD to 1000 nD).

The common method of producing fluids from ultra-low permeability reservoir is the use of multi-stage hydraulically fractures in horizontal wells (Orangi et al., 2011; Bagci et al., 2017; Sharif Md et al., 2017). Well is typically operated below saturation pressure to increase the drawdown (difference between average reservoir pressure and flowing bottom hole pressure) which is the driving force for production. In case of oil reservoir, dissolved gas comes out of oil phase below the saturation pressure (bubble point), hence liquid production rate decreases because gas starts dominating the two phase flow due to the higher mobility than liquid. In a number of instances, this causes liquid producing well to become uneconomic due to high amount of gas with low liquid recoveries. In case of gas-condensate system, below the saturation pressure (dew point), liquid drops out from the gaseous phase into the formation (and remains immobile due to low condensate saturation) and thus, the liquid production is decreased.

Produced GOR was proved to be independent of reservoir permeability and well spacing at the same oil recovery for solution gas drive reservoirs (Levine and Prats, 1961). This is applicable only for conventional reservoir with higher permeability (10-500 mD). In a recent study, authors showed that normalized (with initial gas oil ratio) produced GOR is dependent on the fluid PVT properties and the flowing bottom hole pressure in ultra-low permeability reservoirs (Panja and Deo, 2016a). Another recent paper from authors examined the role of various factors in the production behavior from unconventional reservoirs (Panja et al., 2016). Produced GOR values higher than the initial dissolved GOR were observed despite the fact that the average reservoir pressure was above the bubble point pressure. It was also observed that the production from gas condensate reservoirs with ultra-low permeability (100-2000 nD) is different than that from higher permeability

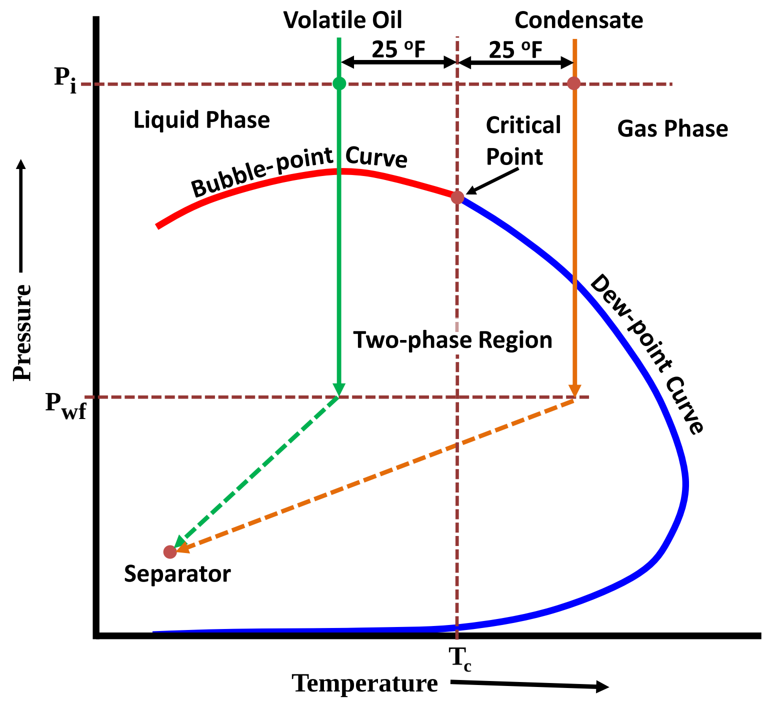


Fig. 2. Different fluid production paths in pressure-temperature diagram showing the near critical fluid such as condensate and volatile oil with same initial compositions.

reservoirs (Panja and Deo, 2016b; Ghanizadeh et al., 2018; Wang et al., 2018).

Whitson and Sunjerga (Whitson and Sunjerga, 2012) observed that the producing GOR for reservoirs with permeabilities of about 1000 nD or less were dependent on the level of undersaturation and the BHP. They also found that the oil recovery and producing gas-oil ratio (GOR) in conventional reservoirs with higher permeability (0.1 mD or more) are independent of permeability and flowing BHP. Using simulations, Lei et al. (Lei et al., 2014) made similar arguments for reservoirs with permeabilities greater than 0.5 mD. Thus, the fact that the production performance of tight oil and condensate reservoirs depends on reservoir permeability and flowing bottom hole pressure (Orangi et al., 2011; Whitson and Sunjerga, 2012; Lei et al., 2014) has been well established.

From the above discussions, it is evident that the reservoir permeability, operating condition, initial gas liquid ratio and saturation pressure are the important factors deciding the fate of a reservoir. This study discusses how the liquid recoveries from tight oil reservoirs are affected by bottom hole pressures, reservoir permeability, fracture permeability, compositions of the fluid and the reservoir temperature or state of the fluid (condensate or volatile). The effects are examined for five fluids with different initial liquids to gas ratios (LGR) at two temperatures- above and below the critical temperatures.

2. Fluid modeling

A wide range of fluids with variable the initial compositions are considered in this study. To form two types of fluid as shown in Fig. 2, reservoir temperatures of volatile oil and condensate are considered to be equally spaced (25 °F) from the critical temperature. It is evident from the Fig. 2 that the single phase fluid is oil when reservoir temperature is lower than the critical temperature above the bubble point pressure. In contrary, gas phase is found when reservoir temperature is higher than the critical temperature and above dew point pressure. Five different fluids with different initial liquid to gas ratio (LGR), namely, fluid 1 (lean condensate), fluid 2, fluid 3 (intermediate condensates), fluid 4 and fluid 5 (rich condensates) at two reservoir temperatures, 25 °F higher and lower than critical point temperatures as shown in Fig. 2, are considered for the study. The compositional data used to create the fluids were partially taken from Whitson and Sunjerga (Whitson and Sunjerga, 2012) as shown in Table 1. The range of fluids with variable compositions are supposed to represent the fluids in Eagle Ford, USA. Compositions were adjusted slightly to get desired liquid to gas ratios for oils and condensates.

The pressure-temperature plots (Fig. 3) of the five fluids were prepared using the Peng-Robinson (Robinson and Peng, 1978) Equation of State in commercial software Winprop from Computer Modeling Group, Calgary, Canada.

Fluid 1 has the lowest initial LGR (98 STB/MMSCF) and fluid 5 has highest initial LGR (246 STB/MMSCF). The mole fractions of methane to C6 have been reduced from fluid 1 to fluid 5, in contrary, mole fractions of C7+ have been increased. The critical temperatures increase with increase in the initial LGR. Each fluid behaves differently depending on the reservoir temperature. The properties of the five different fluids studied here are summarized in Table 2.

Fluid 1 is discussed here as an example. Fluid 1 has a

Table 1. Compositions and critical properties of various reservoir fluids.

