Impact of capillary pressure and flowback design on the clean up and productivity of hydraulically fractured tight gas wells

Citation for published version:

Digital Object Identifier (DOI):
10.1016/j.petrol.2021.109465

Link:
Link to publication record in Heriot-Watt Research Portal

Document Version:
Peer reviewed version

Published in:
Journal of Petroleum Science and Engineering

Publisher Rights Statement:
© 2021 Elsevier B.V.

General rights
Copyright for the publications made accessible via Heriot-Watt Research Portal is retained by the author(s) and / or other copyright owners and it is a condition of accessing these publications that users recognise and abide by the legal requirements associated with these rights.

Take down policy
Heriot-Watt University has made every reasonable effort to ensure that the content in Heriot-Watt Research Portal complies with UK legislation. If you believe that the public display of this file breaches copyright please contact open.access@hw.ac.uk providing details, and we will remove access to the work immediately and investigate your claim.
Impact of Capillary Pressure and Flowback Design on the Clean Up and Productivity of Hydraulically Fractured Tight Gas Wells.

Martin Verdugo, Florian Doster, Heriot-Watt University

Abstract

This work analyses the impact of capillary pressure and flowback operational variables on hydraulically fractured tight gas wells with the objective of understanding the clean-up process at reservoir level and its impact on future well performance. Through numerical reservoir simulation, different scenarios were investigated, varying capillary pressure, flowback duration, shut-in duration and drawdown. These scenarios are interpreted with rate transient analysis. The results of this work show the ambivalent effect of capillary pressure in terms of facilitating imbibition but also holding back water close to the fracture. The novelty of this work consists in the findings that for lower capillary pressures, short shut-in periods lead to a better well productivity while for higher capillary pressure extended shut-in periods are better for well productivity. It was also found that drawdown can be used to minimize fracture face relative permeability damage and as shut-in period extends, flowback should be performed at smaller drawdowns.

Keywords
Flowback, tight gas, capillary pressure, well performance, rate transient analysis.

1. Introduction

Unconventional plays are reservoirs with permeabilities lower than 1 md, while conventional plays are reservoirs with permeabilities above 1 md [20]. Even though, the resources associated to unconventional plays are quite large [31], the low permeability of the reservoir leads to low production rates, which results in low recoveries thereby increasing the commercial risk of developing this low permeability or unconventional plays [15]. In 1978, The United States Gas Policy Act classified tight gas formations as those reservoirs that possess in-situ permeability less than 0.1 md. This definition, given regardless of other properties such as depositional environment, overpressure, etc, was set as a way of giving tax incentives for the development of these less commercially viable resources [20]. Still, even with tax incentives and the advancement of hydraulic fracturing technology, a large amount of unconventional plays around the world fail due to its cost of development being too high compared to the revenue the reservoir can deliver [8, 16, 34]. Hydraulic fracturing is the most used method to improve the productivity of low permeability reservoirs. Hydraulic fracturing increases the contact area between the wellbore and the reservoir by means of injecting a large volume of fluid [11, 19, 25], additives and proppants, thus achieving commercially viability by increasing production and estimated ultimate recovery [6]. During and after the pumping operation, the fracturing fluid (usually water) imbibes into the formation and displaces the hydrocarbons near the fracture. The rock near the fracture is hence saturated with non-hydrocarbon fluid yielding a reduced relative permeability for the hydrocarbon fluid [14]. To clean the fracture and formation from the injected fluid, the flow direction of the well is reversed. This procedure is termed flowback or cleaning process. For single-stage fractured wells, flowback is applied after the fracturing process. For multi-stage fractured wells, the
completed section is plugged and a new section is fracture-stimulated and flowback is performed after the last stage is stimulated.

Previous studies have shown that fracturing fluid recovery varies greatly across a play and from play to play. Marcellus Shale fracturing fluid recovery ranges between 0.2 and 26% [35] while Barnett Shale fracturing fluid recovery reaches up to 70% [24]. Unless there is connection through a fault or mechanical failure along the well (casing, cement), the non-produced fracturing fluid will remain in the reservoir [10]. The non-recovered fracturing fluid (water) lowers the relative permeability to the gas phase. A change in the relative permeability has an effect on production and future well performance [15].

The first work in flowback and reservoir clean-up analysis comes from the late 70’ [14] and the literature has increased in time with the development of tight and shale reservoirs. Holditch [14] analyzed the effect of drawdown and capillary pressure (Pc) by means of numerically simulating a water injection through an already existing fracture. He concluded that capillary pressure and water mobility are critical for clean-up behavior: the higher the capillary pressure and water mobility the better for the performance of the well. Also, drawdown should exceed capillary pressure to minimize the water block to gas flow.

