PRACTICAL INSIGHTS INTO LIQUID LOADING WITHIN HYDRAULIC FRACTURES AND POTENTIAL UNCONVENTIONAL GAS RESERVOIR OPTIMIZATION STRATEGIES

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Abstract

The U.S. has experienced a resurgence of the upstream hydrocarbon sector in recent years, owing to the economic extraction of oil and gas from ultra-tight reservoirs using multistage hydraulic fracturing in horizontal wells. This success is often attributed to slick-water stimulation treatments that help create extensive complexity and contact with the low permeability reservoir. In this process, hundreds of thousands of barrels of water are pumped downhole, along with friction reducers, low concentration linear gel, fracture propping sand and other additives, to create and sustain these fractures. However, only a small percentage of this stimulation water is recovered back once the well is put back on production. This not only leads to excessive water hauling costs for operators in each consecutive well but also liquid blockage for hydrocarbon flow. Such water blockage/loading may become a serious concern in dry gas reservoirs such as the Marcellus field in the northeastern U.S., due to the unfavorable hydrocarbon mobility ratios. In spite of its implications on early and late time well performance, the issue of hydraulic fracture cleanup and gas flowback through it when drained through a horizontal wellbore is still an insufficiently understood subject. In this study the authors investigate the potential of liquid loading (stimulation water or condensate) within the hydraulic fracture itself due to low matrix permeability and insufficient drawdown conditions. Similar conditions may also arise late in the life of well when the reservoir pressure has declined significantly or due to wellbore design issues. A 3D reservoir simulation model with a discrete, planar hydraulic fracture is set up to investigate the competition between capillary, viscous and gravity forces within the fracture. The results indicate a strong tendency for liquid loading in the ultra-low permeability gas reservoirs under common operational constraints and offer recommendations on best practices to minimize its impact.

Introduction

Water management and its impact on unconventional reservoir economics is a key focus area for the industry these days. Slutz et al. (2012), Fedotov et al. (2013) have highlighted the issues at hand and suggested possible best practices. On an average less than 25% of stimulation water is ever recovered back in most of the contemporary unconventional reservoirs under development (Pagels et al., 2012). Loss of stimulation water can broadly be attributed to three factors: 1) imbibition into the matrix due to high capillary pressures, 2) leakage to un-propped induced fractures and their closure after drawdown or 3) retention within stimulated hydraulic fractures. Various researchers have investigated the impact of stimulation water invasion into the matrix and the resulting fracture treatment performance in conventional reservoirs. It is commonly believed that majority of the stimulation fluid is trapped in the matrix due to capillarity effects. Holditch (1979) highlighted the importance of capillary pressure, matrix permeability damage and relative permeability, in understanding the extent of productivity damage due to fracturing water invasion. He concluded that unless the reservoir rock permeability is significantly damaged by the stimulation fluid, a complete water block to gas flow will not occur and that a large enough drawdown will achieve the same cumulative gas production irrespective of the capillary pressure. Solimon et al. (1985) corroborated with these results using a similar 2D cleanup model. Settari et al. (2002) showed the impact of water blocks on well productivity and studied their signatures from pressure transient analysis (PTA) for the Bossier play. Later, Frieauf et al. (2009) developed a flow resistor analytical model for well productivity of hydraulically fractured wells with finite fracture conductivity and invaded zone damage. Gdanski and Walters (2010) simulated various scenarios to study the impact of fracture conductivity, matrix relative permeability and flowback conditions on load recovery and gas production. Higher water relative permeability allowed deeper imbibition of water during shut-in period and reduced fracturing water recovery. Shaoul et al. (2011) studied the impact of damage and different relative permeability models on gas production in unconventional reservoirs with similar simulation setup as above and observed up to 50% reduction in early time gas production due to blockage.

However, all of the above referenced works lack a discussion on accumulation and segregation of liquid within a tall vertical fracture itself, which is drained by a horizontal well, due to gravity and its competition with capillary forces as well as drawdown. Conventional fracture cleanup models worked well for vertical wells where lifting stimulation water to perforations was not an issue (primarily horizontal flow). However, in the case of horizontal wellbores with significant vertical flow within fractures to reach horizontal well perforations, a fresh re-examination of existing cleanup models is needed. A recent experimental study by Parmar et al. (2012) has shown significant liquid loading possibility at fracture bottom due to adverse mobility ratio and gravity segregation at low gas flow rates. The results indicate poorer fracture

