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Evaluating Factors Controlling Damage and Productivity in Tight Gas Reservoirs

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Declaration

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Abstract

Production at economical rates from tight gas reservoirs in general is very challenging not only due to the very low intrinsic permeability but also as a consequence of several different forms of formation damage that can occur during drilling, completion, stimulation, and production operations. The common strategies used in tight gas reservoirs development are hydraulic fracturing and horizontal well drilling. However in many cases of tight gas reservoirs, the key factors that control well productivity and formation damage mechanisms are not well understood, since it is challenging to characterise them in tight formations.

In this thesis I demonstrate how different well and reservoir parameters control well productivity and damage mechanisms in tight gas reservoirs. Reservoir simulation model for Whicher Range tight gas field is built and run. Analytical and numerical simulation approaches are integrated with core flooding experiments and tight gas field data analysis in order to characterize the key reservoir parameters and understand the effects of different parameters on well productivity.

Using core flooding experiments data analysis, the relative permeability curves are generated for Whicher Range tight gas reservoir, and quantitatively is shown how the phase trapping damage can be reduced by use of oil based drilling fluid instead of water based fluid. A new technique of welltest analysis was introduced for tight gas reservoirs that can reduce uncertainties in estimation of average reservoir permeability, and also a new correlation that can determine permeability of the natural fractures in tight formations is proposed in this study. I study and analyse different well completion, production and reservoir data from Whicher Range tight gas field in order to identify why production rates are significantly lower than expectations, and investigate possible remedial strategies to achieve viable gas production rates.

Based on this research, drilling long horizontal deviated wells using non-aqueous fluids in underbalanced conditions may be more efficient than hydraulic fracturing. As the optimum strategy to further improve the well productivity, drilling the well with a high deviation to intersect multiple sand lenses; orienting the wellbore direction perpendicular to the maximum horizontal stress to intersect higher permeability conduits and control wellbore instability issues; completing the well as open-hole to have the advantage of enlarged wellbore caused by large wellbore

breakouts; running slotted liner to control wellbore collapse; open-hole perforation in the direction of maximum horizontal stress to reach a deeper formation penetration; and unloading the wellbore from drilling and fracturing fluids can help achieve commercial gas production rates from tight gas reservoirs.

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Preface

The PhD study was started in July 2009, and several papers were reviewed on different aspects of tight gas reservoirs. The objectives of this study were to review and evaluate the factors that have significant influence on formation damage and well productivity in tight gas reservoirs, such as effective permeability, relative permeability, the degree of formation damage and skin factor. The work presented in this thesis is the result of three years of field data analysis, reservoir simulation, analytical derivation of equations, and analysis of laboratory experiments data in order to generate new knowledge regarding tight gas reservoir characterization and productivity evaluation.

To meet the study objectives, formation damage mechanisms and productivity issues were reviewed, laboratory core flooding experiments were executed, core and field data were analysed, and numerical simulation models for core scale, well scale and reservoir scale were built using commercial reservoir simulation softwares. Data from the Whicher Range tight gas field (SW Western Australia) including well completion, stimulation, reservoir and production engineering data were also reviewed, studied and analysed. The majority of the simulation works in this study are based on Whicher Range field data.

In the early stage of the study, typical tight gas data were gathered from the reviewed papers, and three basic conceptual models were built at core scale, well scale and reservoir scale in order to simulate numerically different damage mechanisms and their effect on well productivity. Then after gathering actual laboratory and field data, the simulation models were updated in a series of trials to get more realistic results.

Simulations were run using industry-standard software that have the advantage of a high degree of validation in real-world situations. CMG-IMEX and ECLIPSE-100 black-oil reservoir simulators were used to numerically model damage mechanisms and the effect on well productivity in tight gas reservoirs, KAPPA-Ecrin software was used for analytical and numerical simulation of well production performance and transient pressure data analysis, ANSIS-FLUENT was used to model wellbore phenomena, Schlumberger SPAN 7.02 was used for perforation modelling, and the SENDRA.2010 program was used to analyse core flooding data and determine the relative permeability curves.

The core flooding experiments in this research study were performed using the lab facilities of Petroleum Engineering Department at Curtin University, which have been designed, developed and setup by Dr. Ali Saeedi (Saeedi, 2012). The experiments were performed to generate a set of relative permeability curves for the tight gas reservoir. In order to understand the damaging effects caused by different fluid types as the invading liquid, the core flooding experiments were also executed in the cases of water and synthetic oil invasion into the core sample.

The study brings new insights regarding tight gas reservoirs characterization for dynamic parameters, and quantifies the phase trapping damage effect on tight gas sand reservoirs productivity for different cases such as non-fractured and hydraulically wells, under-balanced and over-balanced drilling, and invasion of different fluids into the tight formation (water and oil). To the best of my knowledge, phase trapping damage issues have mostly been discussed qualitatively in the published papers to date, and a detailed level of study has not been presented by the authors. The relative permeability and capillary pressure curves were determined for Whicher Range tight gas reservoir using core flooding experiments data analysis. Furthermore, a new method of welltest analysis for more reliable estimation of the average reservoir permeability, a new correlation for estimating the permeability of natural fractures in tight formations, and also the effect of in-situ stresses, wellbore breakouts, perforation parameters and different hydraulic fractures systems on well productivity are presented. A summary of my research over the first two years of PhD studies was presented in the 2011 SPE European Formation Damage Conference, and the published paper went on the list of top 10 downloaded papers from the SPE e-library, which showed interest of the industry in results of the tight gas damage and productivity evaluation study.

During the course of this research, several papers were published in peer-reviewed journals, all of which were relevant to the work carried out in this research. Every paper was peer-reviewed by at least two expert reviewers and their comments were applied to improve this work. These papers cover most aspects of this research; however some parts of the study have not been published yet, since the journal that the papers were submitted to, have not responded yet. Consequently this Ph.D. thesis is presented based on the published papers which are explained briefly in the body of the thesis report and in more detailed in the appendices where the published papers are presented. The sections that have not been published yet are explained in more details in the thesis report. In the different chapters of the thesis report, the published parts are explained briefly, and the papers are referred at the end of each section for more details.

The following list provides the published papers:

1) Bahrami, H., Rezaee. R., Clennell, B., 2012. Water Blocking Damage in Hydraulically Fractured Tight Sand Gas Reservoirs, An Example from Perth Basin, Western Australia. Journal of Petroleum Science and Engineering (Appendix A)
2) Bahrami H., Rezaee R., Hossain M, 2012. Characterizing Natural Fractures Productivity in Tight Gas Reservoirs, Journal of Petroleum Exploration and Production Technology (Appendix B)
3) Bahrami H., Jayan. V., Rezaee. R., Hossain, M.M., 2012. Welltest analysis of hydraulically fractured tight gas reservoirs: An Example from Perth Basin, Western Australia. APPEA Journal (Appendix C)
4) Bahrami H., Rezaee. R., Nazhat D., Ostojic J., 2011. Evaluation of damage mechanisms and skin factor in tight gas reservoirs. APPEA Journal (Appendix D)
5) Murickan G., Bahrami H., Rezaee R., Saeedi A., Mitchel P.A.T., 2012. Using relative permeability curves to evaluate phase trapping damage caused by water-based and oil-based drilling fluids in tight gas reservoirs. APPEA Journal (Appendix E)
6) Ostojic, J., Rezaee, R., and Bahrami, H., 2011. Hydraulic fracture productivity performance in tight gas sands – A Numerical Simulation Approach. Journal of Petroleum Science and Engineering (Appendix F)
7) Bahrami H., Rezaee. R., Rasouli V., Hosseinian A., 2010. Liquid loading in wellbore and its effect on well clean-up period and well productivity in tight gas reservoirs, APPEA Journal, Brisbane, Australia (Appendix G)

Concerning the written thesis, Chapter 1 presents a brief introduction about the problems associated with tight gas reservoirs and a review of past studies conducted by other researchers. The objectives and significance of this research are outlined. In Chapter 2, determination of the effective permeability of tight formations is discussed and the new techniques are proposed. In Chapter 3, reservoir simulation studies for different types of well and tight reservoirs are illustrated. In Chapter 4, the tight gas field data are analysed and the well productivity issues in this field are made clear. Finally, a summary of this work is presented in Chapter 5, followed by conclusions and recommendations.

Acknowledgements

This work could have not been completed without the help and support of many individuals during these three years. I would like to express my deep and sincere gratitude to my supervisor Associate Professor Reza Rezaee for kindly supporting me with his great experience and knowledge, offering invaluable assistance and guidance throughout my studies, and providing a clear road map to complete my thesis work. I am greatly thankful to Dr. Ben Clennell and Dr. Mofazzal Hossain and Dr. Ali Saeedi for detailed and constructive technical guide, advices, help, and valuable feedback that significantly improved quality of my PhD research studies. I wish to give my sincere thanks to Professor Brian Evans, head of the Petroleum Engineering Department at Curtin University, and Associate Professor Vamegh Rasouli for their kind support regarding my PhD research studies and giving valuable feedback about my progress. I wish to extend my warmest thanks to all my colleagues and postgraduate students in the Petroleum Engineering Department who have helped me with my work. I would like to thank KAPPA Engineering, Computer Modelling Group of Canada, and Strategy Central for their generous support by providing free licenses of their software to Curtin University’s Petroleum Engineering Department.

To my beloved parents who always supported me in all stages of my life

1 Introduction to tight gas reservoirs

A tight gas sand (TGS) reservoir is generally characterized as a formation with effective permeability less than 0.1 md (Law and Curtis, 2002). Tight gas sand reservoirs are subject to different damage mechanisms during drilling, completion, work-over and stimulation operations (Fairhurst et al, 2007). If damage in tight gas reservoirs is not controlled, it causes the well productivity to be too low to have economical production rates (Campbell, 2009). The typical tight gas reservoirs produce mainly dry gas, and contain very low amounts of heavy components. Economical development of tight gas reservoirs is challenging as they generally do not naturally flow gas to surface at commercial rates. They must effectively be stimulated by a large hydraulic fracture treatment and/or be produced from a horizontal or multilateral wellbore that can intersect high permeability conduits of the tight reservoir (Holditch, 2006; Meeks et al., 2006).

1.1 Tight gas reservoirs characteristics

The matrix permeability of tight formations may be very low due to the depositional processes, or because of the post-depositional diagenetic events (Gonfalini, 2005). If the tight gas reservoir is naturally fractured, then the gas flow is mainly controlled by the open undamaged natural fractures that are connected to the wellbore (Teufel et al, 2004).

The rock matrix may primarily be composed of micro-pores where average pore throat aperture is very small, causing tremendous amounts of potential capillary pressure energy suction. In tight formations that are water-wet in nature, the capillary forces cause liquid to be imbibed and held in the capillary pores. This causes the critical water saturation and irreducible water saturation to be high in the tight formations (Mahadevan et al, 2007; Bennion and Brent, 2005). Initial water saturation (S_{wi}) in tight gas reservoirs might vary depending on the timing of gas migration. A tight gas reservoir may have normal initial water saturation ($S_{wi} \sim S_{wc}$)

or in some cases sub-normal ($S_{wi} << S_{wc}$) due to water phase vaporization into the gas phase as shown in Figure 1. A sub-normal S_{wi} provides relatively a higher effective permeability for gas phase, close to absolute permeability. The initial water saturation might also be more than critical water saturation if the hydrocarbon trap is created during or after the gas migration time. In the case of high initial water saturation, relative permeability to gas may be very low (Gonfalini, 2005, Bennion and Thomas, 1996).

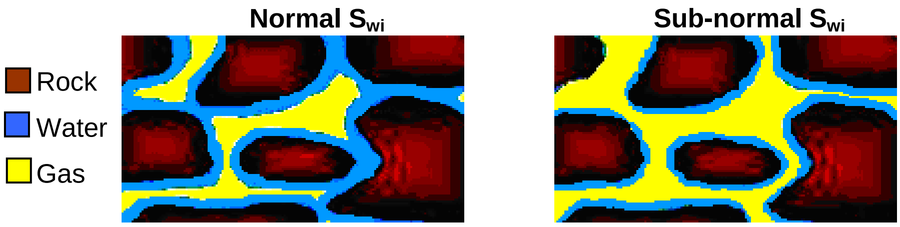

Figure 1: Normal and sub-normal S_{wi} in tight gas reservoirs

The reservoir geometry of tight gas reservoirs depends on their deposition of environment: they normally consist of numerous reservoir layers/lenses, which are discontinuous both vertically and laterally in a thick complex sedimentary system, and separated by non-reservoir shales. The stacks of isolated lenses of sand bodies may vary in characteristics, shape and volume as shown in Figure 2 (Kantanong et al, 2012). The recoverable gas in place in tight gas reservoirs is mainly controlled by the sand lens width, and the effect of sand lens length is not very significant (Bahrami et al, 2012). Horizontal deviated well drilling can help intersecting as many of the sand lenses as possible, and effectively increase lateral reservoir exposure to wellbore (Holditch, 2006).

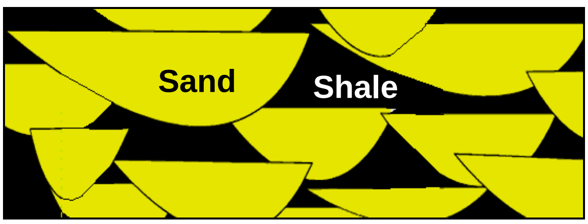

Figure 2: Typical sand lenses in tight gas reservoirs

In addition to the effect of reservoir dynamics and petrophysical characteristics, the tight gas reservoirs productivity may also be affected by in-situ stresses as they can control hydraulic fractures propagation, reservoir flow regimes, permeability anisotropy, wellbore instability and long term production performance. Tight gas sandstones are typically very stiff rocks capable of supporting high, or even extreme deviatoric stresses. Therefore understanding of the relative magnitude of in-situ stresses and their direction, and their relationship with permeability are essential for tight gas development (Abass et al. 2007; Teufel et al. 1993). Tight gas reservoirs are normally heterogeneous and anisotropic in nature, where permeability is a direction dependent property. The permeability anisotropy may be further enhanced by the pattern of earlier geological deformation and amplified by in-situ stresses (Dusseault, 1993), as the permeable conduits and natural fractures that are aligned with maximum horizontal stress (perpendicular to the minimum stress direction) may have larger aperture and greater permeability (Bahrami et al, 2010).

Tight formations commonly have wellbore instability issues during drilling, which causes large wellbore breakouts and washouts across the tight sand intervals. The wellbore instability issues in tight formations can be reduced by drilling the well in the minimum stress direction (Jaeger et al. 2007).

The productivity of tight gas wells may also be controlled by perforation parameters. Perforation performance depends on factors such as length of down-hole penetration, shot phasing, and shot density. Deep penetration, at least 50% beyond the damage thickness, is needed to effectively connect wellbore to undamaged rock. Perforation efficiency in tight gas reservoirs is affected by the high rock strength that makes penetration of perforation jet to be significantly reduced compared with an equivalent sandstone of higher porosity. Using deep penetrating perforation charges run with shock absorbers can mitigate damage to perforation tunnels and reduce the skin factor (Behrmann, 2000).

Note: For detailed explanations regarding the tight gas reservoir characteristics and productivity, Refer to my published papers presented in appendices A and D.

1.2 Damage mechanisms in tight gas reservoirs

Tight gas reservoirs can be subject to different damage mechanisms during well drilling, completion, stimulation and fracturing, such as mechanical damage to formation rock, plugging of natural fractures by invasion of mud solid particles, permeability reduction around wellbore mainly as a result of filtrate invasion, clay swelling and liquid phase trapping (Holditch, 1979). Materials such as mud filtrate, cement slurry, or clay particles may enter the open pores of the formation and reduce permeability around the wellbore as well (Abass and Ortiz, 2007). The solids may penetrate only a short distance into the rock matrix and cause only a shallow mechanically damaged zone. However the damage to natural fractures and open permeable conduits can be severe, as drilling fluids invasion mostly occurs through the natural fractures (Sharif, 2007; Araujo et al, 2005).

Liquid invasion damage into the rock matrix is one of the major factors that cause low productivity in tight gas reservoirs (You and Kang 2009). In the absence of external cake protection, filtrate invasion into the tight formations is huge due to the tremendous amount of capillary pressure suction that potentially imbibes and holds the invaded water in the porous media (Ding, 2006). The liquid phase trapping eventually reduces the near wellbore permeability as shown in Figure 3 as a result of the temporary or permanent trapping of liquid inside the porous media (Bennion et al, 1996). In addition, liquid invasion into the tight formations normally continues for a noticeably long period of time as a result of weak mud cake development on wellbore wall. The weak mud cake and strong capillary pressure suction may amplify the water invasion profile and deteriorate severity of the phase trap damage to the tight formation. The greater the difference between initial water saturation and critical water saturation in tight formations, the more significant is the potential damage to gas permeability (Bennion et al, 2006).

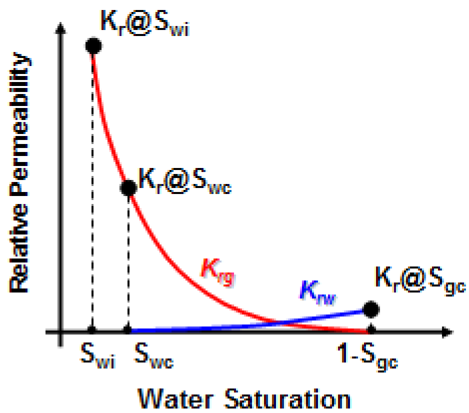

Figure 3: Reduced effective permeability due to phase trapping damage (Bennion et al, 2006)

Producing gas at low flowing bottom-hole pressure may reduce the phase trapping damage, since water content of the gas phase is higher at lower pressure, and water phase may partially be vaporized into the gas phase in the reduced pressure zone around the wellbore (Lokken et al, 2008). However in the cases that are not truly dry gas situation, producing with the large pressure drawdown may cause condensate banking in the reservoir near the wellbore, if the flowing bottom-hole pressure drops below the dew point pressure of the gas phase (Ravari et al, 2005).

Oil based fluids may be considered in some situations for low permeability gas reservoirs. In the case of oil-based drilling fluid invasion, there is no external water being introduced into the formation and the fluid saturations and wettability remaining unchanged. However invasion of the oil filtrate into the tight formations may result in introduction of an immiscible liquid hydrocarbon around wellbore, causing entrapment of an additional third phase in the porous media. In the case of oil-based fluids invasion into water wet gas reservoirs, the invaded oil may tend to be trapped in the central portion of the pore space, rather than adhering tightly to the matrix walls as the wetting phase. Although this central pore space occlusion can cause substantial reductions in permeability, in some cases, the damaging effect in overall is less than the case where water based system is used in the same circumstances. Some types of oil may also dissolve in the gas and clean up after some time. The relative permeability curves illustrated in Figure 4 show the reduced effective permeability due to water invasion into the formation, compared with damage to permeability caused by oil invasion. (Chi et al, 2004, Bennion et al., 2006).

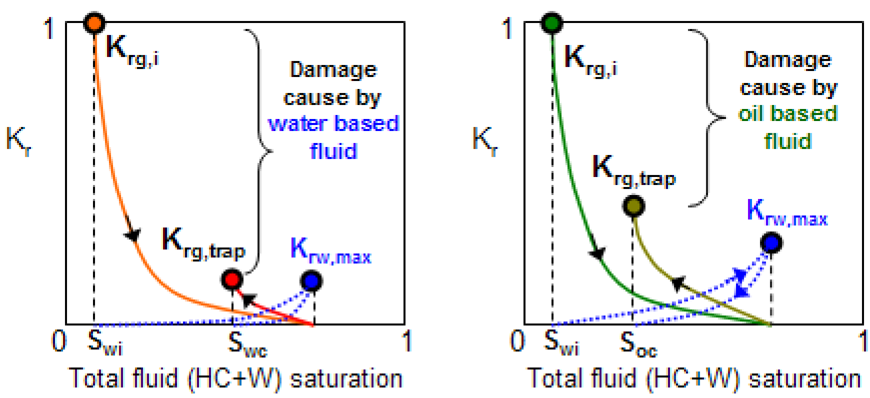

Figure 4: Damage caused by water and oil phase trapping (Bennion et al, 2006)

Note: For more detailed explanations regarding the damage mechanisms in tight gas reservoirs, Refer to my published papers presented in appendices A, D and E.

1.3 Hydraulic fracturing in tight gas reservoirs

Hydraulic fracturing is performed to bypass the damaged zone and create larger contact area between the wellbore and the permeable conduits in the reservoir. The importance of hydraulic fracturing in tight gas sandstone reservoirs is well documented and understanding the hydraulic fracture parameters is essential for evaluation of the well production performance (Wang, 2008). Massive hydraulic fractures in particular, can enhance the effective permeability around wellbore and may connect the wellbore to the adjacent sand lenses that are not penetrated by the well (Cipola and Mack, 2010).

Propagation and direction of hydraulic fractures in tight formations are mainly controlled by in-situ stresses as shown in Figure 5. Where there is high contrast between minimum and maximum horizontal stresses, the stimulation creates a narrow or linear fracture fairway, and where the stress contrast is low, wide or complex fracture geometry are created during the treatment (Fan et al, 2010).

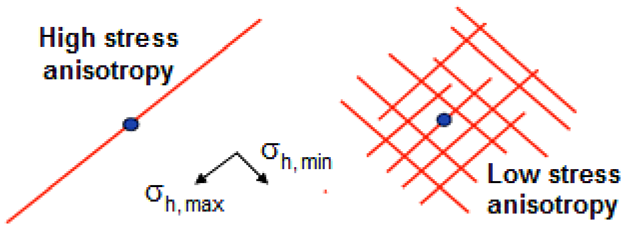

Figure 5: Effect of stress anisotropy on propagation of hydraulic fractures

A common practice in unconventional gas reservoirs is to drill a horizontal well, consider short perforation intervals, and then hydraulically fracture the formation in multi-stages to create a treated zone around each hydraulic fracture (Bagherian et al, 2010). Considering a horizontal well in a normal faulting stress regime, the hydraulic fracture might be different as illustrated in Figure 6. If the horizontal well is drilled in the direction of maximum horizontal stress, the longitudinal hydraulic fractures are likely to be initiated along the wellbore, and if the horizontal well is drilled in the direction of minimum horizontal stress, then the transverse hydraulic fractures are initiated perpendicular to the wellbore axis (Hossain and Rahman, 2008).

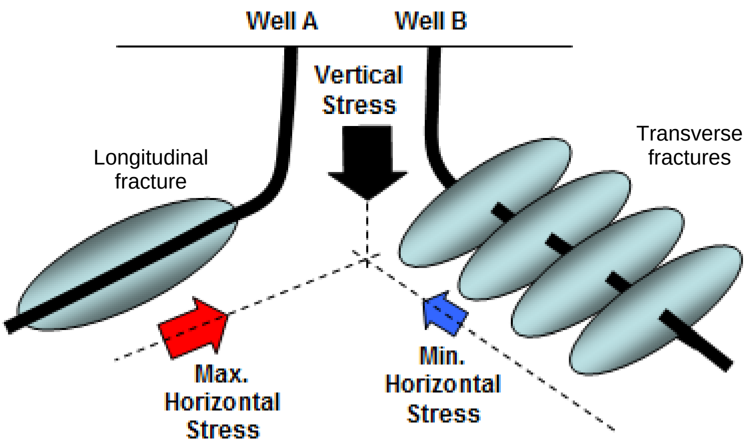

Figure 6: longitudinal and transverse hydraulic fractures in tight gas reservoirs

Note: For more detailed explanations regarding hydraulic fracturing in tight gas reservoirs, Refer to my published papers presented in appendix F.

1.4 Damage due to hydraulic fracturing

Hydraulic fracturing in some cases may not improve well productivity in tight gas reservoirs, or the productivity may increase only temporarily. During the stimulation and fracturing in tight gas reservoirs, fracturing liquids invade the reservoir and may create a bank of fracturing agent around the hydraulic fracture wings, which can develop negative effects on the long term production performance of the well (Wang and Holditch, 2008). Low productivity of a hydraulically fractured well might be due to the existence of damage mechanisms associated with liquid phase trapping in rock pores next to the fractures (Mahadevan, 2007). The tight formations with sub-normal initial water saturation are significantly more sensitive to damage caused by water phase trapping, and therefore water blocking may plague the success of hydraulic fracturing in low permeability gas reservoirs with this characteristic. The injected fluid during hydraulic fracturing should be compatible with formation to avoid clay swelling (Bennion and Brent, 2005). In the case of naturally fractured reservoirs, the fracturing fluids may transport the damaging solids through the natural fractures into deeper parts of the reservoir and further reduce the well productivity (Rodgerson, 2000).

Use of polymer gels with hydraulic fracturing fluid may control the invasion of fracturing liquid and fluid loss into the tight formation, as the polymer is deposited on fracture faces, and cause very short distance penetration of the unbroken polymer gel into the reservoir rock. However this can make the fracturing fluid to be highly viscous, which may result in plugging as well as damaging of the hydraulic fractures face, dramatically lessen the effective length and width of the hydraulic fractures, and restrict the return of fluids during clean-up and gas production period (Raible and Gall, 1985). The damage inside the fractures may also be due to proppant crushing, embedding, or fracture plugging with chemicals and polymers. The polymer may become a highly concentrated gel, and if it is left in the fractures, the gel damage can be the reason for ineffective clean-up and short effective fracture length. The polymer plugging can be reduced if suitable breakers are used, but this breaker must be able to be activated deep within the fractures (Wand and Holditch, 2008).

In tight gas reservoirs that are sensitive to water invasion damage, hydraulic fracturing may fail to produce gas at commercial rates as it causes excessive liquid leak off into the tight formation. The preferred option in tight gas reservoirs might be horizontal well drilling in underbalanced conditions (Veeken et al, 2007).

In hydraulic fracturing, additional production difficulties may also be experienced on the downstream side of the formation interface. These problems include proppant back-production that causes erosion of surface facilities (Abbas 2009). Also in the case of significant liquid leak-off and fluid loss into the tight formation during fracturing, the post-fracturing gas production and the well productivity may be affected by loading of the fracturing liquid in wellbore that cannot be lifted to surface by the natural gas flow (Salim and Lee, 2009).

Note: For more detailed explanations regarding hydraulic fracturing in tight gas reservoirs, Refer to my published papers presented in appendix A. Regarding the effect of liquid loading in wellbore on well productivity, Refer to Appendix G.

1.5 Mitigating damage in tight gas reservoirs

The damage mechanisms in tight gas reservoirs are controlled by pore system geometry, interfacial tension between the invading trapped fluid and the produced (or injected) reservoir fluid, capillary pressure, relative permeability, wettability, fluid saturation levels, depth of invading fluid penetration, reservoir temperature, reservoir pressure and well bottom-hole flowing pressure. With most of the phase trapping problems, prevention is generally more effective than remediation from an economic perspective. Removing damage is more common in the industry although it may be more problematic and certainly more costly (Ding, 2006, Bennion et al, 2006).

The damage due to liquid invasion and clay swelling can be minimized by properly choice of the base fluid for drilling and fracturing treatments, and reducing overbalance pressure during drilling and completion. Improving drilling or fracturing fluid rheology and filter cake building ability, which can provide an effective cake that is later removable can help control the damaged zone depth and reduce the damage due to liquid invasion. Reducing interfacial tension (IFT) between the trapped injected fluid and the reservoir fluid using IFT reducing agents such as methanol and liquid phase carbon dioxide can help more efficient recovery of the trapped phase from the invaded zone. Adding methanol in the fracturing fluid can reduce the water block as it helps faster clean-up and drying of water from the invaded zone (Bazin, 2009, Motealleh, 2009).

Using hydrocarbon-based drilling fluid in designing a drilling fluid can result in minimal phase trap potential, as it can avoid clay swelling. In addition, interfacial tension that directly affects capillary pressure and retention, it is significantly less between oil-gas is less compared with gas-water, and can result in reduced phase trapping damage. Down-hole heating is another method that can remove aqueous phase traps as well as thermally decomposing potentially reactive swelling clays. The water phase trapping may also be removed by injection of dehydrated dry gas into the formation to initiate conduits of higher gas permeability through the damaged zone (Bennion et al, 2006, Jamaluddin et al, 1998).

1.6 Summary

Based on this literature review, it is evident that there are many factors that that can influence the production performance of tight gas reservoir. Understanding the effects can be paramount for successful development and exploitation of tight gas reservoir. This chapter reviewed the different factors that control damage mechanism and well productivity, and the optimum strategies for tight gas reservoirs were discussed.

2 Tight gas reservoirs characterisation for dynamic parameters

Tight gas reservoirs might be very different in term of reservoir characteristics, and it is challenging to adequately determine the reservoir dynamics parameters such as the effective permeability of matrix and natural fractures, relative permeability, skin factor, hydraulic fractures size and conductivity and fluid gradients in the reservoir. Similar to the conventional gas reservoirs, the reservoir characterization tools such as well testing, logging, core analysis and formation testing are commonly used and run in tight gas reservoirs. However due to the tight formations complexity, heterogeneity and very low permeability, use of the acquired data to obtain meaningful results may not be well understood in term of determining the well and reservoir parameters and predicting the well production performance. Especially, the time scales involved, and the ratios between wellbore storage, skin and intrinsic reservoir parameters may be very different in tight gas sands compared with conventional reservoirs (Gonfalini, 2005; Mahadik et al, 2012).

2.1 Estimation average permeability of tight gas reservoirs

Reservoir permeability can be estimated by analyzing the pressure transient data acquired during well testing. The conventional method of welltest analysis is to use the plot of transient pressure (P) and its derivative (P': $-d[\Delta P]/d[Log((t_p+\Delta t)/\Delta t)]$) versus time function on Log-Log scale to identify radial flow regime and determine the slope of Horner plot straight line (*m*) as shown in Figure 7, in order to calculate the reservoir permeability (Kappa Engineering, 2011). In pressure transient tests, different flow regimes might be observed on the pressure derivative curve: the slope of +1 shows wellbore storage effect, the slopes of -0.5, +0.5, +0.25 and +0.36 indicate spherical, linear, bi-linear and elliptical flow regimes respectively, and the slope of zero indicates radial flow regime. Diagnosis of the radial flow regime is critical in quantitative welltest interpretation, since reliable estimation of reservoir permeability and skin factor can be performed when late-time radial flow regime is established in the reservoir (Badazhkov, 2008; Bourdarot, 1998).

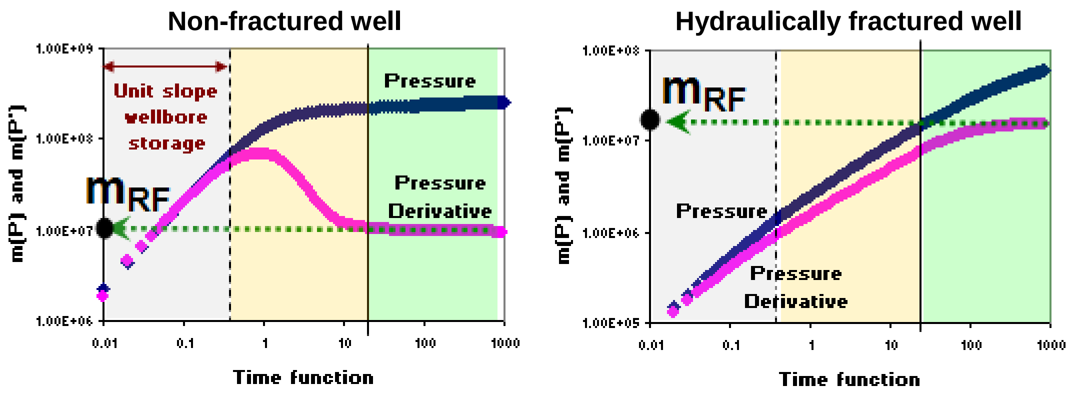

Figure 7: Pressure build-up Log-Log diagnostic plot

The early portion of welltest data during pressure build-up tests is normally affected by wellbore storage and skin factor. In tight gas reservoirs, the low permeability slows down the reservoir response to the pressure disturbance during transient testing, which causes the wellbore storage effect to be significantly long (Garcia et al, 2006). In addition, the need for hydraulic fracturing to obtain commercial flow rates in tight gas reservoirs adds to the complexity of the problem and makes analysis of the pressure transient data more difficult. Field observations in a large number of tight gas wells have also shown a long-term linear flow behaviour due to the very low reservoir permeability, hydraulic fractures and natural fractures, permeability anisotropy, and reservoir geometry (Restrepo, 2009; Arevalo et al, 2001). As a result, tight gas reservoirs typically require a relatively long pressure build-up testing time to reach the late time pseudo radial flow regime, which is often not practical. Therefore, welltest analysis using the conventional techniques may fail to provide reliable results.

In order to reduce the uncertainties, a new method is introduced for welltest analysis based on taking the second derivative of transient pressure with respect to the logarithm of time function, that is defined as P'': $-d^2[\Delta P]/d[Log((t_p+\Delta t)/\Delta t)]^2$. Compared with the first derivative, the advantage of the second derivative of transient pressure as shown in Figure 8 is that its intercept is certain (zero) and therefore the second derivative curve trend might be predictable. The second derivative of transient pressure versus time function on Semi-Log plot can validate the existence of the radial-flow regime on a first derivative chart, when there is uncertainty in radial flow regime identification using the standard diagnostic plots.

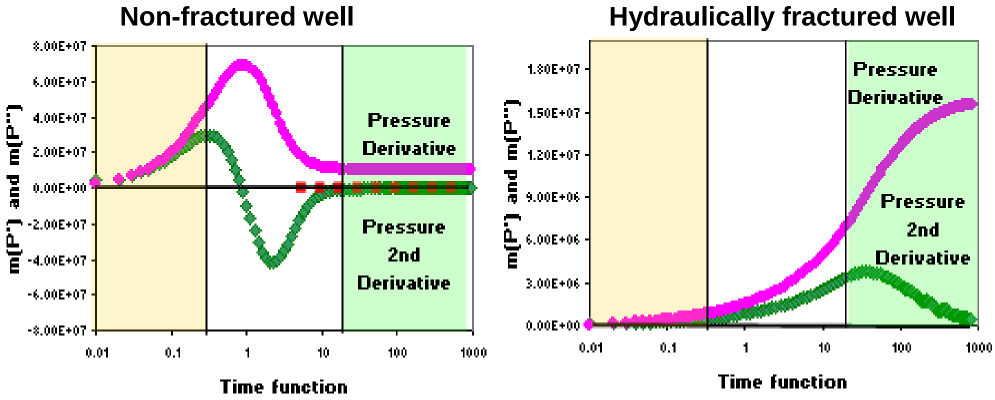

Figure 8: The diagnostic plot based on the 2nd derivative of transient pressure

2.1.1 Field example: Welltest analysis in a West Australian tight gas well

Pressure build-up test in a hydraulically fractured vertical well (longitudinal fracture) in the West Australian tight gas reservoir is analysed in order to estimate reservoir permeability and evaluate the well productivity. However, the test duration was not long enough in this test, and analysis of the welltest data may have uncertainties.

To have reliable welltest analysis results, the second derivative of transient pressure is used (Bahrami and Siavoshi, 2005). Using the welltest analysis shown in Figure 9, the value of pressure derivative in radial flow region is estimated as 3.7E+8 psi^2/cp, which corresponds to permeability of 0.006 mD, skin of -4.3. Using the K and S values, by matching the pressure and the first pressure derivative curves on the standard Log-Log diagnostic plot, it resulted in fracture half length size of 55 ft.

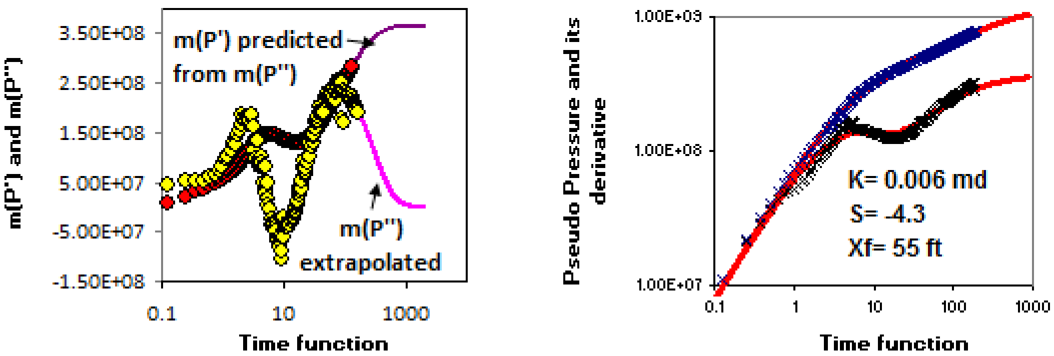

Figure 9: Welltest analysis in the tight gas well

Note: For details of the method using the second derivative of transient pressure, equations derivation, reservoir flow regimes in hydraulically fractured wells, a workflow for welltest analysis in tight gas wells, and verification of the methodology and its reliability, refer to my published paper presented in Appendix C.

2.2 Estimating the permeability of natural fractures

Natural fractures may contribute the most to total gas production from tight gas reservoirs, and identification of their characteristics is essential for well production performance evaluations. The basic dynamic characteristics of the natural fractures are fracture storativity and interporosity flow coefficient, which can be estimated from welltest analysis. Then using the parameters, natural fractures permeability can be estimated as follows (Tiab et al, 2006):

$$K_f = \delta \frac{K_m}{\lambda} r_w^2 \qquad [2\text{-}1]$$

Where K_m is matrix permeability, K_f is fracture permeability, r_w is wellbore radius, δ is shape factor, and λ is interporosity flow coefficient. The shape factor can be estimated from image log fracture spacing, matrix permeability can be estimated from core analysis, and the interporosity flow coefficient can be estimated from welltest analysis if dual-porosity, dual-permeability response is clearly observed on pressure build-up diagnostic plots (Racht, 1982).

However in tight gas reservoirs, due to the long wellbore storage effect and also the tightness and heterogeneity of the reservoir rock, pressure build-up diagnostic plots may not be able to show the dual porosity dual permeability response. Hence, estimating the interporosity flow coefficient and fracture permeability from such welltest data might not be feasible, and the conventional approaches might fail to characterize the fracture parameters in tight gas reservoirs.

To be able to estimate permeability of natural fractures for tight gas reservoirs, a new method is introduced based on Kazemi model that assumes parallel layers of matrix and fracture in a uniform fracture network model (Racht, 1982), averaging reservoir permeability based on thickness of matrix and fracture layers (Bourdarot, 1998), and applying some correction factors. The proposed simplified equation to determine the natural fractures permeability is as follows:

$$K_f = C_1 * K_{welltest} * (\frac{a_f}{b_f})^{C_2} \qquad [2\text{-}2]$$

Where $K_{welltest}$ is welltest permeability, b_f is average fracture aperture, a_f is average fracture spacing, and C_1 and C_2 are the correction factors. For a tight gas reservoir, average permeability can be estimated from welltest analysis, fracture spacing and fracture aperture can be approximated from image log processing, and the constants C_1 and C_2 can be determined from reservoir simulation and sensitivity analysis.

Note: For more details regarding natural fractures characterization, the equations derivation, the assumptions that were used, a field example on typical natural fractures parameters, determining the input parameters that are required for fracture permeability estimation using Equation 2-2, and also the verification of the methodology and its accuracy, refer to the published paper presented in Appendix B.

2.3 Determination of tight gas relative permeability curves

The major damage mechanisms in tight gas reservoirs such as phase trapping are found to be associated with relative permeability and capillary pressure curves. The damaging effects are reflected on gas and water relative permeability curves (Bennion et al, 2006).

The relative permeability data for tight gas sands are extremely difficult to obtain by the conventional steady state flow analysis technique as it requires impractically very long stabilization time and flow rates are usually small (Ning and Holditch, 1990). In this study, however, an unsteady state flow analysis technique is applied to a core flooding experiment, in which the tight core samples are fully saturated with water (initial water saturation of 100% for primary drainage), and then gas-flooded at constant volumetric flow rate to reach irreducible water saturation. During the core flooding experiment, the pressure differential across the core sample and volume of the produced water are recorded. The details of the technique and the experimental procedures are published and available (Saeedi, 2012).

The core flooding experiments were performed using the lab facilities of the Department of Petroleum Engineering at Curtin University, as shown in Figure 10. Different core samples in Whicher Range tight gas field were studied, and the best quality core (effective permeability of 0.035 md and porosity of 9.6%) was selected and prepared for the core flooding experiment.

Figure 10: Core flooding facilities of Pet. Eng. Department in Curtin University

The core flooding experiment provided the data related to water production and differential pressure across the core sample. The experimental core flood data were used in the commercial core flooding data analysis software SENDRA, in order to generate relative permeability curves by matching the core flood data for brine production and pressure differential data as shown in Figure 11.

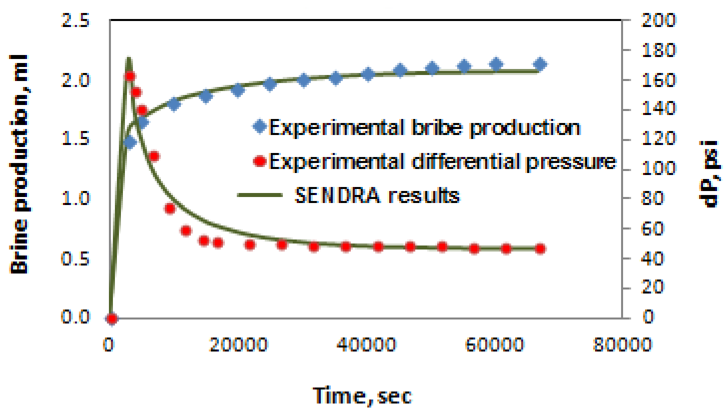

Figure 11: Brine production and pressure differential in the core flooding experiment

The SENDRA analysis results based on the history matching resulted in the following relative permeability curves as shown in Figure 12, which indicate relative permeability to water is significantly lower compared with relative permeability to gas (typical behaviour in water sensitive formations). The core flooding experiment also indicated the irreducible water saturation of 60%. For the core sample, airmercury capillary pressure data were also provided, which then using some conversion factors, the gas-water capillary pressure data could be determined.

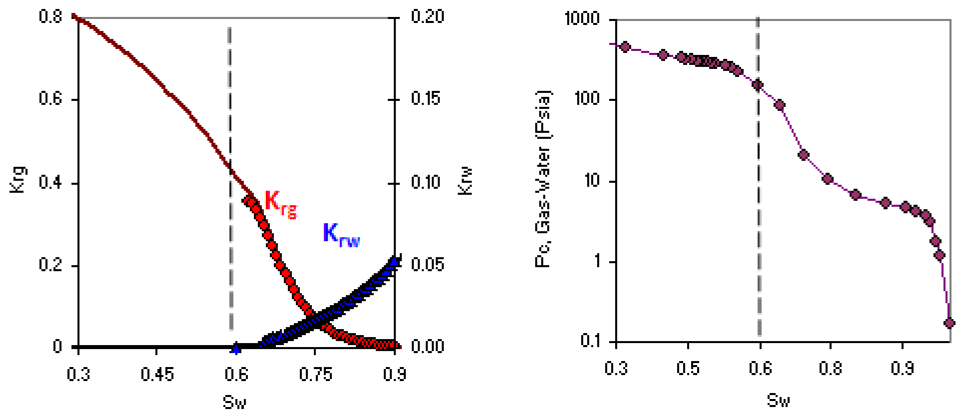

Figure 12: The relative permeability curves for the tight sand core sample

For oil-gas system, the core flooding data that are required for determination of gas-oil relative permeability were not possible to determine due to some limitations in the laboratory facilities when oil is used as liquid phase. Therefore typical published oil-gas relative permeability data had to be considered in the reservoir simulation studies related to oil-gas system (Ravari et al, 2005).

Note: For more details regarding the petrophysical characterises of the core sample that was used in the core flooding experiments, the typical relative permeability data for water-oil and gas-oil, Refer to my published papers presented in Appendices A and E.

2.4 Formation testing in tight gas reservoirs

A formation test is used to measure the pressure of a formation, pressure gradient, and gas water contact. To measure pressure of reservoir at each depth, the tool inserts a probe into the borehole wall to performs a mini pressure drawdown and build-up by withdrawing a small amount of formation fluid, and then waiting for the pressure to build up to the formation pore pressure at that depth. Formation testers measure the pressure of the continuous phase in the invaded region, which is the pressure of the drilling fluid filtrate. Using the pressure measurements at different depths, gradient of pressure in the reservoir is determined, which can indicate reservoir fluid type and water-hydrocarbon contact (Schlumberger formation testing, 2005).

In tight gas reservoirs, formation testing is challenging due to tightness of the reservoir rock, weak mud cake across the wellbore, and presence of large wellbore breakouts across the tight sand intervals. Although using advanced formation testing tools may help improve reservoir characterization of tight gas reservoirs (Schrooten, 2007), formation testing results in tight formations may still have some uncertainties. In good permeability zones, formation tests are effective and normal. However in the case of low reservoir permeability, the mud cake is often ineffective in preventing filtrate invasion, thus causing the measured pressure to be affected by wellbore pressure that might be higher than the actual formation pressure (supercharging effect). In testing of a very tight formation, even a large pressure drawdown may result in no flow from the reservoir (dry test). Tight gas reservoirs are often associated with bad-hole conditions (large wellbore breakouts) causing lost seals around the tool packer and failure during testing of the formation (Schlumberger formation testing, 2005). The formation testing measurements may also be influenced by the effects of capillary pressure in the case of liquid invasion into a gas bearing zone. As a result, the measured pressure might be different to the true formation pressure (Elshahavi et al, 1999; Andrews et al, 2012).

2.5 Summary

The tight gas reservoirs dynamic parameters such as relative permeability, reservoir average permeability, and natural fractures permeability are the key factors that control production performance of tight gas wells. This section presented a new method of welltest analysis for more reliable estimation of the average reservoir permeability and a new correlation for estimating the permeability of natural fractures in tight formations. The relative permeability and capillary pressure curves for Whicher Range tight gas reservoir were also determined.