Sherman et al [32], extended the previous work of Holditch in terms of fracturing fluid recovery and concluded that fracturing fluid recovery increases as fracture conductivity and water mobility increases.

Bertoncello et al [2] analyzed the effect of the shut-in period between the fracturing treatment and flowback and the effect of a second shut-in between flowback and production. He concluded that flowback should be performed as early as possible, followed by a shut-in of a couple of months to minimize damage and productivity loss.

Nasriani et al [23] performed a statistical analysis of clean-up efficiency that included varying reservoir properties, soaking and production periods. He concluded that fracture permeability and the shape of water relative permeabilities have the largest impact on clean-up and well productivity.

Economides et al [9] reviewed several papers related to flowback and clean-up and summaries that flowback is a critical part of the stimulation program, due to its impact on well productivity.

Previous studies have focused on understanding the impact of reservoir properties on the clean-up process of hydraulically fractured wells. However, operators have little to no control over those. In contrast, the literature on the impact of variables that operators are able to control such as the duration of the shut-in period between the treatment and flowback, the drawdowns exerted on the reservoir, the shut-in duration between flowback and definitive production, is sparse [2, 17, 18, 29]. Most studies focused on clean-up are set from a point of view of recovering the largest amount of the injected fluid, as the injected fluid is saturating the rock thus reducing the relative permeability to gas [4, 5, 12, 18, 22, 28, 30]. The most frequent recommendation found in literature consist of exerting a drawdown that is larger than the capillary pressure, to increase recovery of the injected fluid [1, 7, 12, 22, 27]. Unfortunately, these studies do not consider the effect of the remaining injected fluid in the reservoir and ultimately in the performance of the well.

In this work, we focus on the operational variables drawdown, shut-in duration, flowback duration and capillary pressure reduction by surfactants. The analysis is performed in a vertical well with a single-stage hydraulic fracture but the findings scale trivially to multiple fractures as long as imbibition fronts into the rock matrix from different fractures do not
interact. We use numerical simulations to analyze and understand the impact of those on well performance.

This paper is structured as follows: The section Methodology describes how the problem was addressed by means of constructing a numerical reservoir simulation that can best represent the effect of water imbibing into the reservoir after a hydraulic fracturing stimulation treatment. This section also presents RTA (rate transient analysis) as a means to quantify the impact of the studied variables on well performance and an analysis of near fracture gas saturation against the analyzed variables. The section Results and Discussion presents the results and analysis of the numerical simulation and interpretation. The Conclusions list the main findings of this study. The Appendix includes the reservoir rock properties, hydraulic fracture properties, grid cell size and PVT Data.

2. Methodology

2.1 Simulation Setup

Simulation has been used as a tool to represent the behavior of a reservoir system [26]. Numerical reservoir simulation was used by previously mentioned authors to represent the effect of water imbibition into the reservoir due to a hydraulic fracturing stimulation treatment. For our study, ECLIPSE 100 (Schlumberger, 2018) was used as a numerical reservoir simulator.

As unconventional reservoirs have low permeability, the low transmissibility of the system leads to a relatively fast pressure and saturation change in the first few feet of the reservoir parallel to the fracture compared to the much slower response as the distance from the fracture increases. To resolve near fracture effects, the grid size in the fracture was set to 0.2” to resemble an average fracture width. The grid cells in the matrix start with a small width next to the fracture and increase in size away from the fracture (Table 1 in Appendix). The grid coarsening away from the fracture was validated by comparing the results of the base case to the results from an equidistant grid with 0.2” of width (w_f).

The fluid phases are represented by Gas-Water Black Oil System and properties were calculated through Black Oil Correlations (Appendix PVT Data).

The reservoir is 4920x4920 ft large and the well is placed at the center of the domain. The hydraulic fracture half-length is 984 ft long. Figure 1 a) and 1 b) show a schematic of the model and the simulation grid.

![Figure 1 a) Schematic view of the simulation model b) Simulation grid DX size front view.](image-url)
We model the process of water flowing into the reservoir by injecting water at a constant pressure through an already existing hydraulic fracture. During the injection itself (step 1 of the simulation procedure), we set the permeability of the fracture to a high value to mimic an infinite conductive fracture (zero pressure drop inside the fracture) that is propagating. When the injection is concluded, we reduce the permeability in the fracture as the formation will close over the packed proppant agent. The selection of 20 darcy as the fracture permeability ($k_f$) and 0.2 as the fracture width ($w_f$), results in a fracture conductivity of 333.33 md-ft ($k_f \cdot w_f$). This value of fracture conductivity is commonly observed in hydraulically fractured tight reservoirs [3, 33].