Components	Composition(mole %)				
	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5
C1	70.62	69.10	67.57	66.05	64.52
C2	7.11	7.06	7.01	6.96	6.91
C3	5.97	5.93	5.89	5.85	5.81
iC4	1.15	1.11	1.07	1.03	0.98
nC4	1.96	1.93	1.90	1.87	1.84
iC5	0.90	0.87	0.84	0.81	0.78
nC5	0.96	0.92	0.89	0.86	0.82
FC6	1.37	1.35	1.33	1.31	1.29
C7+	7.69	9.46	11.23	13.00	14.78
CO_2	2.14	2.14	2.14	2.14	2.14
N_2	0.13	0.13	0.13	0.13	0.13
Tc (F)	117	176	235	285	337
Pc (psia)	3600	3912	4024	4074	3596
C7+ Mol. Wt.	132	136	140	144	148
C7+ Sp. Gr.	0.776	0.777	0.778	0.779	0.780

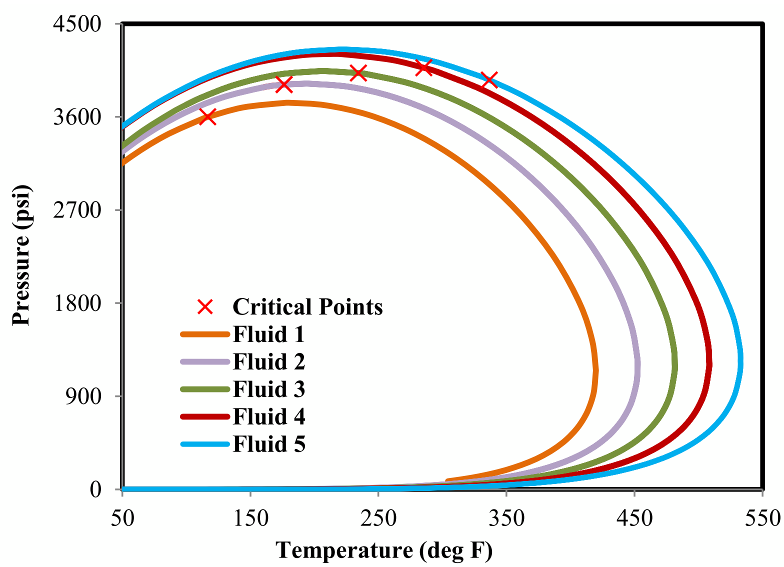


Fig. 3. Pressure-Temperature (PT) diagram showing the phase behavior of fluid 1 to fluid 5.

critical temperature of 117 °F. The temperature of volatile oil corresponding to initial composition of Fluid 1 is 92 °F (25 °F less than critical temperature) and the temperature of condensate corresponding to initial composition of same fluid is 142 °F (25 °F higher than critical temperature). Both, condensates and volatile oils for the same initial composition have identical initial LGR of 98 STB/MMSCF as shown in Table 2. Similarly, all other reservoir fluids are formulated by changing reservoir temperatures.

Fluid 1 as described in Table 2 is considered as a lean condensate at 142 °F with condensate to gas ratio of 98 STB/MMSCF and volatile oil at 92 °F with very high initial gas oil ratio of 10204 SCF/STB. Liquid drop out in the reservoir for lean condensates is expected to be lower than rich condensates. Fluids 2 and 3 behave as intermediate condensates at 201 °F and 258 °F respectively with condensate to gas ratio of 130 STB/MMSCF and 166 STB/MMSCF respectively. The volatile oils corresponding to initial compositions of fluid 2 and fluid 3 contain medium amount of initial gas oil ratios of 7692 and 6024 SCF/STB respectively. Fluids 4

Table 2. Summary of properties of the five fluids.

Fluid	Critical temp., T_c (°F)	Reservoir temp., T_{res} (°F)	Type of fluid based on T_{res}	P_{sat} (psia) at T_{res}	Initial LGR (STB/MMSCF)
Fluid 1	117	92/142	Volatile oil/Lean condensate	3473/3686	98/98
Fluid 2	176	151/201	Volatile oil/Intermediate condensate	3865/3921	130/130
Fluid 3	235	210/260	Volatile oil/Intermediate condensate	4090/4013	165/165
Fluid 4	285	260/310	Volatile oil/Rich condensate	4151/3973	204/204
Fluid 5	337	312/362	Volatile oil/Rich condensate	4070/3810	246/246

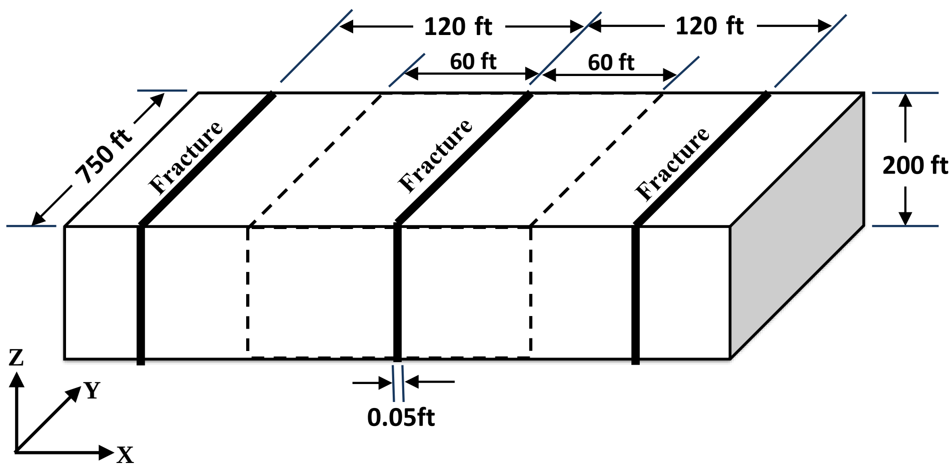


Fig. 4. Schematic diagram of reservoir model with multiple hydraulic fractures. Dotted portion is the simulated part of the model.

and 5 are considered as rich condensates at 310 °F and 362 °F respectively with initial condensate to gas ratio of 204 STB/MMSCF and 246 STB/MMSCF respectively. Gaseous phase contains large amount of vaporized condensate with potentially large amounts of liquid drop out when pressure drops below dew point pressure. The corresponding volatile oils for initial compositions of fluid 4 and fluid 5 have less amount of gas dissolved (4902 SCF/STB for fluid 4 and 4065 SCF/STB for fluid 5) in the oil phase.

3. Reservoir simulation

A generic reservoir model with single vertical fracture in the middle with one horizontal well is simulated using a compositional simulator (Siripatrachai et al., 2017; Neshat et al., 2018). The single fracture representation of entire reservoir is satisfactory in low permeability reservoir (100 nD - 1000 nD) because of the fact that fractures do not interfere for a long time. Considering a typical fracture spacing, the reservoir dimensions are kept fixed as 120 feet in the x-direction which is equal to one fracture spacing. The lengths in Y-direction and Z-directions are 750 feet and 200 feet respectively. Schematic diagram of the reservoir is shown in Fig. 4.

Permeability of the hydraulic fracture depends on the effectiveness of the fracturing job. Fracture closure during production is a common phenomenon due to the increase of overburden stress. The fracture permeability may vary from 25,000 mD to 250 mD (Orangi et al., 2011). Considering the over-pressured nature of the Eagle Ford play, reservoir pressure of 6500 psia is considered. Geomechanics may play a great role depending on the properties like Poisson's ratio, Young's modulus, compressive strength etc. However, geomechanics is not considered in this study to focus more on the impacts of the state of fluids, therefore matrix permeability is kept constant. The fracture width and orientation, fracture permeability, initial hydrocarbon saturation, and reservoir porosity are also selected to be constant for all simulations. Fracture spacing in tight formation varies from as low as 20 ft. to 180 ft. (Sanaei and Jamili, 2014; Lu, 2016). However, an optimum fracture spacing is found to be 120 ft. with the reservoir parameters similar to this study. Same relative permeability curves are used for both condensate and volatile oil because of the small temperature differences between them (Serhat et al., 1999). The simulation parameters used in the study are summarized in Table 3.

Initial reservoir pressure is chosen to be higher than the initial bubble point/dew point pressures for all the fluids to keep reservoir fluids in single phase initially either in liquid phase or gaseous phase (or superfluid because of the initial conditions of temperature and pressure greater than critical conditions). Effects of nanopores on PVT properties such as critical temperature and pressure on production (Khoshghadam

Table 3. Summary of reservoir model parameters and operational parameters.