3 Tight gas reservoir simulation

Analytical and numerical simulation studies are performed to have a qualitative understanding of damage mechanisms associated with production from non-fractured and hydraulically fractured tight gas reservoirs; and evaluate its potential impact on well productivity.

In building tight gas reservoirs simulation model, it is important to use a consistent set of field data in order to get meaningful simulation outputs. Based on the West Australian tight gas field data, the simulation models are built at reservoir scale and core scale.

Note: The detailed information about the core and reservoir scale simulation models, including the input data and 3-D views of the models, are presented in Appendices A, D and E.

3.1 Effect of damage mechanisms on well productivity

Reservoir simulation is used to understand how damage mechanisms are controlled by the well and reservoir parameters such as reservoir permeability, permeability of the damaged zone, radius of the damaged zone, drilling fluid type, capillary pressure and relative permeability curves.

In this section, the effects of different parameters on damage and skin factor are studied using the reservoir simulation models. To evaluate the damage effects, the term flow efficiency (FE) is used in some of the cases, which is defined as the ratio of the pressure drop across the model in the case of zero skin virgin homogeneous rock; to the pressure drop in the case of perforated and/or damaged rock (FE equals to 1 in the case that there is no damage introduced to a non-perforated model).

3.1.1 Damaged zone permeability and radius

The simulation model is run for conventional and tight cores, with damaged zone permeability of K_d and damaged zone radius of r_d. The model results are shown in

Figure 13. According to the results, the effect of damaged zone permeability and damaged zone radius on flow efficiency is more significant in tight gas reservoirs compared with conventional cores, indicating the importance of damage control in tight gas reservoirs.

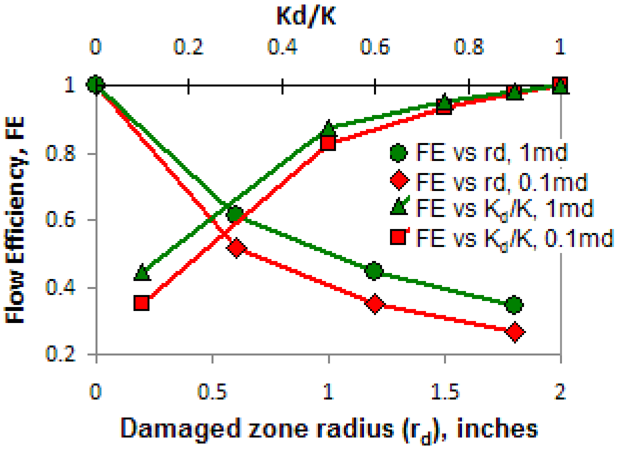

Figure 13: Invaded zone parameters and the effect on flow efficiency

Note: Refer to the APPEA paper presented in appendix C for details of the simulation works including modelling and analysis.

3.1.2 Phase trapping damage caused by water invasion

The effect of water invasion in the reservoir model is evaluated by injecting water at the well location, followed by gas production. The water saturation in the reservoir model at initial conditions (top view) is shown in Figure 14 (Swi=0.6).

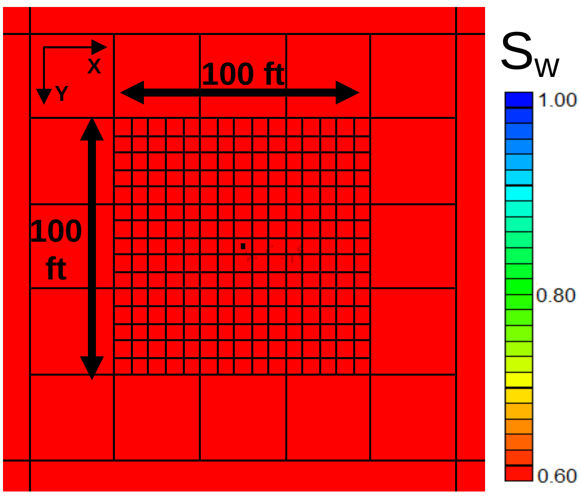

Figure 14: Water saturation in the model before water invasion

First, water is injected at the well location, which increases water saturation around the wellbore. Water saturation at the end of the injection period is shown in Figure 15 (equivalent radius of water invaded zone: 9 ft). Afterwards, the model is put on gas production to clean-up the invading water, and reduce water saturation around the wellbore. Water saturation at the end of the gas production period is shown in Figure 16 (equivalent radius of water invaded zone: 12 ft). The results indicate during the gas production phase, not only water from the near wellbore was not cleaned up by gas production, water invasion was continued into the reservoir due to the strong capillary pressure suction effects, and damaged zone radius (water invaded radius) increased with passage of time.

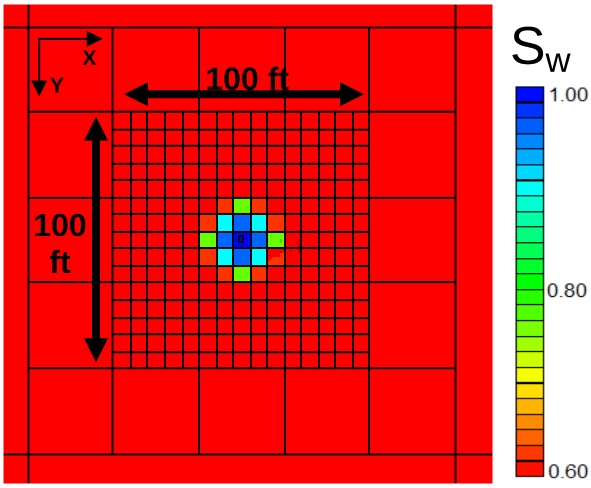

Figure 15: Water saturation in the model at the end of water injection period

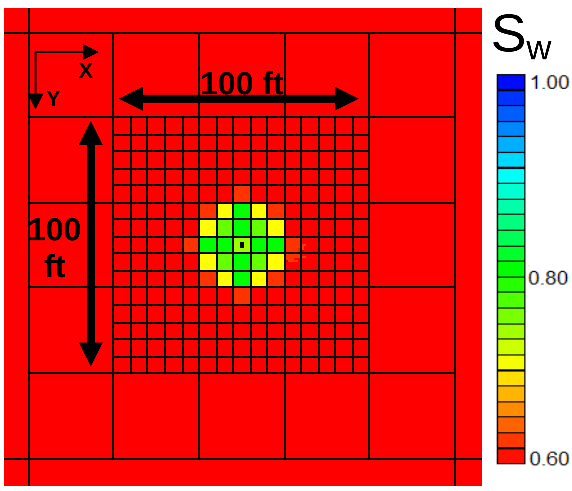

Figure 16: Water saturation in the model at the end of gas production period

Note: Refer to Appendix A for details of the simulation work and results analysis.

3.1.3 Effect of phase-trap damage on skin factor

The reservoir model is also run to understand the effect of phase trapping damage on skin factor for four different cases. Case A considers no leak-off of liquid into formation (no damage). Cases B, C and D, consider, respectively approximately 215, 770 and 1400 barrels of water leaks off into the formation. In each run, the water leak-off is followed by gas production during clean-up.

In each of the models after the liquid leak-off, the well is put on gas production followed by a pressure build-up test. The pressure transient data are generated to calculate the skin factor caused by phase trapping. The cumulative injected volume of water during leak-off (W_i) and the simulated results for cumulative produced water (W_p) during clean-up and gas production are integrated with welltest results as shown in Figure 17. In the case of no liquid leak-off into the tight formation (case A), the water blocking skin is zero. In the case of significant water leak-off into the formation, skin is found to be positive. The results highlight the fact that phase trap related damage due to water leak-off into the tight gas reservoir causes positive skin factor, and significant reduction in gas production rate and gas recovery.

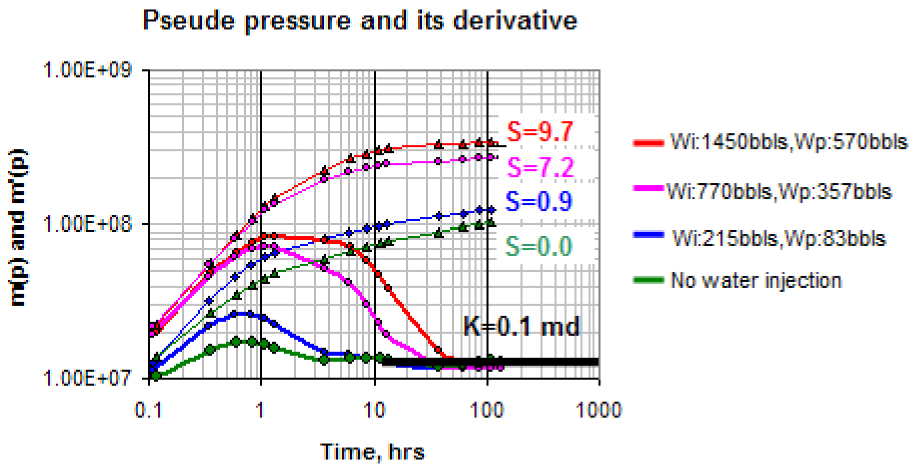

Figure 17: Effect of phase trap damage on skin factor

Note: For more details about model details, production and pressure build-up data and durations, and the simulation results analysis please prefer to Appendix D.

3.1.4 Overbalanced and underbalanced drilling

The model is run at core scale, to understand the effect of wellbore pressure on water invasion during overbalanced, balanced and underbalanced drilling. The model is run for the following cases.

- 500 psia overbalanced pressure resulted in 0.5" liquid invasion into matrix
- Balanced pressure conditions resulted in 0.4" liquid invasion into matrix
- 400 psia underbalanced resulted in 0.3" liquid invasion into matrix
- 1000 psia underbalanced resulted in 0.3" liquid invasion into matrix

From this simulation results as shown in Figure 18, it is obvious that the wellbore liquid invades deeper in overbalanced conditions. However for underbalanced conditions, although the wellbore pressure is less than the reservoir pressure, water still invades the matrix rock due to the strong capillary suction and causes an increase in water saturation around the wellbore. Thus, damage caused by water blocking might still be significant even in the case of underbalanced drilling in tight formations, owing to the ability of high and negative capillary pressure (water suction) to compensate for relatively low mud pressure in the common case where the tight gas formation is strongly water wet.

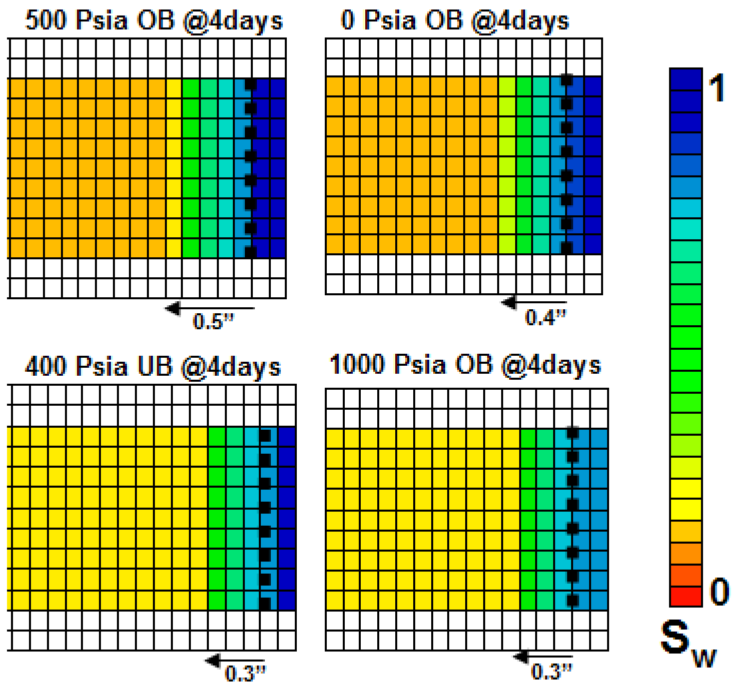

Figure 18: Effect of wellbore pressure during drilling on phase trap damage

Note: Please see Appendix C for details of the simulation work and results.

3.1.5 Phase trapping caused by oil based and water based drilling fluids

The simulation model is run to evaluate the effect of water and oil invasion damage on well productivity. To evaluate phase-trap damage, the model is run for the cases of no liquid invasion prior to gas production (no damage), injection of water into the model, followed by gas production (water damage), and injection of oil into the model, followed by gas production (oil damage).

The simulation results for cumulative gas production rate are shown in Figure 19, which indicate that the well productivity is reduced in both oil and water invasion cases due to the liquid phase trapping that can not be removed by gas production. However, the well productivity is more sensitive to water invasion damage than invasion of oil, and in the case of oil invasion, the damaging effect is significantly less than water invasion.

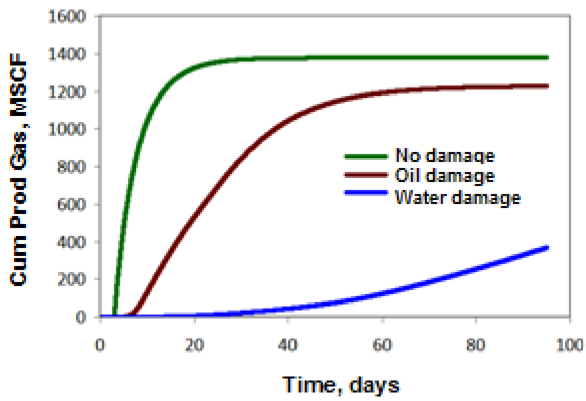

Figure 19: Effect of water and oil invasion damage on gas recovery

Note: See Appendix E for more details about fluids distribution around the wellbore and liquid phase trapping in the cases of oil based and water based drilling fluids.

3.1.6 Water blocking damage in hydraulically fractured wells

Hydraulic fractures are introduced to the reservoir scale simulation model as high permeability planes perpendicular to the wellbore. The model is run to understand the effect of initial water saturation and water invasion damage on gas production rate in non-fractured and hydraulically fractured wells.

The simulation results for the effect of initial water saturation are shown in Figure 20, which indicate significant effect of Swi on well productivity. For all the cases, sub-normal Swi provided significantly higher gas production rate.

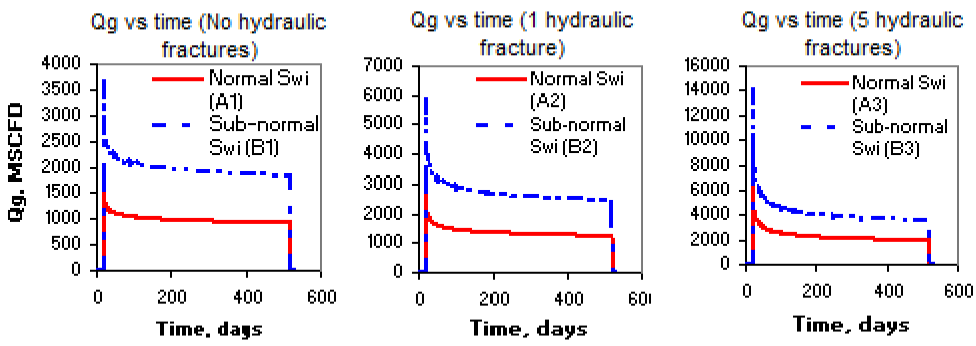

Figure 20: Effect of initial water saturation on gas production rate

The simulation results in Figure 21 show the effect of water blocking damage in tight formations with normal S_{wi}. In the case of non-fractured well, water blocking damage causes significant drop in gas production rate, and in the case of a fractured well, the hydraulic fractures could improve well productivity. With 5 hydraulic fractures, the stabilized gas production rate at late time is almost similar in the cases of damaged and non-damaged wells (A3 and A6), which indicates that the dominant effect of large hydraulic fractures compared with formation damage effect.

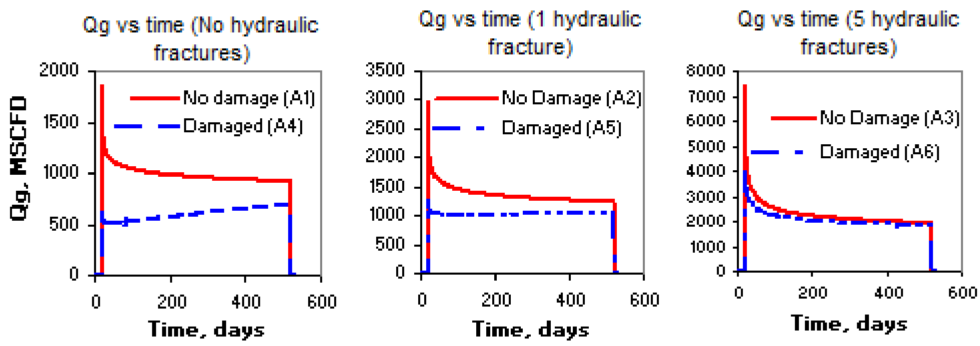

Figure 21: Effect of water invasion damage on gas production rate

The summary of simulated results for cumulative injected water during leak-off, and cumulative produced water during clean-up and gas production are reported in Table 1, which indicate that in the reservoirs with sub-normal Swi, most of the injected water during hydraulic fracturing is held inside the reservoir rock by capillary imbibition. Compared with the normal Swi, the sub-normal Swi models have larger leak-off of liquid into the formation, and significantly smaller volume of cumulative water produced back. In other words, water phase trapping damage is more significant in tight gas reservoirs that have sub-normal initial water saturation.

Table 1: Simulation results for injected water and recovered water

Simulation results for water production/injection	Scenarios	Cumulative Injected Water (bbl)	Cumulative Produced Water (bbl)
A1, normal Swi, no frac A2, normal Swi, 1 frac A3, normal Swi, 5 fracs B1, sub-normal Swi, no frac B2, sub-normal Swi, 1 frac B3, sub-normal Swi, 5 fracs	No water invasion prior to gas production	-	-
A4, normal Swi, no frac	2000 bbl/d water injection prior to gas production	1829	829
A5, normal Swi, 1 frac		1872	911
A6, normal Swi, 5 fracs		2046	1164
B4, sub-normal Swi, no frac		4443	134
B5, sub-normal Swi, 1 frac		4472	146
B6, sub-normal Swi, 5 fracs		4600	192

The simulation results in Figure 22 show the significance of damage control for well productivity improvement are shown. In the case of normal Swi, cumulative produced gas from the well with a single hydraulic fracture that is damaged by water invasion (A-5) is not significantly different as compared with the well with no hydraulic fractures and no damage (A-1). In other words, in the case of single hydraulic fracturing, the well productivity may not be improved noticeably if water blocking damage is significant. For both damaged and non-damaged formation, the models with five hydraulic fractures provided significantly better productivity.

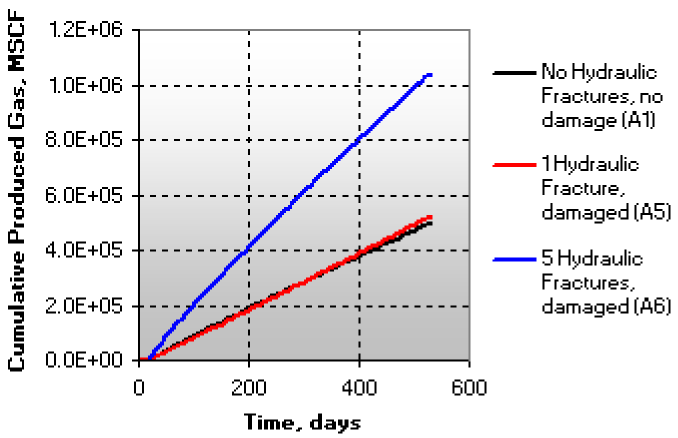

Figure 22: Effect of water invasion on productivity of hydraulic fractured wells

Note: Refer to Appendix A for more details about the simulation model, definition of the different cases, and analysis of the simulation models outputs.

3.1.7 Damage to natural fractures

The reservoir scale simulation model is run in the cases where the well intersects no natural fractures, the well intersects open natural fractures, and the well intersects the natural fractures that have been plugged at the well location. The simulation results for gas production are shown in Figure 23, which indicate a significant reduction in cumulative gas production in the case that the natural fractures are damaged (well productivity close to a non-fractured reservoir).

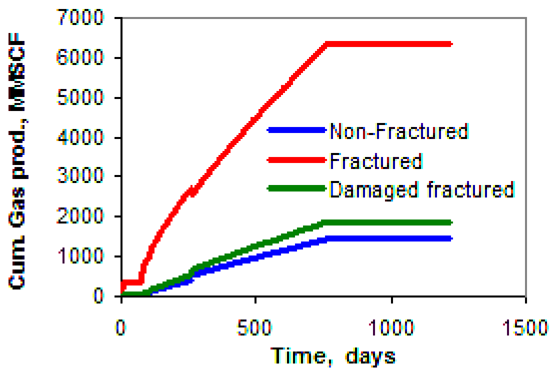

Figure 23: Effect of damage to natural fractures on productivity

Note: For more details about modelling of damage to natural fractures and analysis of the simulation results, Refer to my published paper presented in Appendix D.

3.2 Effect of wellbore related parameters on well productivity

The simulation models are built based on the available field data from the West Australian tight gas reservoir to understand how different parameters affect well productivity in tight gas reservoirs.

3.2.1 Hydraulic fractures

Hydraulic fractures may propagate differently in tight formations depending on wellbore direction and stress anisotropy. In a reservoir with normal stress, depending on wellbore direction and in-situ stresses, the hydraulic fractures might be parallel to the wellbore (longitudinal), or perpendicular to the wellbore (transverse).

Simulation models are built for the cases of a non-fractured and a multi-fractured well, as open-hole (or a fully-perforated cased hole), considering all the hydraulic fractures have similar size (75 ft half length size and 100 md.ft conductivity). The following cases are run in order to understand the effect of wellbore direction on productivity of hydraulically fractured horizontal well: No hydraulic fractures (No HF), one longitudinal hydraulic fracture along wellbore (1 LHF), one transverse hydraulic fracture perpendicular to wellbore (1 THF), five transverse hydraulic fractures perpendicular to wellbore (5 THFs), and nine transverse hydraulic fractures perpendicular to wellbore (9 THFs).

The simulation results are shown in Figure 24, which indicate that the longitudinal hydraulic fracture provides significantly higher gas production rate compared with the single, 5 or 9 transverse hydraulic fractures. Although each single transverse hydraulic fracture has similar size (volume) compared with the longitudinal hydraulic fracture, since a hydraulic fracture along wellbore has larger direct contact area to the wellbore, it provides higher gas rate compared with the transverse hydraulic fractures perpendicular to wellbore.

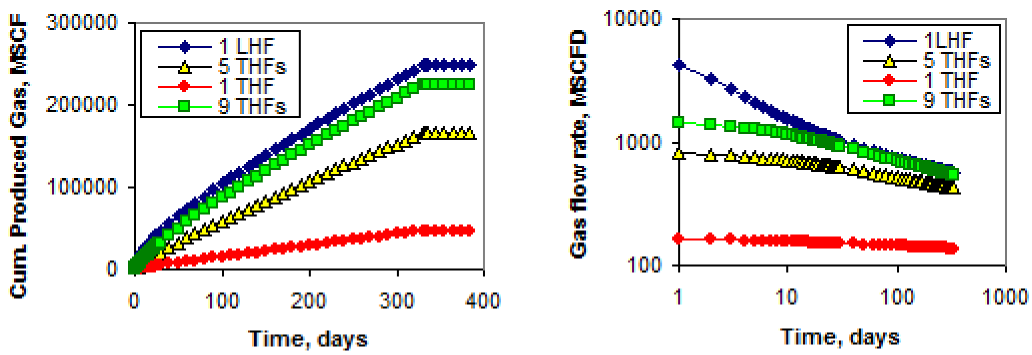

Figure 24: Productivity of hydraulic fractures: transverse versus longitudinal

Note: Refer to Appendix F for more details about the hydraulically fractured reservoir model for the different cases, and analysis of the results.

3.2.2 Drilling direction and permeability anisotropy

A reservoir simulation model is used to understand how the direction of horizontal drilling can affect well productivity in tight gas reservoirs that have significant horizontal permeability anisotropy. The horizontal well length is 1250 ft in a tight formation with significant horizontal permeability anisotropy of 5 ($K_{h,max}/K_{h,min}=5$).

This level of anisotropy could be produced, for example, by oriented sand bodies or channels. First, the wellbore direction is considered to be perpendicular to the direction where permeability is larger. Then the model is run considering the wellbore direction perpendicular to the direction where permeability is the minimum.
The results for gas production rate from the model are shown in Figure 25. The horizontal wells drilled in the direction perpendicular to the direction of maximum permeability (drilling in the direction of minimum horizontal stress, if permeability anisotropy is caused by stress anisotropy) may provide noticeably higher gas production rate compared to the wells that are drilled perpendicular to the direction of minimum permeability (drilling in the direction of maximum horizontal stress, if permeability anisotropy is caused by stress anisotropy).

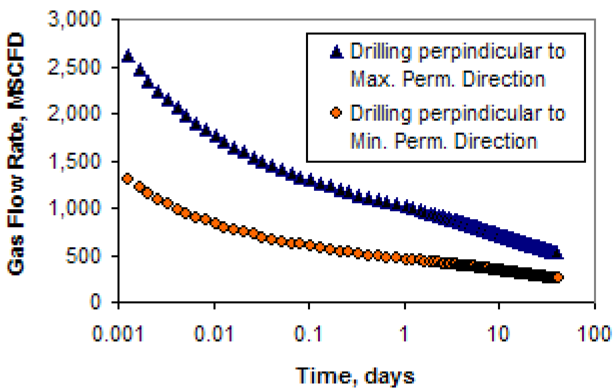

Figure 25: Effect of wellbore direction on well productivity

3.2.3 Wellbore breakouts

In order to understand the effect on well productivity, the horizontal well model is run for a zero skin cased-hole perforated horizontal well (wellbore diameter of 8 inches), and zero skin open-hole horizontal well with enlarged wellbore (wellbore diameter of 20 inches).
The production predictions from the models as shown in Figure 26, they indicate that open-hole completion in the gas wells with large wellbore breakouts can provide significantly higher initial gas production rate compared with cased-hole completion system. In use of open-hole completion, the enlarged wellbore due to break outs can result in higher effective wellbore radius, and therefore a lower skin factor and higher productivity.

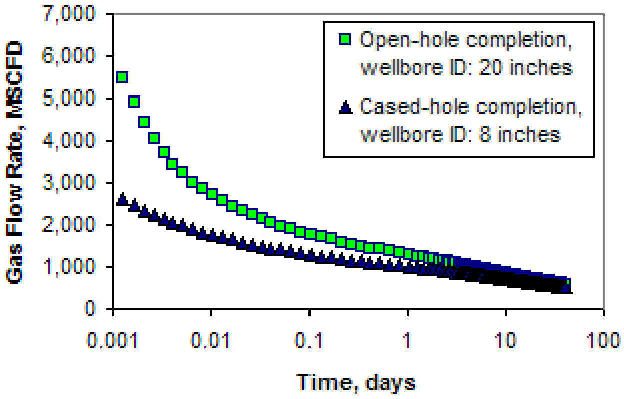

Figure 26: Effect of wellbore breakouts on well productivity

3.2.4 Perforation parameters

The model was run for damaged and non-damaged perforated cores in the cases of tight and conventional reservoirs. The simulation results show that the perforation tunnel provides improvement in core flow efficiency, which is more noticeable in tight sand cores compared to conventional cores as shown in Figure 27.

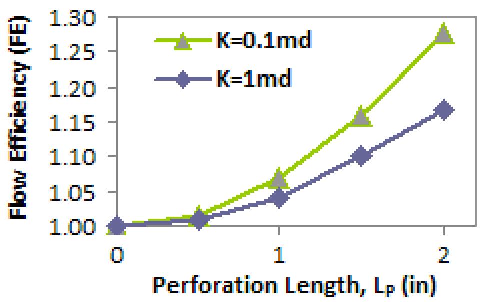

Figure 27: Effect of perforation tunnel length on flow efficiency

The simulation model is also run for the case of a open-hole perforated damaged tight gas reservoir. The results as shown in Figure 28 indicate that if the damaged zone is not fully bypassed by the perforations, the flow efficiency is still significantly reduced. The flow efficiency is sensitive to perforation parameters and highlights the importance of passing damaged zone radius, especially in tight gas reservoirs. According to the simulation results, even for open-hole wells in tight formations, improved productivity (flow efficiency greater than 1) may be achieved by creating deep, clean perforation tunnels that can bypass the mechanical damaged zone.

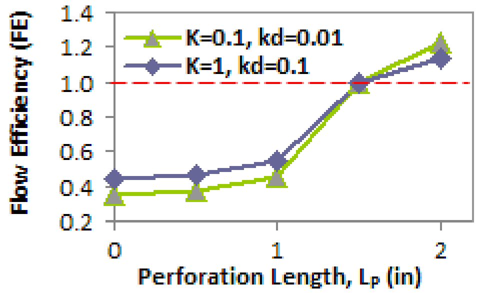

Figure 28: Effect of perforation tunnel length on flow efficiency

Note: Refer to Appendix D for details of the simulation work, analysis of the results, and a field example regarding how the damaged zone radius is determined.

3.2.5 Liquid loading in wellbore

Well stimulation and fracturing operations in tight formations cause significant liquid leak-off into the reservoir rock. The invaded liquids when produced, they may be loaded in wellbore during post-fracturing clean-up period, since natural gas flow rate may not be high enough to lift the wellbore liquids to surface. A series of simulation runs are carried out to model the wellbore phenomena for a horizontal deviated wellbore. The results as shown in Figure 29 indicated water loading problem in wellbore at 4 MMSCFD gas production rate. The problem becomes more serious when gas flow rate is reduced to 1 MMSCFD. Based on the simulation results, liquid loading can be one of the main causes of low well productivity in tight gas wells.

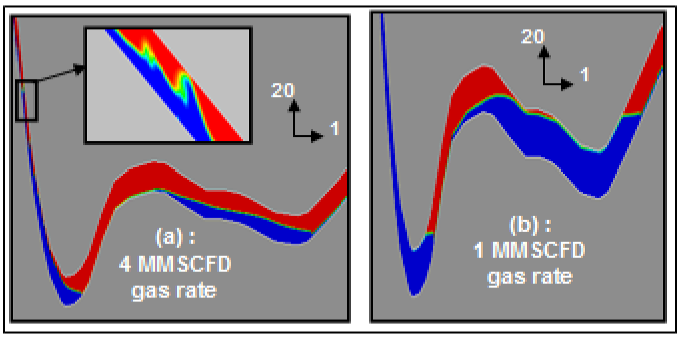

Figure 29: Simulation of liquid loading in wellbore (effect of gas production rate)

The well production performance modelling results also showed that use of oil based mud instead of water based mud can help reducing liquid loading, since oil has less density than water, and therefore gas can better lift the liquid to surface. Therefore, underbalanced drilling using non-aqueous liquid can reduce the issues related to liquid loading in wellbore during clean-up. Tight gas well productivity can also be further improved by gas lift and optimizing the producing liner and tubing size.

Note: Refer to Appendix D for more details about water loading issues, a field example, and also the water unloading techniques that can improve well productivity.

3.3 Effect of natural fractures parameters on welltest response

The tight gas reservoir model is built as a dual-porosity dual-permeability medium using the Kazemi model with parallel layers of low permeability tight matrix and high permeability fractures. The model generates transient pressure data for gas production and pressure build-up periods to show the relationship between welltest permeability and natural fractures parameters.

The model is run for different values of fracture aperture, fracture permeability, matrix permeability, matrix compressibility, fracture compressibility, matrix porosity, fracture porosity and fracture spacing. The simulation results for sensitivity of welltest permeability indicated that among the parameters examined, only the fracture aperture, fracture permeability and fracture spacing have significant impact on welltest permeability (k), and the other parameters can be disregarded. According to the simulation outputs as shown in Figure 30, welltest permeability, k, is directly proportional to fracture aperture, b_f , and fracture permeability, k_f (the power exponent of +1 approximately), and has inverse relationship with fracture spacing, a_f (the power exponent of -1 approximately). The observations are in good agreement with the derived Equation 2-5 regarding how the parameters control fracture permeability, which confirms the reliability of the proposed equation.

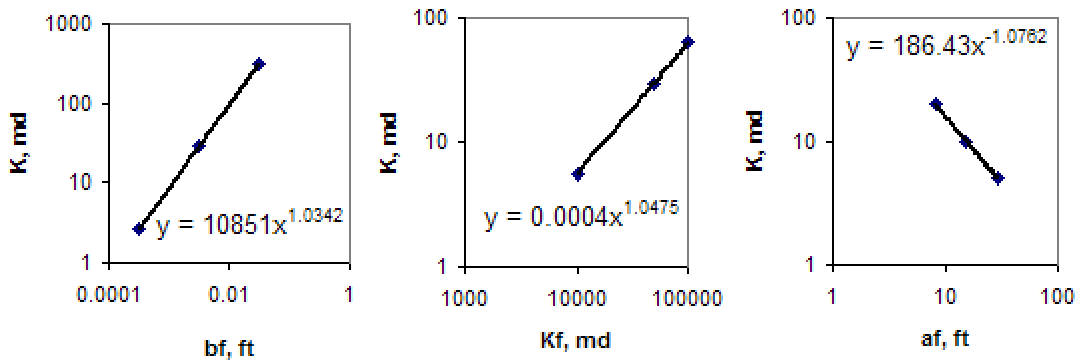

Figure 30: Relationship between fracture parameters and welltest permeability

The curve fitting functions and multi-variable regression on the data (based on Equation 2-2) resulted in the following correlation in field units for fracture permeability estimation in the tight gas reservoir:

$$K_f = 0.795 * K_{welltest} * (\frac{a_f}{b_f})^{1.04} \qquad [3\text{-}1]$$

Note: Refer to Appendix B for more details about derivation of the fracture permeability correlation, verification of its accuracy and the sensitivity analysis.

3.4 Pressure measurement in tight gas reservoirs

Measurement of formation pressure in tight gas reservoirs using formation testers may be affected by the drilling fluids invasion into the formation, and to understand the effect, the reservoir simulation model is run for formation testing at different depths using 20 cc/min production of reservoir fluid, followed by pressure build-up. The simulation model is first run for a non-damaged rock (no liquid invasion). The results as shown in Figure 31, they indicate that in the case of very low permeability of 0.001 md, pressure around the tested interval drops to zero (the tight rock cannot provide the flow rate), resulting in a dry test. In the case of higher permeability, the test is normal. For the normal tested points, the plot of pressure difference ($P–P_{datum}$) versus depth resulted in gas gradient (dp/dh of 0.078 psi/ft).

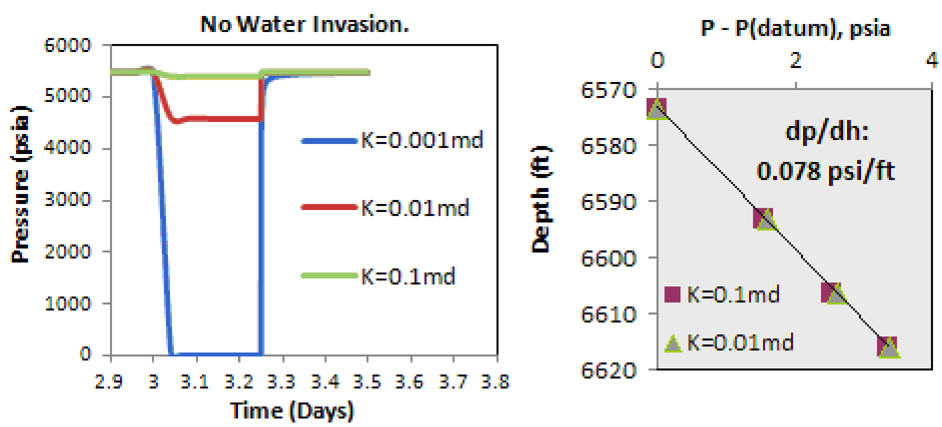

Figure 31: Formation testing response in the case of no water invasion

It can be concluded that for a gas bearing zone drilled with air (similarly, for a water bearing zone in a water-wet formation drilled with water-based mud), the tool measures the true formation pressure and provides a reliable pressure gradient, since there is no capillary pressure effect between the invading fluid and the formation fluid.

In the case of water invasion from wellbore into the reservoir, the presence of water filtrate in the invaded radius of a gas zone may affect pressure measurement during formation testing. The simulation outputs for pressure versus depth are shown in Figure 32. The results indicate that in the good permeability zone (0.1 md), the invasion of water does not have significant impact on the pressure gradient measured by the formation testing tool (0.082 psi/ft). However in tighter sections (permeability of 0.01 md), the water invasion effect causes increase of pressure gradient to 0.1 psi/ft.

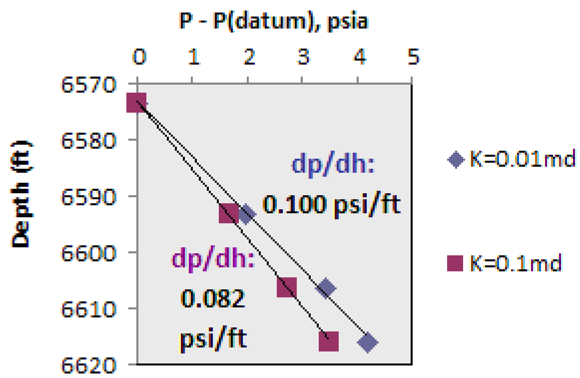

Figure 32: Effect of liquid invasion on formation testing response

In a gas bearing zone drilled with water-based mud (or oil-based mud), the pressure measurements in the gas zone are influenced by liquid invasion effect. The formation tester measures the pressure of filtrate in the invaded zone, which is less than the pressure of the reservoir fluid (gas) by the amount of the capillary pressure, P_c (Elshahavi et al, 1999), thus the tool under-estimates the value of the true formation pressure ($P_{measured} < P_{actual}$). In addition, presence of water in the gas zone causes over-estimation of pressure gradient measured by the tool (pressure gradient higher than the actual gradient), according to the simulation results. These effects (under-estimated reservoir pressure and over-estimated pressure gradient) overall may cause the gas-water contact depth that is based on uncorrected field measurements to be different than the actual gas-water contact depth. A reliable estimation of formation pressure, gradient of pressure and gas-water contact depth for a tight gas reservoir requires that we understand these processes, and take into account the capillary pressure and liquid invasion effects.

3.5 Summary

In this section, the effect of various well and reservoir parameters on well productivity was studied using reservoir simulation models based on the tight gas field data: phase trapping damage in non-fractured and hydraulically wells, in under-balanced and over-balanced drilling, and in the case of invasion of different fluids into the tight formation (water and oil). The effects of permeability anisotropy, wellbore breakouts, perforation parameters, liquid loading in wellbore, different hydraulic fractures systems and natural fractures on well productivity were presented, and it was also shown how formation testing pressure measurements and gas water contact determination may be influenced by liquid invasion into tight gas reservoirs.

4 Tight gas field example: effect of damage mechanims on well productivity

Whicher Range Field, located in the Southern Perth Basin, is a large, low permeability and very heterogeneous gas reservoir. It consists of stacked and isolated lenses of sand separated by shale layers. The wells in this field were mainly drilled vertically using water based mud in over balanced conditions, and completed as cased-hole perforated. Hydraulic fracturing was also performed in some of the wells using water based fracturing fluid. None of the wells produced at viable rates despite various attempts to stimulate the formation (Rezaee et al, 2012).

There is a long history of various DST and production tests performed in this field before. Despite well stimulation and other well intervention operations, gas production rates were found to be low and did not meet the expectations. In this section, various categories of data are reviewed and analysed and obtain a better understanding of the reservoir, to evaluates possible mechanisms that might have contributed to the low productivity and assess the feasibility of achieving commercial production rates.

4.1 Wellbore instability

The wells drilled in the tight sand formation had severe wellbore instability issues during drilling, which caused enlargement of wellbore up to 20 inches (2-3 times bigger than the bit size) across majority of the tight sand intervals.

Note: Refer to Appendix D for more details about the wellbore breakouts, its effect on skin factor, and the calliper log data in one of the wells in the tight gas field.

4.2 Perforation data

Perforations in these wells were mainly performed using 2 1/8” EJ guns. According to the well data, the casing has 7” internal diameter and the borehole may have 10” diameter in the direction of maximum stress where the borehole is stable, and 20” in the direction of minimum stress due to the wellbore breakouts. Damaged zone radius is also assumed as 5”. Schlumberger perforation analysis software (SPAN 7.02) is run for the tight formation to analyse the perforation data in different directions. The software results for perforation jet penetration and skin factor as presented in Table 2 and Figure 33. They indicate a positive skin factor for the tunnels, as penetration is not deep enough to efficiently connect the wellbore to the formation virgin zone. In fact, the perforation efficiency is lower in the direction of σ_{min} due to the large cement volume behind the casing in the intervals with enlarged wellbore.

Because of the reservoir rock tightness and also presence of the large wellbore breakouts behind casing filled by cement, the perforation penetration is significantly reduced. As explained in section 3.2.4, as perforation jet penetration into the tight formation is not deep enough, the wellbore may not have effectively been connected to the undamaged rock. The poor perforation efficiency might be the primary reason of the low productivity in the cased-hole perforated well.

Table 2: Model predictions for perforation jet penetration and skin

Casing	Gun type	Perforation tunnel direction	Formation penetration, inches	Perforation skin
7"	2 1/8" gun	σmax	6.0	2.3
		σmin	4.2	11.5

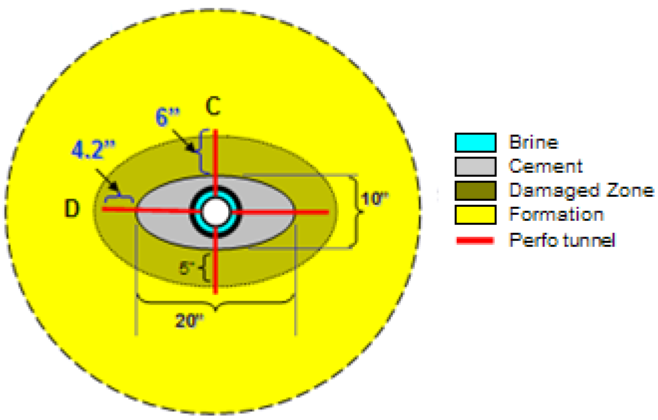

Figure 33: Effect of wellbore breakouts on perforation performance

Note: This section has been published in 2011 APPEA journal. See Appendix D for more details about perforation penetration results in use of conventional perforation guns and deep penetrating guns.

4.3 Hydraulic fractures

Hydraulic fracturing in the tight gas wells had 3-4 fracturing stages, with average maximum pumping pressure of 10,000 psia, average pump rate of 20 bbl/min, average total proppant per stage of 35000 lbs, and average total liquid injected per stage of 2500 bbls. The fracturing models predicted 100-150 ft fracture half length size, and fracture conductivity of 700-2100 md.ft for the fractures.

After the hydraulic fracturing operations and then cleaning up the well from the fracturing liquids by gas production, only 10-60% of the injected fracturing liquid could be recovered (40-90% of fracturing liquid being trapped in the reservoir), which may have caused significant damage to near wellbore formation.

4.4 Formation sensitivity to water invasion damage

The core samples in the tight gas field that were tested and analyzed using X-Ray diffraction, they detected smectite, meaning that the tight formation can have medium to strong sensitivity to fresh or sodium chloride waters (indicating a water sensitive tight formation). With such minerals present, clay swelling may be reduced by using relatively high concentrations of KCl, sometimes accompanied by $CaCl_2$ in the drilling and stimulation fluids.

4.5 Well production history (Pre-fracturing and post-fracturing)

The well after completion and perforation produced at the rate of 1.9 MMSCFD, which was not an economical rate. The well was later hydraulically fractured using KCl based fracturing fluid in order to improve well productivity. The post fracturing gas flow was around 0.5 MMSCFD (production lasted only for a short period of time). After the well clean-up, the well produced 1.3 MMSCFD gas with all the intervals open, which does not show production improvement compared to pre-fracturing flow rate. The well production comparison is shown in Figure 34, which indicates low fracturing efficiency.

In the fracturing job, approximately 60% of the fluids were recovered during post fracturing production test, and significant amounts of water based treating fluids was trapped in the water-sensitive tight formation (we believe that this trapped in the reservoir, causing significant damage to reservoir permeability). Therefore it could be concluded that the leak-off of water into the tight sand gas reservoir during fracturing might be the reasons for the low well productivity after stimulation.

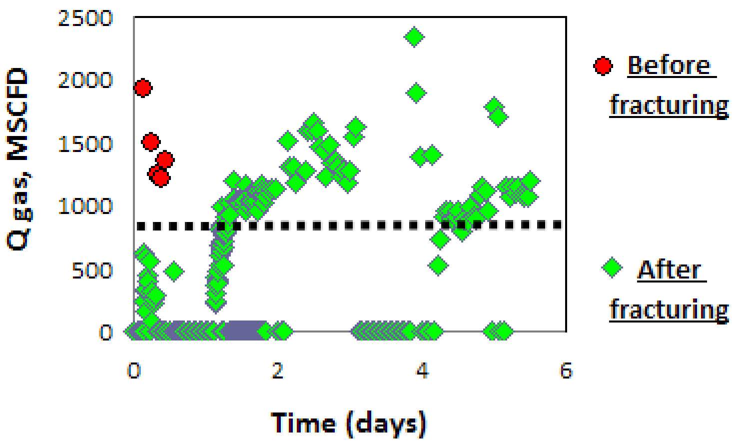

Figure 34: The tight gas well production comparison, before versus after hydraulic fracturing

In term of hydraulic fractures performance, the fracturing job was not successful. The well may produce gas at a commercial rate using massive hydraulic fracturing and creating large treated zone volume, which might be achieved by use of non-damaging fracturing liquid, increasing numbers of fracturing stages (For instance 10-20 fracturing stages instead of 3-4), higher pumping rates of fracturing fluid (For instance 60-80 bbl/min instead of 20 bbl/min) and larger volumes of liquid and proppant injection per stage.

Note: This section has been published in 2012 JPSE journal. See Appendix A for more details.