Simulation procedure:
1. Inject water at a constant bottom hole pressure of 6,000 psia through an already existing fracture with a permeability of 600 darcy.
2. Reduce fracture permeability to 20 darcy.
3. Close the well for 0 to 512 hours
4. Set the well to flow.

The well was set to flow with a fixed bottom hole pressure for a total of 60 days (step 4 of the simulation procedure). For most cases, the well flows for a continuous period of 60 days. When analyzing the specific effect of flowback duration on well performance, the well was flowed between 4 to 1440 hours, followed by a shut-in period of 10 days and then restarting production until completion of a total of 60 production days.

The simulations were run for different capillary entry pressures in a power law relationship and bottom hole flowing pressures (drawdown). Note, that for the sake of brevity, throughout the manuscript we refer to the capillary entry pressure as capillary pressure.

Note, that while hydraulic fracturing stimulation treatment are performed at constant rate, we only modelled a sector of the fracture and a fraction of the injected fluid will flow along the fracture out of the domain. We therefore considered a constant pressure in the injector more appropriate. We indeed modelled a constant rate case, but the qualitative findings were not sensitive to the boundary conditions.

2.2 Rate transient analysis
We quantify the effect of water present in the reservoir due to the injection process with the help of rate transient analysis and the Productivity Index of the well.

Lougheed et al [21] analyzed different well performance methodologies such as rate metrics (cumulative production at different dates and peak rate among others) and rate-pressure metrics (Productivity Index from rate transient analysis). They concluded that rate metrics can lead to error as they don’t consider variables as operation conditions (flowing pressure, shut-ins, etc.) and recommend rate-pressure metrics as a mean of more accurately estimating well performance.

The productive behavior of the well can be characterized by the analysis of the pressure and rate with respect to time.

To calculate the Productivity Index of hydraulically fractured wells in low permeability reservoirs, they recommend constructing a plot of normalized pressure ($\Delta P/q$) against the square root of a time function (time, linear superposition time or material balance time).
From the slope of the straight line fitted to the data and its Y-axis intercept, the Productivity Index $PI$ of the well can be calculated by:

$$PI = \frac{q}{\Delta P} = \frac{1}{m\sqrt{t+b'}}$$ \hspace{1cm} (1)

In Equation 1, $m$ is the slope of the fitted straight line and accounts for the contact area of the hydraulic fracture with the reservoir and the reservoir permeability. $b'$ correspond to the Y-intercept. A value $b'$ larger than zero indicates additional pressure drop due to skin and/or finite conductivity fractures.

The ratio of the Productivity Index where injection was performed to a base case of a well with a fracture without injection is used to normalize the effect of water and operational variables on well performance. This ratio is called Productivity Index Loss $PIL$ and is given by:

$$PIL = \left(1 - \frac{PI_{\text{injection case}}}{PI_{\text{base case}}}\right) \cdot 100\%.$$ \hspace{1cm} (2)

2.3 Near fracture saturation analysis
To understand how the water retained in the reservoir impacts well performance, a group of grid cells was selected to analyze the gas saturation and effective permeability to gas near the fracture in conjunction with the Productivity Index Loss. These grid cells are the first 7 cells perpendicular to the hydraulic fracture grid and cover a distance of 36 inches. Based on the simulation results presented ahead in this work, this is an appropriate choice to conduct the analysis.

3. Results and Discussion

3.1 Effect of capillary pressure on productivity
The effect of capillary pressure on a well where a volume of water has been injected is analyzed. In Figure 2, we find that for a constant shut-in period of 8 hours followed by a production period of 60 days at constant bottom hole pressure of 2,000 psi, well performance diminishes (Productivity Index Loss increases) as capillary pressure increases. This means there is a slight reduction in well performance.
Figure 2 Effect of capillary pressure on Productivity Index Loss and fracturing fluid recovery after a shut-in period of 8 hours followed by a production period of 60 days.

We find that, as capillary pressure increases, the recovery factor of the fracturing fluid decreases. This is due to the fact that the imbibition process with increasing capillary pressure is stronger. As a result, more water will be retained in the reservoir, occupying pore volume and reducing the effective permeability to the gas phase.

Figure 3, shows the gas saturation distribution in the grid cells next to the fracture at the start of the production period for various capillary pressures. As capillary pressure increases, the initial gas saturation is higher. With higher capillary pressures water imbibes faster into the matrix and allows the gas saturation to recover quicker next to the fracture.

Figure 3 Effect of capillary pressure on gas saturation near the fracture at the start of production after a shut-in period of 8 hours.

Figure 4 shows the effective permeability at the beginning and at the end of production period. This permeability corresponds to the harmonic average of the permeability inside the control domain (cells 1 to 7 perpendicular to the fracture). At the start of the production
period the gas permeability is low, hence, there is a high saturation of water near the fracture (Figure 3). This is due to the reduced imbibition effect associated with small capillary pressure.