Reservoir top (ft.)	12800
Reservoir dimension, X(ft.), Y(ft.), Z(ft.)	120, 750, 200
Matrix permeability, k_x, k_y, k_z (nD)	100, 1000
Matrix permeability, k_z (nD)	0.1 k_x
Fracture permeability (mD)	$k_{f_x} = k_{f_y} = k_{f_z} = 300$
Fracture width (ft.)	0.05
Fracture orientation	Parallel to YZ plane
Fracture spacing (ft.)	120
Initial reservoir pressure (psia)	6500
Initial HC saturation (%)	84 (single phase)
Reservoir porosity (%)	5
Flowing bottom hole pressure (psia)	1000, 3000

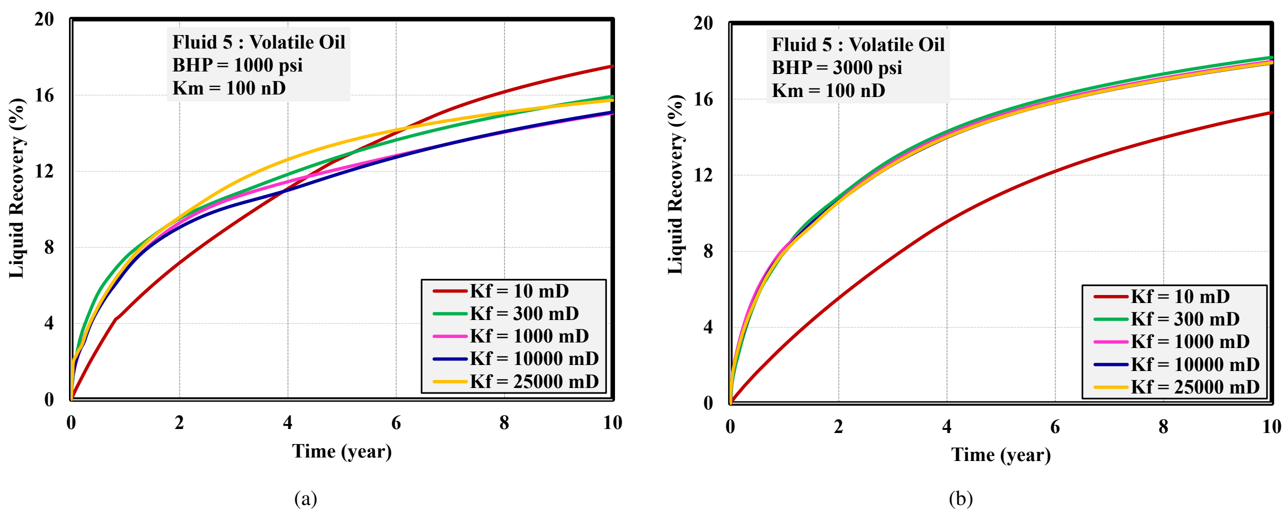


Fig. 5. Liquid recoveries from reservoir of 100 nD permeability for various fracture permeability for fluid 5 at the volatile oil condition and operating at bottom hole pressure of (a) 1000 psia (b) 3000 psia.

et al., 2015) are not considered in this study.

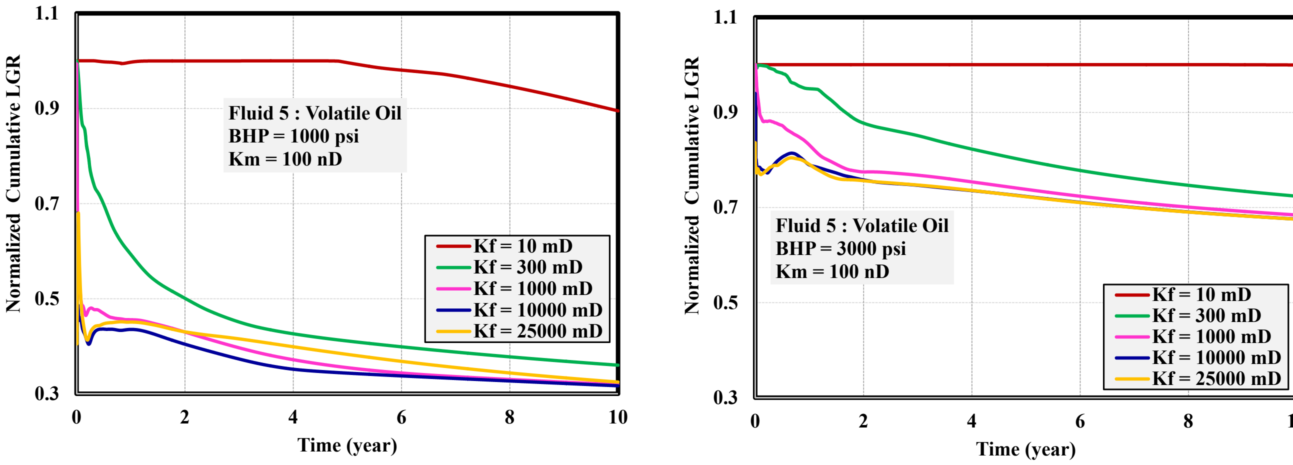
4. Results and discussion

All simulations were conducted using a compositional simulator GEM, Computer Modeling Group (Calgary, Canada). Sufficiently fine grids are used to obtain converged results without any grid effects (Panja et al., 2013). The production characteristics from the ultra-low permeability reservoirs (100 nD to 1000 nD) with these five different fluids are discussed in the next few sections.

4.1 Permeability of hydraulic fracture

Hydraulic fractures serve as high permeability flow paths for fluids in low permeability reservoirs (100 nD - 1000 nD). The permeability of the fractures which is the direct result of effectiveness of completion job is an important parameter in recovering hydrocarbons from shales. In this section, the effect of fracture permeability on production of volatile oil (for fluid 5) from 100 nD permeability reservoir is demonstrated. The recovery factors for various fracture permeabilities ranging from 10 mD to 25,000 mD with flowing bottom hole pressures of 1000 psia and 3000 psia are shown in Fig. 5.

In Fig. 5(a), the oil recoveries for bottom hole pressure of 1000 psia from fracture permeability of 10 mD, 300 mD, 1000 mD, 10000 mD and 25000 mD are compared. The recovery from 10 mD fracture permeability is less than the recoveries from higher fracture permeabilities (greater than 10 mD) until around 1500 days. After 1500 days, there is a crossover with 10 mD fracture resulting in higher recoveries than the higher permeability fractures. In case of bottom hole pressure of 3000 psia as shown in Fig. 5(b), the trend is quite different. The oil recovery from 10 mD fracture permeability is always lower than that from higher fracture permeability in 10 years of production life. The reason behind these behaviors can be explained from the analysis of liquid rates. It is observed that



(a) (b)

Fig. 6. Normalized cumulative liquid to gas ratio from reservoir of 100 nD permeability for various fracture permeability for fluid 5 at the volatile oil condition and operating at bottom hole pressure of (a) 1000 psia (b) 3000 psia.

the initial liquid rates (13,210, 341,561, 444 stb/day/fracture for 1000 psia and 8,130, 377, 471, 507 stb/day/fracture for 3000 psia from fracture permeability of 10 mD, 300 mD, 1000 mD, 10000 mD and 25000 mD respectively) are higher for higher fracture permeability.

For 10 mD and 1000 psia BHP case, although the initial rate is very low compared to others, it is more sustainable and decreases initially but stays constant for longer time. Rates from higher fracture permeability start at high values but they decline sharply and go below the rate from 10 mD fracture. Eventually, liquid rates for the 10 mD fracture go above the rates with larger fracture permeabilities. Finally in long run (5 years), the cumulative production from 10 mD gets past the cumulative productions from higher permeability fractures.