4.6 Formation damage caused by water and oil invasion

Laboratory experiments on the West Australian core samples were performed using the core flooding facilities in Petroleum Engineering Department at Curtin University, in order to compare damage to the core permeability, caused by water invasion versus oil invasion.

Absolute permeability of each core sample is measured at 100% gas saturation. The characteristics of the core samples tested for damage evaluation are reported in Table 3. The test conditions are 5800 psia pore pressure and 109 ˚C temperature.

Table 3: Details of the core samples characteristics

Core sample	Core porosity, %	Core absolute permeability, md
Sample A1	6.7	0.003
Sample A2	9.6	0.034
Sample A3	11.4	0.026
Sample B1	4.6	0.034
Sample B2	5.4	0.032

4.6.1 Damage caused by water invasion

For water damage evaluation, the core samples are saturated with water, followed by flooding of gas into the core samples until water saturation is reduced to the minimum of residual water saturation, and then core effective permeability to gas is measured (K_{rg}@S_{wr}). From the core experiments as reported in Table 4, water invasion causes the relative permeability of gas to be reduced to 0.22-0.35, indicating around 70% reduction in effective permeability.

Table 4: Core flooding experiment results for water invasion damage

Core sample flooded with water, cleaned up with gas			
End point methane K_r @ S_{wr}	Sample A1: 0.224	Sample A2: 0.353	Sample A3: 0.219

4.6.2 Damage caused by oil invasion

For oil invasion damage evaluation, the core samples are saturated with oil, then gas is flooded into the core samples until oil saturation is reduced to minimum of residual oil saturation in order to measure core effective permeability to gas (K_{rg}@S_{or}). From core experiments as reported in Table 5, the effective permeability is reduced by 55% due to oil invasion.

Table 5: Core flooding experiment results for oil invasion damage

Core is flooded with oil, cleaned up with gas		
End point methane K_r @ S_{or}	Sample B1: 0.507	Sample B2: 0.413

4.6.3 Comparison of damage caused by water and oil

The experiments highlight the fact that tight gas reservoirs are subjected to invasion damage in both cases of oil filtrate invasion (from OBM) or water filtrate invasion (from WBM). In other words, even when oil-based fluids are used instead of water-based fluid for drilling or fracturing, the reservoir rock is damaged. However severity of the damage is less in the case of damage caused by oil based fluid as compared to the damage caused by water invasion.

Note: This section has been published in 2012 APPEA journal. See Appendix E for more details about damage caused by oil and water.

4.7 Well productivity evaluation in Whicher Range tight gas field

The wells in the tight gas reservoir were drilled overbalanced using water based mud, and completed as cased-hole perforated wells. Analysis of the field and lab data showed that there are various possible explanations or combination of circumstances that may have contributed to the wells' poor productivities:

- Vertical wells in low permeability gas reservoirs may not provide economical rates due to the very limited formation surface area that is open to the wellbore.
- The core data analysis (X-Ray diffraction) detected smectite which shows the reservoir rock is sensitive to water based fluids. Drilling the wells overbalanced using water based mud, may have caused significant damage and low productivity.
- In addition, perforation efficiency was low due to the reservoir rock tightness and also presence of the large wellbore breakouts behind casing filled by cement.

In the wells that were hydraulically fractured, the fracturing operations did not result in any improvement of productivity which might be due to:

- Job reports indicate that about 40% of the water based treating fluids is not recovered. The formation is sensitive to water damage and the large leak-off of water into formation during fracturing might be one of the main factors that cause low productivity.
- Well production and test data also indicated that hydraulic fracture size is significantly smaller than the expectations. The limited size hydraulic fractures may have caused the hydraulic fractures productivity to be low.

4.8 Tight gas development strategy for optimized productivity

Gas recovery might be low if drainage area of a well is limited to a few sand lenses (which might be the case in vertical wells drilling). The optimum strategy for the tight gas field might be to drill long highly deviated horizontal/deviated wells in underbalanced conditions using non-aqueous drilling fluid to intersect as many as possible of the sand lenses, increase the lateral reservoir exposure to wellbore, and minimize damage to formation. Drilling direction should be designed based on sand lenses width and length. Completing the well as open-hole (and running a slotted liner to control wellbore collapse) can further improve the well productivity as it provides using the advantage of enlarged wellbore and the reduced skin factor due to presence of the wellbore breakouts. Also perforating using deep perforation shots through the slotted liner and penetrating into the formation can help better bypassing the possible mechanically damaged zone in the tight formations. As perforation strategy, shooting the perforation jets aligned with the maximum stress direction (oriented perforation with 180 degrees phasing) might help improve perforation efficiency in the cased-hole perforated tight gas wells.

Improving drilling or fracturing fluid rheology and filter cake building ability, which can provide an effective cake that is later removable can help control the damaged zone depth and reduce the damage due to liquid invasion.

In the cases of significant liquid leak-off into formation, use down-hole pumps, gas lift system in the early stage (especially during cleaning the wells) and/or optimum tubing size, to unload the well from drilling or fracturing liquids, to allow the well to produce at higher gas rates.

5 Conclusions

The objectives of this study were to review, understand and evaluate the factors that have significant influence on formation damage and well productivity in tight gas sand reservoirs. Various tight gas field completion, production and reservoir engineering data were studied, laboratory experiments were performed, and reservoir simulation models were run. Based on the study results, the following conclusions can be drawn:

- Liquid phase trapping damage is one of the main factors that can significantly affect well productivity in tight gas reservoirs. The damage mechanism is mainly controlled by capillary pressure and its resulting relative permeability curves.
- Core flooding experiments using unsteady state technique integrated with numerical simulation approach, provided the relative permeability curves for a typical West Australian tight gas reservoir.
- Damage caused by water blocking is considered to be one of the main causes of low well productivity in water sensitive tight gas reservoirs (i.e. sandstones containing clays, especially smectite).
- In tight reservoir rocks that are sensitive to water, exposure of formation to water during drilling may cause severe damage to near-wellbore formation permeability.
- Core flooding experiments using core samples taken from the typical West Australian tight gas reservoir showed that the damage to formation might be reduced by use of oil based mud drilling fluid, instead of water based mud.
- The field study and reservoir simulation highlighted that hydraulic fracturing may be inefficient in tight gas formations that are sensitive to liquid invasion damage. In some cases, hydraulic fracturing may even reduce well productivity.
- Underbalanced drilling is considered as a method to reduce damage to tight formations. However the study highlighted that even in the case of

underbalanced drilling, mud filtrate (water or oil) may still invade the rock matrix around the wellbore due to the strong capillary pressure suction.

- After the liquid leak-off into formation is stopped, during clean-up period when gas is produced from the tight reservoir, water still continues invading more area of the reservoir due to the very strong capillary pressure suction effect.
- Liquid loading in wellbore may significantly affect well productivity in tight formations, since the initial gas production rates are normally not high enough to lift the wellbore liquid to surface.
- In the case of damage to natural fractures, well productivity is reduced significantly. Well productivity of a damaged naturally fractured reservoir may not be very different than well productivity in a non-fractured reservoir until the reservoir contact area is very great.
- Field observations indicated that wellbore instability can cause large wellbore breakouts and washouts across the tight sand intervals.
- Cased-hole perforated completion may not be the optimum option in tight gas reservoirs. In cased-hole completed wells, the large wellbore breakouts filled by cement may reduce accessibility to the formation via perforation tunnels, as they may fail to penetrate deep enough into the formation. In addition, perforation jet penetration depths are significantly reduced by the tightness of the formation.
- Open-hole completion in tight gas reservoirs, provides using the advantage of enlarged wellbore (reduced skin factor) caused by large wellbore breakouts. Open-hole perforating using deep penetrating perforation charges may further improve the well productivity.
- In the case of perforation, the optimum option might be to use deep penetrating perforation charges oriented towards maximum stress direction i.e., 180 degree phasing (the direction where wellbore is stable and has no considerable breakouts).
- Use of the second derivative of transient pressure in welltest analysis can provide more reliable determination of reservoir permeability, skin factor and hydraulic fracture parameters in tight gas reservoirs.
- In tight reservoirs with significant permeability anisotropy, drilling perpendicular to the maximum permeability provides higher productivity.

- If stress anisotropy is the main cause of permeability anisotropy, drilling long deviated/horizontal wells perpendicular to the maximum horizontal stress direction can result in achieving higher gas production rates, by intersecting the higher permeability conduits.
- Drill directional wells perpendicular to the maximum horizontal stress azimuth to improve wellbore stability, and intersecting higher permeability conduits, especially for the reservoir with normal faulting stress regime condition.
- In the case of fully perforated horizontal well, a longitudinal hydraulic fracture provides noticeably a higher productivity than a transverse hydraulic fracture.
- Welltest permeability and image log fracture aperture and fracture spacing can provide approximation of natural fractures permeability in naturally fractured tight gas reservoir, and result in more reliable evaluation of well productivity.
- Liquid invasion into tight formations may affect the formation pressure measurements and result in under-estimating reservoir pressure and over-estimating pressure gradient.

In this thesis I have demonstrated how different well and reservoir parameters control well productivity and damage mechanisms in tight gas reservoirs. I have also quantitatively shown the effect of phase trapping damage, well parameters and reservoir characteristics on tight gas sand reservoirs productivity for different cases. These cases include non-fractured and hydraulically fractured wells, under-balanced and over-balanced drilling, and invasion of different fluids into the tight formation. Reservoir simulation model for Whicher Range tight gas field is built and run, and analytical and numerical simulation approaches are integrated with core flooding experiments and field data analysis in order to characterize the key reservoir parameters and understand the effects of different parameters on well productivity.

The study brings new insights regarding tight gas reservoirs characterization for dynamic parameters. I determined the relative permeability curves for Whicher Range tight gas reservoir using core flooding experiments integrated with numerical simulation approach. I have quantitatively shown how the phase trapping damage can be reduced by use of oil based drilling fluid instead of water based fluid. I introduced a new technique of welltest analysis for tight gas reservoirs that can reduce uncertainties in estimation of average reservoir permeability, and also developed a new correlation that can determine permeability of the natural fractures in tight formations. I studied and analysed the different well completion, production and reservoir data from Whicher Range tight gas field in order to identify why production rates are significantly lower than expectations, and investigate possible remedial strategies to achieve viable gas production rates. Based on the study outcomes, I have proposed the optimum tight gas development strategies to achieve an improved productivity.

6 Nomenclatures

μ	Viscosity
a_f	Fracture spacing
b_f	Aperture of natural fracture
C	Compressibility
GWC	Gas water contact
h	Thickness
ID	Internal diameter
φ	Porosity
K	Permeability
K_d	Damaged zone permeability
K_f	Fracture permeability
K_r	Relative permeability
m	Slope of pressure derivative versus natural log of time function
MMSCFD	Million standard cubic feet per day
n	Number
OB	Overbalanced
P	Pressure
P_c	Capillary pressure
Q	Flow rate
Q_g	Gas production rate
Q_d	Dimensionless production rate
Q'_d	Rate derivative function
S	Skin
σ	In-situ stress
S_{gc}	Critical gas saturation
S_{gi}	Initial gas saturation
$S_{w,\ connate}$	Connate Water Saturation

S_{wi}	Initial Water Saturation
t	Time
t_p	Production time
T	Temperature
UB	Underbalanced
W_f	Aperture of hydraulic fracture
X	Direction in x direction (horizontal)
X_f	Hydraulic fracture half length size
Y	Direction in Y direction (horizontal)
Z	Direction in Z direction (vertical)

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8 Written Endorsements

I, Hassan Bahrami, co-author of the following paper, contributed in the paper by colleting field and lab data, building and running reservoir simulation models, analysis of core flooding experiments data, interpretation and analysis of reservoir simulation results, paper preparation and writing, in the following paper:

- Murickan G., Bahrami H., Rezaee R., Saeedi A., Mitchel P.A.T., 2012. Using relative permeability curves to evaluate phase trapping damage caused by water-based and oil-based drilling fluids in tight gas reservoirs. APPEA Journal

Signature:..........................

Date:.......5-Nov-2012....

I, the first-author of the paper, endorse that this level of contribution by the candidate indicated above is appropriate.

Name:.....Greeno Murickan..............

Signature:.......................................

I, the co-author, endorse that this level of contribution by the candidate indicated above is appropriate.

Name:..Ali Saeedi......................................

Signature:...

Name:.......Reza...Rezaee..................................

Signature:....R. Rezaee..................................

Name:...M. Tsar..

Signature:...

I, Hassan Bahrami, contributed as co-author in the following papers, with building reservoir simulation, running of simulation models, interpretation and analysis of the results in the following papers:

- Ostojic, J., Rezaee, R., and Bahrami, H., 2011. Hydraulic fracture productivity performance in tight gas sands – A Numerical Simulation Approach. Journal of Petroleum Science and Engineering

Signature:........ Hassan Bahrami

Date:.........30-July-2012..

I, as the first author, endorse that this level of contribution by the candidate indicated above is appropriate.

Name:....JAKOV...OSTOJIC.................................

Signature:.................................30/07/2012

I, as the co-author, endorse that this level of contribution by the candidate indicated above is appropriate.

Name:......Reza..Rezaee.....................................

Signature:...R. Rezaee...........30./07./2012..

9 Appendices

Appendix A:

Water Blocking Damage in Hydraulically Fractured Tight Sand Gas Reservoirs, An Example from Perth Basin, Western Australia. Journal of Petroleum Science and Engineering

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Water blocking damage in hydraulically fractured tight sand gas reservoirs: An example from Perth Basin, Western Australia

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A B S T R A C T

Tight gas reservoirs normally have production problems due to very low matrix permeability and different damage mechanisms during drilling, completion and stimulation operations. Therefore they may not produce gas at commercial rates without production optimization and advanced completion techniques.

Tight formations have small pore throat size with significant capillary pressure energy suction that imbibes and holds liquid in the capillary pores. Leak-off of liquid from the wellbore into the formation may damage near wellbore permeability due to water blocking damage and clay swelling, and it can significantly reduce well productivity even in hydraulically fractured tight gas reservoirs.

This study presents evaluation of damage mechanisms associated with water invasion and phase trapping in tight gas reservoirs. Single well reservoir simulation is performed based on typical West Australian tight gas formation data, in order to understand how water invasion into the formation affects well production performance in both non-fractured and hydraulically fractured tight gas reservoirs. A field example of hydraulic fracturing in a West Australian tight gas reservoir is shown and the results are analyzed in order to show importance of damage control in hydraulic fracturing stimulation of low permeability sand formations.

The study results highlight that water blacking can be a major damage mechanism in tight gas reservoirs. In water sensitive tight sand formations, damage control is essential and the well productivity improvement may not be achieved in the case of excessive water leak-off into formation during hydraulic fracturing operations.

1. Introduction

Tight gas reservoirs normally have production problems due to very low matrix permeability and different damage mechanisms during well drilling, completion, stimulation and production (Fairhurst et al., 2007). The low permeability gas reservoirs can be subject to different damage mechanisms such as mechanical damage to formation rock, plugging of natural fractures by invasion of mud solid particles, permeability reduction around the wellbore as a result of filtrate invasion, clay swelling, liquid phase trapping, etc. (Holditch, 1979; Civan, 2000).

In general, for tight sand gas reservoirs that are water-wet in nature, the average pore throat radius might be very small and therefore it may create tremendous amounts of potential capillary pressure energy suction (Mahadevan et al., 2007). As a result, it causes liquid to be imbibed and held in the capillary pores, and may cause critical water saturation, the maximum water saturation below which no water production will occur from a formation, to be high (Bennion and Brent, 2005).

After drilling of high permeable zones, normally strong mud cake is built on the wellbore wall, which stops further invasion of liquid into the formation. However in tight zones, liquid invasion may continue for a longer time due to the weak mud cake on the wellbore wall and the strong capillary pressure suction effect. In addition, effective matrix porosity is low, i.e. there is small pore volume, and therefore invaded liquid travels deeper into tight rock matrix (Schlumberger formation testing, 2005).

In hydraulic fracturing, additional problems may be experienced such as formation damage due to excessive fluid leak off, early water breakthrough due to fracturing into water leg, poor clean-up due to fluid incompatibility, and proppant back production causing erosion of surface facilities (Abass et al., 2009; Holditch, 1979). As an alternative option, long horizontal wells drilled in underbalanced conditions may increase lateral reservoir exposure to the wellbore with a minimized damage (Veeken et al., 2007).

Controlling damage is important in tight gas reservoirs as the low deliverability and lack of connectivity between the sand bodies, make it challenging to produce gas at commercial rates (Abass and Ortiz,

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2007; Bahrami et al., 2010). This study evaluates phase trapping and liquid blocking damage effect on gas production for different cases of hydraulically fractured tight gas reservoirs.

2. Water blocking damage

Tight gas reservoirs might be different in terms of initial water saturation (S_{wi}) compared with critical water saturation (S_{wc}), depending on the geological time of gas migration to the reservoir. Initial water saturation might be normal, or in some cases lower than S_{wc} (sub-normal initial water saturation) due to water phase vaporization into the gas phase as shown in Fig. 1 (Bennion and Thomas, 1996). The initial water saturation might also be more than S_{wc} if the hydrocarbon trap is created during or after the gas migration time. A sub-normal initial water saturation in tight gas reservoirs can provide higher relative permeability for the gas phase (effective permeability close to absolute permeability), and therefore relatively higher well productivity (Bennion and Brent, 2005).

Liquid invasion into tight formations can increase water saturation around the wellbore from S_{wi} to a higher value, and then as the near wellbore zone is cleaned up by gas production, water saturation is reduced gradually, but not further than S_{wc} (Amabeoku et al., 2006). This process as illustrated in Fig. 2, eventually results in the permeability at initial conditions, $K_r@S_{wi}$, to be reduced to $K_r@S_{wc}$ in the invaded zone. The damaging of permeability is referred as phase trap damage. The greater difference between initial water saturation and critical water saturation results in a more serious liquid phase trapping, causing a greater potential damage to gas permeability and gas production.

The invaded liquids in the reservoir during drilling or fracturing can cause water phase trapping inside rock pores, and reduce the well productivity (Mahadevan et al., 2007). In the case of hydraulic fracturing, leak-off of liquid into the formation can be severe and water damage may more noticeably affect the well productivity. Tight formations with sub-normal initial water saturation are significantly sensitive to damage caused by water phase trapping, and therefore water blocking may plague the success of hydraulic fracturing in low permeability gas reservoirs (Bennion and Brent, 2005).

Water invasion may also cause mechanical damage to the formation. The damage mechanisms such as water phase trapping, partial blockage of open pores by water, reducing pore openings due to clay swelling, etc., can reduce effective permeability in the water invaded zone (Motealleh and Bryant, 2009). The damaging effects are all reflated on gas and water relative permeability curves and therefore they can be used for evaluation of damage mechanisms.

Water sensitive tight formations may initially have high relative permeability ($K_r@S_{wi}$), but very low relative permeability after being exposed to water ($K_r@S_{gc}$), as described in Fig. 2. The effective permeability in the invaded area of water sensitive tight formations, may not be improved during clean-up period, since water has damaged the formation, trapped in the invaded zone, and therefore may cause significant reduction in well productivity.

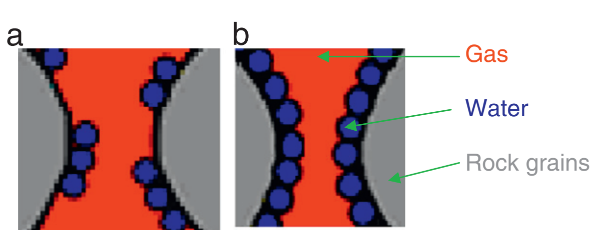

Fig. 1. The concept of normal and sub-normal initial water saturation. a: Sub-normal initial water saturation (Swi ≪ Swc). b: Normal initial water saturation (Swi = Swc).

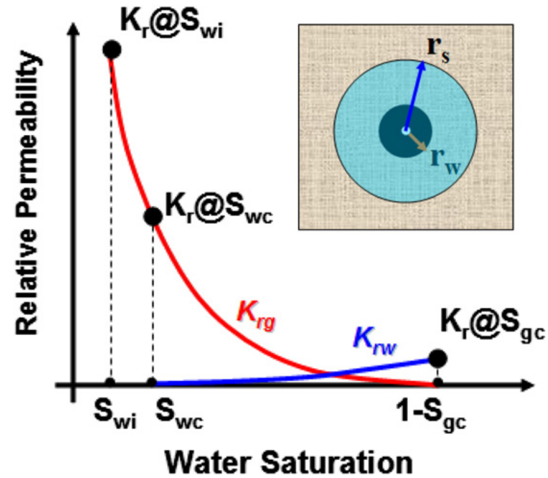

Fig. 2. Typical gas and water relative permeability curves, indicating how near wellbore permeability is reduced due to water invasion.

3. Significance of damage control in tight gas reservoirs: field example from Perth Basin

The gas field is a large, low permeability tight gas reservoir in Perth Basin. The wells drilled in the tight sand formation had severe wellbore instability issues during drilling, that caused wellbore enlargement up to 2–3 times larger than the bit size diameter across the majority of the sandstone intervals.

The tight sandstone gas reservoir is stacks of isolated lenses of heterogeneous sand bodies that are separated by shale layers, according to the field study reports. The reservoir sand bodies and the estimated average water saturation by different petrophysicists for each zone are shown in Fig. 3. The estimations for water saturation have high uncertainties since quality of petrophysical logs may have been affected by formation tightness and significant wellbore enlargement across majority of the sand intervals. Therefore, it is not feasible to comment confidently on initial water saturation or have evaluations regarding depth of water invasion into the formation during drilling.

There are limited core data available in the field that were studied to evaluate production performance of the tight gas reservoir. Core porosity and core permeability at the reservoir conditions for the samples that have core analysis tests data available are shown in Fig. 4. Among the tested cores, only one core sample has reliable relative permeability

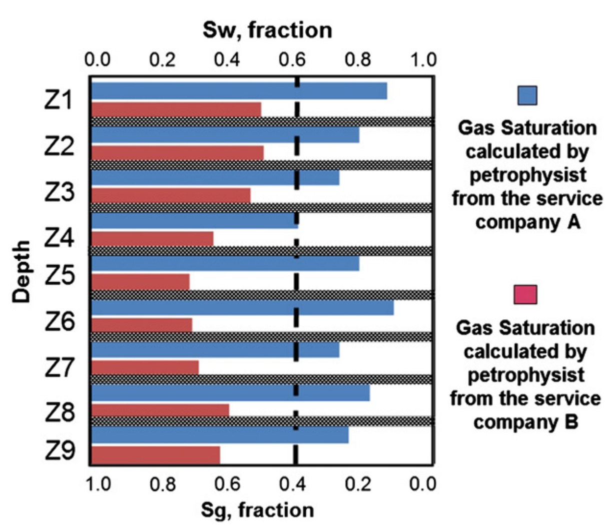

Fig. 3. Water saturation variations along wellbore in the tight sand formation in Perth Basin (total net thickness of the porous sand intervals: 370 ft).

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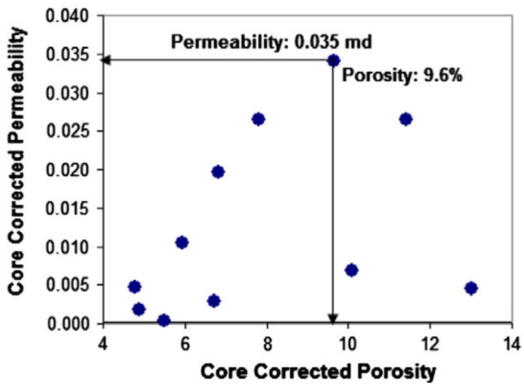

Fig. 4. Corrected permeability and porosity for the core samples of the tight sand formation, which have core analysis tests available.

data measured, which has permeability of 0.035 md and porosity of 9.6% (the core sample was taken from the zone Z3 shown in Fig. 3). The measured capillary pressure and relative permeability curves for the core sample are shown in Fig. 5, which indicate critical water saturation of 0.6 approximately. The relative permeability curves were measured by core flooding test, and provided K_r data in the water saturation range of 0.6–1.0. For K_r data at water saturations below S_{wc} where Kr could not be measured, data extrapolation was performed using the typical trend of relative permeability curves (Dacy, 2010). The relative permeability to water is significantly lower compared with relative permeability to gas, indicating sensitivity of formation to water damage. In other words, the formation cannot provide considerable production rate in the case of high water saturation.

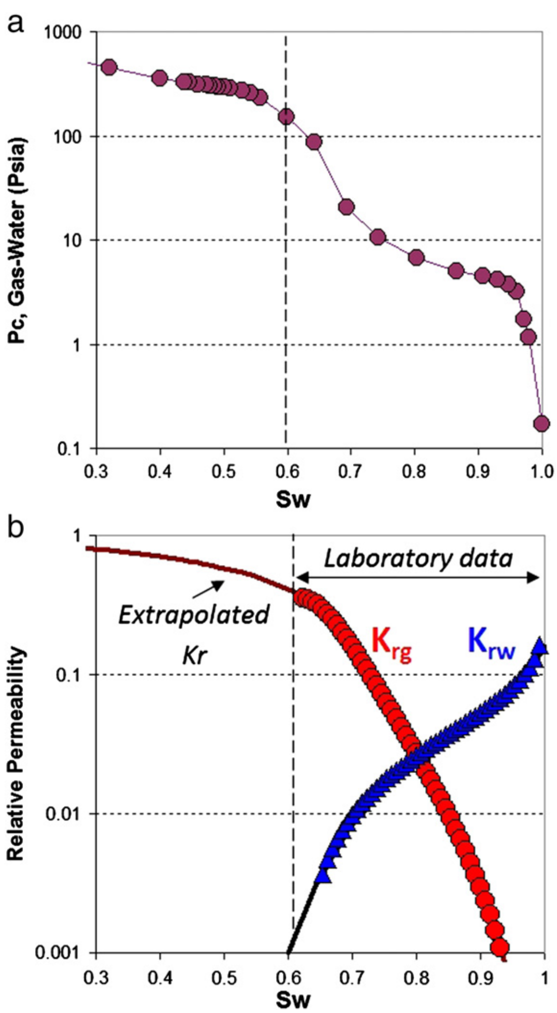

Fig. 5. The relative permeability and capillary pressure curves for the tight sand core sample (core porosity of 9.6%, core permeability of 0.035 md).

A well was drilled using 8.5 in. bit as over-balanced using water based mud in the tight sand gas reservoir, and completed as cased-hole perforated. The well produced gas from the main producer zone after well completion and clean-up, however gas production rate declined sharply with time as shown in Fig. 6 (gas production rate before fracturing).

The well was hydraulically fractured using KCl based fracturing fluid, in order to improve well productivity. During the fracturing job, approximately 2500 bbl of fracturing fluid was pumped into all the intervals. It was estimated that about 60% of the fluids were recovered during post fracturing production test, and 1000 bbl of water based treating fluids was not recovered (we believe that this was trapped in the reservoir, causing significant damage to reservoir permeability).

The fracturing designs predicted fracture half length size (X_f) of 150–200 ft and fracture conductivity ($K_f * W_f$) of 600–700 ft. However the production tests indicated that the fracturing was not efficient and the fracture half length size and conductivity might be significantly less than the predictions. There are no reliable measured field data available regarding actual size and conductivity of the hydraulic fracture.

After the hydraulic fracturing and well clean-up, the well gas production rate data indicated that the hydraulic fracturing failed to provide a significant improvement of gas production rate. The post-fracturing to pre-fracturing Production Ratio (the ratio of the post-fracturing stabilized gas production rate after clean-up, to the initial gas production rate before fracturing) is 0.6 approximately, meaning that the post-fracturing gas production rate is lower compared with the early time production rate before fracturing, as shown in Fig. 6 (gas production after fracturing).

The core samples that were tested and analyzed using X-ray diffraction detected Smectite, meaning that the formation can have medium to strong sensitivity to fresh or KCl waters. Therefore it could be concluded that leak-off of water into the tight sand gas reservoir during fracturing, and trapping of 1000 bbl of water inside the reservoir (not recovered during clean-up), might be the reasons for the low well productivity after fracturing.

4. Damage evaluation using reservoir simulation

Water invasion damage can be modeled based on reduction of the relative permeability when water saturation is increased around the

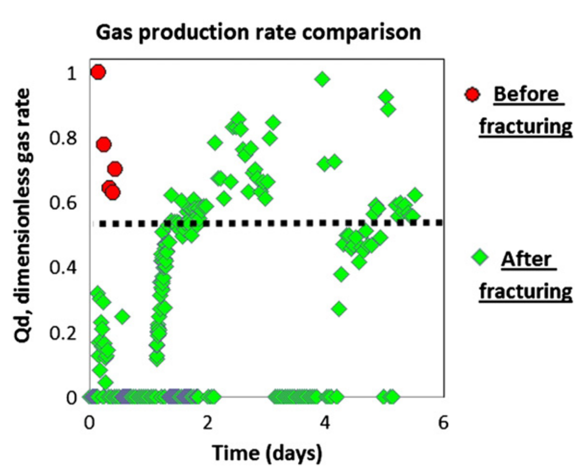

Fig. 6. Production history of a well completed in Perth Basin (pre-fracturing and post-fracturing gas production rates comparison).

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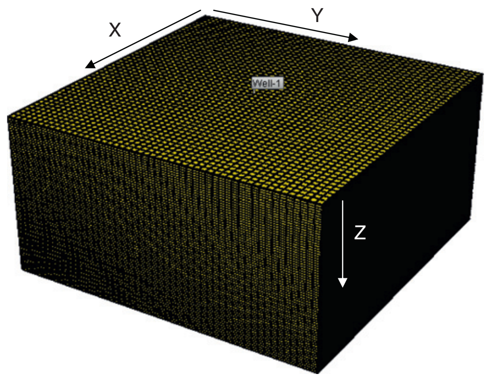

Fig. 7. Reservoir model 3-D view (showing grid sizes in X, Y and Z directions).

wellbore by water injection. The trapping of water phase in the near wellbore zone is controlled by capillary pressure curve that manages how the invaded fluid is held inside the reservoir model grids around the wellbore.

Reservoir simulation of the tight gas reservoir was carried out in order to qualitatively evaluate the effect of water damage on well productivity for different cases of non-fractured and hydraulically fractured wells in tight gas reservoirs. CMG-IMEX black-oil reservoir simulator was used to numerically model water invasion and gas production. The reservoir model 3-D view is shown in Fig. 7, and the model input data details are reported in Table 1. The reservoir model is a simplified homogeneous one, since the details of reservoir heterogeneity are not available.

A vertical well is located at the center of the model, and perforated across all the layers. The hydraulic fractures were introduced to the model by considering a high permeability plane perpendicular to the wellbore. As there are no field measurements available regarding hydraulic fracture parameter values and also the fracture design predictions were optimistic, some initial guess based on typical values (E&P Focus, 2011) was inputted into the model. The fracture parameters were then tuned during matching of the overall production history of the well, which resulted in fracture half length size of 75 ft and hydraulic fracture conductivity of 100 md ft approximately (Table 2).

In this simulation study, the initial gas saturation was considered as 0.4 for the more realistic case, and 0.7 for the optimistic case. The assumptions are base on average water saturation data from the petrophysical evaluations shown in Fig. 3, and the irreducible water saturation of 0.6 from the core flooding test results shown in Fig. 5.

4.1. Effect of water invasion on near wellbore permeability

Water invasion effect in the reservoir model was evaluated by injecting water at the well location, followed by gas production. The preliminary simulation model results for water invasion are shown in Fig. 8-a to c. First, the matrix grids have initial gas saturation of 0.4 ($K_{rg@Sgi=0.4}=0.4$) as shown in Fig. 8-a.

First, water is injected for 5 days at the rate of 1000 barrels per day (STBD), at the well location, which increases water saturation around wellbore. Water saturation at the end of the injection phase is shown in Fig. 8-b (water invasion radius: 9 ft). Afterwards, the model is put on gas production in order to clean-up the invading water, and reduce water saturation around wellbore.

Water saturation at the end of the gas production period is shown in Fig. 8-c (water invasion radius: 12 ft), indicating water saturation of 80% ($K_r=0.03$) in the invaded zone. During the gas production phase not only the water saturation cannot be reduced to the critical water saturation, but also water in the near wellbore continues invading reservoir due to strong capillary pressure suction effects. In other words, even after water injection is stopped and during gas production phase, damaged zone radius (water invaded radius) increases with passage of time.

4.2. Water invasion damage impact on well gas production rate

The simulation model was run for different cases of normal and sub-normal initial water saturation, in order to understand water damaging effect in tight gas reservoirs. For scenario 'A' cases, the simulation models consider normal initial water saturation ($S_{wi}=0.6$, $S_{wc}=0.6$), and for scenario 'B' cases, the models have sub-normal initial water saturation ($S_{wi}=0.3$, $S_{wc}=0.6$).

Different cases as detailed in Table 3 were run to understand the effect of initial water saturation and water invasion damage on gas production rate in the cases that there is no liquid invasion damage (models A-1, A-2, A-3, B-1, B-2, B-3), and in the cases there is 5 days of water injection with 2000 bbl/day injection rate, prior to gas production (models A-4, A-5, A-6, B-4, B-5, B-6). The models were run, and the production predictions were plotted as shown in Figs. 9 and 10.

The well gas production rate simulation results for the effect of initial water saturation are shown in Fig. 9-a (gas production for non-fractured well), Fig. 9-b (gas production rate in case of 1 hydraulic fracture) and Fig. 9-c (gas production rate in case of 5 hydraulic fractures), which indicate significant impact of S_{wi} on well productivity. For all the cases, sub-normal S_{wi} provided significantly higher gas production rate.

The simulation results for the effect of water blocking damage in tight formations with normal S_{wi} are shown in Fig. 10-a to c. In the case of non-fractured well, water blocking damage causes significant drop of gas production rate (Fig. 10-a). However in the cases of fractured well, the hydraulic fractures could reduce the negative impacts of water blocking damage (Fig. 10-b and c). With 5 hydraulic fractures, the stabilized gas production rate of the well at the late time is almost similar in the cases of damaged and non-damaged wells (A3 and A6), as total area of the fractures is big.

The ratio of the stabilized gas production rate in the case of a hydraulic fractured well damaged by liquid leak-off (Fig. 10, model A5), to the initial gas production rate in the case of no hydraulic fractures and no liquid leak-off (Fig. 10, model A1) is 0.6 approximately. The simulation results for the fractured model to the non-fractured model Production Ratio (0.6) are in good agreement with the well actual post-fracturing to pre-fracturing Production Ratio (0.6) shown in Fig. 6, indicating that the simulation results can qualitatively be reliable.

The simulation results related to the significance of damage control for well productivity improvement are shown in Fig. 11. In the case of

Table 1
Details of reservoir simulation model.

No. of grids in x, y and z directions	Grid size (x and y directions) (ft)	Reservoir height (ft)	Reservoir permeability (md)	Matrix porosity (%)
50*50*71	50	370	0.035	9.6
Gas S.G. (air = 1)	Critical water saturation	Initial water saturation	Initial pressure, psia	Reservoir temperature, F
0.6	0.6	0.3 and 0.6	5000	220

Table 2
Hydraulic fracture parameters in the model (hydraulic fracture, perpendicular to the wellbore).

Hydraulic fracture half length size (ft)	Hydraulic fracture conductivity (md ft)
75	100

normal S_{wi}, cumulative produced gas from the well with a single hydraulic fracture that is damaged by water invasion (curve A-5), is not significantly different compared with the well with no hydraulic fractures and no considerable damage (curve A-1). In other words, due to water blocking damage in the case of inefficient hydraulic fracturing with no damage control, the well productivity may not noticeably improve.

For this case, five hydraulic fractures provided significantly better productivity than a well that is non-fractured or has a single hydraulic fracture. Therefore in the case that a tight gas reservoir is sensitive to water invasion damage, limited or inefficient hydraulic fracturing may result in gas production rate to be lower compared with a non-fractured well that has no significant damage.

The simulated results for cumulative injected water during leak-off, and cumulative produced water during clean-up and gas production as reported in Table 4, indicate that in reservoirs with sub-normal S_{wi}, most of the injected water during hydraulic fracturing is held inside the reservoir rock by capillary imbibition, and is not produced back during clean-up. Compared with the normal S_{wi} cases (models A4, A5, and A6), the sub-normal S_{wi} cases (models B4, B5, and B6) have had

Table 3
Reservoir simulation models to evaluate the effect of initial water saturation and water invasion damage on gas production rate.

Model	Number of hydraulic fractures	Initial water saturation	Water invasion rate into formation, prior to gas production period
A1	0	Normal	0
A2	1	Normal	0
A3	5	Normal	0
B1	0	Sub-normal	0
B2	1	Sub-normal	0
B3	5	Sub-normal	0
A4	0	Normal	2000 bbl/day
A5	1	Normal	2000 bbl/day
A6	5	Normal	2000 bbl/day
B4	0	Sub-normal	2000 bbl/day
B5	1	Sub-normal	2000 bbl/day
B6	5	Sub-normal	2000 bbl/day

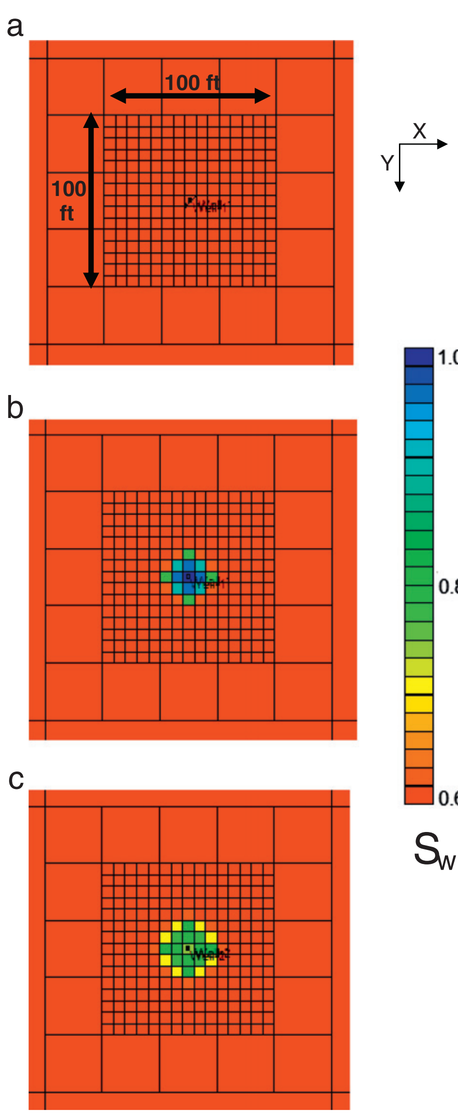

Fig. 8. Simulation of water invasion and phase trapping in the formation (top view of the reservoir model, zoomed in at well location to see the saturation changes around wellbore). a: Water saturation distribution, before water invasion. b: Water saturation distribution, at the end of water injection period. c: Water saturation distribution, at the end of gas production period.

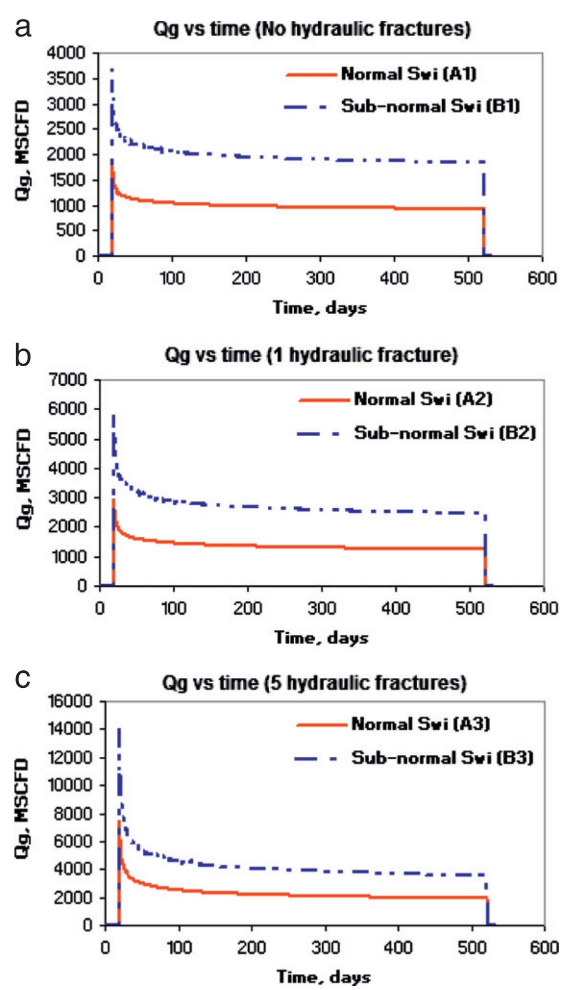

Fig. 9. Gas production rate, the effect of initial water saturation on well gas production rate in the case of non-damaged tight gas reservoir.

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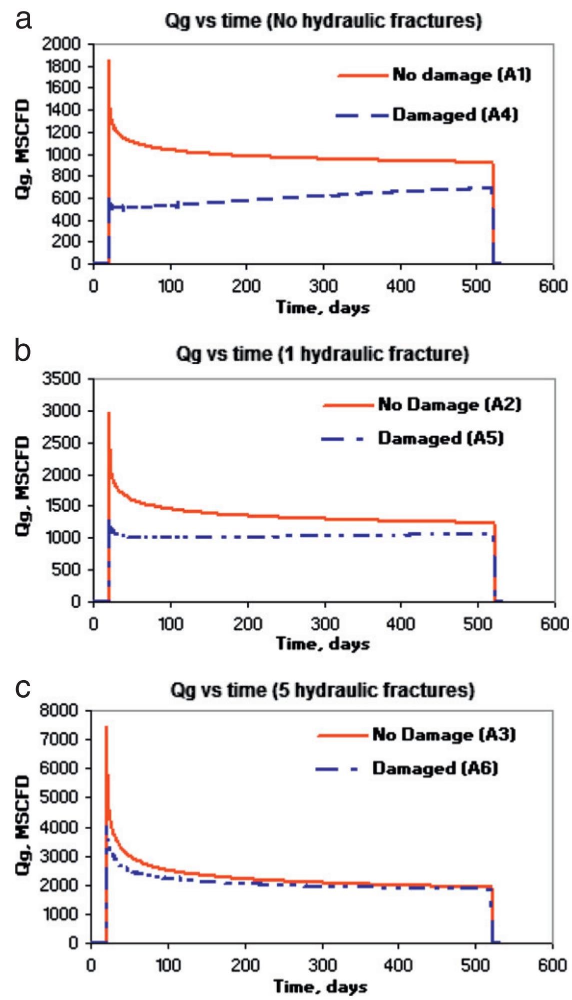

Fig. 10. Gas production rate, the effect of water blocking damage on well gas production rate in the case of normal initial water saturation.

larger leak-off of liquid into formation, and significantly smaller volume of cumulative water produced back. In other words, water phase trapping damage in more significant in tight gas reservoirs that have sub-normal initial water saturation.

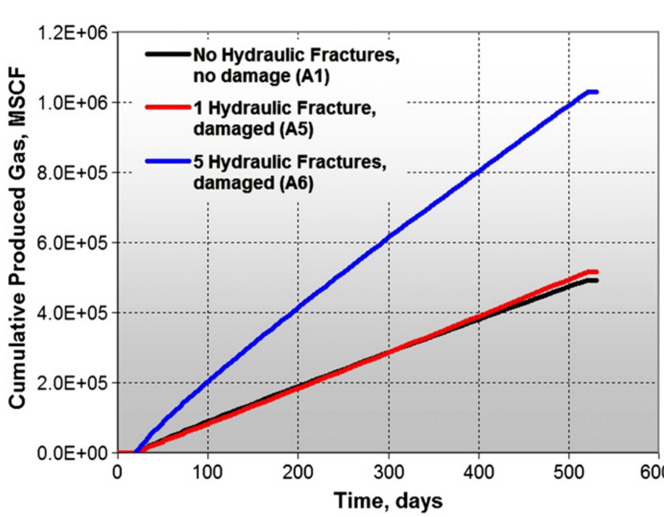

Fig. 11. Cumulative produced gas, comparison of 'non-damaged and no hydraulic fracture' with 'damaged with hydraulic fracture' in the tight gas reservoir.

Table 4
Simulation results for 'water injection prior to gas production' and 'water production during well clean-up'.

Simulation results for water production/ injection	Scenarios	Cumulative injected water (bbl)	Cumulative produced water (bbl)
A1, A2, A3, B1, B2, B3	No water invasion prior to gas production	–	–
A4, normal Swi, no frac	2000 bbl/day water injection prior to gas production	1829	829
A5, normal Swi, 1 frac		1872	911
A6, normal Swi, 5 fracs		2046	1164
B4, sub-normal Swi, no frac		4443	134
B5, sub-normal Swi, 1 frac		4472	146
B6, sub-normal Swi, 5 fracs		4600	192

The reservoir simulation results confirm that water blocking damage may cause well productivity to be low even after hydraulic fracturing.

5. Discussion

Tight gas reservoirs with sub-normal initial water are more sensitive to phase trap damage, and water blocking can significantly reduce their productivity. If a reservoir has normal initial water saturation and it is not sensitive to water damage, single or multiple hydraulic fracturing can improve well productivity.

In tight formations that are sensitive to the damage mechanisms associated with water, special considerations need to be taken into account in designing hydraulic fracturing since it may cause excessive fluid leak off into the formation. In hydraulic fracturing, the injected fluid should be compatible with formation and do not cause clay swelling. If massive hydraulic fracturing cannot be performed, drilling long horizontal/deviated wells in underbalanced conditions using non-aqueous drilling fluid and completing the well as open-hole may be a more efficient option since it increases formation area open to flow into wellbore, minimizes damage, and therefore enhances gas production rate.