cleanup/water displacement by gas moving against gravity and formation of fingers through the proppant pack. In another experimental study, Palisch et al. (2007) had shown that even a small amount of residual liquid in the proppant pack can significantly increase the pressure drop, compared to a completely clean fracture, implying significant reduction in effective conductivity. This is attributed to multi-phase flow effects. These experimental results can help explain field observations such as the one presented in Taylor et al. (2011). This case study highlighted the improvements in production performance of wells which were placed at the bottom of targeted formations and attributed the improvements to gravity drainage effect that helps to clean the fracture above the wellbore. In order to investigate this process numerically, a commercial reservoir simulator was used in this study, to simulate liquid loading in tall, planar hydraulic fractures, which are drained through a horizontal wellbore. Generally, hydraulic fractures in horizontal wells can grow from tens to hundreds of feet in height. If liquid loading takes place in a certain section of the fracture, it will impair the inflow of gas from that section thereby leading to a reduction in the effective contact area or fracture conductivity.

In geomechanically sensitive reservoirs such as the Marcellus or Haynesville, multiple operators employ a surface choke management strategy to control the effective reservoir drawdown and minimize the closure of stimulated fracture network, propped or not. Studies have indicated that in some over-pressured unconventional reservoirs pore volume changes may be as high as 20% due to production induced stress changes (Akande et al. 2012). This will lead to permeability reduction in the matrix which will worsen the liquid loading problem within the fractures because of lower gas inflow velocity. A simple back of the envelope calculation can illustrate the reason for expecting liquid loading under ultra-low perm reservoir settings. Consider a typical well in an unconventional gas play with a daily gas production of 5 MMscf/day (Q). Let us assume the total number of fracs in the well to be 50 (N), the width/aperture of each fracture to be 0.01 ft. (w) and the lateral extent of the fracture to be 100 ft. (x). With a gas expansion coefficient of 1000 scf/cf (B_g) and proppant pack porosity of 40% (ϕ), the downhole gas velocity inside the fracture can be estimated as per Equation 1:

$$v = \frac{Q}{N \cdot x \cdot w \cdot B_g \cdot \phi} = 0.003 \text{ ft/sec} \quad (\text{Eq. 1})$$

To estimate the magnitude of velocity (v) needed to lift the liquid vertically out of the fracture, we can use Turner's critical velocity (Turner et al. 1969) for vertical gas wells:

$$v = 1.92 \cdot \sigma^{\frac{1}{4}} \cdot \frac{(\rho_L - \rho_G)^{\frac{1}{4}}}{\rho_G^{\frac{1}{2}}} \quad (\text{Eq. 2})$$

If we assume σ (surface tension) to be 60 dynes/cm, ρ_L (density liquid) to be 58 lb/ft³ and ρ_G (density gas) to be 3 lb/ft³, we obtain

$$V_{\text{crit}} = 8.4 \text{ ft/s}$$

It is evident from this approximate calculation that the desired lift velocity for unloading the liquid from the fracture and the gas inflow velocity into the fracture may differ by several orders of magnitude. A higher contrast in displaced and displacing fluid viscosities will also negatively impact cleanup (Tidwell and Parker, 1996). In such a scenario, the lower portion of the fractures will be filled with water even after production is initiated. This suggests that when studying the issue of load recovery from hydraulically fractured horizontal wells, even if the drawdown is able to overcome the capillary pressures, the inflow gas velocity may not be high enough to lift the liquid against gravity into the wellbore. Liquid blocked inside the fracture in this way will reduce the productivity of the well as well as overall load recovery.

Figure 1: Schematic showing liquid loading within the fractures

Other effects which can further exacerbate productivity decline due to liquid loading are proppant settling and fracture closure. During the well stimulation process proppant particles typically settle down, closer to the perforations due to higher density as compared to the slick-water. Therefore, when drawdown is applied to initiate production the top portion of the stimulated fracture may not be able to sustain its original aperture. In such a case the propped, bottom portion of the fracture becomes essential to sustaining hydrocarbon production. Any impairment due to liquid loading in this portion will seriously impact well productivity. Fracture closure and proppant banking were not simulated in this study. Therefore in a real life scenario the impact of liquid loading may be much more severe than what is modeled here. Figure 2 shows a schematic explaining this scenario.

Figure 2: Impact of proppant settling and fracture closure

The concept of F_{CD} (dimensionless fracture conductivity) is typically used as a measure of ease of fluid flow through the fracture. By definition it compares the capacity of a fracture to transmit fluid to the wellbore versus the ability of matrix to deliver fluid into the fracture (Pearson, 2001) and is expressed as:

$$F_{CD} = \frac{k_{frac} * w_{frac}}{k_{matrix} * X_{frac}} \quad (Eq. 3)$$

Where, k_{frac} is the fracture permeability, w_{frac} is fracture width, k_{matrix} is matrix permeability and X_{frac} is fracture half-length. The k_{frac} here is directly dependent on fracture cleanup as shown by Palisch et al. (2007). If proper estimates of fracture loading/cleanup and associated non-Darcy flow effects (Guppy et al. 1982, Miskimins et al. 2005, Holditch et al. 1976) are not used, the calculated F_{CD} values maybe over-estimated thereby leading to more optimistic production forecasts.