In the case of 3000 psia bottom hole pressure, declines of liquid rates from higher fracture permeability (other than 10 mD) is less compared to the cases of 1000 psia bottom hole pressure. Having the advantages of starting at higher initial rates and less decline at 3000 psia BHP, the cumulative productions from higher fracture permeability are more than the cumulative production from 10 mD fracture permeability.

Another important observation is that the fracture permeability above 300 mD has insignificant impact on liquid recovery. At this level, hydraulic fractures behave as infinitely conductive channels inside reservoir.

Effect of fracture permeability on produced liquid to gas ratio (LGR) is discussed here as shown in Fig. 6.

For 10 mD fracture permeability, the produced LGR stays constant at initial LGR for bottom hole pressure of 3000 psia (Fig. 6(a)) and it decreases slightly after around 1900 days for bottom hole pressure of 1000 psia (Fig. 6(b)). With higher fracture permeability, the produced LGRs decline sharply from the initial LGR. The decline is higher for low bottom whole pressure such as 1000 psia compared to 3000 psia. As described earlier that the liquid rate from 10 mD fracture permeability is very low despite the fact that the produced LGR is the highest (almost equal to initial LGR) compared to produced LGR from higher fracture permeability. Although the produced LGR is higher for 10 mD fracture permeability, the fracture itself is not very conductive to flow of both liquid and gas. Due to this fact, the rates of liquid and gas are both low and produced LGR stays near initial LGR. On the contrary, for higher permeability fracture, the liquid and gas flow through a highly conductive fracture to the well bore. This causes higher flow rates of liquid and gas initially. During production, higher pressure drop occurs inside the fracture with higher permeability. Fractures act as flash zone for gas to evolve out from liquid. Once sufficient amount of gas comes out of liquid, it dominates the flow causing decline in produced LGR. In case of 3000 psia, the decline is less due to lower pressure drop. Higher fracture permeability facilitates high flow rates of liquid and gas but at the same time, higher pressure drop causes gas to dominate the multiphase flow suppressing liquid rate. Here arises a need for creation of optimal fracture permeably for an effective fracturing performance. In this study, fracture permeability of 300 mD so that the effect of fracture permeability is not felt and other parameters may be investigated.

4.2 Liquid recovery

Liquid recoveries, instead of cumulative liquid productions are compared because the hydrocarbons initially in place are different for condensate and volatile oil for same fluid. It is dependent on compositions, reservoir temperature (or state of the fluid; volatile or condensate), pressure and the size of the reservoir. The initial liquid hydrocarbons in place (based on the simulated reservoir volume as shown in Fig. 4) for both types of fluids (condensates and volatile oils) are compared in Fig. 7.

As shown in Fig. 7, the initial liquid hydrocarbon in-place increases with increasing initial liquid to gas ratio as per design of five fluids (see Table 2). Higher amounts of liquid in place were observed in volatile oil reservoirs than condensate

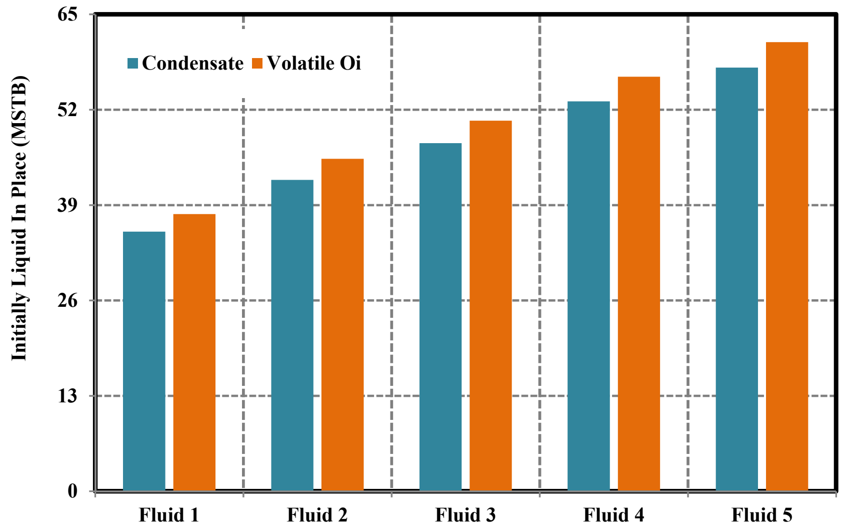


Fig. 7. Variations in initial liquid hydrocarbons (condensate and volatile oil) in reservoir filled with fluid 1 to fluid 5.

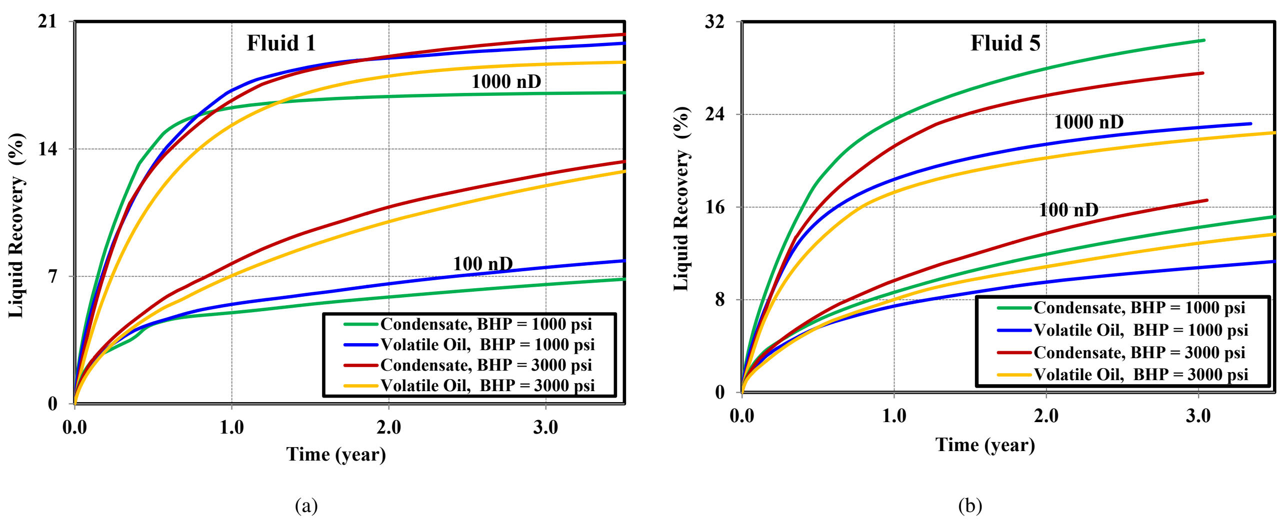


Fig. 8. Liquid recovery from 100 nD and 1000 nD permeability reservoirs with BHP of 1000 psia and 3000 psia for (a) fluid 1 (b) fluid 5.

reservoirs for all fluids. Although the compositions and the hydrocarbon volume at reservoir conditions are same for both volatile oil and condensate in case of any particular fluid, their temperatures are different. Condensate reservoir has less number of moles of hydrocarbon occupying the same reservoir volume because it has higher temperature compared to volatile oil reservoir. Therefore, converting the initially hydrocarbons in-place for both states at stock tank conditions yields less amount for condensate compared to volatile oil. The difference is not significant for less temperature separation (50 °F).