6. Conclusions

Based on the simulation results, the following conclusions can be drawn:

(1) Water blocking is one of the major damage mechanisms in tight sand gas reservoirs due to relative permeability and strong capillary pressure suction effects.
(2) Liquid invasion into formation during drilling or fracturing of tight gas reservoirs can cause trapping of water phase in the invaded zone around the wellbore. Due to capillary suction effects, water may continue invading into the formation even during gas production phase.
(3) Water phase trapping damage in more significant in tight gas reservoirs that have sub-normal initial water saturation.
(4) Damage control is essential in the tight sand formations that are sensitive to water damage, and leak-off of water into formation may plague the success of hydraulic fracturing operations.
(5) Inefficient hydraulic fracturing in the tight formations that are sensitive to water invasion damage may result in gas production rate to be lower compared with a non-fractured well that has not been damaged.

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(6) Multiple-stage hydraulic fracturing that significantly increases area of the formation open to flow can help achieving economical gas production rate from water sensitive tight gas reservoirs.

Nomenclature

Swc	critical water saturation (Swc) defines the maximum water saturation for a formation with a given permeability and porosity below which no water production will occur. Conversely water saturations in excess of Swc will permit water to flow from the reservoir (Tarek Ahmed, 2000)
Sw, Irr	Irreducible Water Saturation is the lowest water saturation that can be achieved in a core plug by displacing the water by gas (Tarek Ahmed, 2000)
Sw, connate	Connate Water Saturation is water trapped in the pores of a rock during formation of the rock
Swi	Initial Water Saturation is water saturation at initial reservoir conditions (Tarek Ahmed, 2000)
Sgc	critical gas saturation
Sgi	initial gas saturation
P	pressure
Q	flow rate
t	time
K	permeability
S	skin
Q_g	gas production rate
Q_w	water production rate
P_c	capillary pressure
K_r	relative permeability
K_f	fracture permeability
W_f	fracture aperture
X_f	fracture half length size
UB	underbalanced
OB	overbalanced
MMSCFD	million standard cubic feet per day

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Appendix B:

Characterizing Natural Fractures Productivity in Tight Gas Reservoirs, Journal of Petroleum Exploration and Production Technology

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ORIGINAL PAPER - PRODUCTION ENGINEERING

Characterizing natural fractures productivity in tight gas reservoirs

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Abstract Tight formations normally have production problems mainly due to very low matrix permeability and various forms of formation damage that occur during drilling completion and production operation. In naturally fractured tight gas reservoirs, gas is mainly stored in the rock matrix with very low permeability, and the natural fractures have the main contribution on total gas production. Therefore, identifying natural fractures characteristics in the tight formations is essential for well productivity evaluations. Well testing and logging are the common tools employed to evaluate well productivity. Use of image log can provide fracture static parameters, and welltest analysis can provide data related to reservoir dynamic parameters. However, due to the low matrix permeability and complexity of the formation in naturally fractured tight gas reservoirs, welltest data are affected by long wellbore storage effect that masks the reservoir response to pressure change, and it may fail to provide dual-porosity dual-permeability models dynamic characteristics such as fracture permeability, fracture storativity ratio and interporosity flow coefficient. Therefore, application of welltest and image log data in naturally fractured tight gas reservoirs for meaningful results may not be well understood and the data may be difficult to interpret. This paper presents the estimation of fracture permeability in naturally fractured tight gas formations, by integration of welltest analysis results and image log data based on Kazemi's simplified model. Reservoir simulation of dual-porosity and dual-permeability systems and sensitivity analysis are performed for different matrix and fracture parameters to understand the relationship between natural fractures parameters with welltest permeability. The simulation results confirmed reliability of the proposed correlation for fracture permeability estimation. A field example is also shown to demonstrate application of welltest analysis and image log data processing results in estimating average permeability of natural fractures for the tight gas reservoir.

Keywords Fracture permeability · Tight gas reservoirs · Natural fractures characterisation · Welltest analysis

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List of symbols

P	Pressure
K	(Perm) Permeability
Q	Flow rate
C	Compressibility
t	Time
h	Layer thickness
r	Radius
φ	(Poro) Porosity
a	Fracture spacing
b	Fracture aperture
δ	Shape factor
λ	Interporosity flow coefficient
ω	Fracture storativity
μ	Viscosity
B	Formation volume factor

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NFR Naturally fractured reservoirs
TGR Tight gas reservoirs

Subscripts
f Fracture
m Matrix

Introduction

A naturally fractured reservoir is mainly a network of natural fractures and matrix which are randomly distributed. Characterization of the natural fractures generally includes estimating the dynamic parameters such as fracture permeability, and determining the static parameters such as fracture spacing (matrix block size), fracture aperture and fracture porosity (Racht and Golf 1982).

The most common geometrical representations of fractured reservoirs are the models introduced by Warren-Root and Kazemi as shown in Fig. 1, assuming that discrete matrix blocks are separated by an orthogonal system of continuous and uniform fractures. The matrix blocks are assumed to be isotropic and homogeneous identical rectangular parallelepipeds with no direct communication between them (Kazemi et al. 1976). The simplified models have been introduced to simulate flow through naturally fractured reservoirs. The double porosity domain assumes a continuous uniform fracture network oriented parallel to the principal axes of permeability.

In many of the naturally fractured reservoirs, fracture permeability can be the major controlling factor of the flow of fluids. Fracture permeability in a dual-porosity and dual-permeability reservoir is the permeability that is associated with the secondary porosity created by open natural fractures (Racht and Golf 1982). The main dynamic parameters commonly used to describe matrix and interconnecting fracture network are interporosity flow coefficient (λ) and fracture storativity ratio (ω) that are defined as follows (Tiab et al. 2006):

$$\lambda = \delta \frac{K_m}{K_f} r_w^2 \quad (1)$$

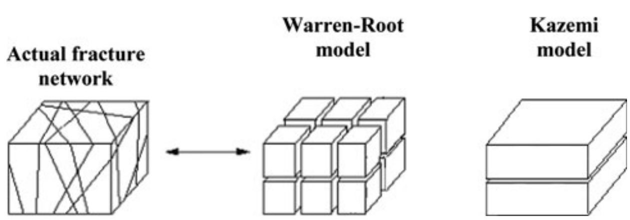


Fig. 1 Dual porosity–dual permeability system (Warren-Root and Kazemi simplified models)

$$\omega = \frac{\varphi_f \cdot C_f}{\varphi_f \cdot C_f + \varphi_m \cdot C_m} \quad (2)$$

Where K_m is matrix permeability, K_f is fracture permeability, r_w is wellbore radius, φ_f is fracture porosity, φ_m is matrix porosity, C_f is fracture compressibility, C_m is matrix compressibility, and δ is shape factor and it is defined as follows:

$$\delta = 4\left(1/a_X^2 + 1/a_Y^2 + 1/a_Z^2\right) \quad (3)$$

In Eq. (3), a_x, a_y and a_z are matrix block size respectively in x, y and z directions (Reiss 1980). In the case of Kazemi model ($a_x \gg a_z$ and $a_y \gg a_z$), the shape factor, δ, is considered to be $4/a^2$. The smaller value of λ (higher fracture permeability) and/or the larger value of ω (higher fracture porosity) result in higher well productivity.

The dual-porosity and dual-permeability reservoirs' dynamic parameters can be estimated using welltest analysis. As illustrated in Fig. 2, a Semi-Log plot of pressure build-up data results in two parallel lines, which the slope gives average permeability, the vertical separation between the parallel lines (ΔP_ω) can provide fracture storativity ratio, and the ΔP at mid-point of the transition period (ΔP_λ) can estimate interporosity flow coefficient (Saeidi Ali 1987).

The main input parameters required to model fluid flow through a naturally fractured formation are fracture permeability, fracture porosity and shape factor (Kazemi et al. 1976). The matrix block size (fracture spacing) to compute the shape factor is primarily obtained from borehole images. The fracture spacing can be attained using results of any type of borehole images (regardless of the drilling mud system used). However, in the case of water-based mud imaging (e.g., FMI), image log processing can also provide fracture aperture and porosity as an additional output of fracture analysis (Dashti and Bagheri 2009; Luthi 1990).

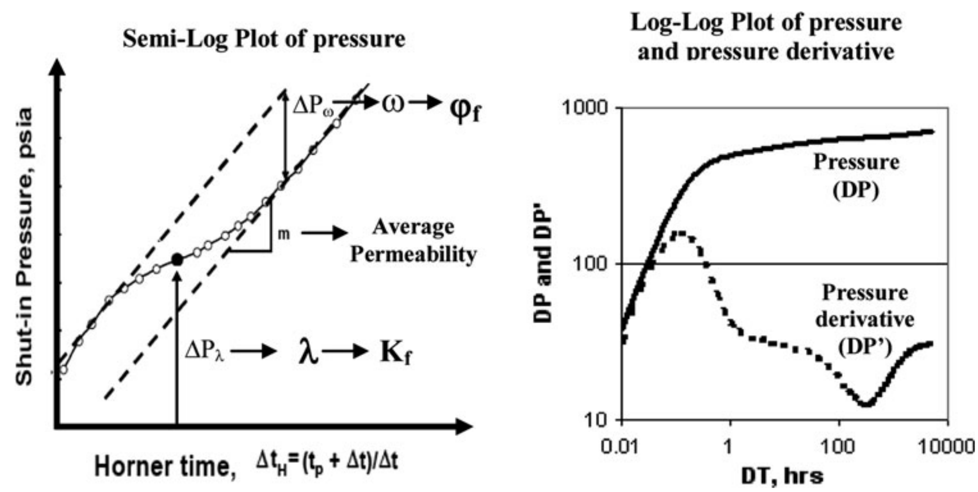
Integrating the welltest results with image log processing results for fracture spacing, and core data for matrix porosity, permeability and compressibility, can be used to estimate fracture permeability and fracture porosity from Eqs. (1) and (2) (Tiab et al. 2006):

$$\varphi_f = \varphi_m \frac{C_m}{C_f} \frac{\omega}{1-\omega} \quad (4)$$

$$K_f = \delta \frac{K_m}{\lambda} r_w^2 \quad (5)$$

Equations (4) and (5) can determine fracture permeability and fracture porosity, in the case that the dual-porosity response is clearly observed on pressure build-up diagnostic plots, and ω and λ values can be estimated certainly. Fracture compressibility in the fracture porosity estimation [Eq. (4)] may have uncertainties (maybe 1–100 folds higher than matrix compressibility) and might be estimated using well testing (Tiab et al. 2006).

Fig. 2 Pressure transient behavior in naturally fractured reservoirs



The image log porosity can be used to verify accuracy of average fracture porosity estimated from welltest analysis.

In tight reservoirs, the very low matrix permeability, complexity of the formation, and long wellbore storage effect may mask the reservoir response to the pressure change during transient testing. Although one can estimate the average permeability value from welltest data in tight reservoirs using advanced welltest interpretation techniques (Bahrami et al. 2010), estimating fracture storativity and interporosity flow coefficient from such welltest data might not be feasible since the dual-porosity response may not clearly be observed on pressure build-up diagnostic plots. The conventional approaches might fail to characterize fracture parameters in naturally fractured tight gas reservoirs, especially in complicated cases such as hydraulically fractured or horizontally drilled wells (Restrepo and Tiab 2009), and therefore application of welltest and image log data in the reservoirs may not be well understood and is proved to be difficult to interpret for meaningful results.

Natural fractures characterisation in tight gas reservoirs

Analysis of acquired data from a tight gas reservoir may provide limited information about the formation characteristics, due to some restrictions such as type of the drilling fluid, complicated and slow response of reservoir, not long enough testing time, etc. (Garcia et al. 2006). Hence, a simple model needs to be used that requires minimum data inputs in determining fracture parameters. The model introduced by Kazemi as shown in Fig. 3 can be used to build a simple dual-porosity and dual-permeability system of naturally fractured tight gas reservoirs. Considering Kazemi model that assumes parallel layers of matrix and fracture in a

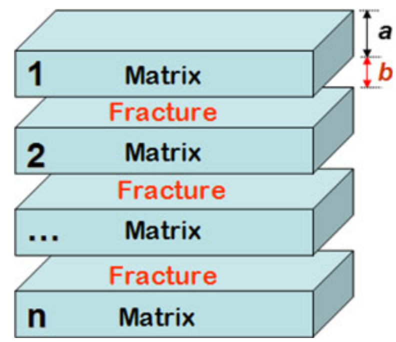


Fig. 3 Kazemi model parameters for naturally fractured reservoirs

uniform fracture network model, similar fracture permeability and aperture for the fracture layers and similar matrix permeability and block size for the matrix layers, then average reservoir permeability based on thickness of matrix and fracture layers (Bourdarot 1998) can be expressed as follows:

$$K \cdot h_{\text{average}} = \sum_{\text{matrix}}^{m=1,\ldots,n} (K_m * a) + \sum_{\text{fracture}}^{f=1,\ldots,n} (K_f * b) \tag{6}$$

$$h = (n * \mathrm{a}) + (n * \mathrm{b}) \tag{7}$$

where K_f is permeability of a natural fracture, b is average fracture aperture, a is average matrix block thickness, K is welltest permeability, K_m is average permeability of the matrix blocks, h is reservoir thickness, n is number of fractures intersecting the wellbore across the reservoir, φ_f is fracture porosity (fraction), $n*a$ is cumulative matrix block thickness, and $n*b$ is cumulative fracture aperture.

Combining Eqs. (6) and (7) results in the following simplified equation [Eq. (8)], using the assumption of $a \gg b$, $K_f \gg K_{\text{welltest}}$ and $K_f \gg K_m$ for tight gas reservoirs:

$$K_f = K_{\text{welltest}} * \frac{a}{b} \tag{8}$$

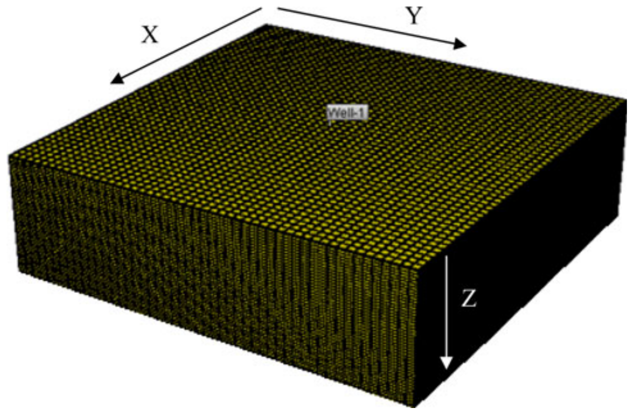


Fig. 4 Reservoir model 3D view, 50 grids in *X* direction, 50 grids in *Y* direction and 71 girds in *Z* direction (36 horizontal matrix layers, 35 horizontal fracture layers)

Since Eq. (8) is based on simplified models and assumptions, using some correction factors might provide more realistic relationship between fracture dynamic parameters. Considering the correction factor, fracture permeability can be expressed in the following generalized form:

$$K_f = C_1 * K_{\text{welltest}} * \left(\frac{a}{b}\right)^{C_2} \tag{9}$$

The constants C_1 and C_2 in Eq. (9) are the correction factors that need to be determined from numerical simulation and sensitivity analysis. Using the Eq. (9), natural fractures permeability can be estimated as function of average permeability × thickness (from welltest analysis) and average fracture spacing and aperture (from image log processing results). Once the natural fracture parameters are estimated, then using Eqs. (1) and (2) fracture storativity ratio and interporosity flow coefficient can be estimated for welltest design applications, well productivity evaluation, and gas production rate forecasting.

Effect of natural fracture parameters on welltest response

To evaluate natural fracture parameters in tight gas reservoirs, reservoir simulation is performed based on the field data from a tight gas reservoir, using the widely used commercial CMG (Computer Modeling Group of Calgary) numerical reservoir simulation software. The model is fully implicit in its basic formulation, and the nonlinear equations in the software are solved by Newtonian iteration with the derivatives of the Jacobian matrix evaluated numerically (Odeh and Aziz 1981).

Reservoir simulation model for dual-porosity and dual-permeability systems is developed by considering matrix layers that have been separated by fracture layers as described in Fig. 3. A well is considered at the center of the model, which has been completed in all the matrix and fracture layers with no flow boundary. The reservoir model has been shown in Fig. 4 and the input data used in the reservoir simulation are provided in Table 1.

Different simulation models are run with different fracture parameters to analyse sensitivity of pressure build-up response outputs to each fracture parameter. The sensitivity analysis is performed for different matrix and fracture parameters to understand the relationship between natural fractures static and dynamic parameters. The simulation model scenarios are provided in Table 2. Each simulation run consists of a production period with gas production rate of 500 MSCFD, followed by pressure build-up period. The pressure build-up data are analysed to estimate welltest permeability for each dual-porosity dual permeability system, and then determine the relationship between each fracture parameter and welltest analysis results.

First, the model is run for different fracture aperture values of 0.1, 1 and 10 mm. Analysis of pressure draw-down data from the simulation runs is shown in Fig. 5. The early time data are affected by wellbore storage effect and

Table 1 Input data to the simulation base model

No of grids in *X* direction	50	–	Matrix compressibility	4E−06	1/psia
No of grids in *Y* direction	50	–	Fracture compressibility	4E−06	1/psia
No of matrix layers	36	–	Fracture layer porosity	100	%
No of fracture layers	35	–	Matrix layer porosity	8	%
Grid size in *X* direction	70	ft	Gas S.G.	0.65	–
Grid size in *Y* direction	70	ft	Reservoir pressure	3000	psia
Fracture layer thickness	1	mm	Reservoir temperature	180	F
Fracture spacing	5	ft	Net thickness	180	ft
Matrix permeability	0.1	md	Wellbore radius	0.25	ft
Fracture permeability	50000	md	Gas production rate	500	MSCFD

Table 2 Input data to the simulation base model

Sensitivity analysis simulation scenarios		
Fracture aperture	mm	0.1, 1, 10
Fracture spacing	ft	5, 10, 20
Permeability of fracture layer	Darcies	10, 50, 100
Porosity of fracture layer	fraction	0.6, 0.8, 1
Matrix compressibility	1/psia	4E−5, 4E −6, 4E−7
Fracture compressibility	1/psia	4E−5, 4E−6, 4E−7
Matrix permeability	md	0.005, 0.1, 2

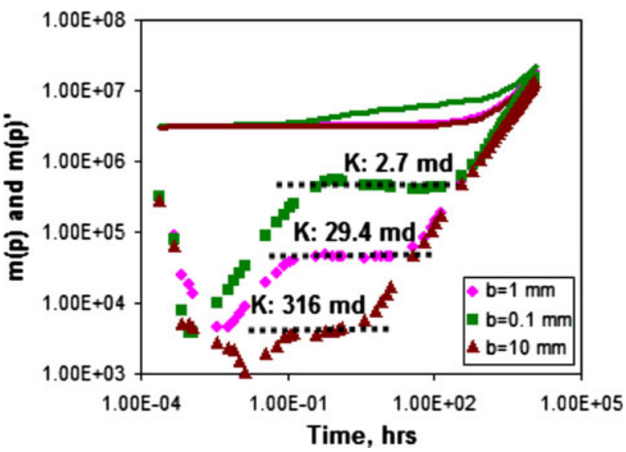


Fig. 5 Effect of fracture aperture (b) on welltest permeability

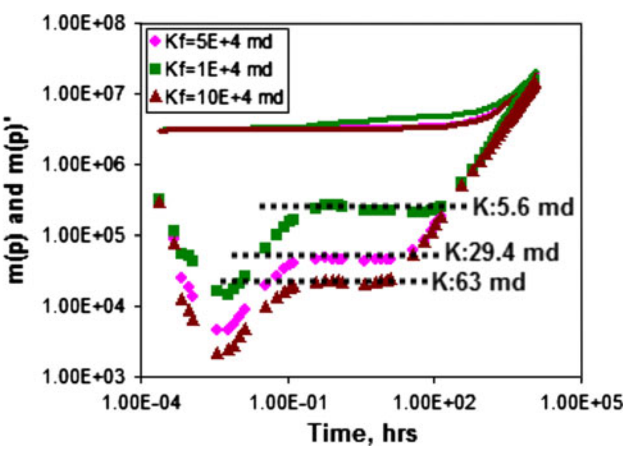


Fig. 6 Effect of fracture permeability (K_f) on welltest permeability

the typical dual-porosity response that is then followed by infinite acting radial flow zero slope line. The late time data are affected by no flow boundary effect, that in the case of higher fracture permeability, its response is reached earlier. Fracture aperture of 0.1, 1 and 10 mm resulted in welltest

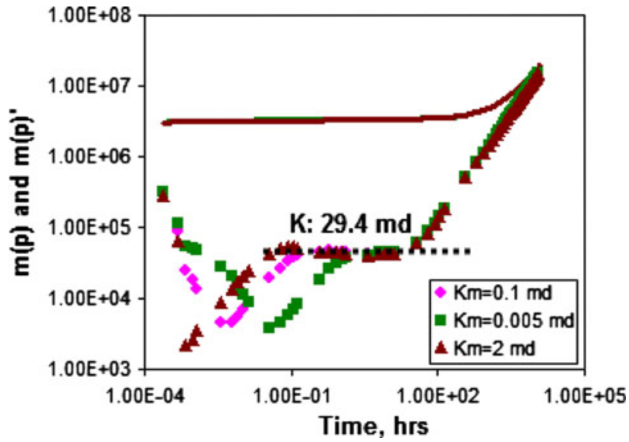


Fig. 7 Effect of matrix permeability (K_m) on welltest permeability

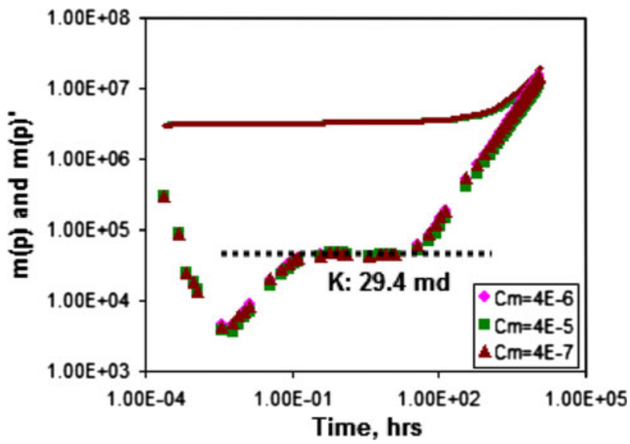


Fig. 8 Effect of matrix compressibility (C_m) on welltest permeability

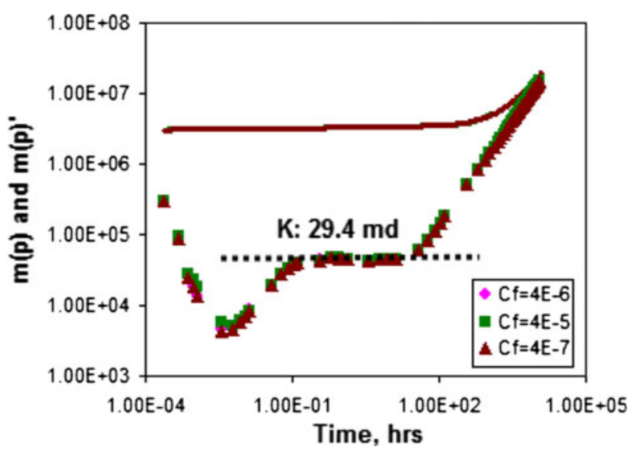


Fig. 9 Effect of fracture compressibility (C_f) on welltest permeability

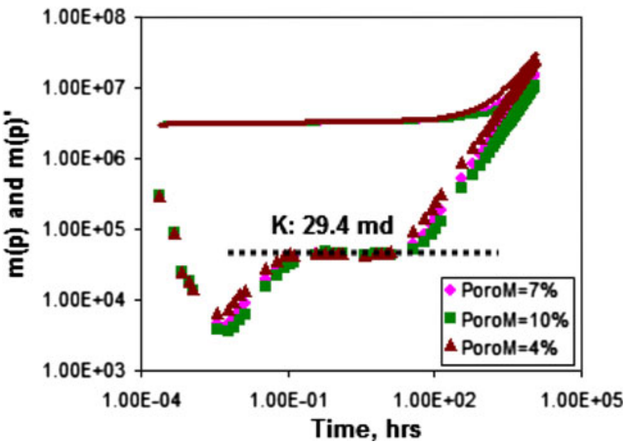


Fig. 10 Effect of matrix porosity (Poro$_M$) on welltest permeability

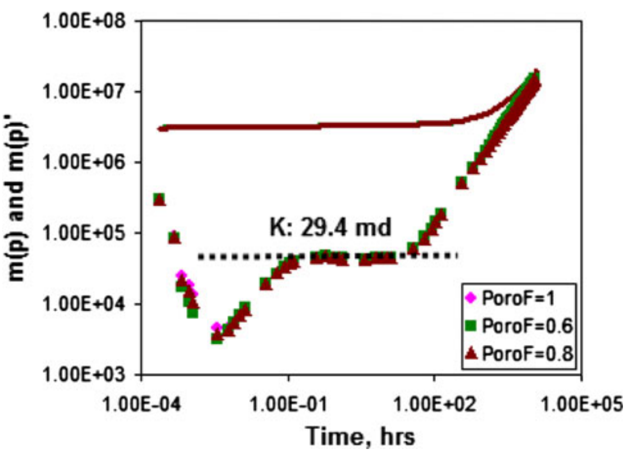


Fig. 11 Effect of fracture porosity (Poro$_F$) on welltest permeability

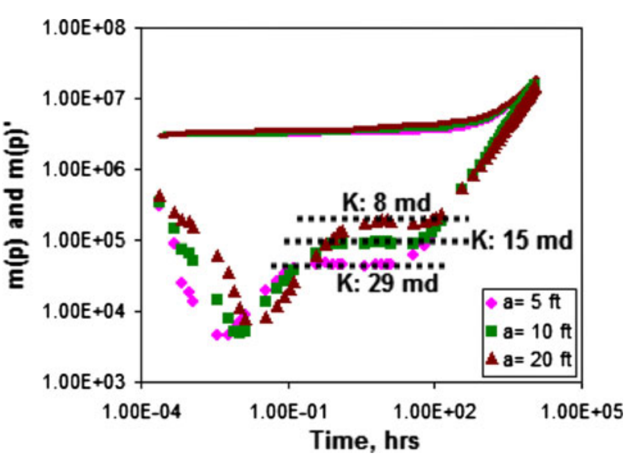


Fig. 12 Effect of fracture spacing (*a*) on welltest permeability

permeability of 2.7, 29.4, and 316 md, respectively. Similarly, the effect of fracture permeability, matrix permeability, matrix compressibility, fracture compressibility, matrix porosity, fracture porosity and fracture spacing are shown in Figs. 6, 7, 8, 9, 10, 11 and 12.

Among the parameters examined in the sensitivity analysis, it is observed that only fracture aperture, fracture permeability and matrix block size (fracture spacing) have posed significant impact on welltest permeability, and the effect of other parameters such as matrix permeability, compressibility of matrix and fracture, and porosity of matrix and fracture can be disregarded. Figure 13 shows the relationship between welltest permeability and each of the main fracture parameters. The observations on the reservoir simulation results are in good agreement with the derived Eq. (8):

- Fracture permeability is mainly function of welltest permeability, fracture aperture and fracture spacing.
- Fracture permeability has linear relationship with matrix block size and welltest permeability, and inverse relationship with fracture aperture (i.e., if K_f is increased, to match the welltest permeability, b should be reduced).

Combining the curve fitting functions shown in Fig. 13 results in the following equation [Eq. (10)]:

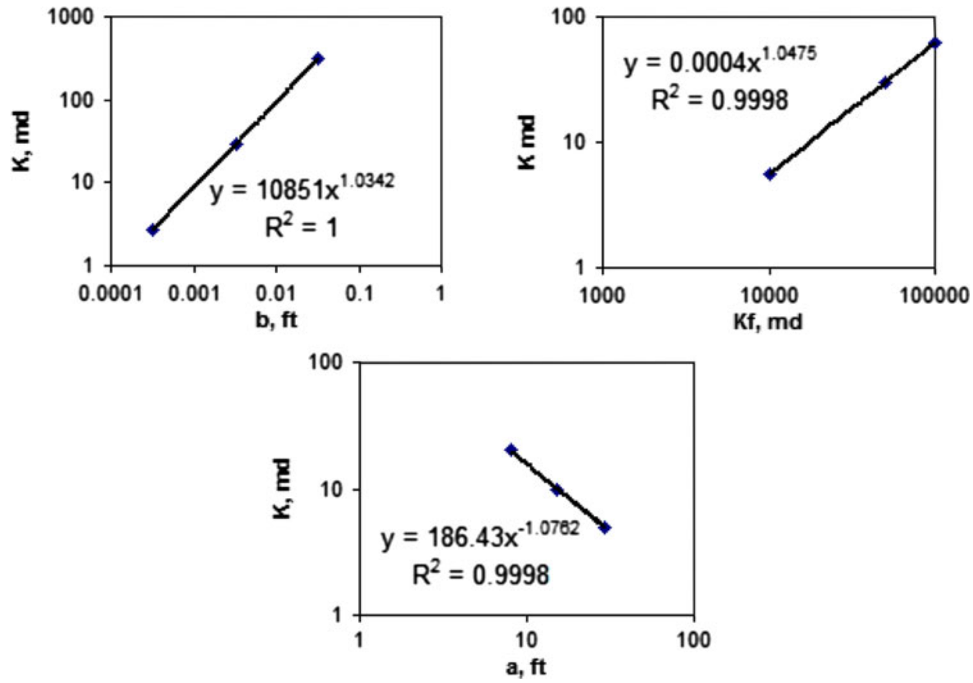
$$K_f = 0.795 * K_{\text{welltest}} * \left(\frac{a}{b}\right)^{1.04} \tag{10}$$

where K_f is fracture permeability in md, b is fracture aperture in ft and a is fracture spacing in ft. The plot of estimated welltest permeability [from Eq. (10)] versus model welltest permeability has been shown in Fig. 14. Comparing the actual simulation outputs and the results from the Eq. (10), it can be observed that the average error is around 5 %, indicating that the multi-variable regression results for the constants C_1 and C_2 are reliable.

The proposed method [Eq. (10)] is based on Kazemi dual-porosity dual-permeability model that has a layered formation, and therefore this approach may perform reasonably well in the formations with high density low angle fracture network, more specifically in the range of the fracture parameters used in sensitivity analysis. The approach is fairly simple, and deeply rooted in the simplified vision of the fractured rock of the Kazemi model, and may provide good first guess values for fracture parameters.

The estimated fracture parameters can be considered as initial guess in reservoir simulation models for naturally fractured tight gas reservoirs, and then be tuned during history matching to get more reliable results for natural fractures productivity and their contribution on total gas production.

Fig. 13 Relationship between fracture parameters and welltest permeability



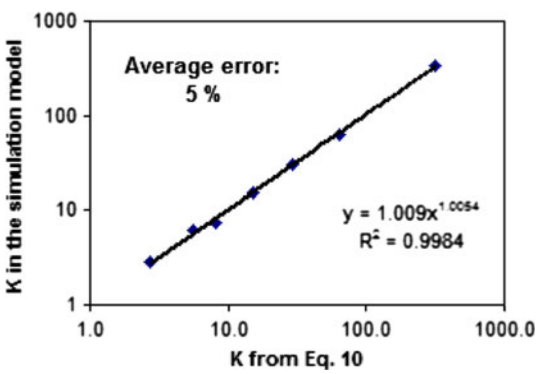


Fig. 14 Welltest permeability from the model, versus welltest permeability calculated from Eq. (10)

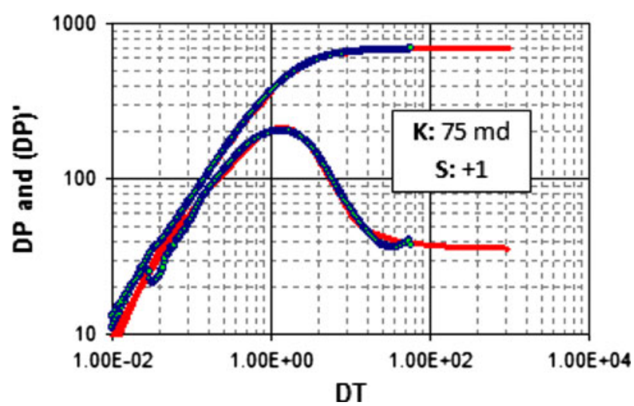


Fig. 15 Pressure transient testing analysis and results

Field example: fracture characterization

For a well completed in a naturally fractured tight gas reservoir (with average matrix permeability of 0.1 md), results of welltest data, core analysis, and image log in water-based mud processing are studied and integrated to characterize fracture parameters.

Pressure fall-off test was performed in this well by injecting water for a period of time, followed by pressure fall-off test. Pressure transient data analysis results are shown in Fig. 15, in which the results showed average permeability of 75 md for the naturally fractured formation. The Formation Micro Imaging (FMI) Log data acquired after the well drilling using water-based mud was also studied. The results for fracture distribution, fracture aperture and fracture porosity are shown in Table 3 and Figs. 16, 17 and 18. The data processing results in this well-showed average fracture porosity of 0.3 %, average matrix block size of 0.93 ft, and average fracture aperture of 0.1 mm. Using welltest permeability and image log fracture spacing and aperture as input data into Eq. (10), it resulted in fracture permeability of 174,000 md.

It should be noted that in this case, the image log fracture parameters might be different compared with fracture parameters during the pressure transient testing. Injection of water prior to pressure fall-off test may have increased aperture of natural fractures in the water invaded reservoir zone around wellbore (over estimating actual fracture

Table 3 Natural fractures data summary

Image log processing results		
Average fracture density	1/ft	1.04
Number of open fractures (n)	–	57
Average matrix block size (a)	ft	0.97
Average Fracture Aperture (b)	mm	0.1
Average Fracture Porosity (φf)	%	0.3
Fracture permeability from Eq. (10)		
Estimated fracture permeability (K_f)	md	174,000

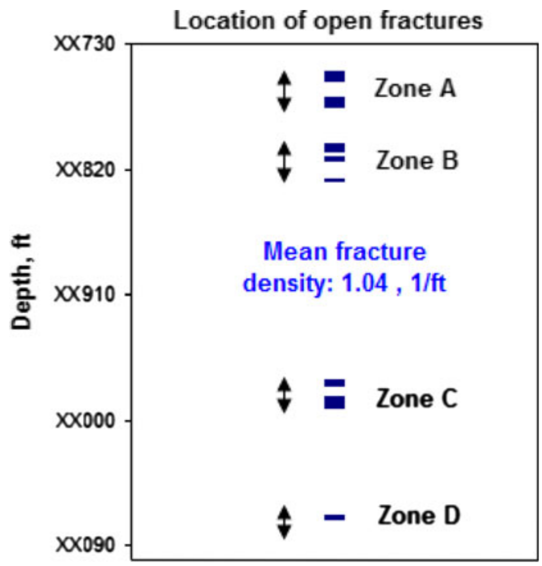


Fig. 16 Fracture distribution data from Image Log processing results (Net reservoir thickness 57 ft)

permeability from welltest data). In the case of pressure drawdown followed by pressure build-up, the results for fracture permeability might be different.

Conclusions

- Natural fractures in the tight formations make significant contribution on production, and therefore it is essential to estimate their dynamic characteristics.
- In tight formations, due to the weak reservoir response to pressure disturbance, the interporosity flow coefficient and fracture storativity coefficients might not be possible.
- Welltesting analysis in tight gas reservoirs has uncertainties and may not directly provide characterisation of fracture dynamic parameters such as fracture storativity and interporosity flow coefficient.
- Welltest permeability is mainly controlled by fracture permeability, matrix block size and fracture aperture, and it is not very sensitive to matrix permeability, matrix and fracture compressibilities, and matrix and fracture porosities.
- In addition to petrophysical evaluation, results that provide important input for welltest analysis of conventional reservoirs, image log data are needed in welltest analysis of naturally fractured tight gas reservoirs.

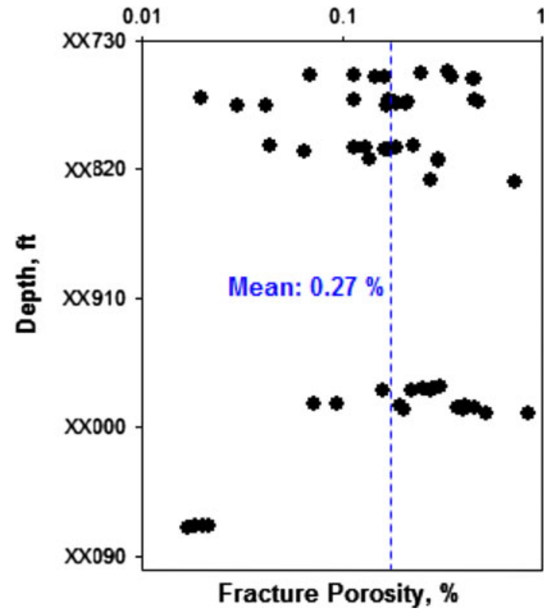


Fig. 17 Fracture porosity data from Image Log processing results

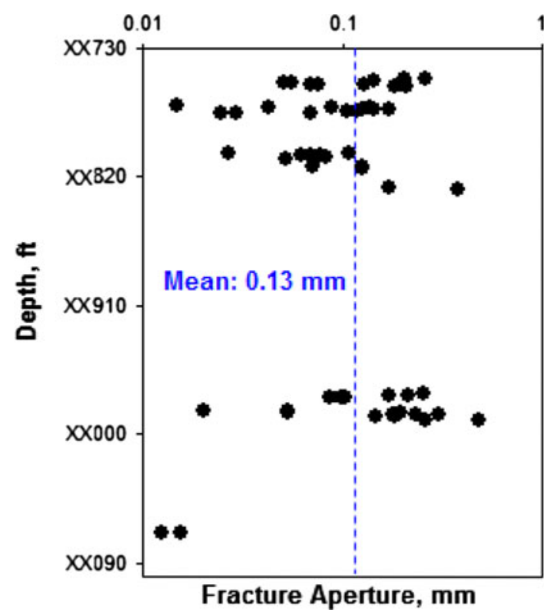


Fig. 18 Fracture aperture data from Image Log Processing Results

- Using welltest permeability and image log fracture spacing and aperture, by considering average permeability based on the thickness of fracture and matrix layers, the proposed method can provide reliable first guess estimation of average fracture permeability for reservoir simulation studies.

Acknowledgments The authors are deeply thankful to Professor Ali Saeidi, the author of the book "Reservoir Engineering of Fractured Reservoirs" for their valuable guides and helpful discussions to initiate this work. We also would like to appreciate Computer Modeling Group (CMG) for use of CMG-IMEX software and Kappa Engineering for use of Kappa-Ecrin software in this study.

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Appendix C:

Welltest analysis of hydraulically fractured tight gas reservoirs: An Example from Perth Basin, Western Australia. APPEA Journal

Lead author
Hassan Bahrami

WELLTEST ANALYSIS OF HYDRAULICALLY FRACTURED TIGHT GAS RESERVOIRS: A FIELD EXAMPLE FROM PERTH BASIN, WESTERN AUSTRALIA

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ABSTRACT

Welltest interpretation requires the diagnosis of reservoir flow regimes to determine basic reservoir characteristics. In hydraulically fractured tight gas reservoirs, the reservoir flow regimes may not clearly be revealed on diagnostic plots of transient pressure and its derivative due to extensive wellbore storage effect, fracture characteristics, heterogeneity, and complexity of reservoir. Thus, the use of conventional welltest analysis in interpreting the limited acquired data may fail to provide reliable results, causing erroneous outcomes. To overcome such issues, the second derivative of transient pressure may help eliminate a number of uncertainties associated with welltest analysis, and provide a better estimate of the reservoir dynamic parameters.

This paper describes a new approach regarding welltest interpretation for hydraulically fractured tight gas reservoirs—using the second derivative of transient pressure. Reservoir simulations are run for several cases of non-fractured and hydraulically fractured wells to generate different type curves of pressure second derivative, and for use in welltest analysis.

A field example from a Western Australian hydraulically fractured tight gas welltest analysis is shown, in which the radial flow regime could not be identified using standard pressure build-up diagnostic plots. Therefore, it was not possible to have a reliable estimate of reservoir permeability. The proposed second derivative of pressure approach was used to predict the radial flow regime trend based on the generated type curves by reservoir simulation, to estimate the reservoir permeability and skin factor. Using this analysis approach, the permeability derived from the welltest was in good agreement with the average core permeability in the well, thus confirming the methodology's reliability.

KEYWORDS

Tight gas reservoir, welltest analysis, reservoir permeability, hydraulic fractures, flow regimes.

INTRODUCTION

Pressure-transient testing has long been recognised as a tool to characterise reservoir dynamic parameters, using an analysis of pressure transient response caused by a change in production rate. Welltest analysis results are the overall response of reservoir to dynamic disturbances made to the formation at the testing time. A pressure transient test can encompass several flow regimes, each seeing deeper into the reservoir than the last. Depending on well completion type, completion configuration, and reservoir geological and geometric attributes, different flow regimes may be revealed in pressure transient data (Bourdarot, 1998).

The early portion of welltest data during pressure build-up tests is controlled by wellbore storage and skin effects. A sufficiently long enough test to overcome wellbore storage is necessary to reveal the reservoir response on the pressure transient data. In the case of tight formations, reservoir flow regimes might be distorted or even masked by an extended wellbore storage effect. Furthermore, hydraulic fractures add to the complexity of the near wellbore region, making reservoir flow regime identification and welltest analysis challenging (Restrepo, 2009).

In hydraulically fractured wells (Fig. 1), the main flow regimes observed in pressure build-up diagnostic plots are:

- a linear flow regime towards the hydraulic fracture wings in the vicinity of the fractures;
- an elliptical flow regime towards the drainage area surrounding the hydraulic fractures; and,
- a pseudo radial flow regime established at a late time when the pressure disturbance propagates deep enough into the reservoir.

Diagnosing the pseudo radial-flow regime is critical to quantitative welltest interpretation. This is because during this regime, reliable values for permeability × thickness and skin factor for the formation layers that contributed to the test can be calculated using standard methods (Badazhkov, 2008).

For tight gas reservoirs with hydraulic fractures, it would typically take a relatively long pressure build-up time to reach the radial flow regime, and this is often impractical. This study presents a welltest analysis of hydraulically fractured tight gas reservoirs where reservoir characteristics cannot be estimated using standard pressure build-up diagnostic plots. An alternative welltest analysis technique is proposed for radial flow regime prediction to determine reservoir permeability and skin factor.

DERIVATIVE OF TRANSIENT PRESSURE

The diffusivity equation solution that describes the radial flow regime in a homogeneous porous medium for a pressure build-up test is expressed in field units as follows (Kappa Engineering, 2011):

$$P_{ws} - P_{wf} = \frac{162.6\,Q\mu B}{kh}[-Log(\frac{t_p + \Delta t}{\Delta t}) + Log(t_p) + Log(\frac{k}{\varphi.\mu.C_t.r_w^{\ 2}}) - 3.23 + 0.87S] \quad (1)$$

The above equation can be simplified to the following general form:

$$\Delta P = m*[-Log(\frac{t_p + \Delta t}{t_p})] + b \quad (2)$$

Taking the derivative of Equation 2 with respect to the logarithm of the time function gives:

$$\frac{d[\Delta P]}{d[-Log(\frac{t_p + \Delta t}{\Delta t})]} = m \quad (3)$$

The above equation can be written as follows:

$$Log[-\frac{d(\Delta P)}{d(\log\frac{t_p + \Delta t}{\Delta t})}] = Log[m] + 0 * Log(\frac{t_p + \Delta t}{\Delta t}) \quad (4)$$

Equation 4 indicates that for the pressure build-up data related to the radial flow regime, a log-log plot of pressure derivative—P': d[ΔP]/d[-Log((tp+Δt)/Δt)]—versus the time function—(tp+Δt)/Δt—results in a zero-slope line that intersects the vertical axis at m, as shown in Figure 2.

Using the value of intercept m_{RF} on the radial flow diagnostic log-log plot, permeability and skin values in field units can be calculated (Kappa Engineering, 2011):

$$\text{Permeability: } K = 162.6\frac{Q\mu B}{m_{RF}h} \quad (5)$$

Skin if t_p is large enough:

$$S = 1.1513[\frac{\Delta P_{1hr}}{m_{RF}} + Log(\frac{t_p + 1}{t_p}) - Log(\frac{k}{\varphi.\mu.c_t r_w^2}) + 3.23] \quad (6)$$

The pressure derivative data can provide useful information about the reservoir characteristics and flow regimes. Based on the derivations of fluid flow and diffusivity equations, on the pressure derivative curve the slope of +1 shows the wellbore storage effect, and the slopes -0.5 (-½), +0.5 (+½), +0.25 (+¼) and +0.36 (~⅓) indicate spherical, linear, bi-linear and elliptical flow regimes, respectively (Badazhkov, 2008; Bourdarot 1998). The typical flow regimes on a pressure derivative curve for a hydraulically fractured well in tight formations have been shown in Figure 3, that is: wellbore storage effect, linear flow regime, elliptical flow regime, and late time radial flow regime.

Welltest interpretation requires a diagnosis of the reservoir flow regimes. To calculate permeability from the derivative plot, reservoir response should be significant, and the test should be long enough to have the radial flow regime established in the formation and observe a reliable zero-slope line on the pressure derivative curve data.

In pressure transient testing, there are instances where the radial flow regime may not be clearly revealed on diagnostic plots of pressure build-up and its derivative, for example—incomplete pressure build-up tests, low-permeability reservoirs and multi-phase producing wells. In hydraulically fractured tight gas reservoirs, due to the wellbore storage effect, heterogeneity and complexity of reservoir response, the use of a conventional welltest analysis may fail to provide reliable results. Consequently, the reservoir flow regimes may not clearly be revealed on diagnostic plots of transient pressure and its derivative, which may result in erroneous welltest analysis outcomes.

SECOND DERIVATIVE OF THE TRANSIENT PRESSURE

Transient analysis techniques that use higher order derivatives have recently been developed to reduce uncertainties associated with welltest analysis (Bahrami and Siavoshi, 2005). The method is based on taking the second derivative of the diffusivity equation solution, with respect to the logarithm of time function.