As presented in Figure 2, as capillary pressure increases, a larger fraction of the fracturing fluid remains in the reservoir saturating the rock. With higher capillary forces the fracturing fluid imbibes faster into the reservoir resulting in a higher initial gas effective permeability (Figure 3 and Figure 4). The gas having a higher initial effective permeability will move more easily compared to the fracturing fluid present in the system, therefore it will be more difficult for the fracturing fluid to be removed from the reservoir. As more fracturing fluid is retained in the reservoir, the clean-up of the reservoir is less effective. This results in a lesser improvement of gas permeability, hence, a higher Productivity Index Loss.

Figure 4 Effect of capillary pressure on gas effective permeability. The shut-in period is 8 hours and the production period 60 days.

At the start of production, the rate of gas and fracturing fluid will depend on the initial saturations of the phases. Hence, mostly fracturing fluid is produced at the onset of production (Figure 5 a). As time passes and the saturation of the fracturing fluid decreases, the gas permeability increases becoming more mobile than the fracturing fluid. This increases gas production and leaves some of the fracturing fluid in the reservoir.
Figure 5 a) Water rate during production after a shut-in period of 8 hours and b) Gas rate.

At higher capillary pressure, more fracturing fluid imbibes into the matrix and the fracturing fluid is distributed wider across the reservoir. Consequently, at the start of production, the fracturing fluid is less concentrated near the fracture. Hence, the initial gas permeability will be higher as capillary pressure increases. The curves shown in Figure 3 and Figure 4 reflect on that. The increased initial gas permeability will result in gas being able to move sooner compared to a low capillary pressure scenario (Figure 5 b). Therefore, the recovery of the fracturing fluid recovery will be lower as the gas will be able to bypass the fracturing fluid present in the system early during the flowback. This will result in more fracturing fluid trapped in the reservoir and ultimately leading to a lower well performance.

The observed capillary pressure-gas permeability behavior, goes in accordance with Figure 2, where at low capillary pressures, the Productivity Index Loss is low and as capillary pressure increases, the Productivity Index Loss increases. This result goes against the results of several authors found in the literature [14, 23], who state that a higher capillary pressure is better for well performance.

3.2 Effect of shut-in duration on productivity

Figure 6 shows the effect of the duration of the shut-in period between the treatment and the production stage on well performance. The scenario was run for one capillary pressure of 500 psi and one bottom hole flowing pressure of 2,000 psi.

During the shut-in period, no fluids are removed from the reservoir. As the fracturing fluid is saturating the near fracture region, the capillary forces try to equilibrate the system by imbibing the fracturing fluid deeper into the reservoir. As shut-in duration increases, there is more time for the fluid to imbibe, this reduces the amount of the recovered fracturing fluid, leaving it trapped in the reservoir. The analysis indicates that an increased shut-in duration deteriorates the performance of the well.
As seen in Figure 6, with more time to imbibe, less fracturing fluid is recovered. This can be seen in Figure 7 which shows the gas saturation profile perpendicular to the fracture in the control domain at the start of the production period for different shut-in periods. It can be seen that for the time range between 0 and 8 hours of shut-in time, most of the fracturing fluid is in the first couples of inches of the near fracture region. As time increases, more fracturing fluid imbibes, in other words, as there is more time for the fracturing fluid to be distributed across the reservoir, the gas saturation at the start of the production period will be higher. As the gas saturation at the start of the production period is higher, so will be the gas effective permeability. As gas effective permeability increases, it will be easier for the gas to flow and bypass the fracturing fluid present in the system as the gas tends to be more mobile due to its low viscosity. Once the fracturing fluid is being easily bypassed by the gas, a reduced amount of it will be recovered as shown in Figure 6.
Even though a higher initial gas saturation and gas effective permeability at the start of production may look promissory, in terms of well performance, this unfortunately has a negative impact. More fracturing fluid is retained at reservoir level blocking the flow to gas, as presented in the Productivity Index Loss plot in Figure 6.

Figure 8 presents a comparison of different saturation profiles across the reservoir at several times of the well life. At the end of injection period, the near fracture region is mostly saturated with the fracturing fluid. After a shut-in period of 8 hours post injection, part of the fracturing fluid has imbibed into the reservoir, seen as an increase in the gas saturation. At the end of the 60 days production period, the gas saturation is higher due to gas bypassing the fracturing fluid. Gas saturation is also improved due to more time for the fracture fluid to imbibe. It can be seen that for a case without injection, after a 60 day production period, the gas saturation is higher compared to the case with injection. This lower gas saturation, generated by the fracturing fluid being immobile in the near fracture region, results in a lower effective permeability to gas. The lower effective permeability results in a diminished productivity index when compared to the base case without injection. In other words, the immobile fracturing fluid generates a Productivity Index Loss.