Effects of state of the fluid and richness of fluid on liquid recovery are discussed here. Liquid recoveries with time for 100 nD and 1000 nD permeability reservoirs are shown in Fig. 8 for the leanest and the richest fluids (fluid 1 and fluid 5).

Higher amount of hydrocarbons (liquid and gas) are extracted from higher permeability (1000 nD) reservoirs containing fluid 5. Significant differences in liquid recoveries between condensate reservoir and volatile oil reservoir are observed for both permeabilities (100 nD and 1000 nD). 2 to 10% more liquid is recovered from condensate reservoir than volatile oil reservoir except for fluid 1 in 1000 nD reservoir at a later time. Levine and Prats (Levine and Prats, 1961) observed that recoveries do increase as permeabilities increase. However, the differences for conventional reservoirs (permeabilities of the order of milli Darcies) observed by Levine and Prats were from 1% to 8%. In tight oil reservoirs, for condensates and volatile oils, the differences are 10-20%. The observation that change in BHP may lead to doubling of recoveries is a significant finding of this study. The differences are more prominent for reservoirs containing fluid 1 at lower permeability of 100 nD. Differences in the condensates and volatile oil recoveries increase with increase in reservoir permeability. Lower FBHP (1000 psia) helps to recover more liquid from both states of fluid from 1000 nD permeability reservoir. Counterintuitive results are noticed for liquid recoveries from 100 nD reservoir; higher FBHP (3000 psia) yields higher recovery of liquid.

Because of the fact that the liquid flow rates are proportional to the initial liquid to gas ratio, the highest liquid flow rates are achieved from reservoir with fluid 5. There are not significant differences in rates of volatile oil and condensate for 1000 nD reservoirs at flowing bottom hole pressures (FBHP) of 1000 and 3000 psia for all fluids. Rates almost overlap each others, therefore, FBHP (in the range of 1000 psia to 3000 psia) has the least effect on liquid rate for reservoir permeability of 1000 nD. The effect of flowing bottom hole pressure is prominent in 100 nD permeability reservoir. Higher liquid production rate is obtained when flowing bottom hole pressure is 3000 psia. Higher FBHP prevents liquid dropout inside the reservoir in case of condensate and prevents evolution of free gas from oil phase (dissolved gas) in case of volatile oil. It also enhances the flow of liquid by relatively suppressing the flow of gas. The differences of the condensate and volatile oil flow rates are subtle for fluid of low initial liquid to gas ratio such as fluid 1. Condensate rates are higher than volatile oil rates for fluids with intermediate to rich liquid content such as fluid 2 to fluid 5. The fact that higher liquid rates could be obtained by holding a higher back pressure (also leading to higher liquid recoveries) is another significant, and new finding of this study.

Ultimate recovery is calculated when the liquid rate reaches to minimum economic rate such as 5 STB/day/fracture in this study (economic rate is defined by producer, therefore it varies). The ultimate recoveries are compared for 100 nD permeability reservoirs at different flowing bottom hole pressure (1000 psia and 3000 psia) for various fluids in Fig. 9.

Highest amount of liquids (condensate and volatile oil) are recovered from the reservoir which is initially filled with highest initial LGR (fluid 5). The condensate recoveries almost in all cases increases with increasing initial LGR (fluid 1 to fluid 5) but ultimate recoveries of volatile oil drop or do not change significantly up to initial LGR of 166 STB/MMSCF (fluid 3). Lesser initial LGR fluid (fluid 1) contains less volatilized condensate in the gas phase in condensate reservoir and higher gas in oil phase in volatile oil reservoir.

Condensate is mainly produced from gas phase (for condensate reservoirs) leaving some amount of condensate inside reservoir and volatile oil is produced from oil phase mostly (for volatile oil reservoirs). If condensate saturation exceeds the critical saturation, condensate starts flowing as liquid phase along with the gas phase. The relative flow rates depend on the condensate saturation i.e., amount of condensate drop out inside reservoir which is dependent on initial LGR.

Volatile oil reservoir initially is in liquid phase with dissolved gas in it. Lesser amount of gas is dissolved in the fluids with higher initial LGR. When the reservoir pressure drops below bubble point, gas evolves from oil phase; this gas phase also contains some volatilized liquid oil. The amount of volatilized oil in gas phase increases with increase in initial LGR but the amount of gas evolved decreases. Once free gas is formed, the flow is dominated by gas phase. The oil production mainly comes from the oil phase rather than gas phase because the amount of oil (in vapor form) in the gas phase is not very significant. It is evident from Fig. 9 that the least amount of volatile oil is recovered at initial LGR of 166 STB/MMSCF (fluid 3).

Recoveries from 1000 nD permeability reservoir are compared in Fig. 10 for FBHP of 1000 psia and 3000 psia.

As discussed earlier that the liquid rate is proportional to drawdown in case of higher permeability reservoir such as 1000 nD. Therefore, higher amount of liquids are recovered with flowing bottom hole pressure of 1000 psia compared to 3000 psia. In case of higher permeability, initial pressure front diffuses deep into the reservoir (from the fracture face) causing a low declining profile of pressure. As a result, the flashing of gas (in case of volatile oil) or dropping out of liquid