Simulation Setup

Cipolla et al. (2009) provided a detailed description of reservoir modeling for shale gas reservoirs with multiple fractures and integration with micro-seismic data. In this study, commercial reservoir simulators IMEXTM (Black Oil) and GEMTM (Compositional) from CMG were used to mechanistically model the 3D cleanup of a single discrete planar hydraulic fracture through a horizontal wellbore. The base case reservoir properties are provided in Table 1 and are based on Eagleford type rock as per Mullen (2010). Fine-scale gridding is employed near the fracture face along the horizontal wellbore to accurately capture pressure and saturation variations in the matrix and in the fracture. It also helps with numerical stability. Along the wellbore (X-direction) the grid cell size increases logarithmically from a minimum of 0.005 ft. to 50 ft. (Wang et al. 2011) The model is based on a 46 X 16 X 20 Cartesian grid in the X, Y, Z direction respectively. Vertical direction fine gridding was employed for compositional simulation scenarios. Figure 3 shows a zoomed in view of a sample fine gridding scheme employed. The red cells correspond to the fracture and the blue to the matrix. Figure 4 shows schematic and perspective views of the model setup.

Figure 3: (Zoomed in sub-section) Fine gridding along the wellbore

Figure 4: A) Schematic showing single hydraulic fracture in a horizontal well within a homogeneous tight reservoir B) Sliced section view of the simulated model with the fracture in green and matrix in red

To simulate the stimulation fluid loss during the fracking operation, 1000 barrels of water were injected into the formation through the fracture. Since fracture propagation is not modeled, water injection at this high rate leads to high pressures in and around the fracture, which can therefore be called a super-charged zone. However this extra energy only leads to higher degree of load recovery not less, as compared to a case where leak-off is modeled during fracture propagation. This was followed by a shut-in time (indicative of lag time between stimulation job and tie in with pipeline system in real world scenario) and then production. Various scenarios were run to investigate the impact of different operational, reservoir or fracture properties on liquid loading within the fracture and on gas recovery. Considering the unavailability of reliable, lab measured capillary pressure curves for ultra-low perm shale reservoirs, this study utilizes the Leverett J-function approach and scales capillary pressures according to the respective porosity and permeability of different regions in the model i.e. matrix and fracture. Such an approach assumes a connected pore network structure (such as ultra-low perm tight gas reservoirs) and applicability of Young-Laplace equation at nano-pore level. This is a justifiable assumption considering the lack of an alternate model for shale rock capillary pressure estimation in the commercial reservoir simulator used. Figure 5 shows the capillary curves utilized in this simulation study which are based on laboratory measurements of J-function for Berea sandstones (Hirasaki 2008). The initial water saturation within the reservoir is equal to residual water saturation. Therefore the only mobile water is the stimulation water. This was done to easily quantify the amount of fracturing fluid recovery.

Figure 5: Leverett J-function scaled capillary pressure curves

Straight line relative permeability curves were utilized for the fractures due to the low capillary pressures. Figure 6 shows a set of synthetic matrix and relative permeability curves used in the simulations. Multiple end point relative perm values were investigated. In addition to black oil simulation, compositional simulation runs were made to understand the nature of condensate buildup within the hydraulic fractures and its cleanup along with fracturing fluid cleanup. Both lean and rich gas scenarios were investigated.

Figure 6: Synthetic relative permeability curves
a) Matrix relative perm b) Fracture relative perm

Table 1: Base Case Black Oil Model Properties	
Description	Value
Matrix Permeability	1 μ D
Fracture Permeability	2 D
Fracture Height	55 ft.
Fracture Thickness	0.01 ft.
Fracture Half Length	175 ft.
Gas-Water Surface tension	40 dyne/cm
Gas Gravity	0.6
Water Density	14.7 lb./ft. ³
Flowing Bottom-hole Pressure	4500 psi
Initial Reservoir Pressure	6500 psi
Matrix Initial Water Saturation	0.2
Matrix Residual Water Saturation	0.2

Buckley- Leverett's theory of immiscible displacement (Buckley et al, 1942) provides a solution for 1D displacement of oil by water and shows that the fractional flow of the water behind the displacement front is directly linked with capillary pressure, direction of drainage against gravity and mobility ratio. This is expressed in Equation 4 below:

$$f_w = \frac{1}{1 + \frac{k_o \mu_w}{k_w \mu_o}} + \frac{\frac{k_o A}{\mu_o q_T} \left(\frac{\partial p_c}{\partial x} + \Delta \rho g \sin \alpha \right)}{1 + \frac{k_o \mu_w}{k_w \mu_o}} \quad (\text{Eq. 4})$$