![Figure 8 Gas saturation profile at the end of the injection period, start of production, end of a 60 day production period and end of 60 days production period without injection.](image)

From this analysis, it can be concluded, that the flowback should start as soon as possible to minimize damage. Minimizing damage will result in a better well performance.

### 3.3 Coupled analysis of the effect of capillary pressure and shut-in duration on productivity.

As described in section 3.1 of this study, our analysis indicates that Productivity Index Loss increases as capillary pressure increases. When the results of the capillary pressure effect and shut-in duration effect on productivity were analyzed together, a different perspective of the effect of capillary pressure on production was observed.

Figure 9 presents the gas saturation variation against shut-in duration, for two different capillary pressures. As discussed in section 3.1 as capillary increases, the imbibition process is stronger. This is observed as for the same shut-in duration, the gas saturation is higher for the 2,000 psi capillary pressure case when compared to the lower 500 psi case. This indicates,
for the same shut-in duration, a larger amount of fracturing fluid has been imbibed deeper into the reservoir. In other words, the near fracture region is cleaner from the fracturing fluid.

As discussed in section 3.2, as shut-in duration increases, there is more time for the fracturing fluid to imbibe deeper into the reservoir. This is seen as an increment of the gas saturation with time. As seen in Figure 9, when shut-in duration extends to very long shut-in times, the gas saturation tends to the initial reservoir conditions used in the simulation. This means, the reservoir can clean itself as shut-in time increases.

Figure 10 shows the Productivity Index Loss against the coupled effect of capillary pressure and shut-in duration. After 8 hours of shut in time, for the 500 psi capillary pressure case, the fracturing fluid is located near the fracture, as for the 2,000 psi capillary pressure case, the fracturing fluid has imbibed deeper into the reservoir (Figure 9). This generates a lower gas saturation and gas effective permeability at the start of production when compared to the 2,000 psi case (Figure 3, 4 and 9). For the lower capillary pressure case it means that more fracturing fluid will be recovered compared to the 2,000 psi where the initial gas effective permeability will be higher resulting in the gas being able to flow easier and bypass the fracturing fluid. For the short shut-in duration, the best lower Productivity Index Loss is seen for the lower capillary pressure case. In other words, the fracturing fluid is near the fracture and removing it from the reservoir results in the best well performance.

When shut-in time is increased, the higher capillary pressure will result in the fracturing fluid imbibing deeper into the reservoir when compared to the lower capillary pressure case where the fracturing fluid would have imbibed less and remain more concentrated near the fracture. When the well is set to produce, the high capillary pressure case will have a higher initial gas saturation and so, a higher initial gas effective permeability with the fracturing fluid being better distributed across the reservoir. In other words, as shut-in duration increases, a higher capillary pressure is most favorable for reservoir clean up and well performance.

From this analysis, we conclude that:
1. At short shut-in durations, a lower capillary pressure results in less damage than a high capillary pressure condition. Productivity Index Loss will be the lowest. This means the well will perform better.

2. As shut-in duration increases, the imbibition of a high capillary pressure reservoir, results in a well with less damage, compared to a lower capillary pressure scenario.

3. If the well is closed long enough, the reservoir will start to clean itself leading to lower Productivity Index Losses.

When considering both the shut-in time and capillary pressure effect, we have corroborated what other studies have found, a higher capillary pressure results in a better well performance [14, 23]. We also found a result not mentioned in the literature review, that is that at short shut-in times a lower capillary pressure results in better well performance.

![Figure 10 Coupled analysis of the effect of capillary pressure and shut-in duration on the Productivity Index Loss after 60 days of production.](image)

We note that shut-in durations of 10 and 500 years are impractical in reality but were simulated to understand if the reservoir was able to clean itself at extended shut-ins as other authors have mentioned.

### 3.4 Effect of flowback duration on productivity

Figure 11 shows the effect of flowback duration on well performance on a well with a capillary pressure of 500 psi that has been set to produce after an 8 hour shut-in at a constant bottom hole pressure of 2,000 psi. When flowback is extended, from 4 up to 48 hours, is when most of the Productivity Index Loss decreases. This means the effect of clean up makes the largest impact on well performance during the first hours of flowback. Also, in the first hours of flowback is when most of the fracturing fluid is recovered. Past the 48 hours period, clean-up is very slow and the rate of improvement in the Productivity Index Loss is reduced. In other words, as flowback is extended, there is little improvement in the performance of the well.

The reduction in the rate of improvement of the well can be seen with the amount of fracturing fluid being recovered. After 48 hours of production, the recovery of fracturing
fluid barely increases, meaning the fluid is remaining in the reservoir practically immobile and being bypassed by the gas.