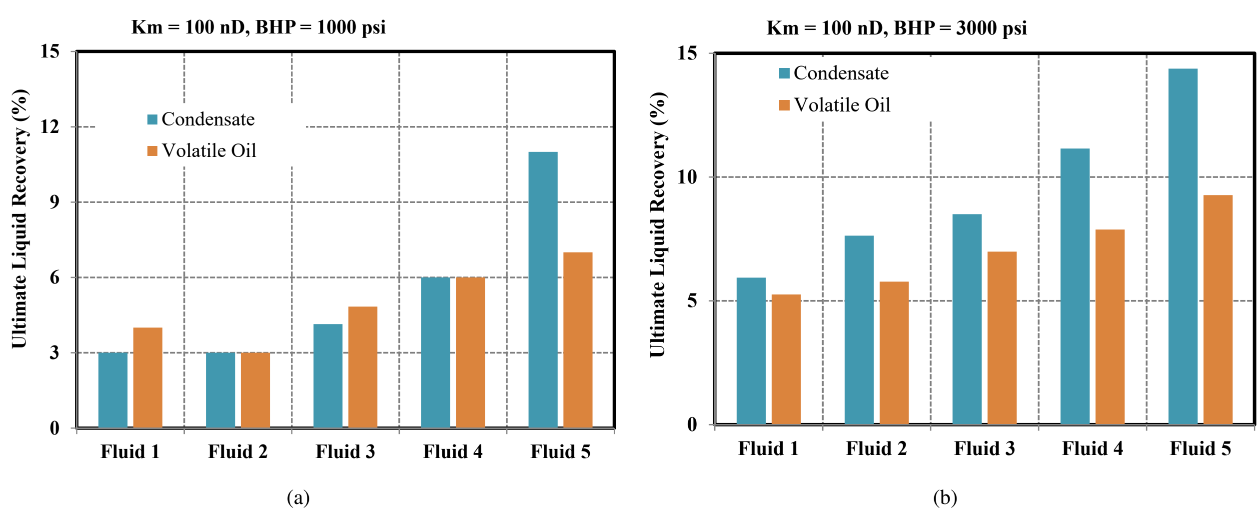
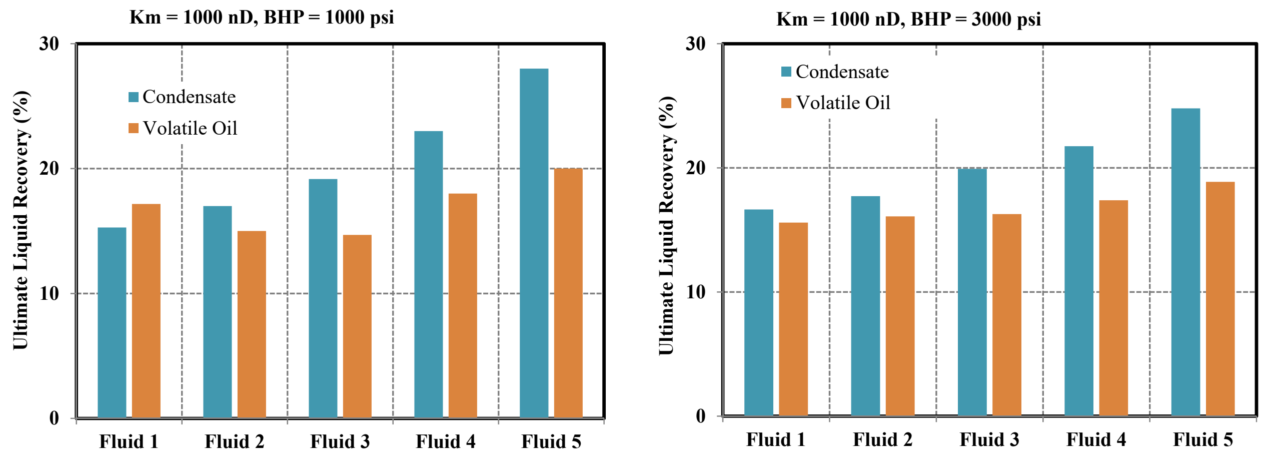
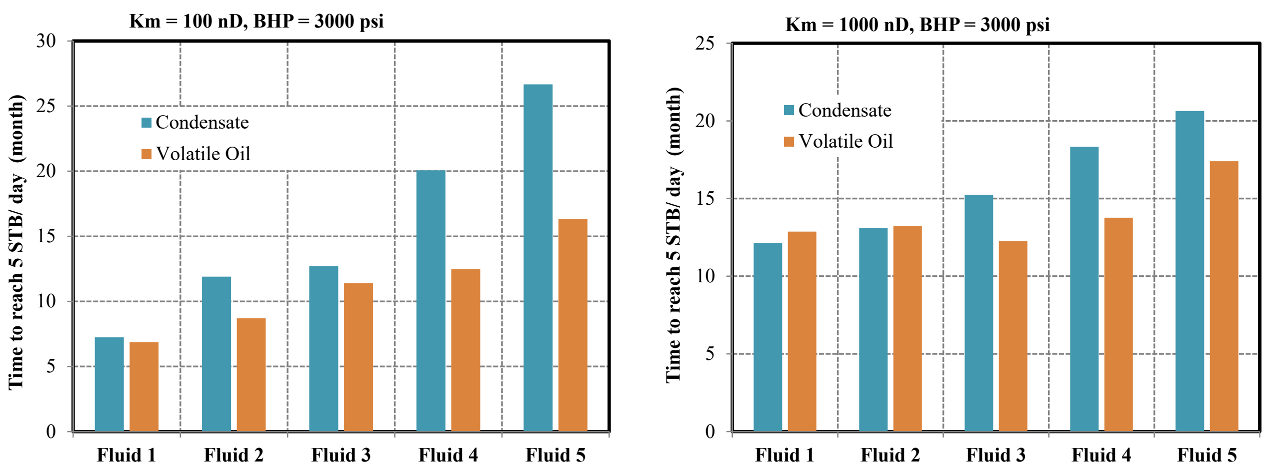


Fig. 9. Comparisons of ultimate liquid recoveries (condensate and volatile) among fluid 1 to fluid 5 from 100 nD permeability reservoirs with BHP (a) 1000 psia (b) 3000 psia.



(a) (b)

Fig. 10. Comparisons of ultimate liquid recoveries (condensate and volatile) among fluid 1 to fluid 5 from 100 nD permeability reservoirs with BHP (a) 1000 psia (b) 3000 psia.



(a) (b)

Fig. 11. Time to reach liquid flow rate of 5 STB/day/fracture for condensate and volatile oil reservoir with permeability of (a) 100 nD (b) 1000 nD.

condensate (in case of condensate) is less which ensures higher recovery of liquid at surface.

Recoveries in Eagle Ford are generally believed to be less than 10%. Fig. 9 and Fig. 10 clearly show how reservoir quality (permeability), flowing bottom hole pressure and fluid quality affect recoveries. With low liquid content (fluid 1) and poor reservoir quality (100 nD permeability), recoveries could be as low as 3%. However, these recoveries could be doubled by operating the well at higher bottom hole pressures.

Although in the most of the cases, the condensate recovies are higher than the volatile oil recoveries, it is important to consider the production time to obtain those recoveries. Various costs related to production such as operating cost, maintenance cost etc. increase with production time. Prices of oil and condensate also vary with time. Therefore, it is improtant to decide the minimum economic rate of production which depends on operating costs and liquid price at the time. Five STB/day of liquid hydrocarbons (condensate and volatile oil) from a single hydraulic fracture is set as minimum the economic rate in this study. Liquid rate takes different time to reach the minimum economic oil depending on reservoir permeability, operating conditions and fluid type as shown in Fig. 11.

Condensate reservoirs take longer time to reach the economic rate of 5 STB/day than the volatile oil reservoirs. Liquid rates from lower permeability (100 nD) reservoirs (with condensate or volatile oil) reach the economic rate limit quicker than the higher permeability (1000 nD) reservoirs but more gas and liquid are recovered from higher permeability reservoirs. An economic model coupled with the production strategy would give a better picture in terms of profitability.

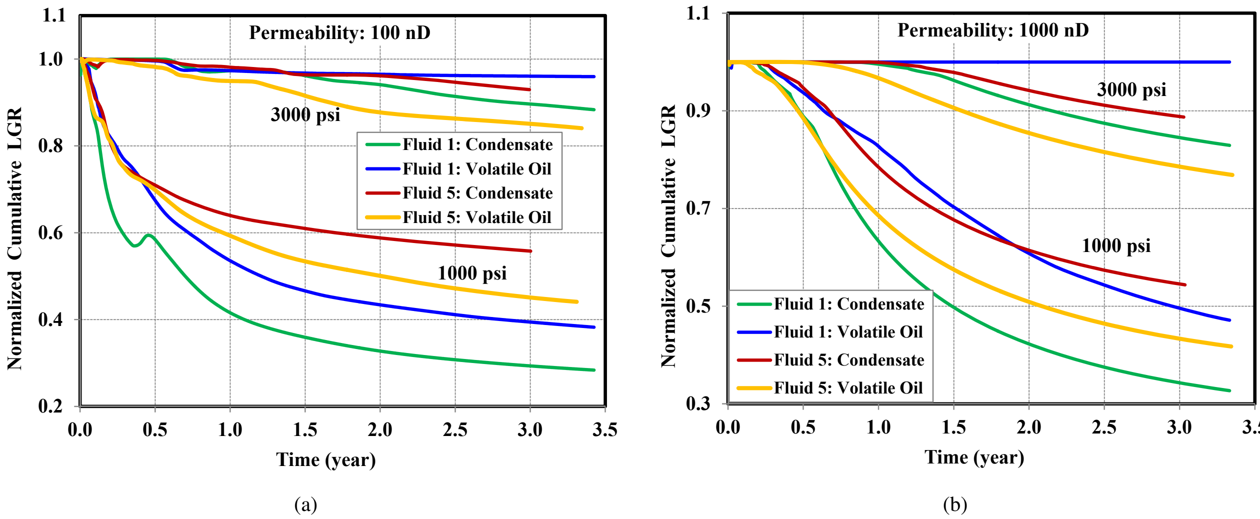


Fig. 12. Comparisons of normalized produced LGR for fluid 1 and fluid 5 in reservoir with permeability (a) 100 nD (b) 1000 nD.