Taking the derivative of Equation 3 results in:

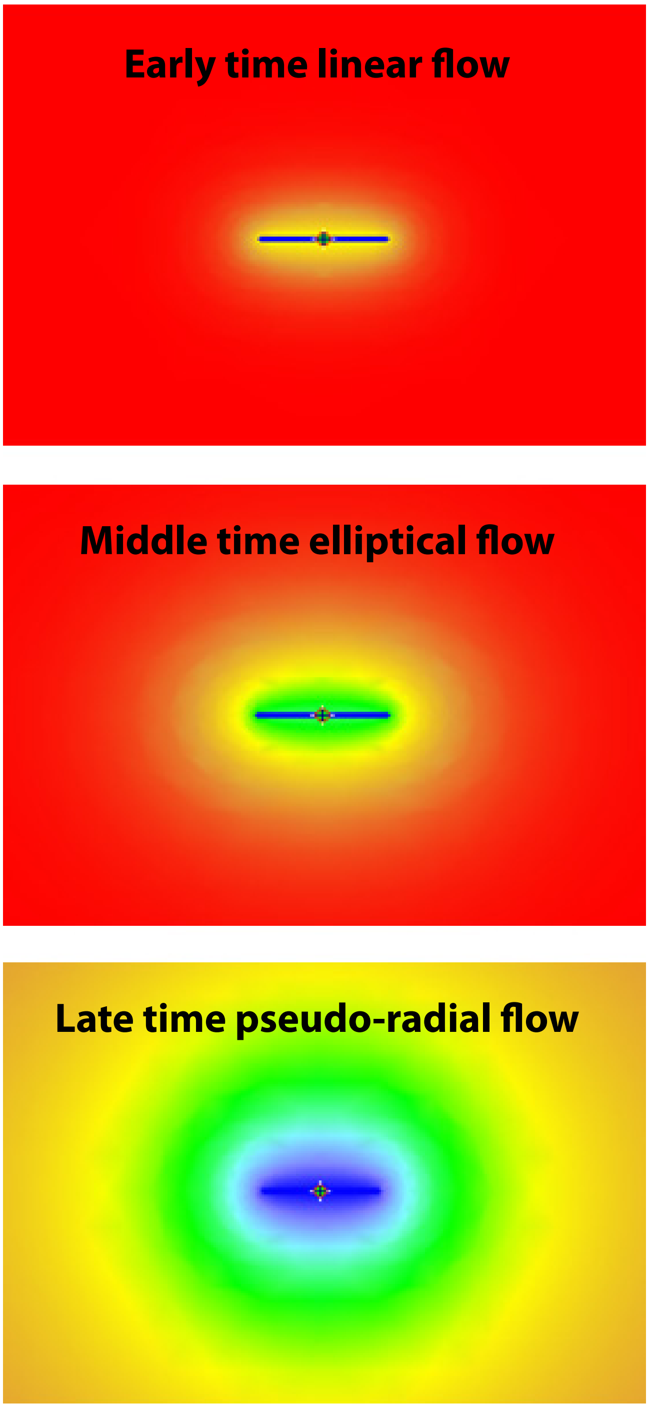

Figure 1. Typical flow regimes in tight gas reservoirs.

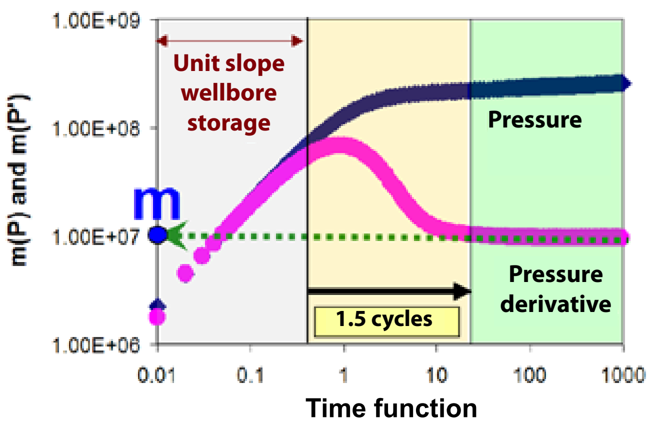

Figure 2. Conventional pressure derivative technique using the first derivative of transient pressure.

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$$\frac{d^2[\Delta P]}{d[-\mathrm{Log}(\frac{t_p+\Delta t}{\Delta t})]^2} = 0 \qquad (7)$$

The above Equation can be written as follows:

$$\frac{d^2[\Delta P]}{d[-\mathrm{Log}(\frac{t_p+\Delta t}{\Delta t})]^2} = 0 + 0 * \mathrm{Log}(\frac{t_p+\Delta t}{\Delta t}) \qquad (8)$$

Equation 8 shows that for a pressure build-up test, a plot of the second derivative of pressure—P”: $-d^2[\Delta P]/d[\mathrm{Log}(\Delta t)]^2$—versus the log of time function—$(tp+\Delta t)/\Delta t$—results in a zero-slope straight line with an intercept of zero (semi-log plot). A typical second derivative curve for a pressure transient test has been shown in Figure 4, which shows that the curve has two extremum points, t_{EP1} and t_{EP2}, and the beginning of radial flow regime around t_{RF}. The first extremum point (t_{EP1}) may roughly indicate wellbore storage end.

The second derivative can validate the existence of the radial-flow regime on the first derivative, where there is uncertainty in radial flow regime identification using the standard diagnostic plots. Compared with the first derivative, the advantage of the second derivative of pressure is that its intercept is certain (zero); thus the second derivative curve trend might be predictable.

To predict the radial flow regime, the approximate time at which the beginning of radial flow regime is expected must be known. As a rule of thumb, the beginning time of the radial flow regime (t_{RF}) is approximately 1.5 log cycles after the pure wellbore storage effect is ended (t_{EP1}). Depending on the well/reservoir parameters, however, the beginning of the radial flow regime may be more or less than 1.5 log cycles after wellbore storage end.

In the case of an insufficiently long pressure build-up test, the radial flow regime can be predicted using the second derivative trend from its second extremum point (t_{EP2}) to the beginning of the radial flow regime (t_{RF}). This is done by interpolation between data points after the second extremum point and a zero value on the x-axis, where it is roughly the start time of the radial flow regime (~1.5 log cycles after the end of the wellbore pure storage effect).

Once the second derivative curve is determined, the first derivative curve can be back-calculated from the predicted second derivative trend, which eventually provides more reliable permeability and skin values. It should be noted that since the second derivative is more sensitive to the downhole pressure changes, data smoothing should also be applied on the second derivative curve.

It is predicted that using both the first and second derivative plots simultaneously in a welltest software package with smoothing functions would improve the quality of well test interpretations. For short transient tests where the first derivative fails to detect a conclusive radial flow regime from the zero-slope line, the second derivative would help to detect or estimate the radial flow with its zero intercept.

RADIAL FLOW REGIME PREDICTION

In predicting the radial flow regime, an important parameter is the estimation of the time when the radial flow regime is started. The KAPPA welltest design software was used to perform sensitivity analysis using the single phase flow reservoir simulation approach, for several cases with different values of permeability, skin, and hydraulic fracture half-length sizes. The objective is to relate well and reservoir parameters to the time for the end of the wellbore storage effect (t_{EP1}), time duration of transition period from wellbore storage effect to radial flow

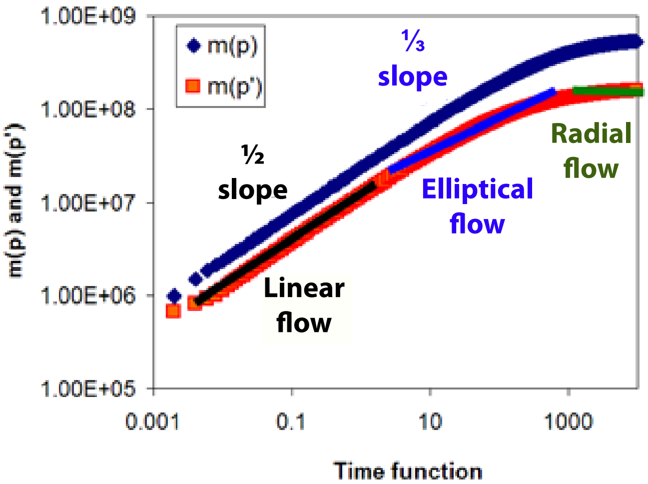

Figure 3. Typical flow regimes on a diagnostic plot of pressure build-up in hydraulically fractured tight gas reservoirs.

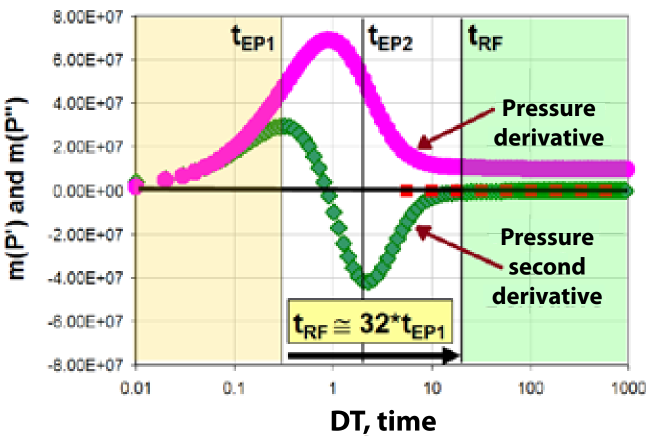

Figure 4. The first and second pressure derivative diagnostic plot.

(t_{RF}–t_{EP1}), and the beginning of radial flow regime (t_{RF}).

The results as shown in Figures 5–7 indicate the well/reservoir parameters can have a significant influence on the duration of the wellbore storage effect, and the time period between the pure wellbore storage effect and the radial flow regime. The effect of permeability, skin, and fracture half-length size on the time durations for different cases are summarised as follows:

- Effect of permeability (in a zero-skin, non-fractured well)—the lower permeability of reservoir may result in a longer duration of the wellbore storage effect (t_{EP1}); however, the permeability may not have a significant effect on the transition time duration from wellbore storage to radial flow (t_{RF}–t_{EP1}).
- Effect of skin factor (in a reservoir with a permeability of 0.1 md, in the case of a non-fractured well)—changing skin factor does not affect the time radial flow is started (t_{RF}); however, the higher skin factor makes the wellbore storage effect (t_{EP1}) longer, which results in a shorter transition time period (t_{RF}–t_{EP1}).
- Effect of hydraulic fractures (in a reservoir with a permeability of 0.1 md, in the case of zero skin)—hydraulic fracture size does not affect the time radial flow is started (t_{RF}); however, larger fractures can increase the initial gas flow rate and therefore reduce the wellbore storage effect duration (significantly shorter t_{RF}), which means a longer transition time period (t_{RF}–t_{EP1}).

The outputs of the sensitivity analysis suggest the time period can vary from 1.0–2.5 cycles depending on the different well-

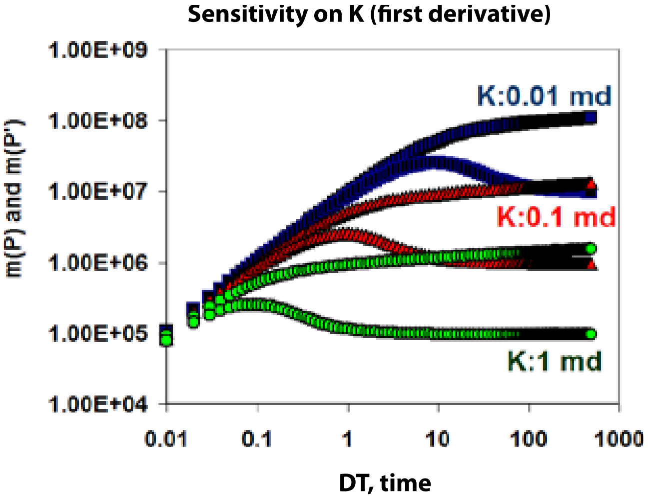

Figure 5a. Sensitivity of pressure build-up response to permeability (pressure and pressure first derivative).

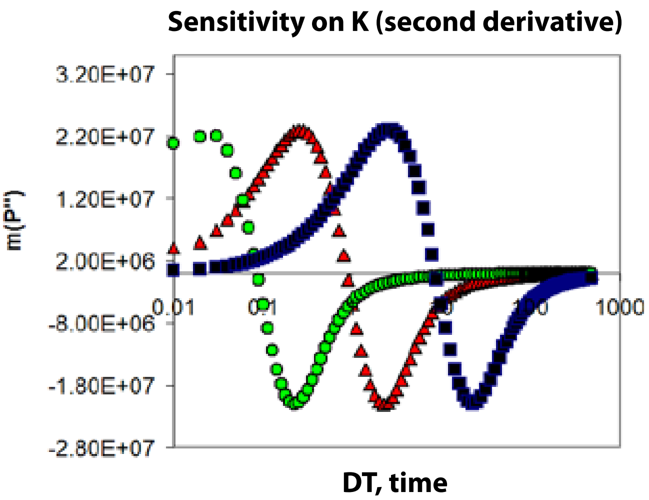

Figure 5b. Sensitivity of pressure build-up response to permeability (pressure second derivative).

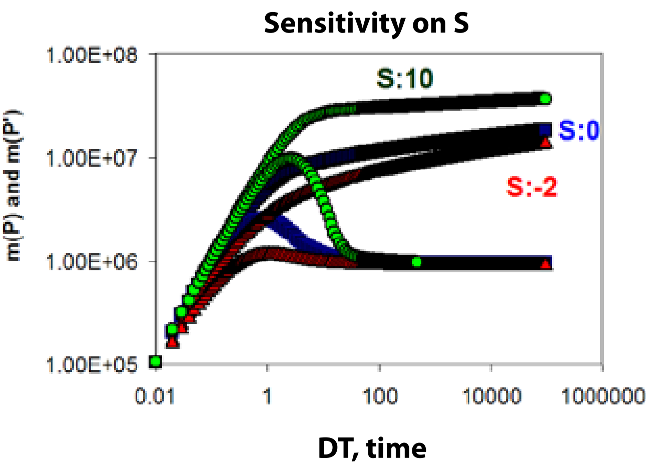

Figure 6a. Sensitivity of pressure build-up response to skin (pressure and pressure first derivative).

bore and reservoir parameters, or even more than four cycles in the cases of very large hydraulic fractures (the assumption of 1.5 log cycles duration may not always be valid). Therefore, for radial flow regime prediction based on the second derivative curve, a sensitivity analysis needs to be performed regarding the effect of well and reservoir parameters.

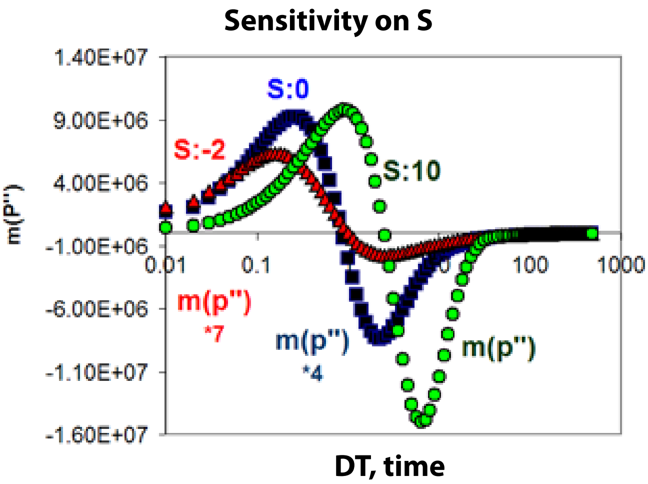

Figure 6b. Sensitivity of pressure build-up response to skin (pressure second derivative).

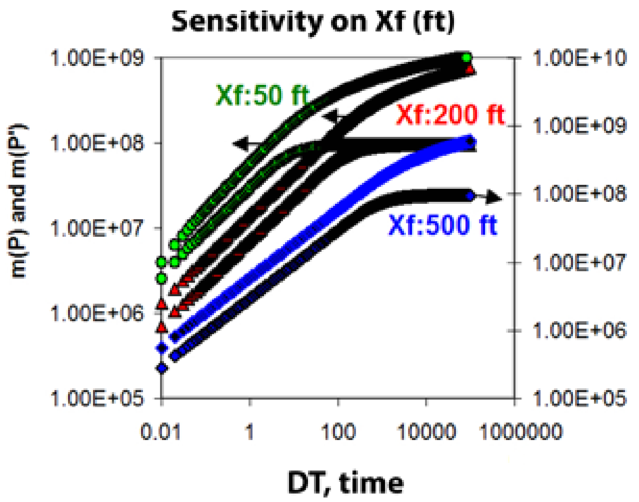

Figure 7a. Sensitivity of pressure build-up response to hydraulic fracture half-length (pressure and pressure first derivative).

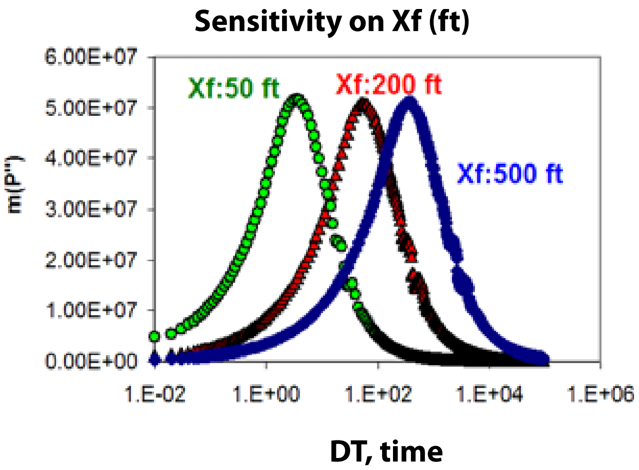

Figure 7b. Sensitivity of pressure build-up response to hydraulic fracture half length (pressure second derivative).

FIELD EXAMPLE: WELLTEST ANALYSIS IN A TIGHT GAS RESERVOIR

A pressure build-up test was performed in a hydraulically fractured well in a WA tight gas reservoir to evaluate well productivity and estimate reservoir permeability. Figure 8 shows the standard log-log diagnostic plot of pressure and pressure derivative for the pressure build-up period. The derivative curve shows a significant effect of wellbore storage on pressure data (unit slope line), followed by a linear flow regime towards the hydraulic fracture wings (+½ slope line). The diagnostic plot indicates the test duration is not long enough to reach the late time radial flow regime, and therefore permeability and skin factor cannot be reliably estimated.

To predict the radial flow regime, the first and second derivative data were first plotted on a semi-log scale, as shown in Figure 9. Based on the sensitivity analysis results on the number of log cycles, the beginning of the radial flow regime was considered to be roughly 2.5 log cycles after the end of pure wellbore storage region. Using this assumption, the beginning of the radial flow regime was estimated at the time function—(tp+dt)/dt—of 1,000.

Using available second derivative data, a curve fit was performed from the second extremum point on the second derivative curve (at a time function of 100) to the zero-value point where the beginning of the radial flow regime is expected (at time function of 1,000). The first derivative of pressure data was the determined from the fitted curve on the second derivative points, as shown in Figure 10.

The value of pressure derivative in radial flow region was estimated as 3.7E+8 psi2/cp, which corresponds to the permeability of 0.0060 mD and skin of -4.3. By considering the K and S values, the match of pressure and pressure derivative curves on the diagnostic plot (as shown in Fig. 11) resulted in a fracture half-length size of 55 ft. This indicates that the hydraulic fracture size is small and the fracturing operations were probably inefficient.

A consistency check of the results was also performed by considering the beginning of the infinite acting radial flow (t_{RF}) at the time function values of 700 and 3,000 hrs. This resulted in a permeability of 0.0058 mD and 0.0063 mD for the different cases, respectively. The results highlight a good convergence of the permeability values, considering the different time values for the beginning of the radial flow regime compared to the es-

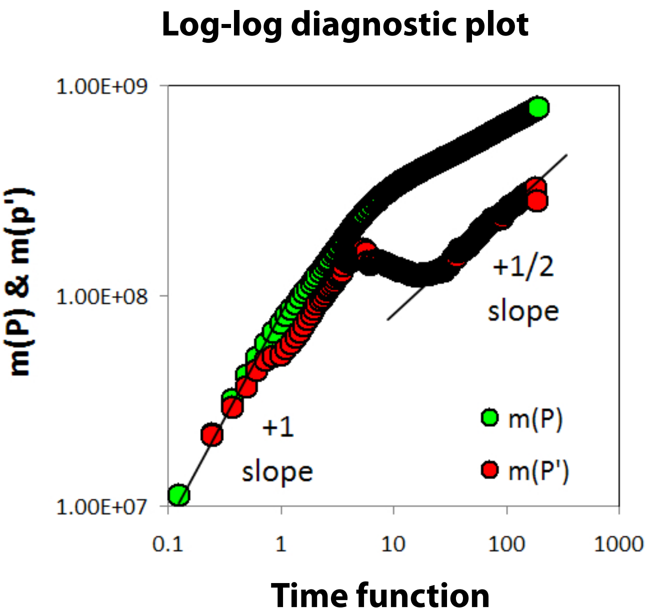

Figure 8. Conventional diagnostic plot for pressure build-up data in a WA tight gas reservoir.

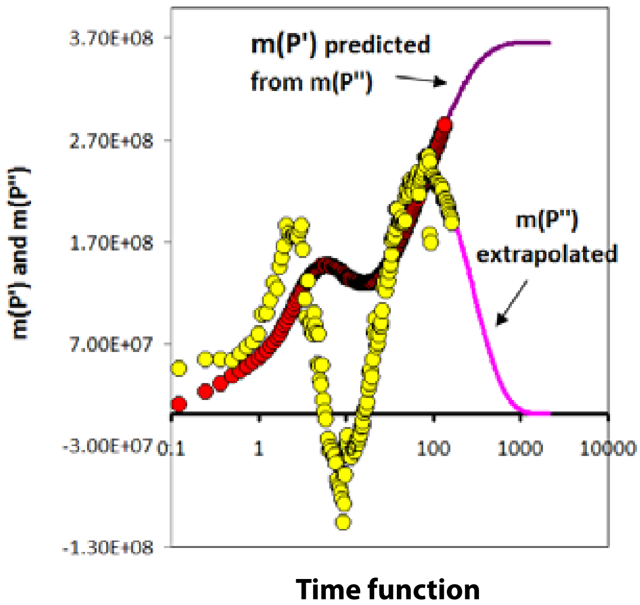

Figure 10. Radial flow regime prediction using the second derivative of pressure.

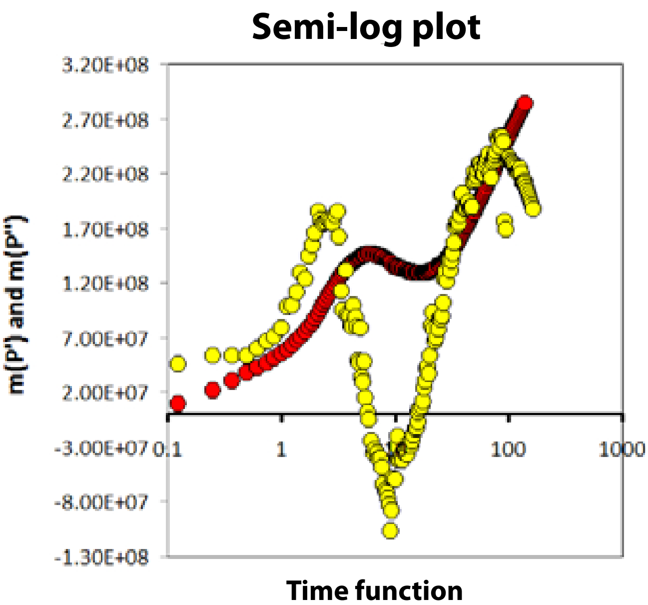

Figure 9. The first and second pressure derivative curves for the pressure build-up in the WA tight gas reservoir.

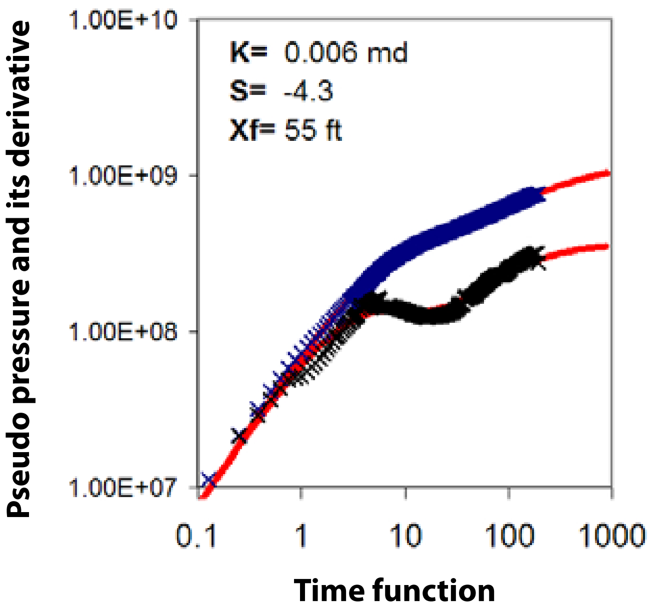

Figure 11. Welltest analysis and match of pressure build-up data for the tight gas well.

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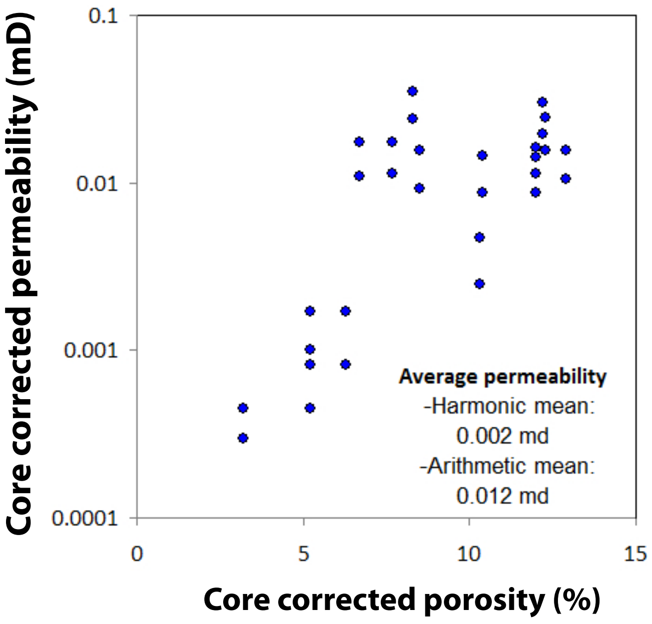

Figure 12. Core permeability versus core porosity in the tight gas well.

timated 0.0060 mD by considering the beginning of the infinite acting radial flow at a time function of 1000. According to this welltest analysis results, the low well productivity is mainly due to the extremely low reservoir permeability.

The core data in this well were also studied to check the reliability of the welltest results. Core permeability data are shown in Figure 12. The harmonic mean showed a permeability of 0.002 md, and the arithmetic mean showed a permeability of 0.011 md; the average of the arithmetic mean and harmonic mean is 0.0065 md.

The welltest permeability results (0.0060 md) were in good agreement with the average core permeability (0.0065 md) in the well, confirming the reliability of the method.

CONCLUSIONS

- The radial flow regime can be indicated by a zero-slope line with a certain intercept on the first derivative curve, and a zero-slope line with a zero intercept on the second derivative curve.
- The end of wellbore storage effect can be detected using the second derivative technique. The first extremum point on the second derivative plot can approximate the time the wellbore storage effect is ended at.
- In tight gas reservoirs, the reservoir flow regimes may not be clearly revealed on the diagnostic pressure build-up plots. The semi-log plot of the first and second derivative of transient pressure versus time function can be used to reduce the uncertainties associated with the analysis of tight formations welltest data.
- The radial flow regime can be predicted using a curve fitting on the second derivative points—from the second extremum point on second derivative to the zero-value point—at around 1.5 cycles after the wellbore storage effect.
- The extrapolated second derivative curve can be used to determine the first derivative curve; thus, the permeability and skin can be estimated.
- As a rule of thumb, the radial flow regime is assumed have started 1.5 time log cycles after the pure wellbore storage effect; however, depending on well and reservoir parameters, it can vary from 1.0–2.5 log cycles. Thus, for radial flow regime prediction based on the second derivative curve, a sensitivity analysis needs to be performed regarding the effect of skin and permeability on wellbore storage duration.
- A successful application of the second derivative approach has been demonstrated in a hydraulically fractured well in a WA tight gas reservoir.

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NOMENCLATURES

P	Pressure
Q	Flow rate
B	Formation volume factor
μ	Viscosity
t	Time
K	Permeability
S	Skin
rw	Wellbore radius
h	Thickness
C	Wellbore storage constant
c_t	Total compressibility
φ	Porosity
RF	Radial flow
WBS	Wellbore storage
P’	First derivative of pressure
P”	Second derivative of pressure
m(P)	Pseudo pressure
m(P’)	Pseudo pressure derivative
t_{EP1}	The time related to the first extremum point on the second derivative of transient pressure (roughly at the end of well-bore storage)
t_{EP2}	The time related to the second extremum point on the second derivative of transient pressure
t_{RF}	The time related to the beginning of radial flow regime
t_{RF}-t_{EP1}	The time duration from the end of the wellbore storage effect to the beginning of the radial flow regime

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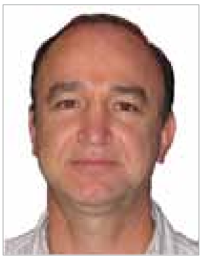

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APPEA

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Appendix D:

Evaluation of damage mechanisms and skin factor in tight gas reservoirs. APPEA Journal

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EVALUATION OF DAMAGE MECHANISMS AND SKIN FACTOR IN TIGHT GAS RESERVOIRS

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ABSTRACT

Tight gas reservoirs normally have production problems due to very low matrix permeability and significant damage during well drilling, completion, stimulation and production. Therefore, they may not flow gas at optimum rates without advanced production improvement techniques.

The main damage mechanisms and the factors that have significant influence on total skin factor in tight gas reservoirs include: mechanical damage to formation rock; plugging of natural fractures by mud solid particle invasion; relative permeability reduction around wellbore as a result of filtrate invasion; liquid leak-off into the formation during fracturing operations; water blocking; skin due to wellbore breakouts; and the damage associated with perforation. Drilling and fracturing fluids invasion mostly occurs through natural fractures and may also lead to serious permeability reduction in the rock matrix that surrounds the natural or hydraulic fractures.

This study represents an evaluation of different damage mechanisms in tight gas formations, and examines the factors that can have significant influence on total skin factor and well productivity. Reservoir simulation was carried out based on a typical West Australian tight gas reservoir to understand how well productivity is affected by each of the damage mechanisms, such as natural fracture plugging, mud filtrate invasion, water blocking and perforation. Furthermore, some damage prevention and productivity improvement techniques are proposed, which can help improve well productivity in tight gas reservoirs.

KEYWORDS

Tight gas reservoir, damage mechanisms, well productivity, skin factor, reservoir simulation.

INTRODUCTION

Tight gas reservoirs normally have production problems due to very low matrix permeability and different damage mechanisms during well drilling, completion, stimulation and production. Wellbore instability while drilling due to stress regimes is also a common issue in tight sand formations, which can result in large wellbore breakouts (Dusseault, 1993). The severe stress anisotropy in tight sand reservoirs can result in higher permeability in the conduits perpendicular to maximum stress direction (Bahrami et al, 2010). In reservoir geometry, the tight sand formations are normally stacks of isolated lenses of sand bodies, vertically separated by shale layers. The tight sand reservoir's low deliverability, geometry and lack of connectivity between the sand bodies makes it challenging to produce gas at commercial rates (Abass et al, 2007).

Stress regimes and the effective stress (the difference between total stress and pore pressure) can also affect well productivity in low permeability gas reservoirs, since the wells normally produce with a large pressure drawdown. Therefore, the effective stress is highest especially near the wellbore, causing further permeability reduction in addition to the damage and skin effect near the wellbore (Abass et al, 2007; Teufel et al, 1993).

The tight sand matrix is primarily composed of micropores where the average pore throat aperture might be less than 1 micron in diameter. In such formations, the initial water saturation ($S_{w,i}$) might be significantly less than critical water saturation (S_{wc}) due to water phase vaporisation into the gas phase (Bennion et al, 1996). The sub-normal saturation and small pore size creates tremendous amounts of potential capillary pressure energy suction, which can potentially imbibe and hold a liquid saturation in the porous media (Brant and Brent, 2005). The low initial water saturation provides relative permeability for the gas phase close to absolute permeability. Figure 1 shows capillary pressure and relative permeability curves for a typical tight gas reservoir (Holditch, 1979; Ward, 1987; Abass, 2009). Presence of liquid in such pore systems can result in the significant reduction of gas relative permeability.

Low permeability gas reservoirs can be subject to a number of different damage mechanisms during drilling, completion and production operations. The main damage mechanisms and the factors that have significant influence on total skin factor in tight gas reservoirs include: mechanical damage to formation rock; plugging of natural fractures by invasion of mud solid particles; relative permeability reduction around the wellbore as a result of filtrate invasion; liquid leak-off into the formation during fracturing operations; water blocking (liquid phase trapping); skin due to wellbore breakouts; and damage associated with perforation (Holditch, 1979; Behrmann et al, 2000). Migration of fines can also be a damaging source in the case of large pores with small throats (Civan, 2000). Drilling and fracturing fluid invasion mostly occurs through natural fractures and may also lead to serious permeability reduction in the rock matrix that surrounds the natural or hydraulic fractures.

DAMAGE DUE TO LIQUID INVASION AND WATER BLOCKING

During well drilling, completion, stimulation and fracturing in tight gas reservoirs, wellbore liquids invade the reservoir and may create a bank of fracturing agents around the wellbore, causing a significant reduction in well productivity. Mud overbalance injects the drilling fluid into the formation. In highly permeable zones, a strong mud cake is normally built up around the wellbore, which stops fluid invasion. In tight zones, however, liquid invasion is continued for a longer time due to weak mud cake surrounding the wellbore. Thus, liquid invasion into the tight rock matrix may be deeper due to low matrix porosity, that is, small pore volume and strong capillary pressure in tight zones (Schlumberger, 2005).

The injected liquids into the reservoir during drilling or fracturing can result in reduced well productivity due to water blocking in rock pores. In the case of hydraulic fracturing, leak-off of liquid into the formation is more severe and phase trapping may negatively affect the well productivity. In a field example (Josef et al, 2009), about 2,000 barrels of water was leaked off into the formation during fracturing operations, and about 700 barrels of water was produced back during 35-day clean-up period (1,300 bbl water was trapped in the invaded zone). During this period, gas flow rate reduced from 3.5 MMSCFD to 1.5 MMSCFD.

During liquid invasion, water saturation increases from S_{wi} to a higher value, and as the near wellbore zone is cleaned up by gas production the water saturation is reduced to S_{wc}. This process eventually results in permeability reduction in the invaded zone as shown in Figure 2.

Trapped liquid in the formation near the wellbore can cause additional pressure drop and positive skin in reservoir rock around the wellbore. Using a general form of skin factor definition (Tarek, 2000), the equation can be written as follows to show the relationship between invasion radius and relative permeability in the invaded zone with skin factor:

$$S_{wb} = \left(\frac{K_{r@S_{w,initial}}}{K_{r@S_{w,critical}}} - 1\right) \ln\left(\frac{r_{invaded}}{r_{wellbore}}\right)$$

Where S_{wb} is skin factor due to water blocking, $K_{r@Swc}$ is relative permeability at critical water saturation, $K_{r@swi}$ is relative permeability at initial water saturation, $r_{invaded}$ is invaded zone radius, and r_w is wellbore radius. The greater difference between initial water saturation and critical water saturation results in a more serious liquid phase trap in the matrix, causing a greater potential damage to gas permeability and gas production. Water blocking often plagues the success of low permeability gas reservoir production operation. To produce gas, there must be sufficient reservoir pressure to recover liquids from the invaded formation and wellbore.

Invasion of aqueous phase into the matrix causes swelling of clayey porous rocks. The damage mechanism is controlled by absorption of water by a water-exposed surface hindered diffusion process (Civan, 2000). When clays are exposed to low salinity solutions, it causes

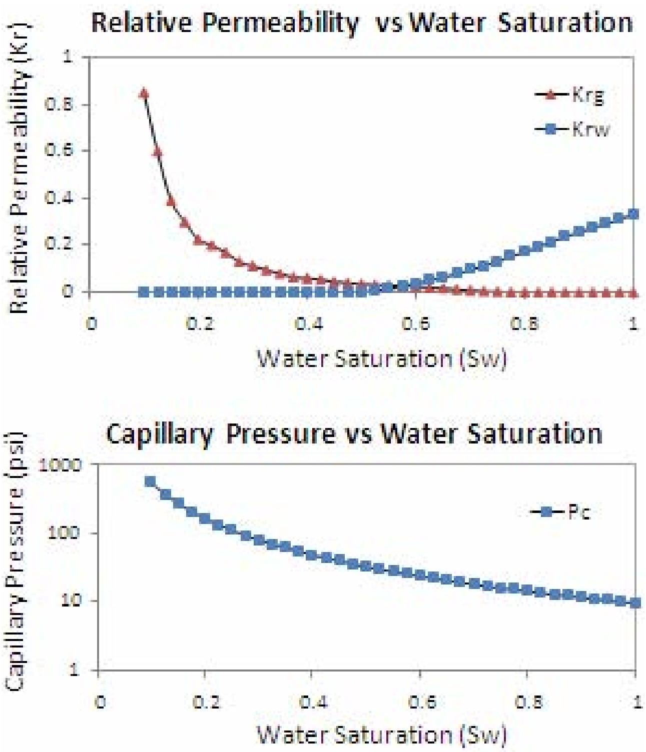

Figure 1. Typical relative permeability and capillary pressure curves for a tight sand formation.

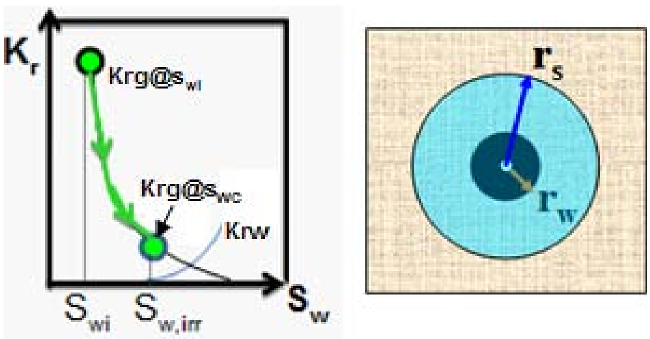

Figure 2. Reduced gas relative permeability due to water blocking.

formation damage as swelling clays imbibe water into their crystalline structure, enlarge them in size, and hence plug the pore space. Mobilisation, migration, and deposition of clays can also plug the pore throats.

Damage due to liquid invasion can be minimised by choosing the proper base fluid for fracture treatments. Wellbore heating is also a treatment that can remove aqueous phase traps around the wellbore. Electrical heaters can be used to elevate downhole temperatures high enough such that water is vaporised into the gas phase, resulting in reduced water saturation around the wellbore (Bennion et al, 1996).

MECHANICAL DAMAGE

Mechanical damage refers to solid particle invasion into natural fractures, tight formation matrix surrounding the wellbore or hydraulic fracture face during overbalanced drilling, completion, or fracturing operations. Natural fractures in tight formations are very sensitive to solid invasion damage as the natural fractures generally have small aperture. In sandstone reservoirs, since acidising is normally impractical, the damage may not be removed (Araujo et al, 2005).

Drilling fluids invasion into tight formation occurs through permeable matrix pores, which leads to solid plugging of matrix rock next to the wellbore. Formation testing tools can help for evaluation of the mechanical damage caused by plugging the near wellbore formation pores by solid particles. Two tests were performed using a cased-hole dynamics tester (CHDT) formation testing tool to drill a hole into the formation and test its dynamic characteristics by creating a pressure drawdown, followed by a pressure build-up in the tested point (Bonner and Saljooghi, 2007). In test A, the CHDT formation tester was run in a cased-hole well. Figure 3 shows bit penetration and reservoir pressure response during the formation testing. According to the data, the tool bit first drilled through casing and cement (1" penetration), then started to penetrate through the formation. When bit penetration reached 2.5" (1.5" penetration through formation), formation response and a pressure increase in the tool flow-line was detected by pressure sensors. In other words, the formation mechanical damage radius was about 1.5" at the tested point in this well (Bonner and Saljooghi, 2007).

In test B, the CHDT formation tester was run in an open-hole well. Figure 4 shows bit penetration and reservoir pressure response during the formation testing. First, conventional formation testing (no bit penetration) was performed on an open-hole wellbore wall using the tool probe. The pressure drawdown and pressure build-up tests (time period 3–10 minutes) showed very weak reservoir response to transient pressure, and the build-up of pressure did not stabilise. In the next test (time period 10–15 minutes), the tool bit penetrated 0.6" through formation, prior to formation testing. The formation testing after drilling the hole showed improvement in reservoir response to pressure drawdown and build-up in the test. The tool bit then penetrated 1.2" through the formation

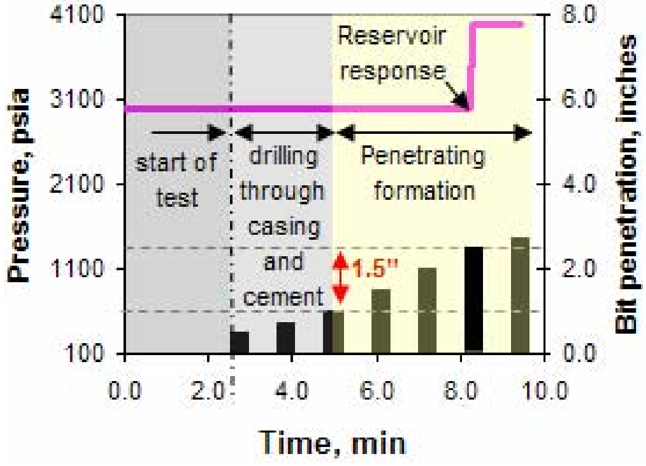

Figure 3. Field example of running cased hole dynamic tester in a cased-hole well to evaluate mechanical damage.

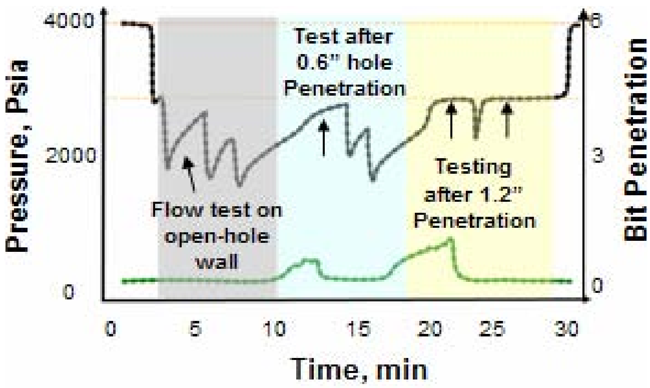

Figure 4. Field example of running cased hole dynamic tester in an open-hole well to evaluate mechanical damage.

(time period 15–25 minutes), and formation testing was repeated. The pressure response during the pressure drawdown and build-up indicated that the rock damaged radius had been passed since pressure build-up stabilised in a short period of time (Bonner and Saljooghi, 2007). In the above cases, the mechanical damage extent into formation was estimated to be around 1" in the tested points. These tests showed the importance of passing the damaged zone in open-hole wells.

In open-hole completed wells in tight sand formations, although the mechanical damage is highly localised and solids normally penetrate a very short distance into the tight reservoir rocks, optimum productivity may not be achieved if the wellbore is not connected to the undamaged formation rock.

Mechanical damage to the formation matrix can also occur during hydraulic fracturing jobs in which the fracturing fluids transport solids through the fractures and into deeper parts of the reservoir. The fracturing fluid invasion into tight formations can lead to solid plugging of the formation pores next to fracture wings and also causes water trapping and clay mineral impairments (Abass, 2009).

WELLBORE BREAKOUTS AND SKIN FACTOR

Tight sand formations have severe wellbore instability during drilling due to large horizontal and vertical stress anisotropy, which leads to large wellbore breakouts across the tight sandstone sections. The wellbore breakouts occur in the direction of minimum stress and cause enlargement of the wellbore in that direction. Drilling perpendicular to the maximum stress direction results in fewer wellbore instability issues.

Figure 5 shows caliper and gamma ray (GR) readings for tight gas well XX-01 in Western Australia. The well was drilled using an 8.5" sized bit. The caliper log indicates an increase of wellbore diameter up to 20" due to breakouts across the tight sandstone intervals. The tight zones with low shale content (low GR readings) have severe wellbore instability issues, which are expected to have high strength, whereas in the shale intervals (high GR reading), no significant wellbore enlargement is observed.

In the case of open-hole completion in tight gas wells, the wellbore breakouts can affect well productivity positively by causing an enlargement of wellbore diameter and therefore reducing total skin factor. The effect of wellbore enlargement on skin factor can be estimated by using the following equation (Ahmed, 2000):

$$S = -\ln\left(\frac{r_{breakout}}{r_w}\right)$$

Where $r_{breakout}$ is wellbore radius in the intervals with wellbore breakouts, r_w is wellbore radius in stable intervals, and S is skin factor. The above equation shows the relationship between skin factor and radius of wellbore breakouts. The larger the wellbore breakouts, the lower the total skin factor. An open-hole completion system in gas wells with large wellbore breakouts can provide significantly higher initial gas production rates compared to a cased-hole completion system.

PERFORATION AND SKIN FACTOR

In perforating tight formations, the perforating jet penetration into the reservoir rock is significantly reduced due to the high strength of the formation rock. Therefore, the formation penetration in tight formations with high rock uniaxial compressive strength (UCS) may be significantly shallow. Moreover, the wellbore breakouts may have a negative impact on perforation and clean-up efficiency due to the large cement volume behind the casing in the intervals with enlarged wellbore, which reduces accessibility to the formation via perforation tunnels (Behrmann et al, 2000; Halleck et al, 1998).