Figure 11 Effect of flowback duration on Productivity Index Loss and fracturing fluid recovery after 60 days of production.

The same clean up effect can be seen in Figure 12. In the first 48 hours of flowback, gas saturations increases faster. Past the 48 hours period, the clean up process is very slow. After this point, the fracturing fluid is practically immobile and keeps an almost stable saturation in the control domain. This means, there is little improvement to gas flow and well performance. This analysis could give an indication as to how long a flowback could be to reduce costs.

Figure 12 Effect of flowback duration on gas saturation in two cells next to the fracture after 60 days of production.

3.5 Effect of drawdown on productivity

Figure 13 shows the effect of drawdown on the performance of the well when it is flowed at different but constant bottom hole pressures against a reservoir pressure of 4,000 psia, with a capillary pressure of 500 psi. It was found that as drawdown is reduced, Productivity Index
Loss is reduced. In the same manner, as drawdown is reduced, less fracturing fluid is recovered. This means that the best performance was not obtained at the largest drawdown nor where a larger fraction of the fracturing fluid was recovered.

Capillary pressure and drawdown act as opposite forces, capillary pressure pulls the fracturing fluid away from the fracture and drawdown pulls the fluids into the fracture and out of the reservoir. This affects the way the fracturing fluid ends up being distributed across the reservoir.

If a large drawdown is exerted, more fracturing fluid is pulled close to the fracture and removed from the reservoir. As the fracturing fluid is being removed, the gas saturation will increase and it will be easier for the gas to flow and bypass the fracturing fluid. At this point, the improvement of gas effective permeability will be slower as the fracturing fluid will be almost immobile. This results in the fracturing fluid being more concentrated near the fracture.

If a small drawdown is exerted, only a small fraction of the fracturing fluid near the fracture is being removed. The fracturing fluid that imbibed deeper into the reservoir during injection and shut-in period will be less affected by the smaller exerted by the drawdown. This will result in a larger amount of fracturing fluid being imbibed deeper into the reservoir even during the start of the production period while a part of it is still removed from the reservoir. As the remaining fracturing fluid is distributed deeper across the reservoir but also, a part of it is removed from the near fracture region, the overall gas effective permeability of the system is higher, resulting in a lower Productivity Index Loss.

It can be noted that, when the shut-in period between the injection and flowback is extended (512 hours case), the drawdown required to reduce damage compared to the short shut-in case (8 hours), is smaller (higher flowing pressure). This indicates that, as shut-in duration increases, flowback should be performed at smaller drawdowns to improve clean up and future well performance (minimize the Productivity Index Loss).

For the 512 hours shut-in period scenario, even when almost no fracturing fluid is being recovered, at reservoir level, fluids are still moving and being distributed and impacting the clean-up process.

![Figure 13 Effect of drawdown on Productivity Index Loss and fracturing fluid recovery at the end of a 60 day production period.](image)

An anomalous effect is seen when flowing pressures are too high, the Productivity Index Loss results to be negative. A second commercial reservoir simulator was used to model and
analyze this situation, but the results were similar. At high flowing pressures (smaller drawdown), the wells where injection was simulated, produced more gas and delivered a higher Productivity Index compared to the well without injection. As injection occurs at a pressure higher than the reservoir pressure (2,000 psi above reservoir pressure for our model), the fracturing fluid imbibes into the reservoir displacing and compressing the fluids in place near the fracture, generating a super charged or high pressure zone. When production starts, this over pressured zone drives the additional production, (or acceleration of reserves), resulting in a slightly higher cumulative gas production and Productivity Index compared to a case without injection. As drawdown is increased, the high pressure zone dissipates faster and its impact in cumulative production and Productivity Index decreases.

Figure 14 shows the effect at reservoir level at the end of the production period for the 8 hours shut-in scenario for two flowing pressures. The results indicate that the case where a smaller drawdown or higher flowing pressure is used, results in a higher gas saturation. In accordance with Figure 13, this means the well will perform better. This situation is clearly an imbibition effect, as when drawdowns are too large, too much water is forced to flow against the capillary pressure effect, leaving trapped water near the fracture.

![Figure 14](image)

From this analysis it can be understood that a perfect flowback is a balance of removing injected fracturing fluid from the reservoir and imbibition of the fracturing fluid into the rock matrix further away from the fracture. The objective is to attain the most favorable gas saturations to flow. If 100% fracturing fluid could be recovered, this would also maximize the clean-up process ending in an ideal case without saturation alteration.

### 3.6 Effect of surfactant on productivity

Most authors conclude that surfactants additives used to reduce interfacial tension and hence capillary pressure are not required as the common opinion is that a higher capillary pressure is better for reservoir clean-up and well performance. However, service companies promote these additives as an enhancer of production, especially in multi fracture wells, due to their long shut-in periods.