4.3 Liquid to gas ratio

The proportion of liquid produced in the total fluid stream (liquid plus gas) is the main reason for the significant differences in recoveries. The produced LGR starts from initial LGR of the fluid and then decreases with time. Since various fluids have different initial LGRs, it is difficult to compare the production performance of produced LGR among the fluids. Thus, cumulative produced LGR is normalized with initial LGR of the corresponding fluid to compare them in the same scale as shown in equation below:

$$Normalized\ cumulative\ LGR = \frac{Cumulative\ LGR}{Initial\ LGR}$$

Normalized cumulative LGRs for volatile oil and condensate are shown in Fig. 12 for fluid 1 and fluid 5.

It is clear from the Fig. 12 that operating well at higher FBHP (3000 psia) is advantageous to produce more liquid and relatively less gas. Produced LGRs from 100 nD and 1000 nD permeability reservoirs behave in the same manner, the only difference is in the decline rate for FBHP of 1000 psia. Decline of produced LGR is sharper for 100 nD permeability reservoirs compared to 1000 nD. Constant initial LGR is noticed mainly for FBHP of 3000 psia. Fluid 1 has longer flat plateau; initial LGR is produced in this time. This can be explained by the fact that a small amount of condensate drops out in condensate reservoir and a little amount of oil is volatilized in gas phase in volatile oil reservoir because fluid 1 is a lean condensate in condensate reservoir and has high gas content in volatile reservoir. The reasons for these types of behavior are discussed earlier.

4.4 Production optimization

It is not very common to operate well at constant BHP. Initially well is opened at higher BHP because of high reservoir pressure to control the flow rate. Then pressure is reduced as the reservoir is depleted in the course of production. The reduction of BHP can be scheduled in different ways. In this section, four cases of operating strategies are studied; constant BHP of 1000 psia and 3000 psia, step down of 500 psia in every 3 months and step down of 500 psia in every 2 years from 3000 psia to 1000 psia as shown in Fig. 13.

To keep this section short, only condensate recoveries from fluid 1 and fluid 5 are discussed. The effect of operating strategies on production from 100 nD permeability is shown in Fig. 14.

The fact that more condensate is produced from higher BHP (3000 psia) from 100 nD reservoir has already been established in earlier sections. Similar results are obtained from 3 months step down (or quick descending to 1000 psia BHP from 3000 psia BHP) and 2 years step down (or slow descending to 1000 psia BHP from 3000 psia BHP). Effect of variable BHP is more pronounced for lean condensate (fluid 1) than rich condensate (fluid 5). Only 2.4% difference in recovery between BHP of 3000 psia and 1000 psia for the richest fluid (fluid 5) after 10 years of production is observed. On the other conditions, 9.3% more condensate is recovered using 3000 psia BHP compared to 1000 psia BHP for the leanest fluid (fluid 1). In case of the rich fluid, both the low and high BHP help to produce liquid either in gaseous form or in liquid form before reaching surface. At low BHP, amount of dropout condensate inside reservoir is sufficiently large to flow on the surface without leaving any significant amount in the reservoir. At higher BHP, condensate is produced in gaseous form before reaching in the separator on the surface with minimum liquid dropout in reservoir. Therefore, both mechanisms are enhancing the condensate production for rich condensate reservoir.

5. Conclusion

The state of the near critical fluid changes with the minor change in reservoir temperature. Volatile oil is produced when

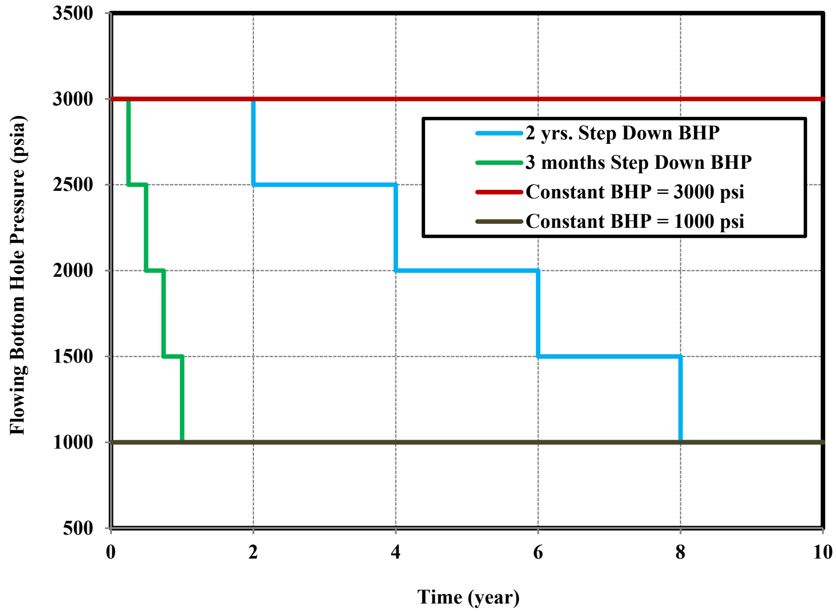


Fig. 13. Various well operating strategy to control production.

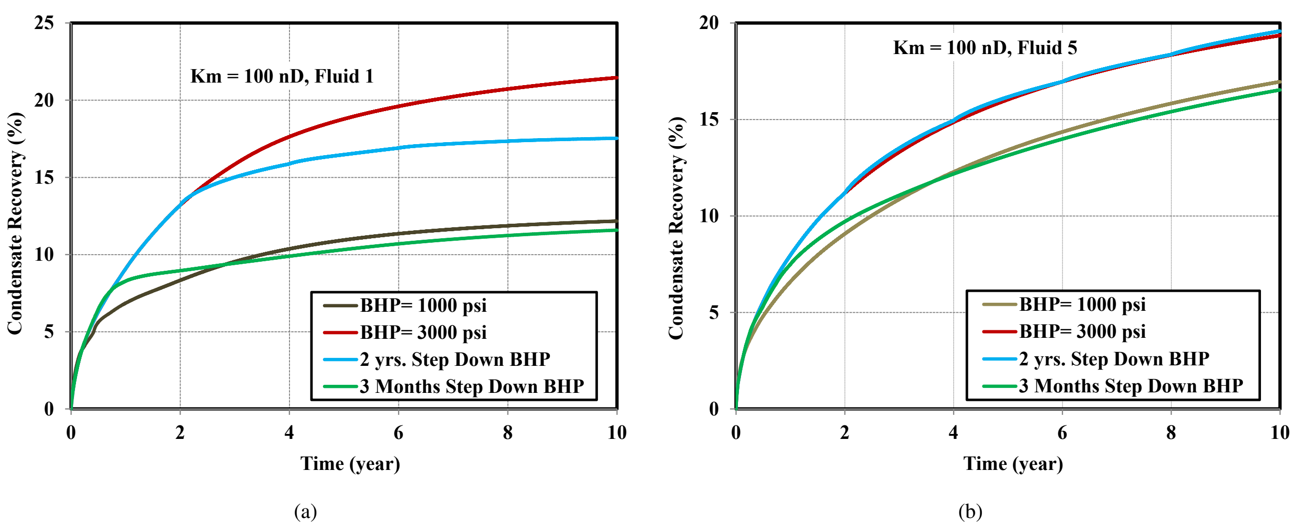


Fig. 14. Comparisons of condensate recoveries for constant and periodic step down of operating bottom hole pressure for (a) fluid 1 (b) fluid 5.

the reservoir temperature is less than critical temperature. In contrary, reservoir fluid is gas-condensate when the temperature is higher than critical temperature. This study investigated the impacts of changes in reservoir temperature on liquid production from hydraulically fractured tight formations with low permeability (100-1000 nD) and low porosity (5%). The results are based on compositional simulations of a shoe-box shaped reservoir model with single vertical fracture considering 120 ft. spacing. Sensitivity of fracture permeability (10 mD to 25,000 mD), effect of flowing bottom hole pressure on production are also studied.