Here, f_w refers to the fractional flow of water (displacing fluid) when it is displacing oil (displaced fluid), k_o , k_w refer to respective permeabilities and μ_o , μ_w to the phase viscosities. The mobility ratio (M) is defined as the ratio of mobility (k/μ) of displacing versus displaced fluid and is an indicator of displacement efficiency.

$$M = \frac{k_w \mu_o}{k_o \mu_w} \quad (\text{Eq. 5})$$

High mobility ratios (typically >10-100 or more) lead to high f_w (as per Eq.4), showing that displacing fluid by-passes the displaced fluid, causing inefficient displacement. In a similar manner if we look at fluid cleanup within the fracture, the displaced fluid (water) is way more viscous than displacing fluid (gas) leading to unfavorable mobility ratio and therefore inefficient cleanup. In addition to this when the displacement is against gravity the displacement efficiency is further reduced.

Results

In the base case black oil scenario, the reservoir is at residual water saturation initially and a flowing bottomhole pressure of 4500 psi is applied after a shut in wait time of 30 days following the stimulation (water injection) process. The cumulative gas and water produced at the end of a 500 day period are 70.7 MMcf. and 279 bbl. respectively. This means that out of the 1000 bbl. of fracturing fluid pumped in only 28 % is recovered back and the rest is still trapped, either in the matrix or in the fracture itself. Figure 7 shows the variation of water saturation at the top and bottom of the fracture over time (measured at two specific points). It is interesting to note that by the 500 day time step the water saturation in the entire fracture reduces to a residual level. However, the water saturation inside the matrix (0.1 ft. from fracture face) is still in decline at the end of the 500th day due to high capillary pressures (Figure 8). There is a measurable difference in water saturation in the matrix adjacent to fracture top versus matrix adjacent to fracture bottom.

Figure 7: Variation of water saturation inside fracture over time

Figure 8: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

Figure 9: Fracture water saturation maps at different time steps, Base case

Figure 9 shows the saturation distribution within the fracture, surrounded by the matrix (red), over time. The plots show the Y-Z cross-section of the model and the horizontal wellbore goes in the X direction i.e. into the plane. The region showing high water saturation at time = 1 day, corresponds to the fracture and the rest is the matrix. These plots show that water imbibition cleans up the fracture during the shut-in period because the matrix is water wet. However once production is initiated, water comes out into the fracture from the formation. Continued production leads to cleanup of water that is present inside the fracture. The bottom of the fracture though does not cleanup for a while. If we look at Figures 7 and 8 again, notice that the matrix (near fracture face) does not start cleaning up until the fracture has cleaned up completely.

This is because the two zones are in saturation equilibrium and if there is water inside the fracture, the matrix will keep imbibing it. Hence we observe a counter-current imbibition effect that impairs gas relative permeability near fracture face, thereby reducing inflow velocity.

Implications of Matrix Permeability on Liquid Loading

Since matrix permeability is a critical control on gas inflow velocity, sensitivities were run to study the impact on fracturing water cleanup and productivity. Figure 10 shows that increasing the matrix permeability led to early peak productivity as the fracture and matrix cleanup faster. However, the 0.1 μD reservoir showed delayed and much lower peak productivity. This is because lower permeability leads to lower gas inflow velocity. In addition to this, higher capillary pressures as per the J-function scaling also increase water blockage in matrix which further reduces the gas relative permeability and thereby the flow rates. If gas velocities are lower than the critical lift velocity, fracture cleanup will be inefficient. The cumulative gas production in this case is 7.5 MMcf and the cumulative water recovery is 154.2 bbl. (15.4 %). Figures 11-13 compare the cleanup profiles of low matrix permeability ($K_m = 0.1 \mu\text{D}$) scenario against the high permeability ($K_m = 10 \mu\text{D}$) scenario in Figures 14-16.