In reality, most studies just compare production to different capillary pressure scenarios but none of them actually models the effect of surfactant injection or capillary pressure alteration.
The only work found in literature regarding capillary pressure alteration was Holdtich (1979) [14]. Holdtich simulated the effect on production of a well where the fracture face matrix permeability was damaged; he reduced the matrix permeability and increased its capillary pressure in the damaged zone post-injection as they are linked by the J-Leverett equation. He found that water tends to move from the reservoir to the altered high capillary pressure zone, resulting in a block to gas flow.

As the commercial simulator used for this work does not include the option to inject a surfactant additive, the opposite approach from Holdtich was taken. After the injection simulation a “restart file” was generated, and the capillary pressure in the first 6” of reservoir perpendicular to the hydraulic fracture was reduced from 500 psi to 250 psi.

Figure 15 shows the effect of surfactant in the Productivity Index Loss and Fracturing Fluid Recovery. As expected from a reduction in capillary pressure, more fracturing fluid is being recovered, as the imbibition process is weaker and the fracturing fluid won’t imbibe deep into the reservoir and will remain close to the fracture with a high saturation, just as the low capillary pressure cases presented in section 3.1.

For a shut-in duration up to 32 hours is when the major difference in fracturing fluid recovery was obtained. Beyond the 32 hours mark, there is little difference in the recovery of the fracturing fluid as the reservoir still has enough capillary pressure to imbibe the fluids into the reservoir.

Even when beyond the 32 hours of shut-in, there is no difference in the amount of fracturing fluid being recovered, for all the analyzed shut-in periods, the Productivity Index Loss is lower for the case where the capillary pressure has been locally reduced. This indicates that the reservoir still has a higher gas effective permeability to gas in the zone where the fracturing fluid has been imbibed.

![Figure 15 Effect of surfactant on Productivity Index Loss and fracturing fluid recovery at the end of the 60 days production period.](image)

The saturation analysis at the start of the production period shows little difference between a case with and without capillary pressure reduction after 8 hours of shut-in between the treatment and the flowback (Figure 16).
At the end of a 60 day production period (Figure 17) the effect of capillary pressure reduction is more noticeable in the control domain (cells 1 to 7 perpendicular to the hydraulic fracture). In the zone where the capillary pressure was reduced, most of the fracturing fluid was removed has can be seen by the high gas saturation, resulting in less fracturing fluid blocking the flow for the gas phase. In other words, the well will perform better.

Even when the difference in the recovery factor of the fracturing fluid is not significant, the water saturating the rock near the fracture was reduced and the water that had penetrated further into the reservoir, imbibed further away during the production period.

This analysis indicates that surfactant injection during the fracturing treatment could be used to improve well performance by means of reducing damage due to water retention or phase trapping. Still, this situation should be analyzed for each reservoir, considering its own rock-fluid properties and type of treatment.
4. Conclusions

A numerical simulation model was built to analyze the effect on well performance generated by the fracturing fluid imbibing into the reservoir. Aided by Rate Transient Analysis we quantified the Productivity Index Loss under different operational and capillary pressure conditions. The results of our simulations agree with previous work from other authors. We have confirmed that fracturing fluid does generate damage in the form of fracture face damage. This form of damage results from immobile fracturing fluid saturating the near fracture region. The saturation generated by the fracturing fluid reduces the relative permeability to gas. This reduction in relative permeability to gas ends in a lower well performance. Also, flowback should start as soon as possible to reduce damage. However, we observe as a novel phenomenon, that if shut-in time is extended to very long times, damage is reduced by the imbibition process and that for short shut-in period a lower capillary pressure results in better well performance, but as shut-in period increases, higher capillary pressure result in better well performance. The following conclusions reflect the findings of our work:

1. For short shut-in times, a lower capillary pressure delivers a better well performance or Productivity Index (lower fracture skin damage).
2. For extended shut-in times, a higher capillary pressure delivers a better well performance or Productivity Index (lower damage),
3. Drawdown can be used to minimize reservoir damage due to water blocking, even when shut-in time is long and imbibition due to capillary pressure is high.
4. Drawdown should be selected with the objective of obtaining the most favorable gas saturation that leads to the best well performance and not based on maximize water recovery, unless 100% of it can be recovered.
5. The locally reduced capillary pressure case indicates that the use of surfactant does help in reducing damage by means of reducing water blockage and recovering more fracturing fluid near the fracture.
6. Reduction of capillary pressures generates higher water recovery. However, it requires a longer production time to reach peak gas rate.
7. A perfect flowback or clean-up process is a balance of removing water or fracturing fluid from the reservoir and imbibition of water into the reservoir away from the fracture with the objective of achieving the most favorable gas saturations to flow.