Five different fluids varying liquid richness are chosen to study the production behavior from the reservoirs operated at high (3000 psia) and low (1000 psia) flowing bottom hole pressure. The higher fracture permeability doesn't guarantee higher production of liquid. An optimum fracture permeability may be needed depending on reservoir permeability, operating bottom hole pressure, type of fluid and state of fluid.

Recoveries are higher for the higher permeability tight oil reservoirs (~1000 nD) as expected. The differences in recoveries are much more pronounced in these systems as permeabilities increase (~10%). Condensate recoveries are better than volatile oils everything else being the same. Operating wells at higher flowing bottom hole pressures is better from a recovery viewpoint for lower permeability reservoirs with leaner fluids. Surprisingly, the liquid rates are also higher under these conditions.

For low permeability reservoir (100 nD), the same conclusions hold true for the richer fluid. However, the differences are not as pronounced in richer fluids, indicating that there is a wider range of acceptable producing conditions for richer (liquid-rich) compositions. For higher reservoir permeabilities (1000 nD), it is better to operate the wells at lower flowing bottom hole pressures. The recoveries and rates may be optimized by gradually stepping down the bottom hole pressures however, the resulting increase in recoveries is modest (1-2%). These new and novel conclusions from this research have strong impact on production strategy to maximize recovery from complex fluid systems in low-permeability reservoirs.

Nomenclature

FBHP = Flowing bottom hole pressure, psia
GOR = Gas oil ratio, SCF/STB
k_{fx} = Fracture absolute permeability in X-direction, mD
k_{fy} = Fracture absolute permeability in Y-direction, mD
k_{fz} = Fracture absolute permeability in Z-direction, mD
kx = Reservoir absolute permeability in X-direction, nD
ky = Reservoir absolute permeability in Y-direction, nD
kz = Reservoir absolute permeability in Z-direction, nD
LGR = Liquid to gas ratio, STB/MMSCF
PVT = Pressure volume temperature, -
SCF = Standard cubic foot, -
STB = Stock tank barrel, -
X = Reservoir dimension in X-direction, ft
Y = Reservoir dimension in Y-direction, ft
Z = Reservoir thickness, ft

Acknowledgments

The authors gratefully acknowledge the academic license to CMG products from Computer Modeling Group, Calgary, Canada.

References

Akin, S., Castanier, L.M., Brigham, W.E. Effect of temperature on heavy oil/water relative permeabilities. Paper SPE49021 Presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 27-30 September, 1998.

Amin Gherabati, S., Browning, J., Male, F., et al. The impact of pressure and fluid property variation on well performance of liquid-rich Eagle Ford shale. J. Nat. Gas Sci. Eng. 2016, 33: 1056-1068.

Bagci, S., Castro, L., Flores, J. Optimization of hydraulic fracturing and production enhancement: Case studies for us shale plays and tight sand reservoirs. Paper SPE185773 Presented at the SPE Europec Featured at 79th EAGE Conference and Exhibition, Paris, France, 12-15 June, 2017.

Ghanizadeh, A., Clarkson, C.R., Song, C., et al. Controls on liquid hydrocarbon permeability of tight oil and liquid-rich gas reservoirs: Examples from Bakken and Montney formations (Canada). Paper AAPG2902898 Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA, 23-25 July, 2018.

Khoshghadam, M., Khanal, A., Lee, W.J. Numerical study of impact of nano-pores on gas-oil ratio and production mechanisms in liquid-rich shale oil reservoirs. Paper SEG2154191 Presented at the Unconventional Resources Technology Conference, San Antonio, Texas, USA, 20-22 July, 2015.

Lei, G., Cheng N., Whitson, C.H. Liquid-rich shale versus conventional depletion performance. Paper SPE167788 Presented at the SPE/EAGE European Unconventional Resources Conference and Exhibition, Vienna, Austria, 25-27 Feburary, 2014.

Levine, J.S. Prats, M. The calculated performance of solution-gas-drive reservoirs. SPE J. 1961, 1(03): 142-152.

Lu, Q. Unconventional reservoir perforating cluster spacing optimization method for staged-fracturing horizontal well. Paper SPE184483 Presented at the SPE Annual Technical Conference and Exhibition, Dubai, UAE, 26-28 Semptember, 2016.

Neshat, S.S., Okuno, R., Pope, G.A. Simulation of water and condensate blockage and solvent treatments in tight formations using coupled three-phase flash and capillary pressure models. Paper SPE190242 Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA, 14-18 April, 2018.

Orangi, A., Nagarajan, N.R., Honarpour, M.M., et al. Unconventional shale oil and gas-condensate reservoir production, impact of rock, fluid, and hydraulic fractures, Paper SPE140536 Presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, 24-26 January, 2011.

Panja, P., Conner, T., Deo, M. Grid sensitivity studies in hydraulically fractured low permeability reservoirs. J. Petrol. Sci. Eng. 2013, 112: 78-87.

Panja, P., Conner, T., Deo, M. Factors controlling production in hydraulically fractured low permeability oil reservoirs. Int. J. Oil. Gas Coal T. 2016, 13(1): 1-18.

Panja, P., Deo, M. Factors that control condensate production from shales: Surrogate reservoir models and uncertainty analysis. SPE Reserv. Eval. En. 2016a, 19(1): 130-141.

Panja, P., Deo, M. Unusual behavior of produced gas oil ratio in low permeability fractured reservoirs. J. Petrol. Sci. Eng. 2016b, 144: 76-83.

Pathak, M., Deo, M., Craig, J., et al. Geologic controls on production of shale play resources: Case of the Eagle Ford, Bakken and Niobrara. Paper SEG1922781 Presented at the Unconventional Resources Technology Conference, Denver, Colorado, USA, 25-27 August, 2014.

Railroad Commission. Eagle Ford shale information. Texas Railroad Commission, 2016.

Robinson, D.B., Peng, D.Y. The characterization of the heptanes and heavier fractions for the GPA Peng-Robinson programs. GPA RR-28-1978.

Sanaei, A., Jamili, A., Callard, J. Optimum fracture spacing in the eagle ford gas condensate window. Paper

SEG1922964 Persented at the Unconventional Resources Technology Conference, Denver, Colorado, USA, 25-27 August, 2014.

Sharif, M.D.A., Nagalakshmi, N.V.R., Reddy, S.S., et al. Advance technique to increase production from tight formations using HiWAY Flow-Channel Hydraulic Fracturing Technique. J. Adv. Chem. Eng. 2017, 07(01): 1000165.

Siripatrachai, N., Ertekin, T., Johns, R.T. Compositional simulation of hydraulically fractured tight formation considering the effect of capillary pressure on phase behavior. SPE J. 2017, 22(04): 1046-1063.

Wang, M., Chen, S., Lin, M. Enhancing recovery and sensitivity studies in an unconventional tight gas condensate reservoir. Petrol. Sci. 2018, 15(2): 305-318.

Whitson, C.H., Sunjerga, S. PVT in liquid-rich shale reservoirs. Paper SPE155499 Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 8-10 October, 2012.