Figure 10: Effect of matrix permeability on normalized gas productivity

Figure 11: Variation of water saturation inside fracture over time

Figure 12: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

Water saturation inside fracture after 1 day
(end of fracture treatment)

Water saturation inside fracture after 30 days
(beginning of production, end of shutin)

Water saturation inside fracture after 210 days

Water saturation inside fracture after 500 days
(end of production)

Figure 13: Fracture water saturation maps at different time steps, $K_m = 0.1 \mu D$

Figure 14: Variation of water saturation inside fracture over time

Figure 15: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

Water saturation inside fracture after 1 day
(end of fracture treatment)

Water saturation inside fracture after 30 days
(beginning of production, end of shutin)

Water saturation inside fracture after 210 days

Water saturation inside fracture after 500 days
(end of production)

Figure 16: Fracture water saturation maps at different time steps, $K_m = 10 \mu D$

Implications of Fracture Permeability on Liquid Loading

Figure 17: Effect of fracture permeability on gas productivity during cleanup (Dashed line indicates the peak trend)

Fracture permeability is taken as a proxy for modeling proppant pack conductivity. Figure 17 shows that lower fracture permeability leads to delayed and reduced peak productivity. However, even with much higher fracture permeability gas productivity is not significantly higher. This may be explained by observing the cleanup profiles in Figures 18-20. They indicate that higher fracture permeability leads to easier piling up of liquid at fracture bottom due to gravity segregation. The matrix properties remained the same so inflow velocity did not change, which implies that gravity starts dominating vertical flow in the fracture. Therefore the fracture remains loaded at bottom till approximately 375th day whereas the top cleans up by the 120th. For a fracture permeability of 0.2 D, Figures 21-23 show that the entire fracture cleans up by the 300th day. This is because water produced from the matrix faces more resistance in moving downwards towards fracture bottom due to low fracture permeability. Cleanup is governed by drawdown and is, therefore, uniform at the top and bottom. These results indicate that even if we achieve high F_{CD} fractures, it does not necessarily reduce the impact of liquid loading in the hydraulic fracture section which is below the horizontal wellbore.

Figure 18: Variation of water saturation inside fracture over time

Figure 19: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

Water saturation inside fracture after 1 day
(end of fracture treatment)

Water saturation inside fracture after 30 days
(beginning of production, end of shutin)

Water saturation inside fracture after 210 days

Water saturation inside fracture after 500 days
(end of production)

Figure 20: Fracture water saturation maps at different time steps, $K_f = 20 \text{ D}$

Figure 21: Variation of water saturation inside fracture over time

Figure 22: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

Water saturation inside fracture after 1 day
(end of fracture treatment)

Water saturation inside fracture after 30 days
(beginning of production, end of shutin)

Water saturation inside fracture after 210 days

Water saturation inside fracture after 500 days
(end of production)

Figure 23: Fracture water saturation maps at different time steps, $K_f = 0.2 \text{ D}$

Implications of Drawdown on Liquid Loading

Figure 24: Effect of drawdown on gas productivity during cleanup
(Lower Pwf means higher drawdown; Dashed line shows the peak trend)

As previous results have indicated, gas inflow rates play a critical role in fracture cleanup especially at the bottom. Thus a logical deduction is to increase the drawdown by reducing bottomhole pressure which will enhance the cleanup. Figure 24 shows the variation in gas productivity over time for different bottomhole pressure scenarios. When the flowing bottomhole pressure is reduced to 2500 psi, the increased drawdown leads to a better cleanup (shown in Figures 25 to 26). The cumulative gas and water produced are 131.2 MMcf and 401.5 bbl. (40.1 %). As expected higher drawdown leads to better fracture cleanup and higher cumulative gas. The figures indicate that the fracture cleans up both at the top and bottom of the fracture by the 400th day even though there is a considerable amount of water trapped at the fracture face. Water does not accumulate at the bottom of the fracture because the high drawdown leads to high gas velocities which continuously push the fracturing water to the wellbore by overcoming gravity.

Figure 25: Variation of water saturation inside fracture over time

Figure 26: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

However, if drawdown is limited to 1000 psi the cumulative gas and water recoveries reduce to 33.9 MMcf and 165.5 bbl.

(16.5 %). Figures 27-29 below show the poor cleanup inside the fracture and at the fracture face.

Figure 27: Variation of water saturation inside fracture over time

Figure 28: Variation of water saturation inside matrix, 0.1 ft. from fracture face with time

**Water saturation inside fracture after 1 day
(end of fracture treatment)**

**Water saturation inside fracture after 30 days
(beginning of production, end of shut-in)**

Water saturation inside fracture after 210 days

**Water saturation inside fracture after 500 days
(end of production)**

Figure 29: Fracture water saturation maps at different time steps, Lower drawdown

It becomes evident that lower drawdown leads to lower gas inflow velocity and therefore liquid stays at the bottom of the fracture for a longer duration. This effect can be a significant productivity inhibitor in dry gas reservoirs such as Marcellus, where geomechanics is a key control on reservoir performance. Excessive drawdown early in life of the well may enhance cleanup but can also lead to propped/un-propped fracture closure and thereby negatively impact long term EUR (Estimated Ultimate Recovery). Higher drawdowns may also be constrained in a condensate rich gas reservoir. If the reservoir pressure drops below the dew point, an additional liquid phase (condensate) may form within the reservoir which will reduce gas relative permeability and thereby flow velocity. To study the fracture cleanup for condensate rich reservoirs, compositional simulations were run on similar models as described earlier. The next section describes those results and observations.