Acknowledgements

The author would like to thank ENAP – Empresa Nacional del Petróleo for sponsoring this work.

Appendix

Reservoir simulation set up

<table>
<thead>
<tr>
<th>Cell</th>
<th>Width [ft]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 (fracture)</td>
<td>0.0167</td>
</tr>
<tr>
<td>1</td>
<td>0.0334</td>
</tr>
<tr>
<td>2</td>
<td>0.0668</td>
</tr>
<tr>
<td>3</td>
<td>0.1336</td>
</tr>
<tr>
<td>4</td>
<td>0.2672</td>
</tr>
</tbody>
</table>
Table 1 Grid cell width perpendicular to the fracture.

| Grid cell width | 0.4906 | 2.0000 | 3.0000 |

Table 2 Reservoir rock and fluid properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix permeability (k) [md]</td>
<td>0.02</td>
</tr>
<tr>
<td>Gas end point (k_{rg} max)</td>
<td>0.25</td>
</tr>
<tr>
<td>Water end point (k_{rw} max)</td>
<td>0.375</td>
</tr>
<tr>
<td>Corey gas n factor (n_g)</td>
<td>2</td>
</tr>
<tr>
<td>Corey water n factor (n_w)</td>
<td>2</td>
</tr>
<tr>
<td>Water irreducible saturation (S_{wir}) [%]</td>
<td>50</td>
</tr>
<tr>
<td>Gas residual saturation (S_{gr}) [%]</td>
<td>10</td>
</tr>
<tr>
<td>Matrix porosity [%]</td>
<td>15</td>
</tr>
<tr>
<td>Net pay [ft]</td>
<td>60</td>
</tr>
<tr>
<td>Capillary pressure model</td>
<td>Power law</td>
</tr>
<tr>
<td>Capillary pressure – power law exponent</td>
<td>2</td>
</tr>
<tr>
<td>Capillary entry pressure [psi]</td>
<td>100, 500, 1000, 1500, 2000</td>
</tr>
<tr>
<td>Reservoir pressure [psi]</td>
<td>4000</td>
</tr>
<tr>
<td>Reservoir temperature [ºF]</td>
<td>225</td>
</tr>
<tr>
<td>Gas specific gravity</td>
<td>0.65</td>
</tr>
<tr>
<td>Gas properties</td>
<td>Black oil correlations</td>
</tr>
</tbody>
</table>

Table 3 Hydraulic fracture properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability during injection (k) [darcy]</td>
<td>600</td>
</tr>
<tr>
<td>Permeability during production (k) [darcy]</td>
<td>20</td>
</tr>
<tr>
<td>Porosity [%]</td>
<td>25</td>
</tr>
<tr>
<td>Hydraulic fracture half-length [ft]</td>
<td>984</td>
</tr>
<tr>
<td>Gas end point (k_{g} max)</td>
<td>1</td>
</tr>
<tr>
<td>Water end point (k_{rw} max)</td>
<td>1</td>
</tr>
<tr>
<td>Corey gas n factor (n_{g})</td>
<td>1</td>
</tr>
<tr>
<td>Corey water n factor (n_{w})</td>
<td>1</td>
</tr>
<tr>
<td>Water irreducible saturation (S_{wir}) during production [%]</td>
<td>10</td>
</tr>
<tr>
<td>Gas residual saturation (S_{gr}) during production [%]</td>
<td>10</td>
</tr>
<tr>
<td>Water irreducible saturation (S_{wir}) during injection [%]</td>
<td>0</td>
</tr>
<tr>
<td>Gas residual saturation (S_{gr}) during injection [%]</td>
<td>0</td>
</tr>
</tbody>
</table>

Nomenclature

b': Y-axis intercept value in the linear flow plot, $\text{Psi}^2/(\text{cP} \times \text{MMscfd})$

k: permeability, md, d, milidarcy, darcy
m: slope in the linear flow plot, \( \text{Psi}^2/(\text{cP} \cdot \text{MMscfd}) \)
n: Corey relative permeability exponent
Pc: capillary pressure, psi
Pwf: bottom hole flowing pressure, psi
q: volumetric rate, stb/d, MMscfd
S: saturation, fraction
Stb: volume, standard barrel
w: width, in
x: length, ft
%: percentage
\( \Delta \text{P} \): delta pseudo pressure, \( \text{Psi}^2/\text{cP} \)

Abbreviations
HF: Hydraulic Fracture
P.I: Productivity Index
P.I.L: Productivity Index Loss

Greek letters
\( \mu \): viscosity, cP

Subscripts
f: fracture
g: gas
r: relative, residual
wir: irreducible water

References