To understand the effect of wellbore breakouts on perforation results in tight formations, Schlumberger perforation modelling software (SPAN version 7.02) was run based on tight gas well XX-01 data. The model was used to predict perforation efficiency using two different gun systems:

- 2 1/8" conventional phased gun with API 19-B standard penetration of about 23"; and,
- 4 1/2" deep penetrating gun with API 19-B standard penetration of about 60".

The penetration values under reservoir conditions were modelled for the intervals where, due to wellbore instability, the wellbore diameter was 10" in the direction of maximum stress, and 20" in the direction of minimum stress. Damaged zone radius was assumed as 5" and the ratio of damaged zone permeability to virgin zone permeability (K_d/K) was assumed to be 0.2. The model input data are reported in Table 1.

The perforation model results are displayed in Figure 6, and indicate that the perforating jet penetration into the formation rock is significantly reduced in the direction that wellbore breakouts occur.

Table 2 shows estimated skin and productivity values for each of the perforation scenarios. Using the 4 1/2" gun, the model predicted jet penetration of 13.3" into the formation (skin value of –0.6) in the direction of maximum stress, and 11.5" penetration (skin value of +0.1) for perforation tunnels in the direction of minimum stress where wellbore breakouts occur. Using a 2 1/8" gun, the model predicted jet penetration of 6.0" into formation (skin value of +2.3) in the direction of maximum stress, and 4.2" penetration (skin value of +11.5) for perforation tunnels in the direction of minimum stress where the wellbore had breakouts.

The wellbore breakouts have a negative effect on the perforation efficiency and consequently may cause the well

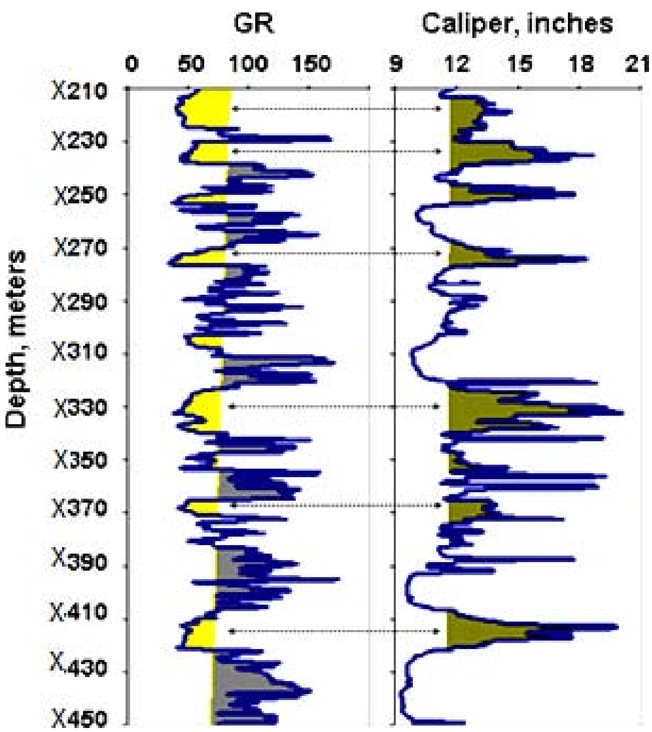

Figure 5. Wellbore breakouts in a tight gas reservoir (GR and calliper logs).

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Table 1. Input parameters in perforation model.

Reservoir	Well	Perforation top depth, ft	Perforation thickness, ft	Wellbore fluid	Lithology	Porosity %	Permeability md
Tight gas	Vertical	11,000	160	Water	Sandstone	10	0.1
Kd/K	**Damage radius, in**	**Fluid**	**Gas gravity**	**UCS, psia**	**Overburden stress**	**Reservoir pressure, psia**	**Reservoir temp, F**
0.2	5	Gas	1	21,000	11,500	5,100	220

Table 2. Model predictions for perforation jet penetration and skin

Casing	Gun type	API RP19-B penetration, inches	Perforation tunnel	Average actual formation penetration, inches	Perforation skin
7" 29 lb/ ft L80	4.5" gun	60	A	13.3	-0.6
			B	11.5	0.1
	2 1/8" gun	23	C	6.0	2.3
			D	4.2	11.5

productivity to be reduced, especially with the use of short perforating guns with shallow penetration. Therefore, as a perforation strategy in tight gas wells, using 180-degree phased deep penetrating guns (oriented perforation) that can shoot perforating jets in the maximum stress direction can provide optimum productivity and minimum perforation skin.

To achieve higher well productivity, open-hole completion in tight gas wells may be more effective than cased-hole completion, because enlarged wellbore diameter due to wellbore breakouts can further reduce skin factor and significantly increase initial gas production rate (Bahrami et al, 2010). Open-hole perforation using deep penetrating charges run with shock absorbers may help in passing the damaged zone and effectively connect the wellbore to the virgin formation.

CORE SCALE SIMULATION FOR DAMAGE EVALUATION

The modelling studies and simulation runs were based on data acquired in a West Australian tight gas reservoir. The typical tight sand capillary pressure and relative permeability curves shown in Figure 1 (initial water saturation of 0.2 and critical water saturation of 0.5) were used as input into the simulation model. Reservoir simulation runs were carried out to understand how well productivity is affected by each of the damage mechanisms.

Flow efficiency (FE) for a core was defined as the ratio of the pressure drop between core inlet and core outlet for a zero skin virgin homogeneous core, to the pressure drop from core inlet to core outlet for a perforated and/or damaged core (FE of original clean core equal to 1). To understand the effect of different damage mechanisms on core flow efficiency, numerical simulation was performed using commercial reservoir simulation software to model flow through the core and evaluate damage and productivity for different scenarios. The model details are outlined in Table 3 and Figure 7. The model consists of 13*13 grids in x and y directions (horizontal), and 59 grids in z direction (vertical). The top two (layer numbers 58 and 59) and bottom two layers (1 and 2) in z direction were considered as core holder caps with high permeability of 10,000 md, and the matrix grids in layer numbers 3–57 as core matrix with permeability of 0.1 md in the original model. A single well in layer 1 and another well in layer 59 were defined for injection and production purposes in the core.

Effect of mechanical damage on core flow efficiency

The simulation model was first run by considering the first 12 layers of core in z direction as a damaged zone (damaged permeability for girds in layer numbers 3–14). The model was run for core virgin matrix permeability of 0.1 md, then the test was repeated for a core with a matrix permeability of 1 md. In the model, damaged zone radius was assumed as 1.2", and K_d/K values of 0.9, 0.75, 0.5 and 0.1 were used for sensitivity analysis. The simulation model was also run for different damaged zone radii (r_d) of 0", 0.6", 1.2" and 1.8". The results are shown in Figure 8, which indicates the effect of damaged zone permeability and damaged zone radius on flow efficiency in tight and conventional cores. According to the results, flow efficiency in tight cores is more sensitive to damaged zone permeability and damaged zone radius, compared with conventional cores. This indicates the importance of damage mitigation in tight gas reservoirs.

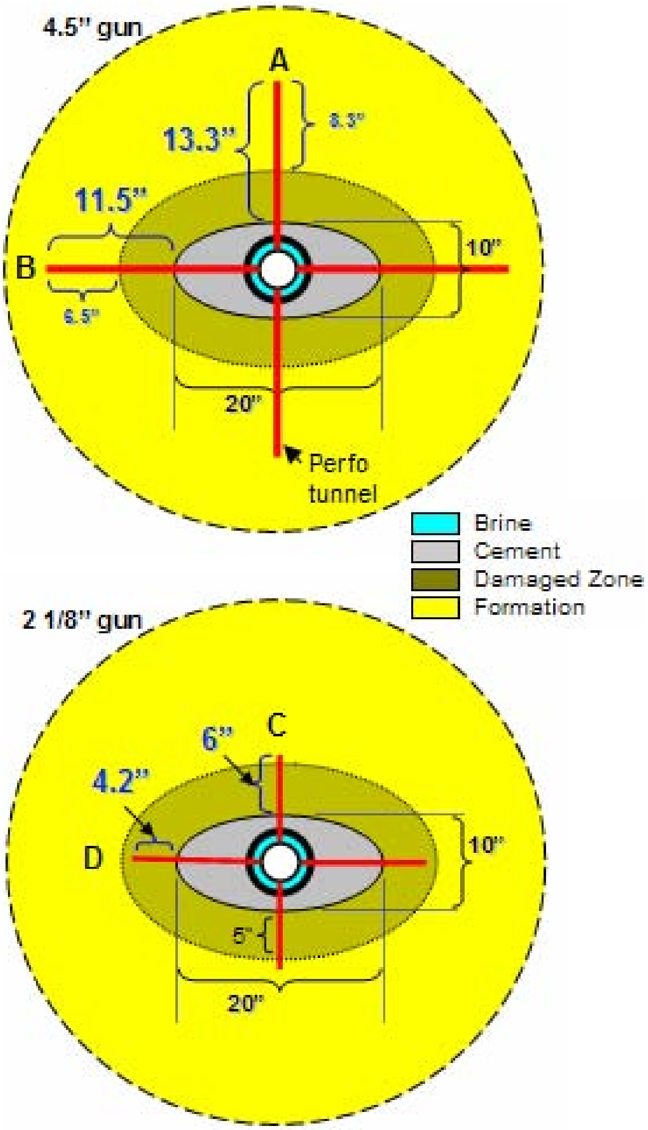

Figure 6. Perforation jet penetration prediction for wells with wellbore breakout.

Effect of perforation on core flow efficiency

The simulation model was built for non-perforated and perforated cores, with virgin zone matrix permeability of 0.1 md for the tight sand core and 1 md for the conventional core. A sensitivity analysis was performed by simulating single phase gas flow through perforation tunnels, with different perforation tunnel lengths of 0.5", 1", 1.5" and 2".

The model details for the undamaged core model are given in Figure 9 and the simulation results are shown in Figure 10. The outcomes indicate the effect of perforation tunnel length on flow efficiency in tight and conventional undamaged cores. As expected, perforation resulted in an increase of core flow efficiency. The improved productivity due to perforation is more noticeable in tight cores compared with conventional cores. This is because the

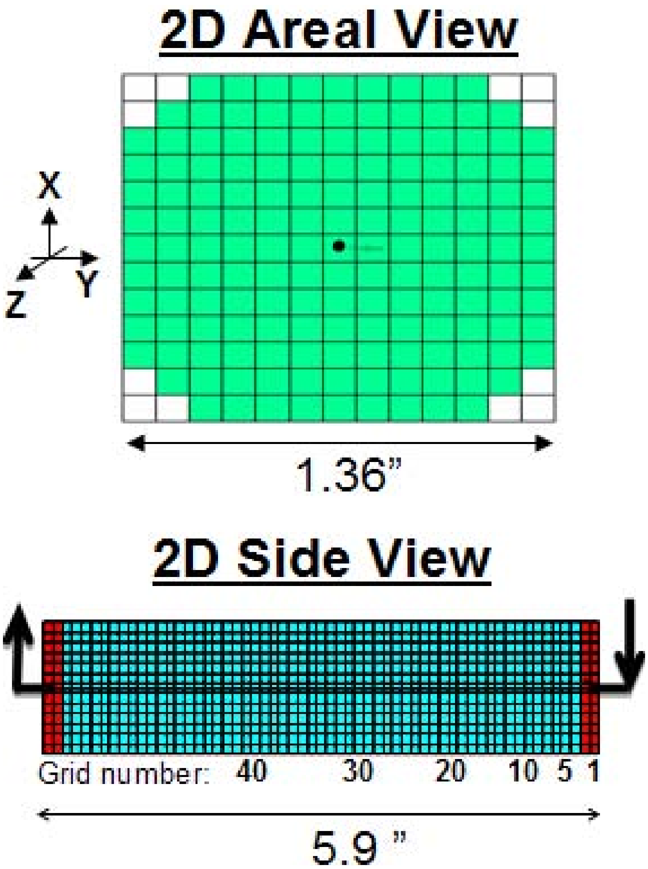

Figure 7. Core flood simulation model details.

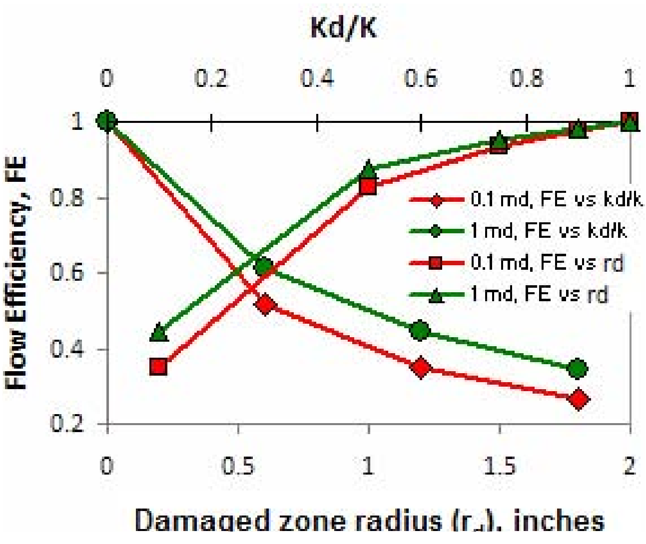

Figure 8. Effect of damaged zone permeability and radius on flow efficiency.

tight sands have deliverability problems and require production enhancement to flow gas, whereas conventional gas reservoirs in normal cases can naturally flow gas with commercial rates without a need for stimulation.

For the damaged core scenario, the model K_d/K was

Table 3. Details of core scale simulation model.

No. of grids in x, y and z directions	Model length, inches	Model diameter, inches	Grids permeability in core caps, md	Permeability of tight core, md	Permeability of conventional core, md
13*13*59	5.9	1.36	10,000	0.1	1
Initial pressure, psia	**Porosity %**	**Initial water saturation**	**Critical water saturation**	**Damaged zone permeability in tight core, md**	**Damaged zone permeability in conventional core, md**
6,200	10	0.2	0.5	0.01	0.1

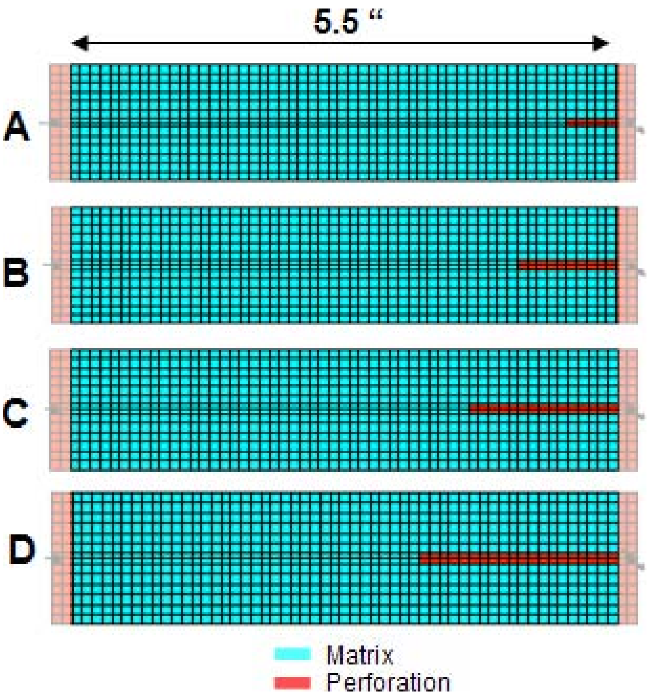

Figure 9. Model details related to the effect of perforation tunnels length on flow efficiency.

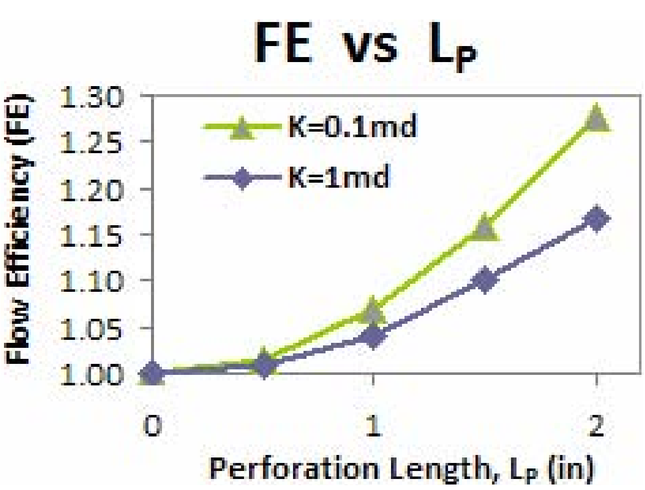

Figure 10. Simulation results related to the effect of perforation tunnels length on flow efficiency.

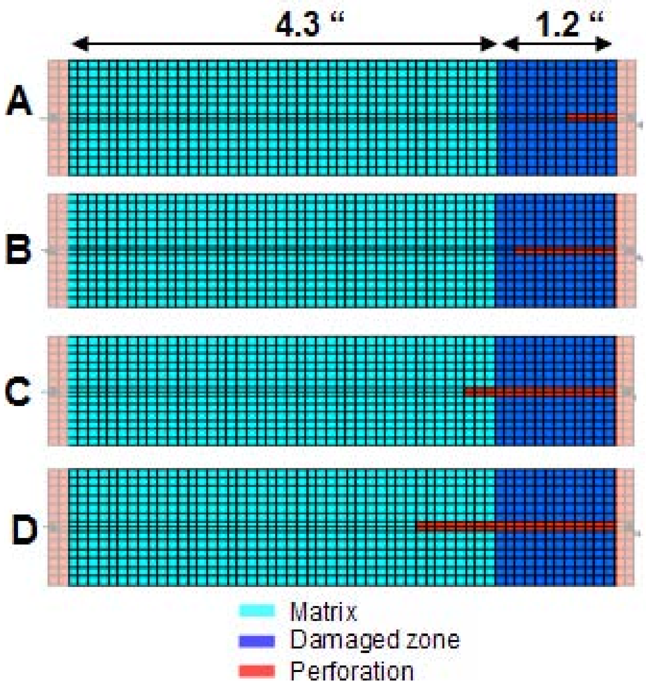

Figure 11. Model details related to the effect of perforation tunnels length on flow efficiency of a damaged core.

considered as 0.1 and damaged zone radius as 1.2" for both tight and conventional cores. The model details are shown in Figure 11, and simulation results are shown in Figure 12, which indicate the effect of perforation penetration length on flow efficiency. According to these results, if the perforation jet penetration is not deep enough to go beyond the damaged zone to connect the wellbore to the virgin rock matrix, flow efficiency is significantly reduced. The flow efficiency is more sensitive to perforation parameters for tight core samples, which highlights the importance of passing the damaged zone radius in tight gas reservoirs. Therefore, even for open-hole wells in tight formations where mechanical damage may be highly localised near the wellbore, improved productivity can be achieved by creating deep clean perforation tunnels.

Effect of water blocking on core flow efficiency

In order to model water blocking in tight formations, first water invasion into the rock matrix was modelled, as

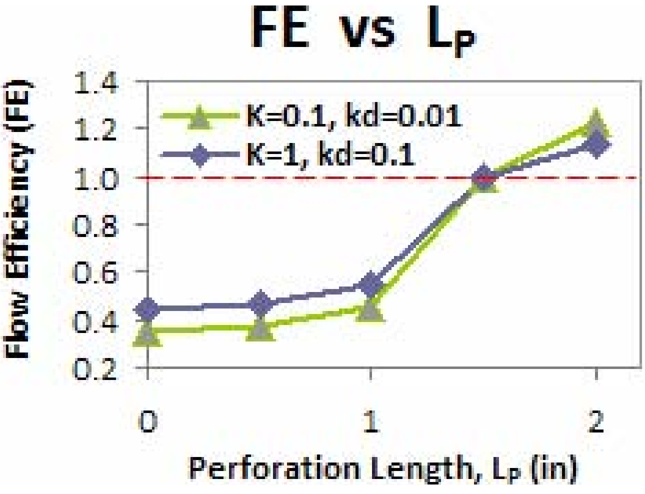

Figure 12. Simulation results related to the effect of perforation tunnels length on flow efficiency of a damaged core.

shown in Figure 13. After that, water (W) was injected at the injection well, while gas (G) was simultaneously produced at the production well. Once the time step reached 364, water injection and gas production were stopped. The water injection well was then changed to a gas producer (the well produced both gas and water during clean-up), and the gas production well was changed to a gas injector to model the flow of gas from reservoir towards wellbore during the clean-up phase.

The results shown in Figure 13 depict that during the simulation runs, water saturation changed from initial water saturation (0.2) to its maximum value in the water invaded cells. Then, during the clean-up, the water saturation in the invaded zone was reduced to 0.5 (critical water saturation) and did not drop further even with very long gas production time. This is due to capillary and relative permeability effects. The simulation results showed that the water phase was trapped in grid layers 2–6 in the z direction.

The simulation run was repeated for a longer period of water injection time (until time step 453) as shown in Figure 14, to understand the effect of cumulative water injected volume and water invasion radius on flow efficiency. The simulation results are displayed in Figure 15, which shows a considerable reduction of flow efficiency for higher water injection volume and deeper water invasion radius.

Water invasion during overbalanced, balanced and underbalanced drilling

To evaluate water invasion during drilling, layers 1 and 2 were considered as wellbore grids with 100% water saturation, and layers 3–57 as reservoir matrix grids. Different pressure values were assigned to the wellbore grids compared with the reservoir grids to model overbalanced, balanced and underbalanced drilling conditions.

The liquid invasion was modelled for the following cases, assuming the wellbore was exposed to wellbore fluid for

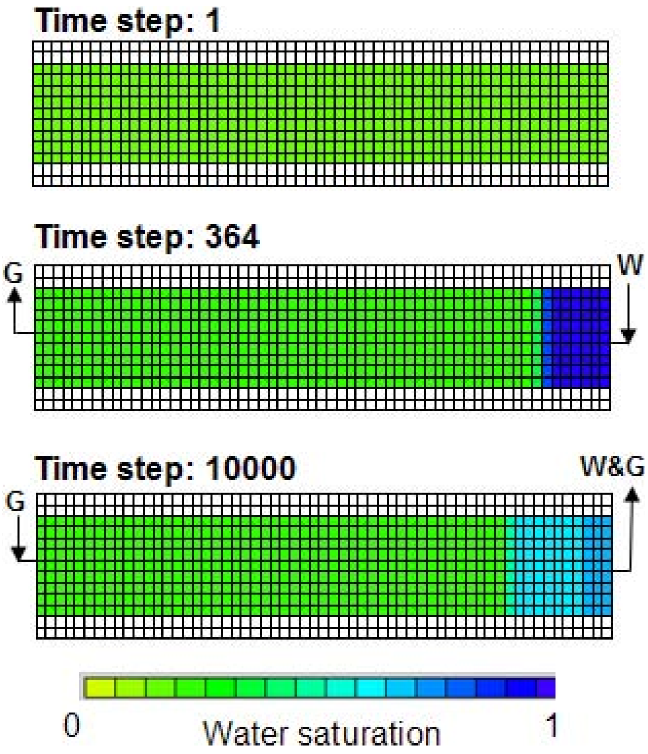

Figure 13. Numerical simulation of water blocking effect on flow efficiency (364 time steps of water injection duration).

about four days. As shown in Figure 17, the simulation results are as follows:

- 500 psia overbalanced pressure (wellbore pressure of 6,700 psia), resulted in 0.5” liquid invasion into matrix;
- balanced pressure conditions (wellbore pressure of 0 psia) resulted in 0.4” liquid invasion into matrix;
- 400 psia underbalanced (wellbore pressure of 5,800 psia) resulted in 0.3” liquid invasion into matrix; and,
- 1,000 psia underbalanced (wellbore pressure of 5,200 psia) resulted in 0.3” liquid invasion into matrix.

The simulation runs showed deeper liquid invasion for overbalanced conditions. For underbalanced conditions, however, although the pressure within the wellbore was less than reservoir pressure, water still invaded through matrix rock due to strong capillary suction, which caused an increase in water saturation and liquid phase trapping around the wellbore. According to the results, water invaded the matrix even in highly underbalanced conditions in the wellbore. Considering the fact that during drilling in tight formations a weak mud cake is built and matrix rock is exposed to wellbore fluid for a long time, the capillary suction even in underbalanced conditions can cause water blocking of the rock matrix around the wellbore.

RESERVOIR SIMULATION FOR DAMAGE EVALUATION

To understand the effect of different damage mechanisms on gas recovery from tight gas reservoirs, a reservoir

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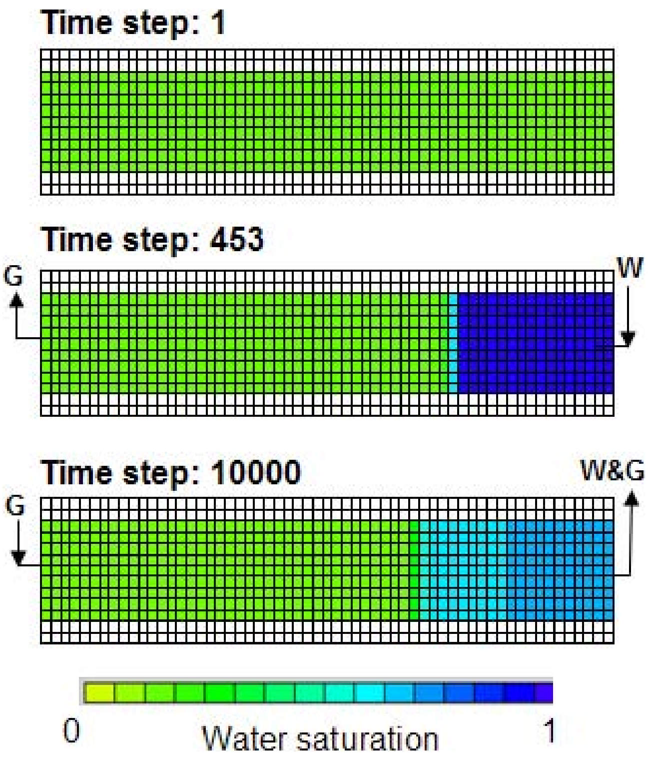

Figure 14. Numerical simulation water blocking effect on flow efficiency (453 time steps of water injection duration).

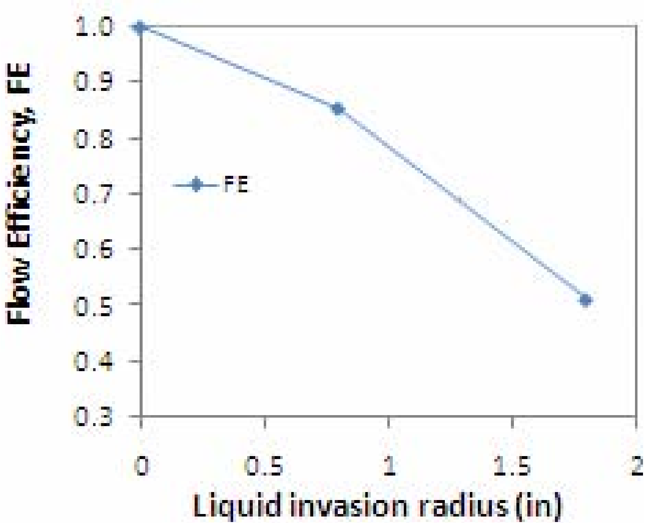

Figure 15. Simulation results related to the effect of water blocking on flow efficiency.

simulation model was built, detailed in Table 4. Different scenarios were defined and the simulation models were run to assess the damage-related factors that have significant influence on well productivity. Each simulation run consisted of three pressure drawdown and pressure build-up periods, each longer than the previous one. The data generated from the longest production and pressure build-up periods were used for skin and productivity evaluation.

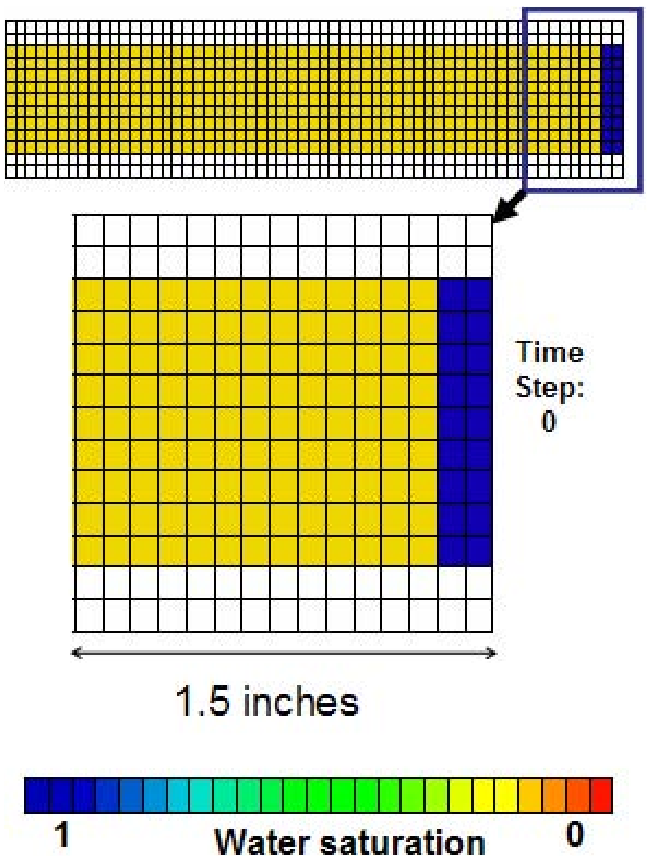

Figure 16. Model details related to the effect of wellbore UB pressure during drilling on flow efficiency.

Effect of natural fractures mechanical damage on gas recovery

To understand how natural fracture productivity in a tight gas formation is affected by the mechanical damage caused by mud solid particle invasion, five fracture planes with 1 mm aperture were defined in the model. The fracture planes intersect the gas producing well at the center of the model, as shown in Figure 18.

Gas production rates were predicted for scenarios in which: the well intersects no natural fracture; the well intersects natural fractures (fracture permeability of 28,000 md); and natural fractures have been plugged at the well location (grid permeability at the well location 0.1 md). The simulation results shown in Figure 18 indicate a significant reduction in cumulative gas production in the case that the natural fractures are damaged. The examples have shown very large skin factors in wells where natural fractures are damaged (Araujo et al, 2005), confirming the reliability of the simulation results.

Effect of water blocking on skin factor and gas recovery

For this simulation study, four different cases were simulated to model phase trapping after water leak-off

Table 4. Details of reservoir scale simulation model.

No. of grids in x, y and z directions	Reservoir size in x and y directions, ft	Reservoir height, ft	Reservoir permeability, md	Fracture permeability, md
50*50*71	2,500	177.5	0.1	28,000
Initial pressure, psia	**Matrix porosity %**	**Initial water saturation**	**Critical water saturation**	**Reservoir temperature, F**
6,200	8	0.2	0.5	220

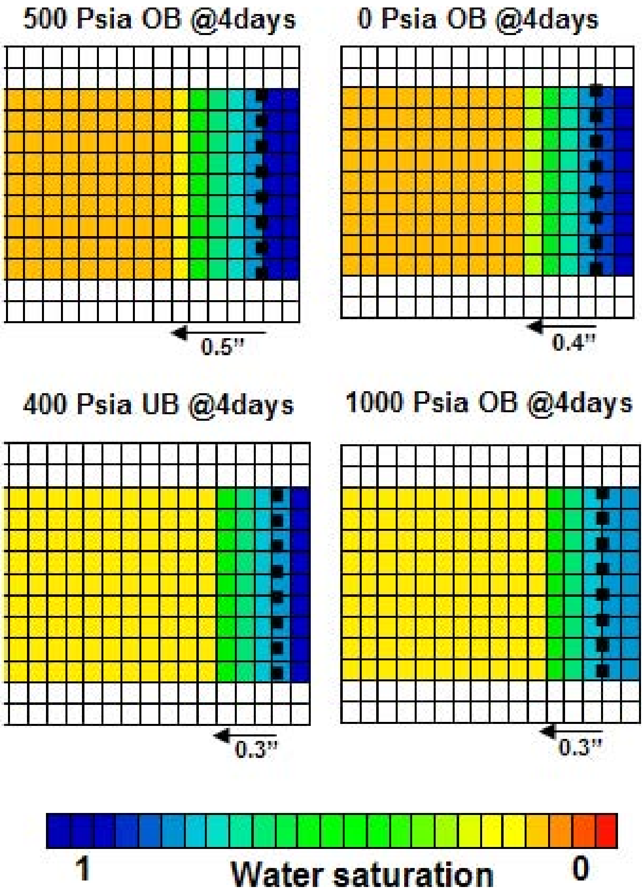

Figure 17. Simulation results related to the effect of wellbore underbalanced (UB) pressure during drilling on flow efficiency.

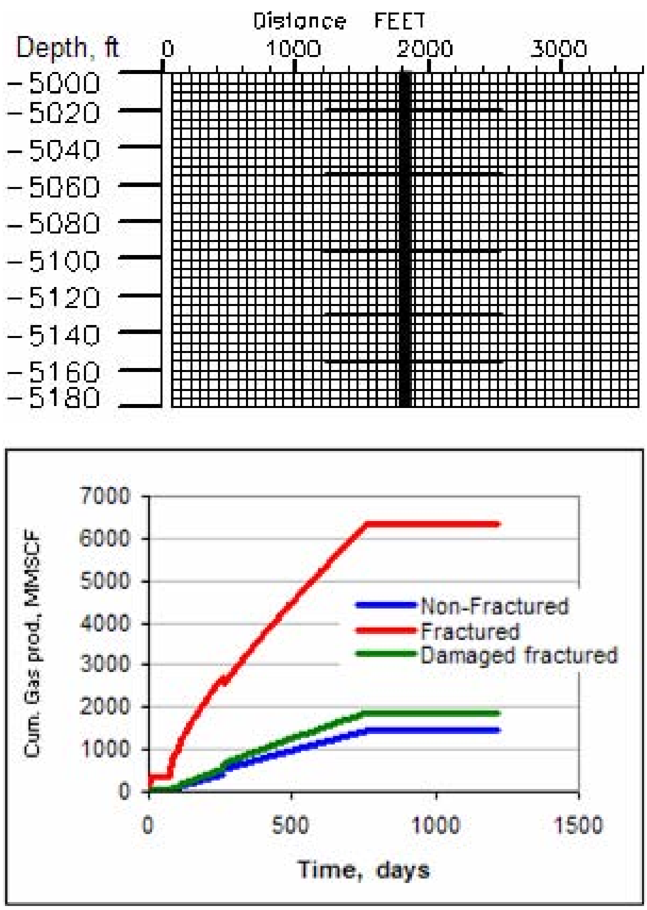

Figure 18. Simulation results related to the effect of mechanical damage to natural fractures on gas recovery.

into the formation. The water leak-off was followed by gas production during clean-up. In case A, no leak-off occurred. In case B, C and D about 215,770 and 1,400 barrels of water leaked off into the formation, respectively. In each of the models after the liquid leak-off, the well was put on a production followed by pressure build-up test. The pressure transient data was generated to analyse skin caused by phase trapping.

The cumulative injected volume of water during leak-off (W_i) and the simulated results for cumulative produced water (W_p) during clean-up and gas production are reported in Figure 19. Due to water leak-off, the phase trap caused a significant reduction in the gas production rate and gas recovery from the tight gas reservoir.

To quantitatively understand how phase traps can influence skin factor, the generated pressure build-up data was analysed to estimate skin value for the tight gas reservoir, as shown in Figure 20. The water blocking increased skin factor. In the case of no leak-off of liquid into the formation, the water blocking skin is zero, and in the case of 1,400 bbl of water leak-off into the formation, water blocking damage resulted in skin value of +9.7 in this well.

CONCLUSION

According to the simulation and modelling results performed in the study for gas wells in tight sand reservoirs, the following conclusions can be drawn:

- Tight gas reservoirs have severe in situ stress anisot-

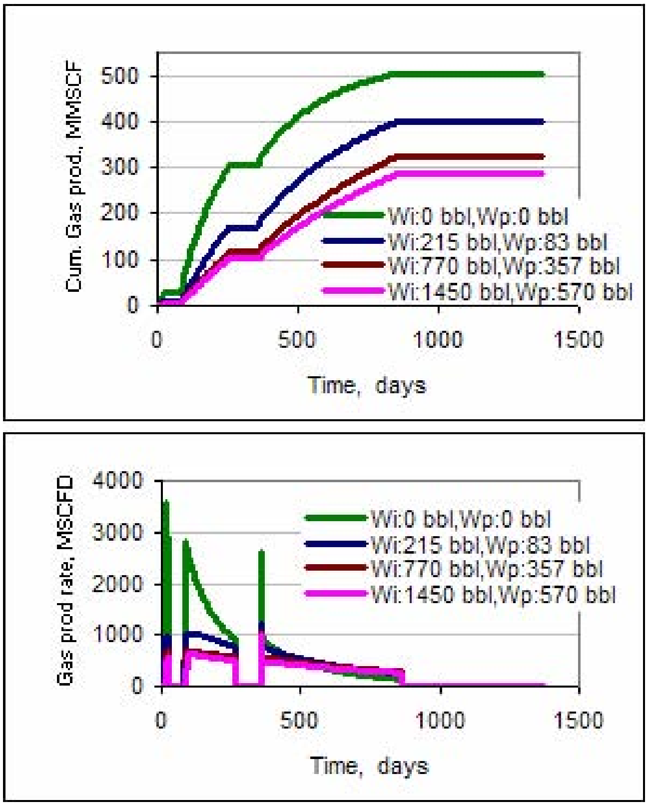

Figure 19. Simulation results related to the effect of water blocking on gas recovery.

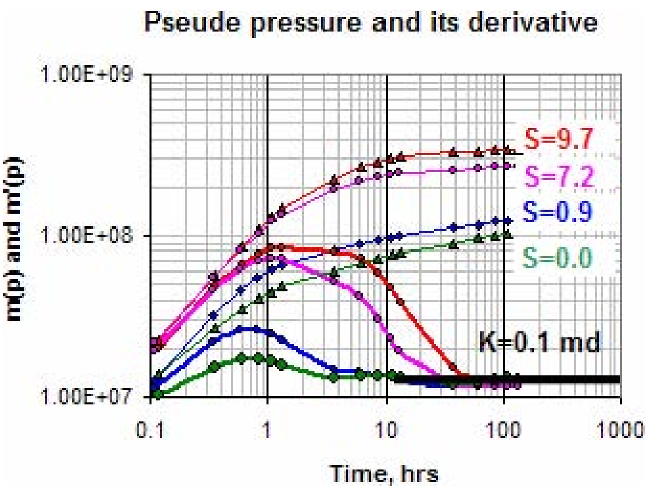

Figure 20. Pressure build-up analysis for skin values created by different volumes of water leak-off into formation.

ropy that results in large wellbore breakouts across the wellbore during drilling.

- In cased-hole completion in tight formations, perforation jet penetration into the formation may be significantly shallow due to the high strength of the rock matrix. In addition, severe wellbore instability and the large cement volume behind the casing in the intervals with enlarged wellbore may greatly reduce the efficiency of perforation in tight sand reservoirs. Therefore, the wellbore breakouts have a negative impact on productivity of cased-hole perforated wells.
- In open-hole completion systems in tight gas wells, since the large wellbore breakouts can affect well productivity positively by enlarging the wellbore and reducing total skin factor, it may be more efficient than a cased-hole perforated system. To avoid wellbore collapse, slotted liner can be run across the open-hole section.
- Water blocking (liquid phase trap) is one of the major damage mechanisms in tight sand reservoirs due to relative permeability and capillary pressure effects. Liquid invasion during drilling or fracturing can result in trapping of the water phase inside the formation and clay swelling around the wellbore. Therefore, it causes positive skin factor and a noticeable reduction of effective permeability within the invaded radius.
- Due to the strong capillary suction effect in tight formations and the presence of weak mud cake across the wellbore in tight formations, even in underbalanced drilling water can invade the nearby wellbore formation. Use of non-aqueous liquids for drilling and stimulation can help mitigate formation damage.
- Minimised damage to tight formations may be achieved by: using drilling long deviated wells perpendicular to the maximum horizontal stress; underbalanced drilling using non-aqueous drilling fluids; open-hole completion systems; and open-hole perforation using oriented deep penetrating charges.

NOMENCLATURE

P	Pressure
Q	Flow rate
ID	Internal diameter
t	Time
K	Permeability
S	Skin
L	Length
W_i	Cumulative injected water
W_p	Cumulative produced water
r_d	damage radius
k_d	damaged zone permeability
r_i	invaded radius
P_c	Capillary pressure
K_r	Relative permeability
S_{wi}	Initial water saturation
S_{wc}	Critical water saturation (the maximum water saturation at which the water phase will remain immobile)
FE	Flow efficiency
S_{wb}	Damage due to water block and phase trap
GR	Gamma ray
L_p	Perforation tunnel length
UB	Underbalanced
OB	Overbalanced
$MMSCFD$	Million standard cubic feet per day

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APPEA

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Appendix E:

Using relative permeability curves to evaluate phase trapping damage caused by water-based and oil-based drilling fluids in tight gas reservoirs. APPEA Journal

Lead author **Geeno Murickan**

USING RELATIVE PERMEABILITY CURVES TO EVALUATE PHASE TRAPPING DAMAGE CAUSED BY WATER-BASED AND OIL-BASED DRILLING FLUIDS IN TIGHT-GAS RESERVOIRS

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ABSTRACT

Low matrix permeability and significant damage mechanisms are the main signatures of tight-gas reservoirs. During the drilling and fracturing of tight formations, the wellbore liquid invades the tight formation, increases liquid saturation around the wellbore, and eventually reduces permeability at the near wellbore zone. The liquid invasion damage is mainly controlled by capillary pressure and relative permeability curves.

Due to high critical water saturation, relative permeability effects and strong capillary pressure, tight formations are sensitive to water invasion damage, making water blocking and phase trapping damage two of the main concerns with using a water-based drilling fluid in tight-gas reservoirs. Therefore, the use of an oil-based mud may be preferred in the drilling or fracturing of a tight formation. Invasion of an oil filtrate into tight formations, however, may result in the introduction of an immiscible liquid-hydrocarbon drilling or completion fluid around the wellbore, causing the entrapment of an additional third phase in the porous media that would exacerbate formation damage effects.

This study focuses on phase trapping damage caused by liquid invasion using a water-based drilling fluid in comparison with the use of an oil-based drilling fluid in water-sensitive, tight-gas sand reservoirs. Reservoir simulation approach is used to study the effect of relative permeability curves on phase trap damage, and the results of laboratory experiments of core flooding tests in a West Australian tight-gas reservoir are shown, where the effect of water injection and oil injection on the damage of core permeability are studied. The results highlight the benefits of using oil-based fluids in drilling and fracturing of tight-gas reservoirs in terms of reducing skin factor and improving well productivity.

KEYWORDS

Tight-gas reservoirs, relative permeability, phase trap damage, oil-based drilling fluids, water-based drilling fluids.

INTRODUCTION

Tight-gas reservoirs normally have production problems due to very low matrix permeability and different damage mechanisms during well drilling, completion, stimulation and production (Dusseault, 1993). The low-permeability gas reservoirs can be subject to different damage mechanisms such as mechanical damage to formation rock, plugging of natural fractures by invasion of solid mud particles, permeability reduction around the wellbore as a result of filtrate invasion, clay swelling, and liquid phase trapping (Holditch, 1979).

In general, for tight-gas sand reservoirs, the average pore throat radius might be very small and, therefore, it may create tremendous amounts of potential capillary-pressure energy suction. As a result, it causes liquid to be imbibed and held in the capillary pores (Bennion and Brent, 2005), and causes significantly high critical water saturation (Bennion et al, 2006). Tight-gas reservoirs might be different in the case of initial water saturation (S_{wi}) compared with critical water saturation (S_{wc}), depending on the geological time of gas migration to the reservoir. Initial water saturation might be normal, or in some cases sub-normal (S_{wi} less than S_{wc}) due to water phase vaporisation into the gas phase (Bennion and Thomas, 1996). The initial water saturation might also be more than S_{wc} if the hydrocarbon trap is created during or after the gas migration time. A sub-normal initial water saturation in tight-gas reservoirs can provide a higher relative permeability for the gas phase (effective permeability close to absolute permeability), and therefore, relatively higher well productivity (Bennion and Brent, 2005).

Liquid invasion into tight formations can increase water saturation around the wellbore and then, as the near wellbore zone is cleaned up by gas production, water saturation is reduced gradually but no more than the critical water saturation (Amabaoku et al, 2006). This process eventually results in the reduction of near wellbore permeability. The damaging of permeability is referred to as phase trapping damage. Phase trapping was found to be related to capillary pressure and relative permeability, which both are direct functions of pore system geometry, interfacial tension between the invading trapped fluid, and the produced (or injected) reservoir fluid, wettability, fluid saturation levels, depth of invading fluid penetration, reservoir pressure, temperature, and drawdown potential (Bennion et al, 2006). The greater difference between initial water saturation and critical water saturation results in a more serious liquid phase trapping, causing a greater potential damage to gas permeability and gas production in tight formations with sub-normal initial water saturation (Bennion and Brent, 2005).

EVALUATION OF LIQUID INVASION DAMAGE USING RELATIVE PERMEABILITY CURVES

Damage mechanisms such as water phase trapping, partial blockage of open pores by water, and reducing pore openings due to clay swelling can reduce effective permeability in the water-invaded zone (Motealleh, 2007). The damaging effects are all reflected on gas and water relative permeability curves and therefore, these curves can be used for the evaluation of damage mechanisms. Damage of permeability by water invasion and the effect on relative permeability curves are shown in Figure 1.