Impact of shutting the well for longer duration was also studied (Agrawal et al. 2013) and the results indicated deeper fracturing fluid invasion with longer shut-in times. Imbibition of water further into the formation reduces the extent of water block near the fracture face itself, which leads to improved gas relative permeability and therefore high initial rate when well is put on production. However no impact was observed on long term EUR and productivity. Similar results were reported by Fakcharoenphol et al. (2013). Figure 30 below shows the imbibition of fracturing fluid into the matrix for different shut-in times.

**Figure 30: Fracturing water imbibition into matrix for different shut-in times
(Distance measured from fracture face)**

Compositional Simulation Model

For the compositional study, a lean and a rich gas composition were selected as in-situ reservoir fluids. The mole fractions and Peng-Robinson EOS (Equation of state) parameters for the rich gas are shown in Table 2. The liquid dropout curve from CCE (constant composition expansion) is shown in Figure 31. Maximum liquid dropout is approximately 35% and the dew point pressure is 3470 psi.

Table 2: Rich gas mole fractions and EOS tuning parameters

Components	Mol Frac	Pc (atm)	Tc (K)	Acentric Factor	Mol. Wt.	Vc (l/mol)	Parachor
N2	0.0283	33.5	126.2	0.04	28.013	0.0895	41
CO2	0.0613	72.8	304.2	0.225	44.01	0.094	78
CH4	0.4625	45.4	190.6	0.008	16.043	0.099	77
C2-3	0.1624	45.03	337.91	0.1253	35.82	0.172327	102.3429
C4-6	0.1439	34.6	461.72	0.2348	69.2	0.296256	197.7143
C7P1	0.10069	19.9	508.82	0.3319	109.33	0.550326	312.3714
C7P2	0.03944	14.42	814.39	0.5931	210.23	1.112666	600.6571
C7P3	0.00148	8.48	1096.89	1.0344	424.84	2.150231	1213.829

Figure 31: Liquid dropout for rich gas (CCE)

As for the lean gas scenarios, composition as per Table 3 was selected. Figure 32 shows the corresponding liquid dropout profile as per CCE experiment. The maximum liquid dropout is 1.5% and the dew point is ~4950 psi.

Components	Mol frac	Pc (atm)	Tc (K)	Acentric Factor	Mol Wt.	Vc (l/mol)	Parachor
CO2	5.3	72.8	304.2	0.23	44.01	0.094	78
N2	0.09	33.5	126.2	0.04	28.013	0.0895	41
CH4	80.54	45.4	190.6	0.01	16.043	0.099	77
C2H6	5.6	48.2	305.4	0.1	30.07	0.148	108
C3H8	3.34	41.9	369.8	0.15	44.097	0.203	150.3
IC4	0.8	36	408.1	0.18	58.124	0.263	181.5
NC4	0.83	37.5	425.2	0.19	58.124	0.255	189.9
C5-C6	1.23	38.87	480.1	0.23	74.64	0.275	217.4307
C7-C8	0.8	30.82	585.8	0.32	102.69	0.3887	297.0892
C9-C11	0.703	25.12	652.2	0.48	136.5	0.5136	388.5041
C12-C15	0.445	20.21	699.7	0.51	183.85	0.6757	508.0737
C16+	0.322	14.72	836.2	0.7	280.59	0.974	721.6981

Figure 32: Liquid dropout for lean gas (CCE)

When the condensate drops out in the reservoir, a representative oil relative permeability needs to be used. Stone 2 model is used to obtain the oil end point relative permeability (K_{ro}) from the two-phase K_{row} and K_{rog} . The ternary diagrams for matrix and fracture are presented below.

Figure 33: K_{ro} values for Matrix from Stone 2 model

Figure 34: K_{ro} values for Fracture from Stone 2 model

Multiple gas and water end point relative permeabilities were also tested along with different drawdown scenarios for each of the lean and rich gas reservoirs. Only the most representative rich gas case will be discussed here. Detailed results may be obtained at Agrawal (2013) and Agrawal et al (2013). Flow through evaporation effect for water was enabled in the simulator to study if it was a significant factor as it is for conventional gas reservoirs (Mahadevan et al. 2005, 2007). However considering the low gas velocities and volume throughput, flow through drying effect contributed minimally towards fracture cleanup.

The impact of velocity dependent relative permeability as proposed by Pope et al. (2000) was also investigated. The proposed model stipulated that residual oil saturation and thereby relative permeability are functions of not only capillary pressure (i.e. surface tension) but also viscous drag and buoyancy. To account for all the forces acting on a phase, “trapping number” was defined as the sum of capillary and bond numbers. The implication of using this effect is that when displacing fluid velocities are high, the residual displaced fluid saturations would be lower than estimated without velocity impact. For conventional reservoirs with condensate dropout, enabling velocity dependent relative permeability helped explain lower condensate banking as higher gas velocities stripped away the condensate from near wellbore region. Considering the extremely low inflow velocities from the matrix to the fracture in ultra-low permeability rocks, inclusion of this effect didn’t materially impact the fracture cleanup process in our models. However it provided an additional insight into stimulation water distribution near fracture face. As Figures 35 below shows, enabling the velocity dependent relative permeability effect reduces the near fracture face residual gas saturation to zero (whereas $S_{rgw} = 0.25$) right after stimulation (high rate injection), which in turn reduces gas relative permeability to zero. This might help explain why some wells flowback only stimulation water for first few days and then experience gas breakthrough. As per the author’s knowledge, a simulation modeling of this observation has not been shown in literature earlier.

Figure 35: Phase saturation near fracture after stimulation, with velocity dependent relative permeability enabled

Compositional Simulation Results

Multiple unconventional reservoirs being exploited today have condensate windows where the in-situ hydrocarbons are in gaseous phase but contain heavier components that drop out as liquids once the pressure drops below dew point e.g. Eagleford in South Texas. Fluid composition and distribution across the play are known to have significant impact on production. (Tian et al. 2013). As discussed in the previous section, one of the possible strategies for minimizing liquid loading at the bottom of fracture is application of high drawdown. However that may not be the optimal strategy for condensate rich reservoirs. Below the dew point, condensate will accumulate in the fractures and further deteriorate gas productivity, in addition to damage from stimulation water loading. Cleanup techniques such as chemical treatment (Bang et al. 2008) and Huff-n-Puff (Ahmed et al. 1998) which focus on re-dissolution and flowback of condensates may need to be deployed. Results shown below demonstrate the scenario of condensate loading in fractures and how the cleanup varies.

As Figure 31 shows, peak liquid drop out for the rich gas occurs at 2500 psi. Hence a constant bottomhole pressure control of 2500 psi is applied during production for the high drawdown scenario. Considering the high drawdown and higher gas gravity (compared with earlier dry gas scenario) the cleanup of water from the fracture and nearby matrix is much more efficient as per Figures 36-38. The oil saturation on the other hand increases significantly with the fracture. In addition to water we also observe condensate loading at bottom (as per Figures 39-41).

Figure 36: Water saturation variation within fracture

Figure 37: Water saturation variation in matrix near fracture

Figure 38: Water saturation within the fracture at 30th day (end of shut-in) and 500th day (end of production)

Figure 39: Oil saturation variation within fracture

Figure 40: Oil saturation variation in matrix near fracture

Figure 41: Oil saturation within the fracture at 30th day (end of shut-in), 120th day and 500th day (end of production)

The saturation maps above indicate the extent of condensate dropout when pressure falls below dew point. Towards the bottom of the fracture, oil saturation is significantly higher than maximum liquid dropout because of gravity segregation and accumulation over time. Thus, the liquid rich gas supported the cleanup of fracturing fluid but led to condensate buildup instead. Figure 42 shows the comparison between gas productivity profiles for different drawdown scenarios. It shows that the base case productivity (bottomhole pressure higher than dew point) is slightly higher than the high drawdown case productivity (with condensate dropout). So increasing the drawdown has marginal impact on gas productivity. This shows that pressure managing the well initially would not only allow higher bottomhole pressure which will reduce the extent of geomechanic fracture closure but also minimize the loss of condensate downhole. Since natural gas liquids are valuable commodities as per current prevailing prices their loading/trapping within fractures must be avoided to optimize well economics. Multi-phase and non-Darcy flow can lead to significant loss in productivities. (Miskimins et al. 2005) Therefore once the reservoir pressure is below dew point, periodical condensate cleanup cycles using Huff-n-Puff or chemical treatment may be considered. In organic rich oil-wet matrix reservoirs, counter imbibition of oil from fracture into matrix may become significant. Hence utilization of surfactants with fracturing treatments will help in reducing condensate trapping at the fracture face.