Water-sensitive tight formations may initially have a high relative permeability (K_r at S_{wi}), but very low relative permeability after being exposed to water (K_r at S_{gc}). The effective permeability in the invaded area of water-sensitive tight formations may not be improved during the clean-up period, since water has already damaged the formation, and been trapped in the invaded zone, and therefore, may cause significant reductions in well productivity. Tight sandstone formations that have a strong sensitivity to fresh or sodium chloride waters (for example where Smectite is present in the formation) might be severely damaged by water invasion when they are exposed to water-based drilling or fracturing fluid.

Phase trapping can also cause damage when an oil-based drilling fluid is used. The invasion of an oil filtrate into tight formations may result in the introduction of an immiscible liquid-hydrocarbon drilling or completion fluid around the wellbore, causing the entrapment of an additional third phase in the porous media that would exacerbate formation damage effects (Bennion et al, 2006). The relative permeability curves illustrated in Figure 2 (Bennion et al, 2006) show the reduced effective permeability due to water-filtrate invasion into the formation (Fig. 2a), compared with damage to permeability with oil invasion (Fig. 2b).

Various different correlations have been proposed to estimate the representative relative permeability curves of a hydrocarbon reservoir for drainage and imbibition processes. Using correlations such as the ones explained in the following sections, measured relative permeability data from core flooding experiments can be smoothed, and be used for reservoir simulation studies.

Corey's formula

In Equations 1–3, S_w is water saturation, $S_{w,irr}$ is irreducible water saturation, K_{rw} is relative permeability to the wetting phase, and K_{rnw} is relative permeability to the non-wetting phase.

$$K_{rw} = [S_w^*]^{\frac{2+3\lambda}{\lambda}} \tag{1}$$

$$K_{rnw} = [1-S_w^*]^2[1-S_w^{*\frac{2+\lambda}{\lambda}}] \tag{2}$$

$$S_w^* = [S_w - S_{w,irr}]/[1-S_{w,irr}] \tag{3}$$

Corey observed that a log-log plot of S^*_w against P_c results in a straight line and slope, which is the characteristic of the pore structure (Wells and Amaefule, 1985).

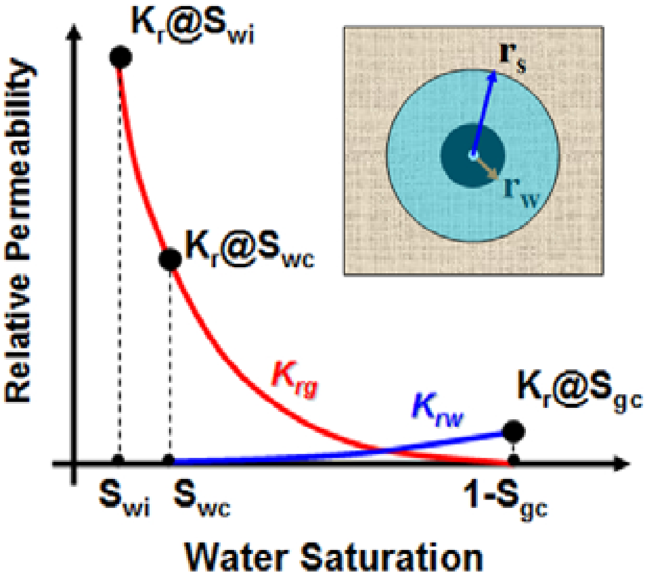

Figure 1. Reduced gas relative permeability due to water blocking.

Ibrahim, Bassiouni and Desbrandes method

This method is based on combining the tortuosity model of Wyllie and Grander with capillary pressure data. This method proposes a normalised method of relative permeability estimation using capillary pressure data. The relationship between water saturation and capillary pressure is given in Equation 4.

$$P_c = a / S_w^{\,b} \tag{4}$$

Equation 4 indicates that a log-log plot of P_c versus S_w results in a straight line. From its slope and intercept, the coefficients a (the entry capillary pressure) and b (the inverse of the pore throat distribution index) can be estimated. The theory is based on Purcell's theoretical expression relating relative permeability and capillary pressure. It is said to be based on the analogy between Darcy's empirical law for the sand packs and Poiseuille's

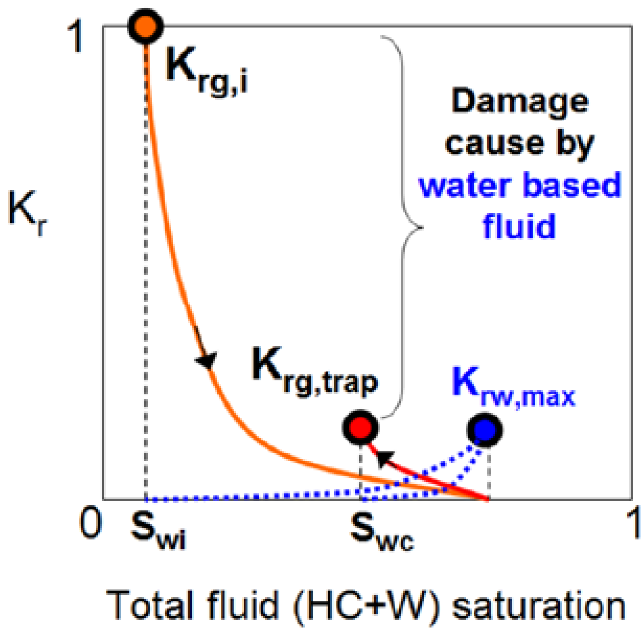

Figure 2a. Illustration of phase trap damage effect of water-based fluids in low-permeability, sub-normally water-saturated gas reservoirs (Bennion et al, 2006).

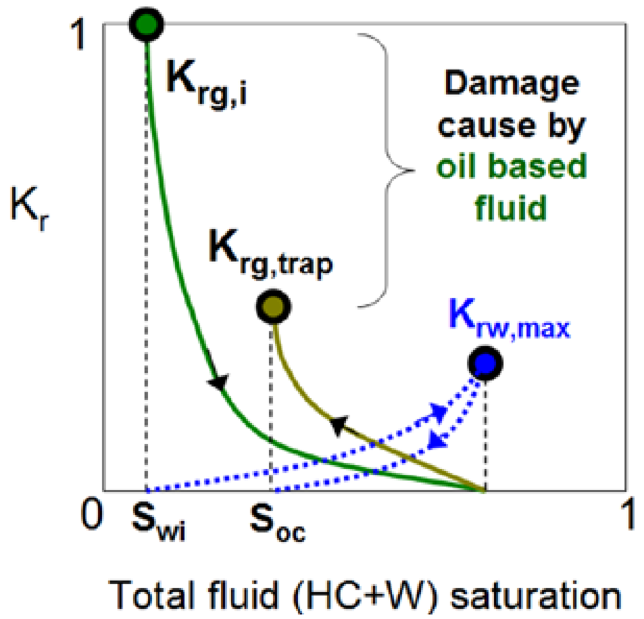

Figure 2b. Illustration of phase trap damage effect of oil-based fluids in low-permeability, sub-normally water-saturated gas reservoirs (Bennion et al, 2006).

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formula, which models the reservoir as a bundle of capillary tubes with the same length, but different diameter. Wyllie and Grander modified Purcell's model to simulate the probability of the interconnection of pores by cutting the bundle of tubes into a large number of thin slices, and reassembling them in a random way. This accommodated tortuosity into the model. The relative permeability correlations for drainage process are presented in Equations 5–8.

$$K_{rw} = S^{*}_{w}{}^{2}[S_{w}{}^{c} - S_{wirr}{}^{c}]/[1 - S_{wirr}{}^{c}] \tag{5}$$

$$K_{rnw} = [1 - S^{*}_{w}]^{2}[1 - S_{w}{}^{c}]/[1 - S_{wirr}{}^{c}] \tag{6}$$

$$S^{*}_{w} = [S_{w} - S_{w,irr}]/[1 - S_{w,irr}] \tag{7}$$

$$c = 2b + 1 \tag{8}$$

K_{rw} is the relative permeability of the wetting phase (water), K_{rnw} is the relative permeability of the non-wetting phase (gas), and $S_{w,irr}$ is irreducible water saturation (Ibrahim, Bassiouni and Desbrandes, 1992).

Naar and Henderson model

This model addresses the entrapment of the non-wetting phase during the imbibition process, and estimates imbibition relative permeability using drainage relative permeability data. Naar and Henderson related the drainage and imbibition saturation for equal values of non-wetting relative permeability as Equation 9.

$$S^{*}_{w(\mathrm{Imb})} = S^{*}_{w(\mathrm{drg})} - R[S^{*}_{w(\mathrm{drg})}]^{2} \tag{9}$$

$S^{*}_{w(\mathrm{Imb})}$ and $S^{*}_{w(\mathrm{drg})}$ are effective water saturation for imbibition and drainage respectively, and R is the residual saturation of the non-wetting phase. It is empirically related to porosity (ϕ) by Equation 10.

$$R = 0.617 - 1.28\phi \tag{10}$$

For tight-gas sands, Ibrahim, Bassiouni and Desbrandes developed the wetting phase relative permeability as Equation 11.

$$k_{rwt} = \frac{1}{2k}\frac{S_{b}^{w}\sigma}{a}(\phi^{*} S^{*}_{w})^{3} \tag{11}$$

K is the absolute permeability, σ is the interfacial tension, and ϕ is the reduced porosity defined as Equation 12.

$$\phi^{*} = \phi(1 - S_{wi}) \tag{12}$$

The saturation values during calculation are normalised using the following relationships (Eqs 13 and 14) and the normalisation factor.

$$x = \frac{\log(2 - Sgc - Swi)}{(\log(Swi)} \tag{13}$$

$$S_{wi\ \mathrm{normalized}} = [\frac{S_{w}}{S_{wi}}]^{x} - (1 - S_{wi}) \tag{14}$$

Ibrahim and Koederitz method

Ibrahim and Koederitz correlations are based on regression models, which are reliable for a particular range of the data (Ibrahim and Koederitz, 2001). For a water-gas system, the regression model suggests the following correlations (Eq. 15 and 16).

$$\begin{aligned} k_{rgw} = {} & 1.3046802\, S_{g}{}^{*} - 8.159598\, S_{g}{}^{*2} \\ & + 25.50978\, S_{g}{}^{*3} - 31.53754\, S_{g}{}^{*4} \\ & + 13.883828\, S_{g}{}^{*4} \end{aligned} \tag{15}$$

$$\begin{aligned} k_{rw} = {} & 0.9455537\, S_{l}{}^{*} - 1.2967293\, S_{l}{}^{*2} \\ & + 1.69592185\, S_{l}{}^{*3} - 0.0424518\, S_{gc}(\ln k_{a})^{3} S_{l}{}^{*5} \\ & - 145.83028 S_{wc}^{1.5}(\phi S_{l}{}^{*})^{2} + .02764389(k_{a}S_{gc})^{4} S_{l}{}^{*4} \end{aligned} \tag{16}$$

$S_{g}{}^{*}$ and $S_{l}{}^{*}$ are defined in Equations 17 and 18.

$$S_{g}{}^{*} = \frac{S_{g} - S_{gc}}{1 - (S_{gc} + S_{lc})} \tag{17}$$

$$S_{l}{}^{*} = 1 - (\frac{S_{g}}{1 - S_{lc}}) \tag{18}$$

S_{g} is gas saturation, S_{gc} is critical gas saturation, S_{l} is liquid saturation, S_{lc} is the total of critical liquid saturations present in the system, S_{w} is water saturation, S_{wc} is critical (connate) water saturation, S_{wi} is initial water saturation, k_{a} is absolute permeability, k_{rgw} is the relative permeability of gas with respect to water, and k_{rw} is the relative permeability of water. The saturation data from the capillary pressure data is used in this regression model to find the relative permeability.

RESERVOIR SIMULATION FOR DAMAGE EVALUATION

Invasion damage can be modelled based on the reduction of the relative permeability when liquid saturation is increased around the wellbore by liquid injection. The trapping of the water phase in the near wellbore zone is controlled by relative permeability and capillary pressure curves that manage how the invaded liquid is held inside the reservoir model grids around the wellbore. Reservoir simulation of tight-gas reservoirs was carried out to qualitatively evaluate the effect of water and oil invasion damage on well productivity.

To build a reservoir model, different field data were reviewed to gather the required data. The reservoir data from tight-gas sandstones in Western U.S. basins (Department of Energy, 2011) and the Perth Basin in WA were studied to determine an estimation of the parameters that are required for building a reservoir simulation model. The available data related to the in situ critical gas saturation and critical water saturation distribution for different in situ porosity, routine porosity, and permeability values are reported in Figures 3a–3d. The WA field data from the productive sandstone sections showed an average porosity and absolute permeability of 9% and 0.1 mD, respectively.

A set of gas-water relative permeability data (measured under 4,000 psia effective pressure) was also available for the WA field, which were smoothed using the Ibrahim, Bassiouni and Desbrandes relative permeability correlations (Eqs 5 and 6). For the oil-gas system, there was no core flood test data available, and therefore, published typical oil-gas relative permeability data in a tight-gas reservoir simulation study (Ravari et al, 2005) was used. The relative permeability data for gas-water and gas-oil systems are shown in Figures 4a and 4b, respectively.

CMG's (Computer Modelling Group) IMEX black-oil reservoir simulator was used to numerically model liquid invasion and gas production. The model is block sized, with a grid system of 22 × 22 × 20 grids in an x-, y- and z-direction. The size of each grid block is 1 m. The reservoir model 3D view is shown in Figure 5, and the model input data details are reported in Table 1. The reservoir model is simplified and homogeneous since the details of reservoir heterogeneity were not available.

The data summarised above was used to build the reservoir simulation model, and evaluate phase-trap damage for different cases of water-based versus oil-based drilling fluid. The model was run for the following scenarios:

- no liquid invasion prior to gas production (no damage);
- injection of water in the well to model water invasion, then gas production from the model to clean-up the water from the invaded area (water damage); and,
- injection of oil in the well to model oil invasion, then gas production from the model to clean-up the oil from the invaded area (oil damage).

The operational constraint for the injection well is a constant liquid injection rate (oil or water) and that of the producer is a constant bottom hole pressure. This is supposed to simulate the invasion of fluids during drilling. The water damage model

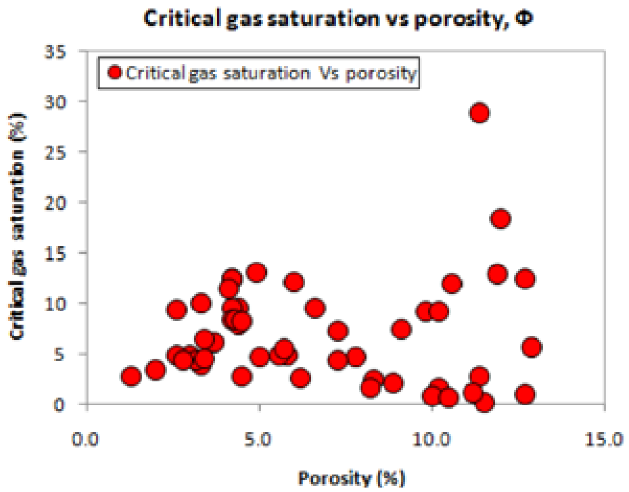

Figure 3a. Critical gas saturation versus porosity in tight-gas reservoirs.

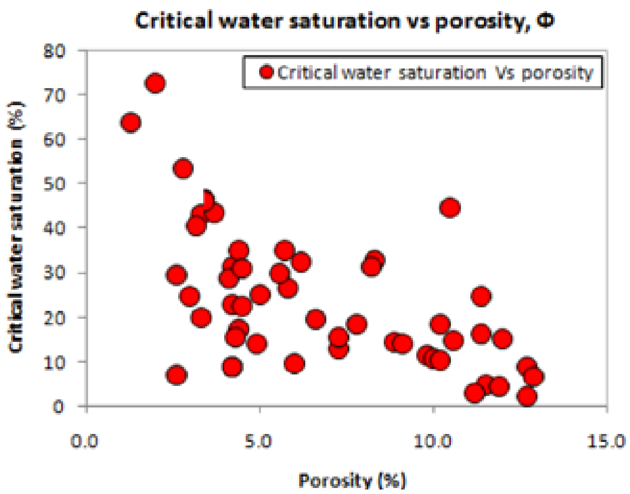

Figure 3b. Critical water saturation versus porosity in tight-gas reservoirs.

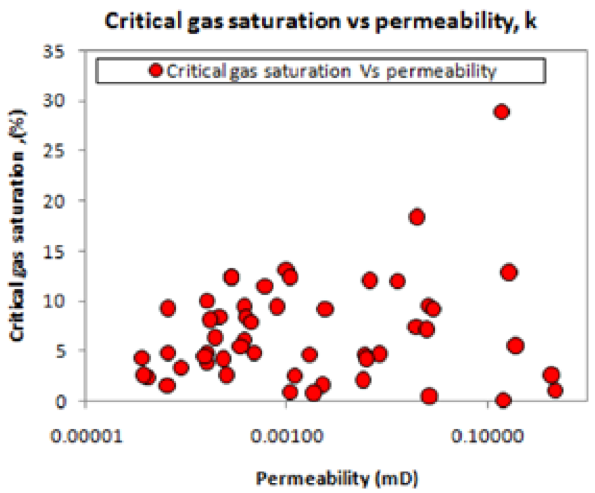

Figure 3c. Critical gas saturation versus permeability in tight-gas reservoirs.

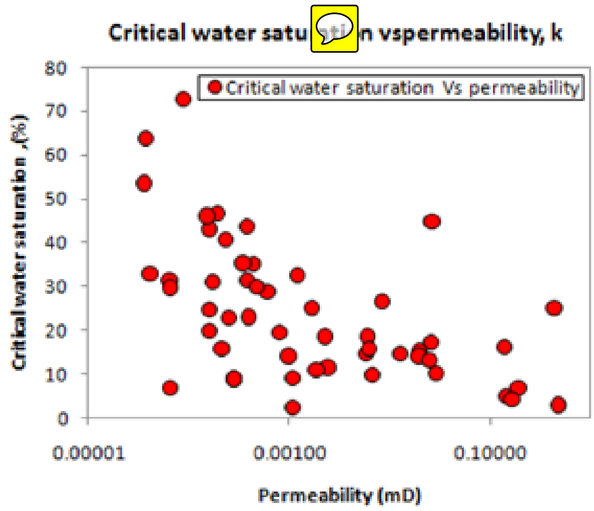

Figure 3d. Critical water saturation versus permeability in tight-gas reservoirs.

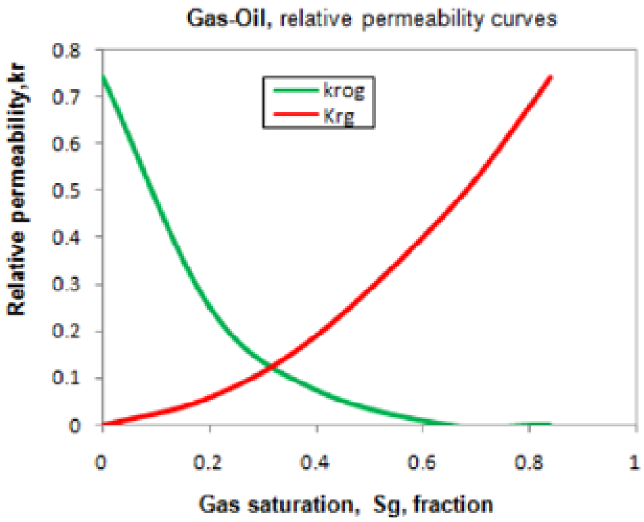

Figure 4b. Capillary pr and relative permeability for a gas-oil system.

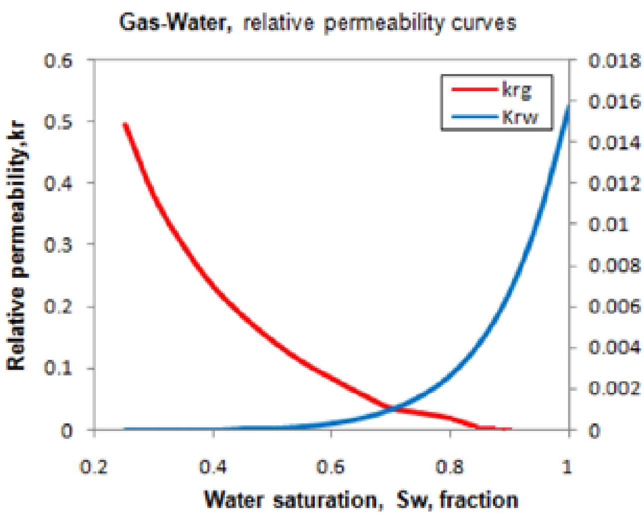

Figure 4a. Capillary pressure and relative permeability for a gas-water system.

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is a two phase water-gas system, and the oil damage model is a three phase water-oil-gas system.

The effect of phase trapping damage can be seen from the invading liquid saturation distribution (water or oil) in the model after the injection period, compared with the saturation distribution at the end of the gas production period. The phase trap damage in the cases of water invasion followed by gas production, and oil invasion followed by gas production are shown in Figures 6 and 7, respectively. Figures 6a and 6b, respectively, show water saturation distribution around the wellbore after the water injection time (at the end of water invasion), and after the gas production period (at the end of clean-up), in the case of water damage. Figures 7a and 7b, respectively, show gas saturation distribution around the wellbore after the oil injection time (at the end of oil invasion), and after the gas production period (at the end of clean-up). As seen in Figure 7, there is trapped water as well as oil in the model, which has not been removed from the invaded zone, even after 90 days of gas production in both cases.

To evaluate the oil and water phase trapping effects on well productivity, the cumulative production rate for the three models were plotted in Figure 8. The results highlighted that both oil and water invasion reduces well productivity. The model is more sensitive to water invasion damage, and injection of water has caused the cumulative gas produced from the water-damaged model, to be significantly lower compared with the no-damage model. In the case of oil injection, the damaging effect is significantly less than water damage, and therefore, in the case of oil injection, the model produced more gas than the water-damaged model.

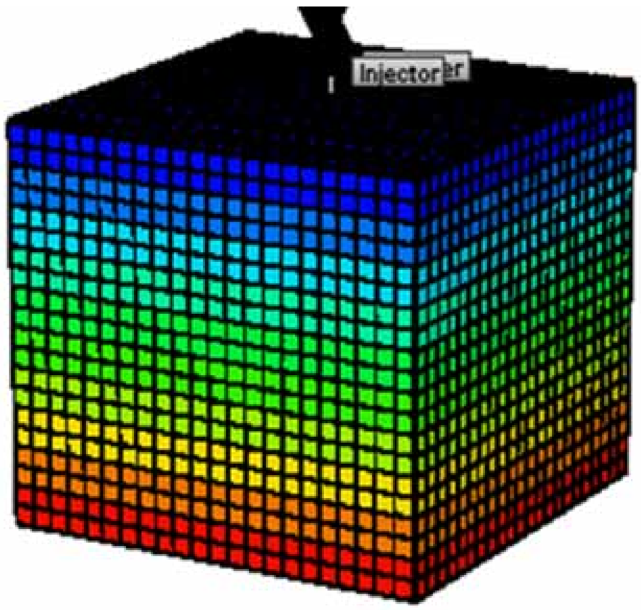

Figure 5. Reservoir model, 3D view (x and y are horizontal, and z is vertical).

Table 1. Input parameters in the simulation model.

Reservoir	Tight-gas
Well	Vertical
Porosity	9%
Permeability	0.1 mD
Reservoir pressure	41,368.5 KPa
Reservoir temperature	100°C
Wellbore fluid	Water or oil
Fluid	Gas
Gas gravity	0.62
Critical water saturation	0.5
Critical gas saturation	0.1
BHP, flowing	25,000 KPa

LABORATORY EXPERIMENTS: OIL VERSUS WATER INVASION DAMAGE

Laboratory experiments on the WA core samples were performed to compare damage to the core permeability caused by water invasion versus oil invasion. Absolute permeability of each core sample was measured at 100% gas saturation. The characteristics of the core samples that were tested for damage evaluation are reported in Table 2. For water damage evaluation, the core samples were saturated with water, followed by flooding of gas into the core samples until water saturation was reduced to the minimum of residual water saturation, then core effective permeability was measured (K_{rg} at S_{wr}). Similarly, for oil damage evaluation, the core samples were saturated with oil, then gas was flooded into the core sample until oil saturation was reduced to the minimum of residual oil saturation to measure core effective permeability (K_{rg} at S_{or}). The core testing conditions were 5,800 psia pore pressure and a temperature of 109°C.

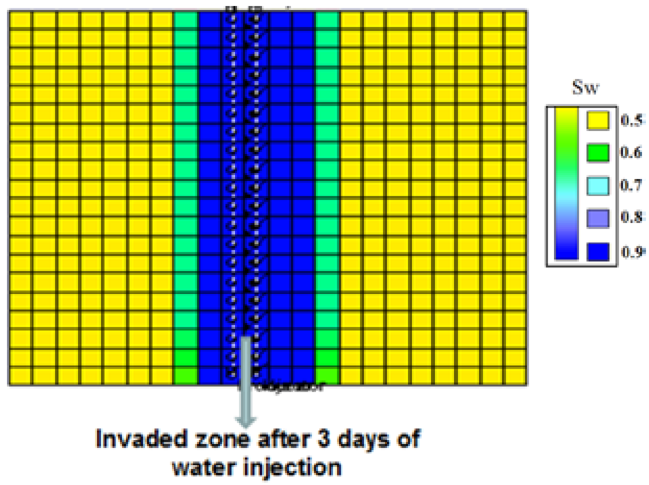

Figure 6a. Water saturation distribution at the end of the water invasion period (water damage).

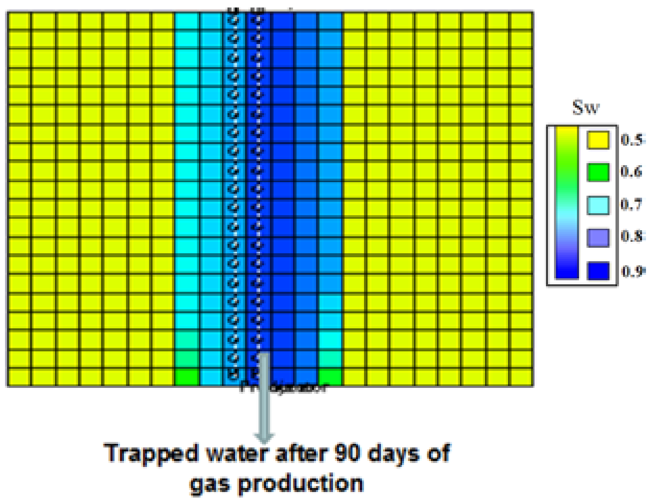

Figure 6b. Water saturation distribution at the end of the gas production and clean-up period (water damage).

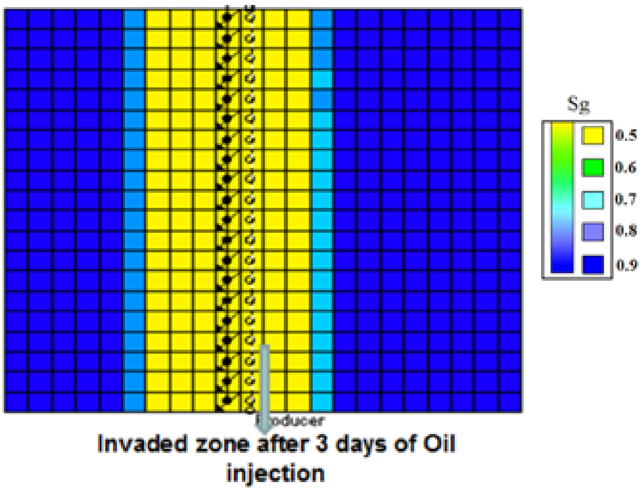

Figure 7a. Gas saturation distribution at the end of the oil invasion period (oil damage).

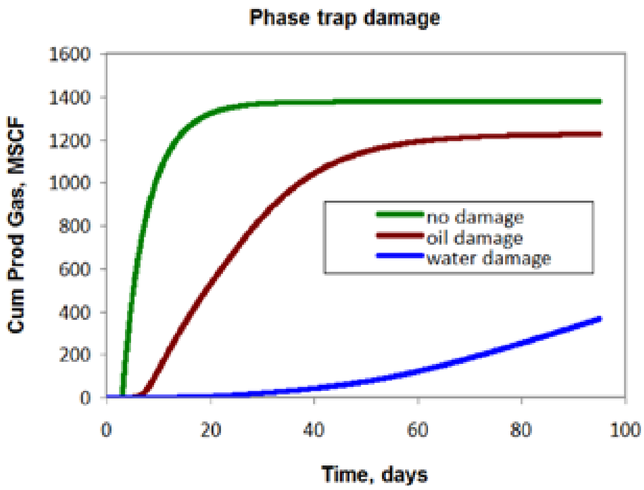

Figure 8. Cumulative gas production, no-damage compared with oil-based and water-based drilling fluid damage.

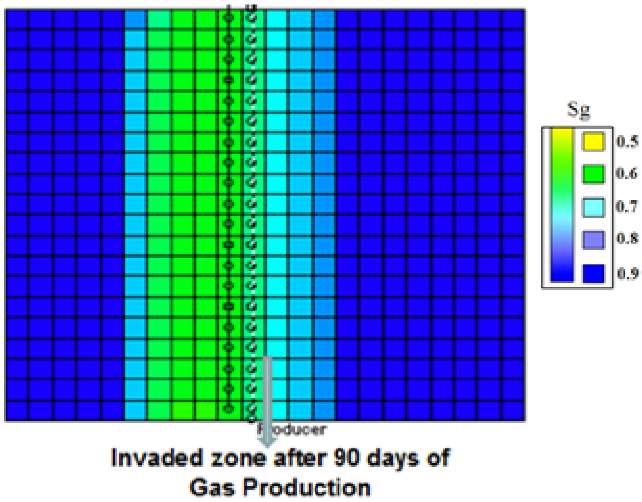

Figure 7b. Gas saturation distribution at the end of the gas production and clean-up period (oil damage).

Table 2. Details of the core samples' characteristics.

Core sample	Core porosity, %	Core absolute permeability, mD
Sample A1	6.7	0.003
Sample A2	9.6	0.034
Sample A3	11.4	0.026
Sample B1	4.6	0.034
Sample B2	5.4	0.032

Table 3. Core flooding experiment results.

Core sample flooded by water, cleaned up with gas			
End point methane K_r at S_{wr}	Sample A1: 0.224	Sample A2: 0.353	Sample A3: 0.219
Core was flooded by oil, cleaned up with gas			
End point methane K_r at S_{or}	Sample B1: 0.507	Sample B2: 0.413	–

The core flooding test results are shown in Table 3. As illustrated in the case of oil damage, the core samples' effective permeability is reduced from 1 to 0.41–0.51, and in the case of water damage, it is reduced to 0.22–0.35. The tight formation is subjected to invasion damage in both cases of oil injection and water injection into the core. Severity of the damage is less, however, in the case of oil damage compared to water damage. For damage caused by oil and water invasion (the severity of oil damage being less than water damage), the core flooding experiment results confirm the validity of reservoir simulation runs.

CONCLUSIONS

- Phase trapping is one of the main damage mechanisms in tight-gas reservoirs, which significantly reduces the well productivity in the cases of water or oil invasion.
- In the case of drilling with water-based fluids, tight formations might be sensitive to water invasion, water phase may get trapped in the reservoir, and their permeability to gas may markedly drop during exposure to water.
- In the case of drilling with oil-based fluids, invasion of oil filtrate into tight formations may result in the introduction of an immiscible liquid hydrocarbon drilling or completion fluid around the wellbore, causing the entrapment of an additional third phase in the porous media that would exacerbate formation damage effects.
- Severity of damage is less in the case of oil-based drilling fluids compared with water-based drilling fluids. The use of oil-based mud fluid instead of water-based mud in the drilling of tight formations may reduce damage to the formation, and therefore, provide improvement in gas production and ultimate recovery.

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NOMENCLATURE

ϕ	Porosity
P_c	Capillary pressure
k_{rw}	Wetting phase relative permeability
k_{rnw}	Non-wetting phase relative permeability

S_{wr} Residual wetting phase saturation
λ Slope of the linear relation between natural logarithm of P_c and S_w^*
a , b Coefficients reflecting the formation pore size distribution
K_{rw} Relative permeability of the wetting phase
K_{rnw} Relative permeability of the non-wetting phase (here, gas)
c Coefficient
S_w^* Effective water saturation
S_{wi} Irreducible water saturation
$S^*_{w(Imb)}$ Effective water saturation for imbibition
$S^*_{w(drg)}$ Effective water saturation for drainage
R Residual saturation of the non-wetting phase
S_g Gas saturation
S_{gc} Critical gas saturation
S_l Liquid saturation
S_{lc} Total of critical liquid saturations present in the system
S_w Water saturation
S_{wc} Critical (connate) water saturation
S_{or} Residual oil saturation
k_a Absolute permeability, mD
k_{rg} Relative permeability of gas
k_{rgw} Relative permeability of gas with respect to water
k_{rlg} Relative permeability of liquid with respect to gas
k_{rw} Relative permeability of water

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Authors' biographies next page.

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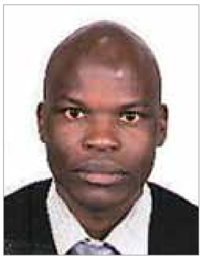

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APPEA

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Appendix F:

Hydraulic fracture productivity performance in tight gas sands – A Numerical Simulation Approach. Journal of Petroleum Science and Engineering

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Production performance of hydraulic fractures in tight gas sands, a numerical simulation approach

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ABSTRACT

Hydraulically fractured tight gas reservoirs are one of the most common unconventional gas sources being produced today, and will be a regular source of gas in the future. The extremely low permeability of tight gas sands leads to inaccuracy of conventional build-up and draw-down well test results. This is primarily due to the increased time required for transient flow in tight gas sands to reach pseudo-steady state condition. To increase accuracy, well tests for tight gas reservoirs must be run for longer periods of time which is in most cases not economically viable. The large amount of downtime required to conduct well tests in tight sands makes them far less economical than conventional reservoirs, which leads to the need for accurate simulation of tight gas reservoir well tests.

This paper presents simulation results of a 3-D hydraulically fractured tight gas model created using Eclipse software. The key aims are to analyze the effect of differing fracture orientation, number and length. The focus of the simulation runs will be on the effect of hydraulic fracture orientation and length. The results will be compared to simulation runs without the abovementioned factors to determine their effects on production rates and well performance analysis. All results are plotted alongside an un-fractured tight gas scenario in order to put the hydraulic fracture performance in perspective.

Key findings from this work include an approximately linear relationship between initial gas rate and the number of hydraulic fractures intersecting the wellbore. In addition, fracture length is found to have less of an impact on initial gas rate compared to number of fractures intersecting the wellbore, for comparable total fracture volumes.

1. Introduction

The increasing global demand for energy along with the reduction in conventional gas reserves has lead to the increasing demand and exploration of unconventional gas sources. Tight gas sands are one of the most commonly produced unconventional gas resources around the world, but the low productivity and permeability provide further challenges in meeting economic production (Pankaj and Kumar, 2010). Tight gas sands are most commonly defined as a reservoir system with low permeability, generally less than 0.1 mD, and low porosity, generally less than 10%, (Pankaj and Kumar, 2010). More recent definitions outline the importance of reservoir stimulation by hydraulic fracturing in modern tight gas production. Tight gas sands have been defined by Holditch, 2006 “a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fractures.” Addis and Yassir (2010) also defined tight gas sands as requiring “man-made” permeability systems for economic production.

Due to the extremely low permeability, and subsequently low reservoir flow of tight gas sands, many conventional well tests and analysis methods are not economically viable (Manrique and Poe, 2007). This is partly due to the fact that tight gas sands require much longer time periods to reach stable reservoir pressure for conventional build-up tests. Similar issues arise with determining hydraulic fracture performance, the inherently low reservoir permeability increases time required to determine fracture performance (Garcia et al., 2006).

There are many documented studies regarding optimization of various fracture properties, such as fracture length and aperture, to improve performance. For example, Pankaj and Kumar (2010), analyzed various studies conducted on the impact of initial reservoir pressure (2100–2500 psi), reservoir permeability (0.01–0.1 mD) and fracture half length (100–500 ft). However, fracture orientation with respect to the wellbore is not covered by the simulation analysis. Initial reservoir pressure was found to have a minimal impact on initial production rate compared to reservoir permeability. Shah et al. (2010), discusses the theoretical difference between hydraulic fracture performance based on orientation, comparing fractures perpendicular and along the wellbore. Hydraulic fractures formed along

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Table 1
Model description and properties.

	Unit	Value		Unit	Value
Number of cells	x, y, z	50, 50, 71	Reservoir constraint	Gas rate, MSCF	500
Cell size	x, y, z (ft)	75, 75, 2.5	Production and buildup tests	3 consecutive	Varying time interval
Porosity	%	8	Fracture half length	ft	275–575
Permeability	mD	0.1	Number of hydraulic fractures	–	0–12
Reservoir pressure	psia	4000	Fracture porosity	%	80
Well type	–	Vertical, single well	Fracture permeability	mD	28,000
Reservoir thickness	ft	177.5	Perforation length	ft	177.5

the wellbore can be expected to have a greater impact on production performance due to the increased contact area of the hydraulic fracture and wellbore. In addition, the reduced contact area provides a smaller flow path into the wellbore, increasing fluid velocity therefore resulting in more turbulent flow.

Jamiolahmady et al. (2009), modified the Unified Fracture Design method (UFD), originally proposed by Valko and Michael (1998), to account for coupling and internal effects.

Addis and Yassir (2010), take the approach of optimizing hydraulic fracture design via intersecting already existing natural fractures. The idea of intersecting natural fractures is economically advantageous as overall reservoir permeability and sweep is increased by both the new hydraulic fractures, and by increased connectivity with high permeability natural fractures.

Rushing and Blasingame (2003), used a combination of decline curve analysis and simulation of long production periods to determine the stimulation effectiveness of hydraulically fractured gas wells. A combination of Material Balance Decline Type Curve (MBDTC) methodology and different type curve plotting functions were used to match results against real tight gas reservoir data. Rietman (1998) also used decline curves to analyze the sensitivity of optimum fracture length under different reservoir parameters. The findings showed that reservoir porosity and pay thickness are more influential on performance than permeability and drainage area.

The aim of this paper is to generate common trends between fracture size, fracture spacing and fracture orientation on initial tight gas reservoir response. Using post hydraulic fracture production data, already calculated on most fields, to analyze early time reservoir response. As previously discussed, reducing time required for analysis is a major challenge for tight gas reservoirs; therefore the use of early time data is the key focus of this paper.

The approach is to use a 3-D reservoir model to analyze impacts of the abovementioned facture parameters on a single vertical well completed in tight gas sands. Overall fracture volume between comparable hydraulic fracture scenarios will be similar, with an overall difference less than 10% (not equal due to the size of cells within the model). The variables varied for this investigation are, fracture number, fracture length and fracture orientation. The results will aid in determining the most efficient hydraulic fracture layout with comparable proppant volume used (as per fracture volume). Comparisons will be made between 1150 ft fractures and 550 ft fractures; more 550 ft fractures are simulated to obtain similar overall fracture volume. Gas production rates and cumulative gas production data will be used to analyze the impact of additional 1150 ft and 550 ft fractures on production performance.

Fracture orientation with respect to the wellbore is also simulated and analyzed. Similar to the previous comparison, the comparable hydraulic fracture models have equal overall fracture volume. One model has the hydraulic fracture created along the wellbore, while the other model has the hydraulic fracture perpendicularly intersecting the wellbore. This comparison aims to determine the production performance of hydraulic fractures orientation with respect to the wellbore; hence the results should be comparable for horizontally completed wells.

The findings from this analysis can be used in conjunction with other optimization techniques to improve overall hydraulic fracture design.

2. Model description

Commercial simulation software is used to create a 3-D homogeneous model with tight gas properties, the properties of the model are outlined in Table 1. Commercial reservoir simulation software, Eclipse, is used for all simulations. Eclipse 100 is a numerical 3-D simulator capable of simulating various types of oil and gas reservoir production including tight gas reservoirs (Schlumberger GeoQuest, 2008). A single vertical well is created in the center of the reservoir to ensure symmetrical depletion throughout the production periods. Numerous simulations are completed examining fracture orientation, size and fracture number effects on well test response in terms of early time production rate and cumulative production.

To analyze the effect of fracture orientation, two simulations with fractures perpendicular to one another are created, both having equal fracture volume. One model contains a single fracture perpendicular to the wellbore, and the other model with a single fracture along the wellbore, Fig. 1 shows a schematic of the two cases for a vertical well. The hydraulic fracture along the wellbore model is created to with the expectation to achieve greater production. The

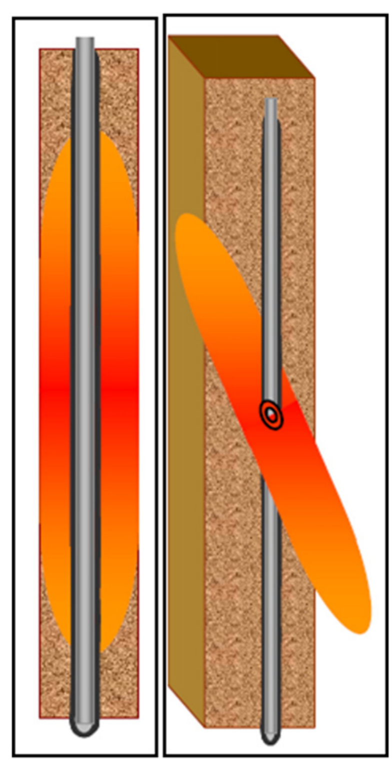

Fig. 1. Contact area with wellbore for perpendicular (bottom) and along the wellbore (top) fractures, Shah et al. (2010).

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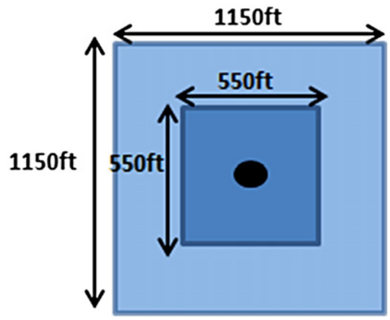

Fig. 2. Schematic of 550 ft and 1150 ft fracture sizes (not to scale).

"perpendicular fracture" is simulated in the center of the perforated section of the box model intersecting the wellbore perpendicularly.

The impact of fracture size vs. fracture number is conducted with each comparative model containing almost equal total fracture volume but with a different number of fractures. The fracture volumes are not exactly equal between the models due to the size of the grid-blocks used for simulation, however the difference is negligible (less than 10%) compared to the overall fracture volume. Having very similar fracture volume ensures that the overall increased permeability of the model is equal, leaving only the fracture size and spacing as the variables. One scenario compares one 1150 ft horizontal fracture to four 550 ft horizontal fractures; with the single fracture and four fracture models having equal fracture volume. This analysis aims to determine which hydraulic fracture method is more beneficial in terms of production performance, numerous smaller fractures or fewer larger fractures.

3. Results and discussion

For all scenarios two sets of plots are discussed, gas production rate vs. time and cumulative gas production vs. time. Both the fracture size vs. number of fractures, and perpendicular vs. along the wellbore fracture cases are compared to a no fracture scenario, in order to put the increased production performance in perspective. This is achieved by making the production rate vs. time plots dimensionless with respect to the un-fractured model. In other words, the production rates of all fractured models are divided by the no fracture production rate to emphasize the benefit with respect to an un-fractured tight gas reservoir. The production period is 12,000 h (~500 days), however only the early time gas production rate results (first 72 h) along with cumulative production after 500 days are analyzed.

The gas production rate results are plotted on a semi-log plot, with time displayed on a logarithmic scale; this creates clarity for early time production rate behavior analysis.

3.1. Fracture size vs. number of fractures

As discussed, this analysis is conducted to compare the production performance of generating large fractures (1150 ft) or smaller fractures (550 ft), all with comparable overall fracture volume.

The fractures simulated are symmetrical and have equal length and width, with all fractures also having equal aperture of 1 mm (Fig. 2). The equal length and width of the fractures means that 1 single fracture with a length, and width, of 1150 ft has approximately four times the fracture volume of a single 550 ft fracture (Table 2). Hence, the results of a 1 × 1150 ft, 2 × 1150 ft and 3 × 1150 ft fracture models are compared to 4 × 550 ft, 8 × 550 ft and 12 × 550 ft fracture models, respectively. As stated previously, the production rates in Fig. 3 are dimensionless with respect to the un-fractured model.

From Fig. 4 it is evident that increasing the number of fractures intersecting the wellbore drastically impacts the initial flow rate of a tight gas reservoir. In addition, initial production rate increases similarly with fracture number regardless of fracture volume. Simulation results show that the 4 × 550 ft fracture model produces initially at a higher rate than the 3 × 1150 ft fracture model although it has only 30% of the total fracture volume (Table 3). In terms of immediate drainage of tight gas formations, numerous smaller fractures will increase productivity more per volume of fracture, compared to fewer longer fractures.

This is due to the initial gas being produced only from sands near the wellbore and hence within the drainage radius of both the simulated fracture sizes. The key difference between the different fracture length models is that the 1150 ft fractures maintain the initial production for a longer period of time, whereas the 550 ft fractures experience a drastic reduction in production rate within the first few days (Fig. 4).

These simulation results show that the initial production rate of a single hydraulic fracture can be used to determine efficiency of subsequent fractures created. The results show that each additional fracture created should increase initial gas production by a similar value compared to the previous fracture over the first 24 h (Fig. 5). This relatively linear increase in initial production rate is created as a result of the increased permeability near wellbore by hydraulic fractures. Therefore, the effectiveness of a fracture job can theoretically be estimated within 24 h of first production, based on post shut-in initial gas rate.

In terms of assessing the performance of a hydraulic fracture jobs on real tight gas reservoirs, this form of analysis could serve as immediate feedback of additional fracture performance after shut-in. A lower increase in initial production rate (compared to the previous fracture) could be a result of near wellbore damage caused by poor clean-up post hydraulic fracture.