Figure 42: Gas productivity variation for different drawdown (DD) scenarios (Condensate rich gas)

Discussion and Conclusions

As the results above have indicated, liquid loading within tall hydraulic fractures is a very realistic possibility. With fracture closure and uneven proppant distribution, the hydrocarbon inflow area can be significantly reduced. Depending on the actual drawdown experienced by a particular perforation cluster/stage and the matrix permeability, different extent of loading would occur across the multiple fractures generated. We have shown the loading of fracturing fluid (slick-water) and condensate at the bottom of the fracture, with no mobile water in the formation. However when the connate water saturation is higher than the residual water saturation to gas, gas relative permeability would be even lower and there would be more mobile water that will potentially load up within or near the fracture zone. This will severely hurt gas production over the entire life of well and not just the early time.

The results were also able to showcase the strong interplay of capillary, viscous and gravity forces when considering vertical lift of liquids by gas within the fracture. Impact of drawdown, reservoir and fracture permeability was also highlighted. Under insufficient drawdown, capillary and gravity forces trap the liquid within/ near the fracture. In case of water wet rocks, we observe counter current imbibition because water keeps imbibing into the matrix as long as the fracture is not completely clean. This residual liquid saturation within the fracture not only leads to loss of liquid production on the surface (fracturing fluid or condensate) but also impacts the peak gas productivity. Peak productivity may be delayed or reduced in magnitude depending on extent of liquid loading. Residual liquid saturation in the fracture can reduce fracture conductivity significantly. Shutting the well for long durations after stimulation has been shown to improve initial gas productivity since the stimulation water gets imbibed deeper into the formation, thereby improving near fracture face gas relative permeability and inflow rates. However no impact was observed on long term recovery or productivity. This means there is a balance to be achieved between shutting the well for longer durations (which improves early time flow rates) and NPV (Net Present Value) considerations where earlier production outweighs later production (due to time value of money).

One of the primary operational controls to minimize the likelihood of loading within fractures is maximizing drawdown. For geomechanically sensitive reservoirs like Marcellus or Haynesville, application of high initial drawdown may prematurely close the stimulated fracture network, due to which the EUR will suffer significantly even if the initial rates and load recoveries are high. Also, for condensate rich gas reservoirs like the Eagleford, excessive drawdown may cause retrograde condensate dropout within the reservoir as pressure goes below dew point. This will lead to further gas relative permeability reduction within/near fracture and ultimately lead to condensate loading within the fractures. These results were shown with the help of compositional flowback simulation. Considering the high economic value of NGLs (natural gas liquids) in today's market scenario, their recovery should be maximized. Lastly, excessive initial drawdown might lead

to proppant flowback or embedment as it has not had the time to fully settle in the fractures. Hence pressure management techniques as already employed by certain operators are recommended. Gradual decrease of bottomhole pressure helps with the geomechanic fracture closure, proppant flowback as well as condensate dropout issues.

Counter-intuitively high fracture permeability scenarios demonstrated higher liquid loading at fracture bottom early on. The top however cleaned much earlier. This was attributed to the fact that in a highly conductive vertical fracture with a horizontal well perforation in the middle, it becomes very easy for gravity to move the liquid down but becomes very difficult to move up, in case of insufficient drawdown. Hence the issue of lateral placement within the target zone also becomes a key factor in fracture cleanup and optimizing productivity. Placing the lateral towards the bottom of the zone will minimize the chances and extent of liquid loading within hydraulic fractures as gravity will support drainage. Few earlier field studies have also shared similar observations.

As the reservoir pressure is diminished, the extent of productivity damage due to liquid loading is only expected to increase. Stages where drawdown is reduced due to wellbore trajectory/hydraulics complications may experience significant productivity decline. Hence usage of ESPs (Electrical Submersible Pumps) for groups of stages might help enhance well life and fracture productivity. The operator may also consider energized fracturing alternatives (Ribeiro et al. 2012, Grundmann et al. 1983) if permeability damage due to swelling is a concern, load recovery is low and/or water availability is a big concern.

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Nomenclature

bbbl. = Barrel of Oil
scf. = Standard cubic feet
ppg. = Parts per gallon
mD = milli Darcy
ft. = Feet
lb. = Pounds
MMscf/day = Millions of standard cubic feet of gas per day
k_{frac} = Fracture Permeability (mD)
w_{frac} = Fracture Width (ft.)
k_{matrix} = Matrix Permeability (mD)
X_{frac} = Fracture half length (ft.)
V_{crit} = Turner's critical gas velocity
Q = Gas rate (MMscf/d)
N = No. of hydraulic fractures
h = Height of stimulated fractures (ft.)
w = Thickness of stimulated fractures (ft.)
B_g = Gas formation volume factor (scf/cf)
Φ = Effective propped fracture porosity
σ = Surface tension between gas and water (dynes/cm)
ρ_L = Density of liquid phase (lb./ft³)
ρ_G = Density of gas phase (lb./ft³)

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