There is minimal difference in cumulative gas production between the 550 ft fracture cases, particularly between the 8 and 12 fracture cases after 500 days, overall difference of less than 2% (Fig. 6). This is due to the fact that with increased fracture number, fracture spacing is reduced as a result of the reservoir size remaining constant (Table 2). Reduced fracture spacing can result in several fractures potentially producing from the same drainage area. With this in mind, it can be assumed that the 12 × 550 ft fracture model is not directly comparable to the 3 × 1150 ft model in terms of cumulative production performance. Similarly the 8 × 550 ft model is likely to produce less cumulative gas than the 2 × 1150 ft fracture model due to multiple fractures producing from a common drainage area. Therefore the 1 × 1150 ft and 4 × 550 ft is the only comparable pair in terms of cumulative production based on similar fracture volume.

As both scenarios have almost equal fracture volume, and fracture spacing is sufficient to ensure individual drainage area for each fracture, it can be expected that individual fracture drainage area is equal between the two cases. The single 1150 ft fracture produces ~10% less cumulative gas and therefore can be said to be less effective

Table 2
Fracture spacing, initial gas rate and volume for different fracture number models.

Fracture number and size	1 × 1150 ft	2 × 1150 ft	3 × 1150 ft	4 × 550 ft	8 × 550 ft	12 × 550 ft
Fracture volume (ft^3)	4338	8676	13,013	3969	7938	11,906
Delta initial gas rate per additional fracture (MSCF/day)	–	9294	7223	10,979	8189	8187
Fracture spacing (ft)	90	60	45	36	20	14

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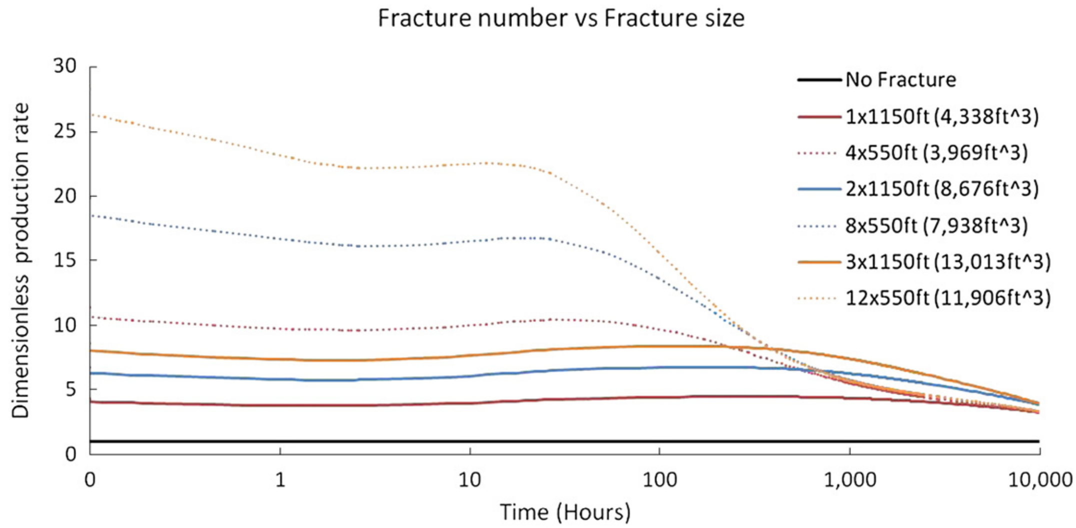

Fig. 3. Gas production rate vs. time for all simulated 1150 ft and 550 ft fracture cases.

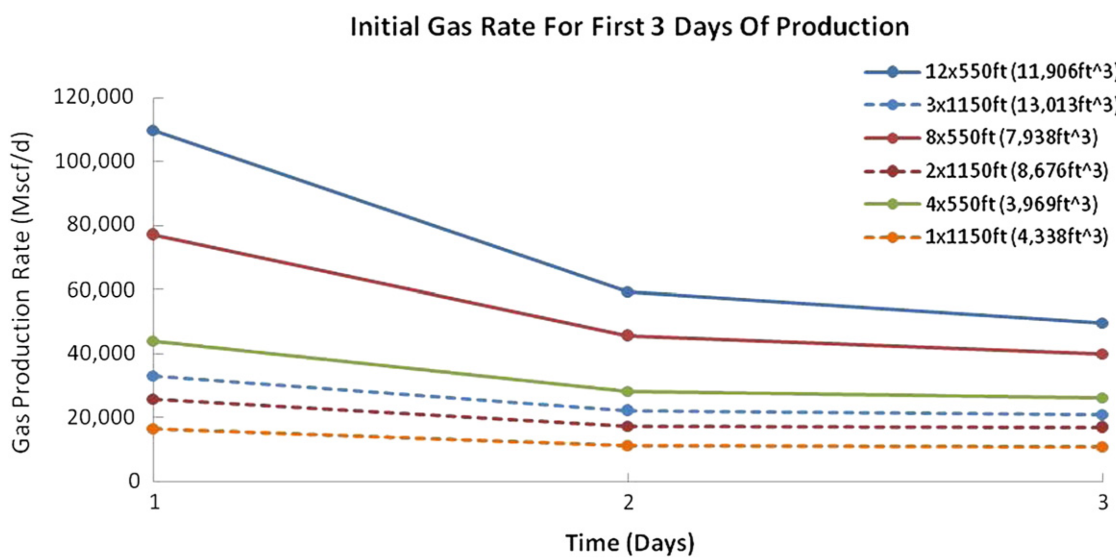

Fig. 4. Average gas production rates for first three 24 h periods for all simulated 1150 ft and 550 ft fracture models.

compared to 4 smaller fractures. Another of the mitigating factors can be explained by the theoretical findings of Shah et al. (2010) regarding perpendicular fractures having more turbulent flow than fractures along the wellbore. With only one fracture providing flow for the 1150 ft model (compared to four 550 ft fractures), the majority of production comes from the single flow path via the hydraulic fracture, thus causing highly turbulent and flow and reducing production performance.

However, the cost of additional hydraulic fractures would have to be determined individually for all tight gas reservoirs prior to reaching any conclusions regarding fracture job planning and design. For instance, a highly faulted or discontinuous tight gas reservoir formation can have substantially less benefit from additional fractures than large homogenous tight gas reservoir.

3.2. Perpendicular versus along the wellbore fracture

Two models with equal fracture volume (identical fracture length and width) are simulated, one fracture model intersecting the vertical wellbore perpendicularly, and the other intersecting parallel along the wellbore. Dimensionless production rate and cumulative gas rate vs. time plots are created and analyzed (Figs. 7 and 8).

The facture along the wellbore produces ~60% more cumulative gas after 500 days of production, and doesn't drop below the perpendicular fracture production rate at any stage of production. This increase in production is due to the higher surface area of wellbore that the fracture along the wellbore intersects if compared to the perpendicular fracture (Shah et al., 2010). The increase in contact area between the wellbore and hydraulic fracture increases average

Table 3
Increase in initial gas production rate per subsequent fracture.

	2 × Frac–1 × FRac	3 × Frac–2 × FRac	4 × Frac–3 × FRac	8 × Frac–4 × FRac	12 × Frac–8 × FRac
Delta initial gas rate (MSCF/day)	9294	7223	10,979	32,756	32,746
Delta initial gas rate per fracture (MSCF/day)	9294	7223	10,979	8189	8187

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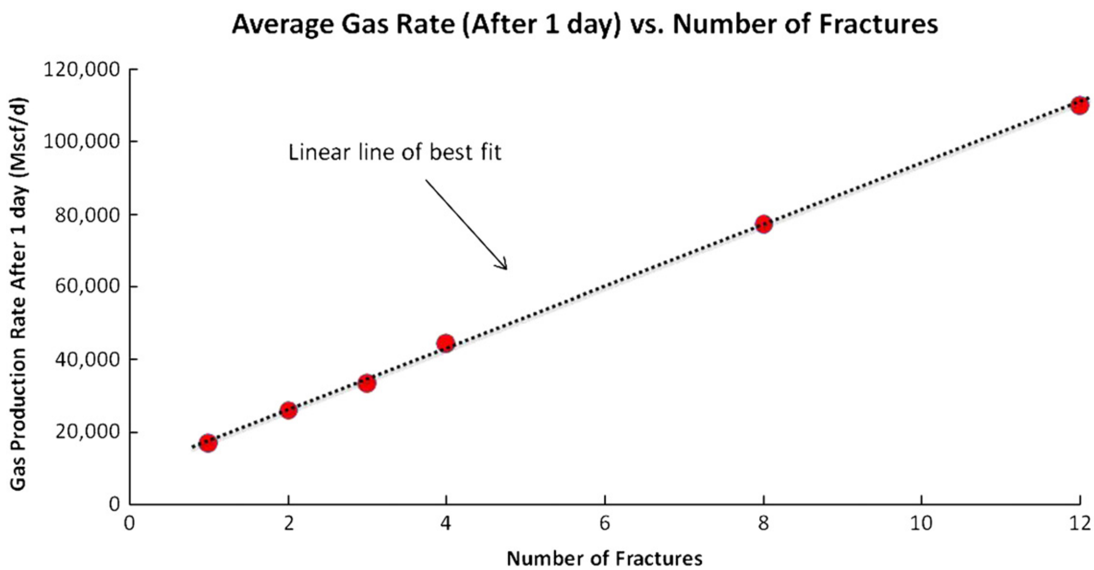

Fig. 5. Average gas rate after 1 day vs. number of hydraulic fractures.

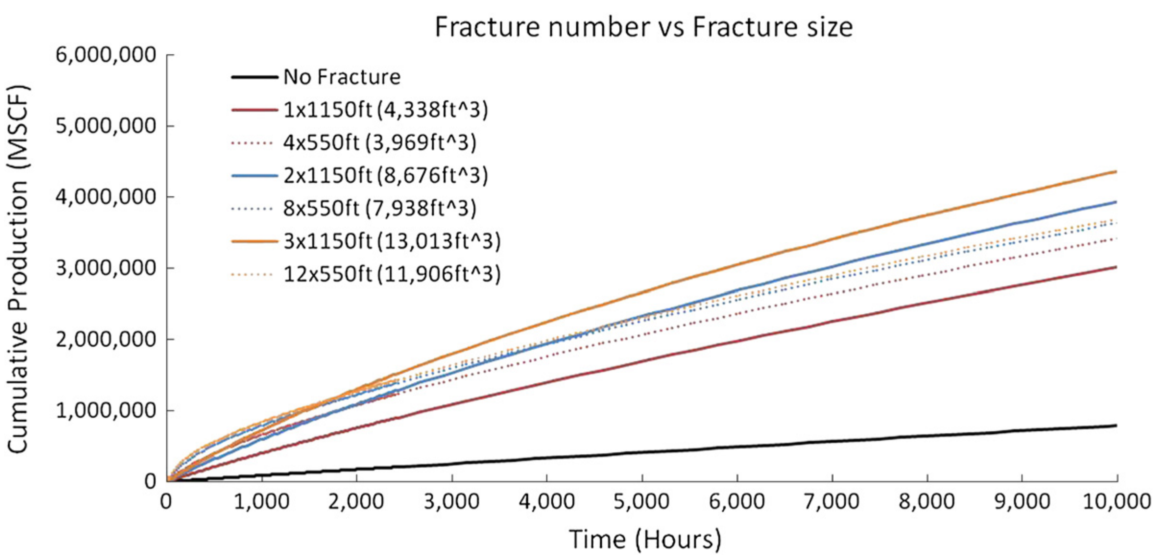

Fig. 6. Cumulative gas production vs. time for all simulated 1150 ft and 550 ft fracture cases.

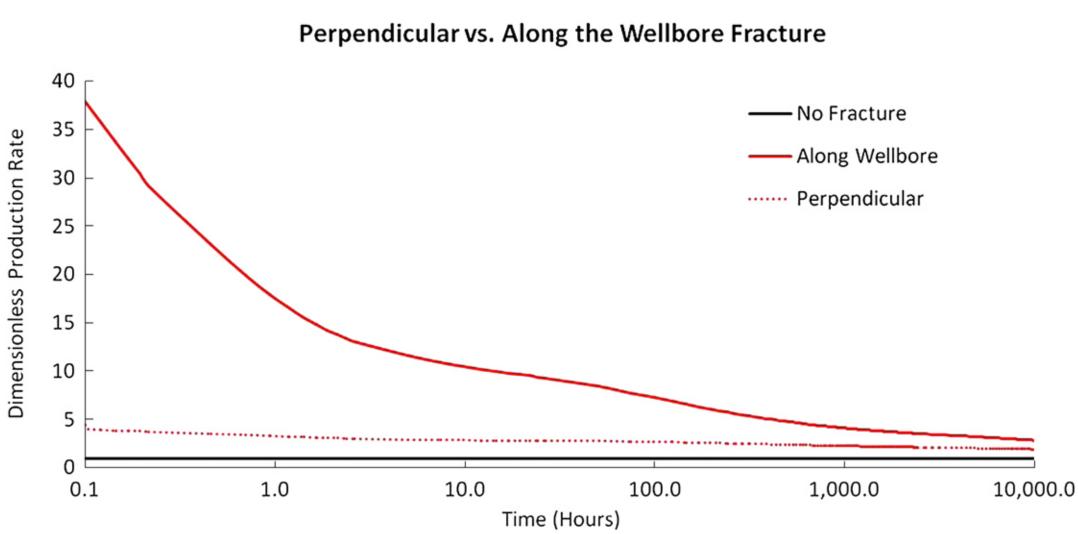

Fig. 7. Gas production rate for single perpendicular and along the wellbore fracture models.

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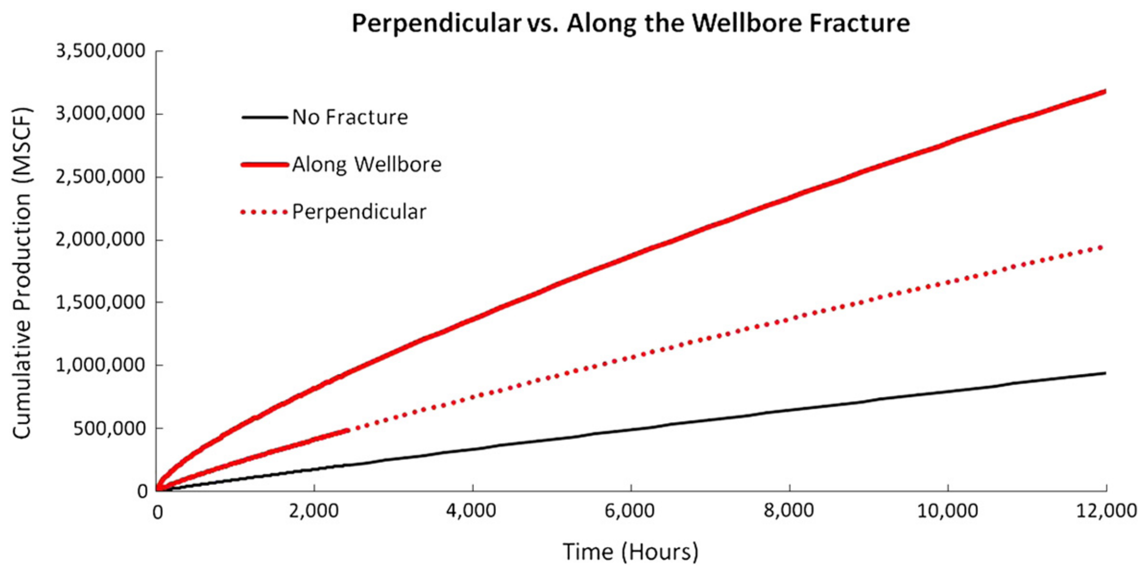

Fig. 8. Cumulative gas production for single perpendicular and along the wellbore fracture models.

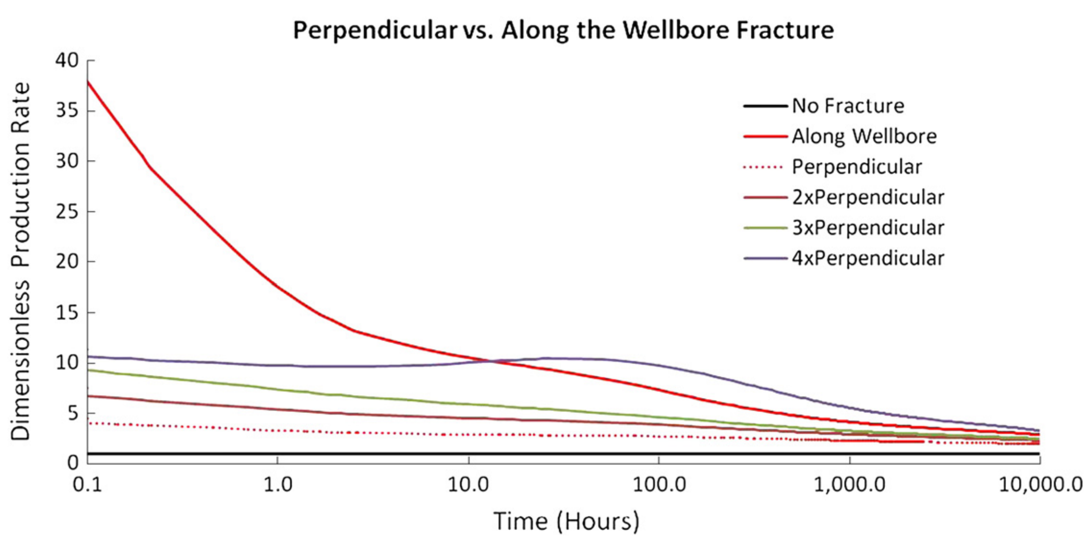

Fig. 9. Gas production rate vs. time for perpendicular and along wellbore hydraulic fracture models.

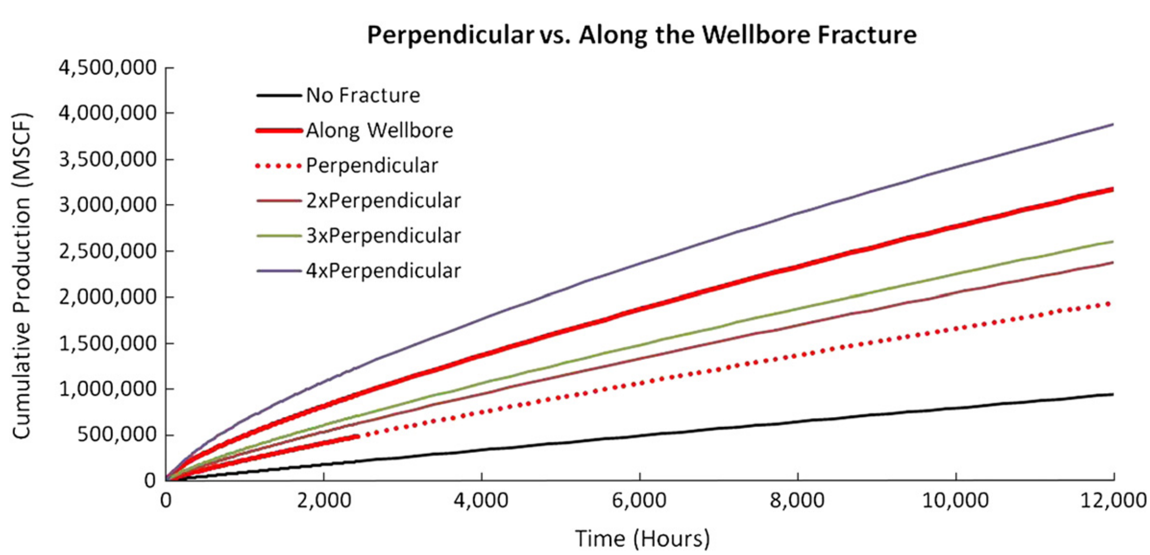

Fig. 10. Cumulative gas production rate vs. time for perpendicular and along wellbore hydraulic fracture models.

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permeability near the wellbore and hence inflow performance. Similar to the multiple 550 ft fracture model results, the parallel fracture model experiences a large decrease in production rate for the first day of production.

As further investigation, 2, 3 and 4 perpendicular fracture models are plotted against the single fracture along the wellbore to determine the number of perpendicular fractures required to achieve similar initial gas production rates and cumulative production (Figs. 9–10).

The simulation results show that only the 4 perpendicular fractures achieve a higher cumulative production over the simulated time interval (Fig. 10). Based on these results, and assuming symmetrical drainage, fractures along the wellbore have a significantly increased ultimate recovery compared to perpendicular fractures. Therefore it is suggested that whenever possible, hydraulic fractures should be created along the wellbore, rather than intersecting it perpendicularly. As discussed by (Shah et al., 2010), the fractures created along the wellbore have a higher contact area between the hydraulic fracture and wellbore. This increase in contact area increases the permeability, and therefore production performance, of the near wellbore section. For tight gas formations, this increase in near wellbore permeability has a significant impact on production performance, which makes the reservoir more economically viable. However, it must be noted that fracture propagation is dependent on the in-situ stresses within the reservoir, and the most productive fracture orientation may not be achievable in all tight gas sands.

4. Conclusions

Based on the analysis of all simulation results the following conclusions can be reached regarding the impact of fracture length, spacing and orientation on tight gas production performance:

– Fracture number has more significant impact on well productivity (initial production rate/capacity) than fracture length, in the cases with equal total fracture volume. This is due to the smaller fractures having a larger contact area with the wellbore and subsequently increased production performance.
– However, fracture length has a larger impact on cumulative gas recovery than fracture number. This is primarily a result of the larger fracture spacing of longer fractures in this model, hence the longer fractures are not producing from the same zone as other fractures and accessing new portions of the reservoir.
– When possible, fractures should be completed along the wellbore to increase contact area between the wellbore and hydraulic fracture.
– Fractures along the wellbore are far more effective than perpendicular fractures, based on simulation results, 4 perpendicular fractures are required to better the along the wellbore fracture performance.
– After the initial hydraulic fracture, each subsequent fracture increases the initial gas production rate (within first 24 h) by a similar amount, and is independent of fracture length.

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Appendix G:

Liquid loading in wellbore and its effect on well clean-up period and well productivity in tight gas reservoirs, APPEA Journal, Brisbane, Australia

Lead author
Hassan
Bahrami

LIQUID LOADING IN WELLBORES AND ITS EFFECT ON CLEANUP PERIOD AND WELL PRODUCTIVITY IN TIGHT GAS SAND RESERVOIRS

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ABSTRACT

Tight gas reservoirs normally have production problems due to very low matrix permeability and significant damage during well drilling, completion, stimulation and production. Therefore they might not flow gas to surface at optimum rates without advanced production improvement techniques.

After well stimulation and fracturing operations, invaded liquids such as filtrate will flow from the reservoir into the wellbore, as gas is produced during well cleanup. In addition, there might be production of condensate with gas. The produced liquids when loaded and re-circulated downhole in wellbores, can significantly reduce the gas production rate and well productivity in tight gas formations.

This paper presents assessments of tight gas reservoir productivity issues related to liquid loading in a wellbore using numerical simulation of multiphase flow in deviated and horizontal wells. A field example of production logging in a horizontal well is used to verify reliability of the numerical simulation model outputs. Well production performance modelling is also performed to quantitatively evaluate water loading in a typical tight gas well, and test the water unloading techniques that can improve the well productivity.

The results indicate the effect of downhole liquid loading on well productivity in tight gas reservoirs. It also shows how well cleanup will speed up with the improved well productivity when downhole circulating liquids are lifted using the proposed methods.

KEYWORDS

Tight rock gas reservoir, liquid loading in wellbore, well productivity, production improvement.

INTRODUCTION

In gas producing wells, different downhole flow regimes might be present in a wellbore depending on gas and liquids velocities, and their relative amounts in the wellbore (Guo and Ghalambor, 2005). Under multiphase flow conditions, the light phase moves with a velocity different than the heavier one by a magnitude known as slippage velocity (Kappa Engineering Team, 2005). In a deviated wellbore, the lighter phase flows at the top side of the wellbore, and water as the heaver phase stays at the bottom side. The typical velocity profiles in horizontal wells in different deviations are shown in Figure 1. The density difference of coexisting fluids, the hold-up of liquid (Y_L: the ratio of a given pipe cross section occupied by liquid), and well deviation can control the slippage velocity and flow regimes in multiphase flow in oil and gas wells.

The basic flow regimes that usually represent multiphase flow in a gas well are shown in Figure 2. During progression of a typical gas well from initial production to end of life, one or more of these regimes might be encountered (Lea et al, 2008). In initial conditions, gas flow rate is high and the flow regime is in mist flow, and therefore the produced gas can carry the wellbore liquids to the surface. Then as the reservoir pressure drops, the gas velocity in the wells is declined, causing the carrying capacity of gas to decrease. When the gas velocity is less than a critical level, liquids begin to accumulate and be loaded in the wellbore. The liquid loading can gradually change the downhole flow regimes in a wellbore to annular flow and later to slug flow. Eventually, the well will undergo bubbly flow regime, with no economical production rates (Guo and Ghalambor, 2005).

Liquid loading is a common problem in gas wells, and can be in the form of liquid water and/or condensate. The liquids are loaded in the wellbore and cannot be lifted when the flow rate is less than the minimum gas flow rate and gas velocity is not high enough. As a result, the well's productivity is affected due to the additional drop of pressure in the wellbore where the circulating liquids are present. The liquid circulation makes the well downhole operating conditions unstable.

The carrying capacity of the gas to lift liquid in gas wells depends on the tubular sizes, pressure losses across the wellbore, the surface pressure, the amount of liquids being produced with the gas, wellbore deviation, and the gas composition (Lea et al, 2008; Veeken et al, 2009). A

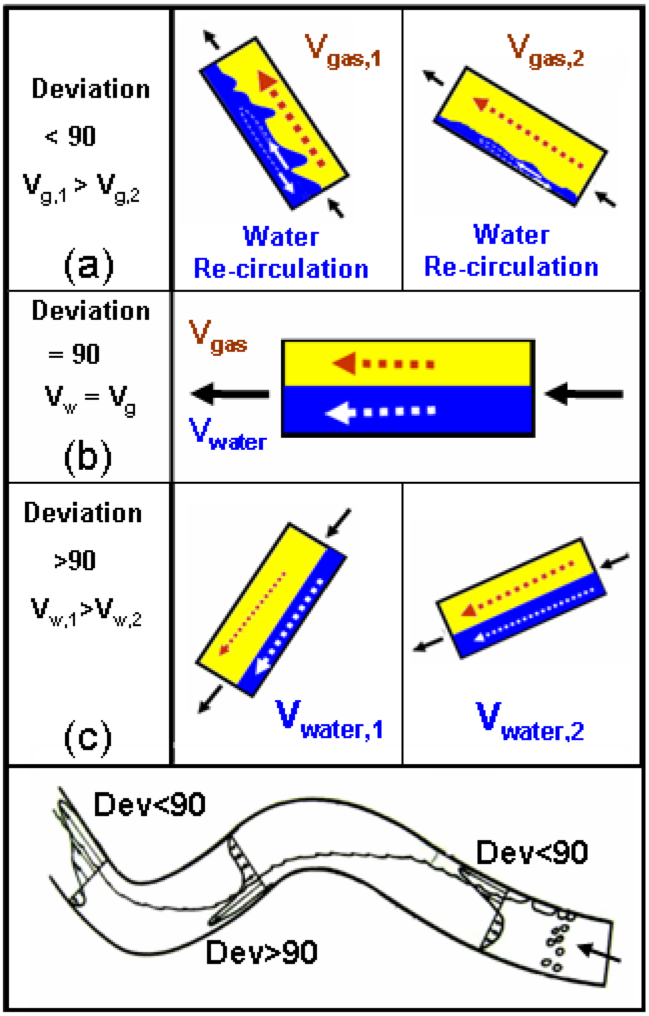

Figure 1. Typical flow regimes in deviated horizontal wells.

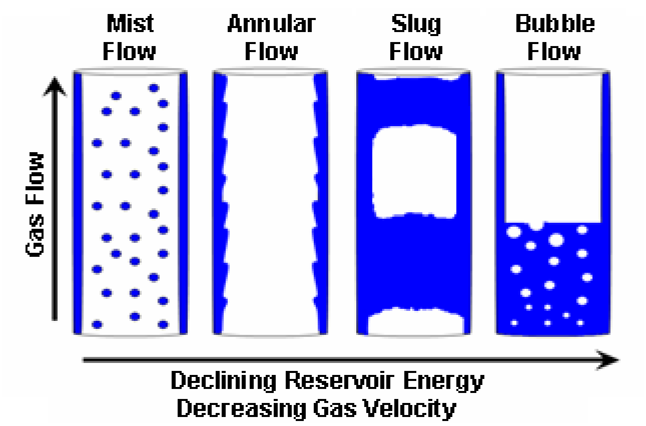

Figure 2. Flow regime changes with decline of reservoir pressure and gas velocity.

sharp decline in the gas production rate can indicate that the liquid column is building up in the well and an additional energy is required to lift the liquids out (Guo and Ghalambor, 2005). If a corrective action is not taken after a liquid loading problem starts, the well production rate will continue to decline and eventually log off (Lea et al, 2008). To reduce liquid loading and modify flow regimes in gas wells, different methods can be employed such as: flowing at a high velocity by use of optimum tubing diameter; creating a lower wellhead pressure using pump; using gas lift to take the liquids out of the well; and using surfactants. Foaming the liquids to reduce water density is also another technique to enable the gas to lift liquids from the well (Lea et al, 2008).

When reservoir energy is low and natural gas flow rate is not high enough to lift the wellbore liquids to the surface, the liquids are loaded in the wellbore and create problems for well productivity. This study aims to evaluate the water loading problem as one the factors that can control productivity of tight gas wells.

CLEANUP IN TIGHT GAS RESERVOIRS

Tight gas reservoirs normally have production problems due to a very low matrix permeability and significant damage during well drilling, completion, stimulation and production. Therefore they might not flow gas to the surface at optimum rates without advanced production improvement techniques (Brant and Brent, 2005).

After well stimulation and fracturing operations, invaded liquids such as filtrate will flow from the reservoir into the wellbore as gas is produced during well cleanup. In addition, there might be production of condensate with gas. The produced liquids when loaded and re-circulated downhole in the wellbore, can significantly reduce the gas production rate and well productivity from tight gas formations. As a field example of tight gas cleanup after stimulation (Shaoul and Koning, 2009), a total of around 2,000 barrels water leaked off into the formation during the fracturing operations, and around 700 barrels of water was produced back during the 35-day cleanup period. In this time period, gas flow rate reduced from 3.5 MMSCFD to 1.5 MMSCFD.

A commercial reservoir simulation software was used to build a reservoir simulation model of a multiple hydraulic fractured tight gas reservoir and study water and gas production behavior during the well cleanup period in case of an efficient stimulation operation. The 3-Dimentional view of the model with hydraulic fractures across the horizontal wellbore in well XX-01 and the model input data are shown in Figure 3 and Table 1 respectively. In the multiple hydraulic fractured tight gas reservoir model, first water was injected for two days to have water invasion, and then the well was put on production to predict water production behavior as gas is produced.

Dimensionless production rates (Q_d: ratio of production rate to the initial production rate) of water and gas were plotted, as presented in Figure 4. The observations indicated that the very low permeability in the tight gas

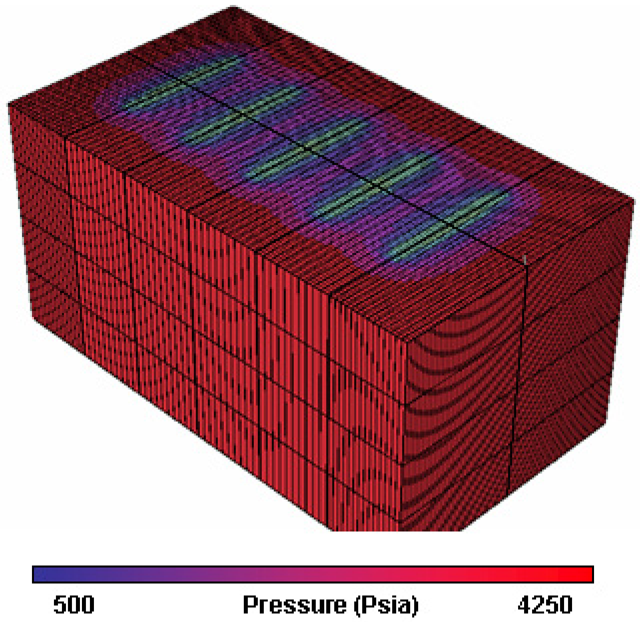

Figure 3. The 3-D view of the tight gas simulation model, with 5 hydraulic fractures perpendicular to the horizontal leg.

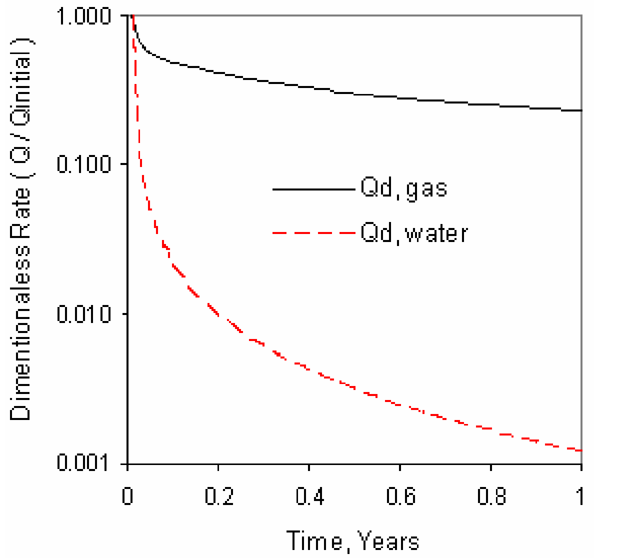

Figure 4. A typical gas and water production behavior during cleanup of the stimulated tight gas reservoir.

reservoir made the cleanup period last for a relatively long period of time. The effect of relative permeability and capillary pressure curves is also an important consideration, since they can have significant impact on the amounts of produced water from an invaded zone. The cleanup of invaded liquids might take a few months or even up to one year, depending on reservoir permeability. Knowing that the gas production rate and driving energy normally declines in tight gas reservoirs sharply, the presence of produced liquids in gas flow in such wells especially in deviated sections may cause the well to face a liquid loading problem and not produce to its maximum gas deliverability potential.

Table 1. Input parameters in reservoir simulation model of well XX-01.

Porosity	%	5
Permeability	md	0.002
Reservoir thickness	ft	60
Reservoir pressure	psia	4,250
Horizontal well length	ft	4,000
No. of hydraulic fractures	-	5
Fracture half length	ft	710
Initial gas production rate	MMSCFD	12
Gas production rate after one year	MMSCFD	3

FILED EXAMPLE OF WATER LOADING

A production logging tool with water hold-up measurements sensors was run in the horizontal well YY-01 to evaluate the well's production performance. There was no water production reported at the surface of this well. Figure 5 shows the well trajectory in a vertically zoomed scale (Figs 5a and 5b), the water hold-up (Y_w) data across the horizontal leg (Fig. 5c), and also water hold-up measurement sensor positions on the production logging tool (Fig. 5d). The four water hold-up sensors were mounted on caliper arms to record water hold-up data during the production logging: a probe at the top side of wellbore (probe 1), two probes around middle (probes 2 and 3), and one at the bottom side of the wellbore (probe 4).

As can be seen in Figure 5c, from point A to point D, wellbore deviation varies between 89 and 92 degrees, and no significant water loading was detected by hold-up sensors. From point D to point E where deviation changes to 85, significant amounts of water were detected by production logging water hold-up sensors. In this interval, the bottom probes 3 and 4 read almost 100% water (Y_w=1), whereas top probes 1 and 2 read mainly hydrocarbon (Y_w=0).

The results indicate that there is re-circulation of water downhole and the well faces a water loading problem, although no water was coming to the surface at the time of logging. In low productivity gas wells—especially when they are deviated or horizontal—evaluating production performance using production logs can help detect possible liquid loading, which in such cases can provide an option for improving well productivity.

NUMERICAL SIMULATION OF LIQUID LOADING

Multi-phase flow is a very complex physical phenomenon, in which different phases travel with different speeds depending on the difference between density of phases, hold-up of each phase, and the wellbore deviation. In multiphase flow, the liquid-gas contact line is not stable due to the presence of a disturbed interfaces (e.g. surface waves on a falling film, or large, highly deformable drops or bubbles) and since there is transition between different gas-liquid flow regimes. The difficult physical laws and mathematical treatment of phenomena occurring in the presence of the two phases (the interface dynamics, drag, etc.) are still largely undeveloped, causing some uncertainties in results of simulation models (Ghorai, 2008). In this study, the numerical simulation approach was used to qualitatively model water loading in a gas well.

A series of simulation runs were carried out using a commercial computational fluids dynamics (CFD) simulation software, which solved continuity and momentum equations for a deviated horizontal wellbore with two phase flow

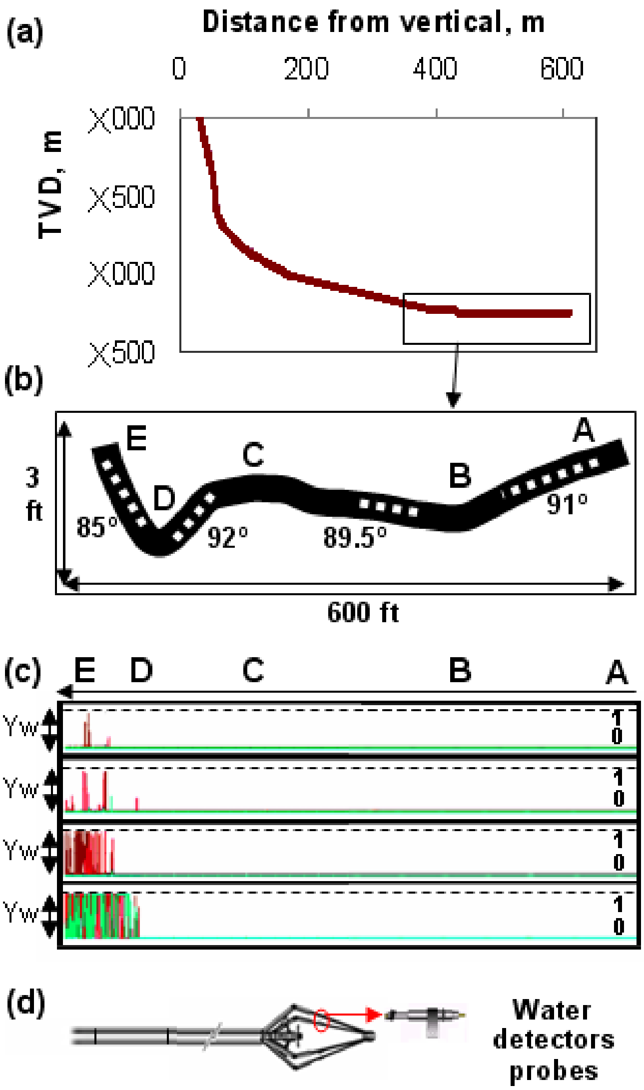

Figure 5. Production logging tool water holdup readings in the horizontal well YY-01.

of gas-water. The input data into the model are presented in Table 2. The data similar to well YY-01 were input to have a model that is calibrated with an actual case and therefore have appropriate selection of equations in the software. Figure 6 shows qualitative results from the simulation model of 20 MMSCFD gas flow with 0.99 gas fraction. The results indicate water loading in deviations below 90 degrees. Section B-C with deviation of 89.5° showed very small amounts of water loaded in the lower side of the wellbore. In section D-E with deviation of 85°, significant amounts of water loading was observed in wellbore. The results from the simulation were approximately in agreement with observations in well YY-01 water loading conditions, confirming the reliability of the model in terms of water loading prediction. This model was used as the base model, to perform sensitivity analysis.

Figures 7a and 7b show water loading when the gas flow rate is reduced to 4 MMSCFD and 1 MMSCFD, which indicates the well will have more severe water loading problem in lower gas flow rates. Based on simulation results, in addition to the sharp decline of drive energy and gas flow rate with time in tight gas sand reservoirs, when there is water re-circulation downhole in wellbore, the loading of the considerable amounts of water can cause more deterioration of well productivity with passage of time. Therefore in addition to the declining production rate, liquid loading can cause further reductions in productivity of tight gas wells.

PRODUCTIVITY IMPROVEMENT BY WATER UNLOADING

Well production performance modelling was performed using a commercial multiphase flow simulator software to evaluate water loading in the typical tight gas well ZZ-01, and to test the water unloading techniques and improve the well productivity. Table 3 shows model input data. First, several cases were run as sensitivity analysis

Table 2. Input data to the CFD simulation model of fluid flow in wellbore, based on well YY-01 data.

Horizontal well length in the model	ft	600
Wellbore ID	Inches	6.2
Operating pressure	psia	5,000
Downhole gas density	kg/m³	140
Downhole gas viscosity	cp	0.0204
Downhole water density	kg/m³	1,006
Downhole water viscosity	cp	0.3
Primary fluid in wellbore	-	Water
No. of cells in the model	-	236,000
No. of nodes in the model	-	248,000
No of iterations in each simulation run	-	5,000

in order to select appropriate models and equations for flow regime and critical unloading velocity options in the software. Due to a low gas production rate, some models were insensitive to the changes in well parameters, some were too sensitive, and some gave unrealistic results. After sensitivity analyses were completed, finally the Hagedorn and Brown flow model and the Coleman critical unloading velocity were selected in the base model, as they provided more reasonable results in the sensitivity analysis runs.

Figure 8 shows inflow performance relationship (IPR) and tubing performance relationship (TPR) curves, and the liquid loading (LL) line that resulted from the well performance modelling results. The well operating point, which is the intersection of IPR and TPR curves, shows that the well can produce with a flow rate of 2.55 MMSCFD. The liquid loading line indicates that a minimum gas flow rate to avoid water loading is around 2.65 MMSCFD. In other words, the well has a water loading problem under these well and reservoir conditions.

Different water unloading techniques were considered to improve the wells productivity. Figure 9 shows the use of a water foaming system in which water density is reduced from 1 gr/cc to 0.8 gr/cc. Using the system, the line showing the minimum gas flow rate to avoid water loading was moved from 2.55 MMSCFD [LL1] to 2.52 MMSCFD [LL2], which means water can be unloaded using the technique. The water unloading might result in slight productivity improvement at this stage, however the main objective is removing the water from the wellbore to improve well productivity in the long term. The liquid loading predication results also indicate that if the mud had been selected as oil-based mud instead of water-based mud, the well would not have faced the liquid loading problem since oil has less density than water.

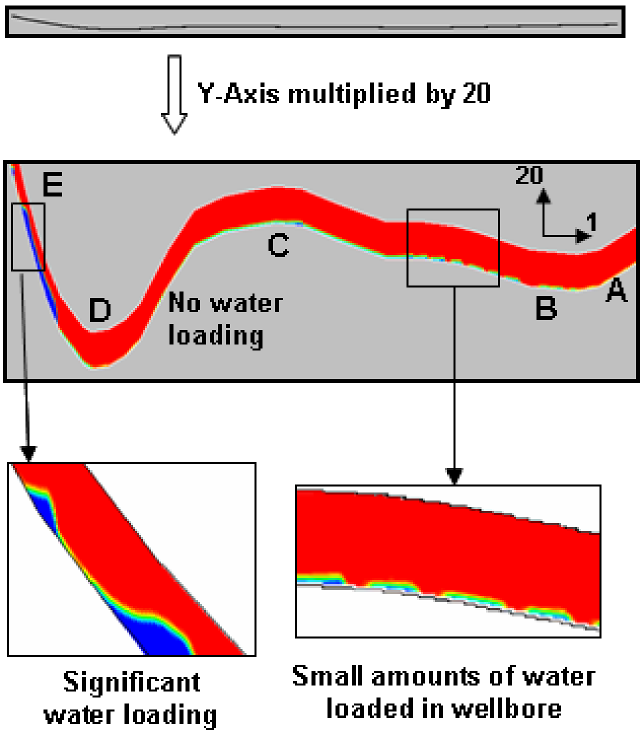

Figure 6. Preliminary model qualitative simulation results in case of 20 MMSCFD gas flow rate. Water loading results approximately calibrated with well YY-01 water loading (Y-Axis multiplied by 20 to better visualise the simulation results).

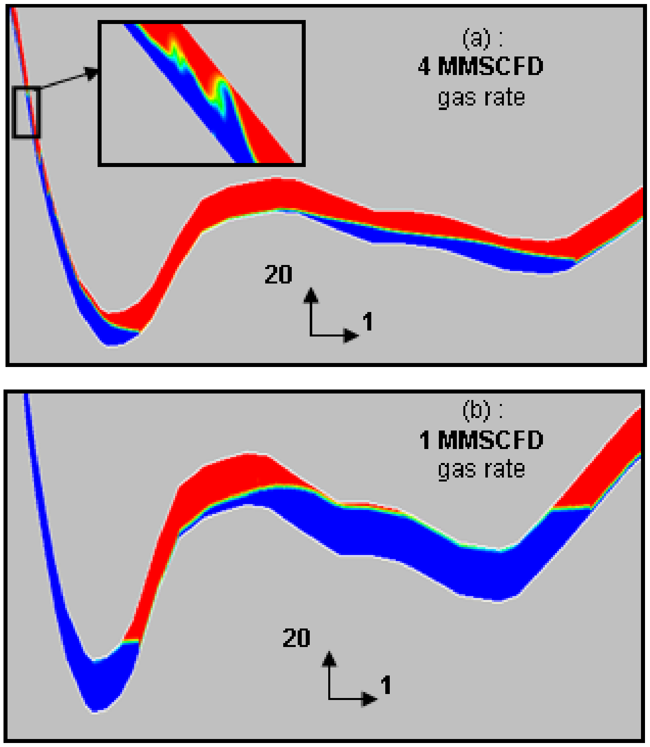

Figure 7. Sensitivity analysis to evaluate effect of gas flow rate on water loading in well YY-01 (Y-Axis multiplied by 20 to better visualise the simulation results).

Table 3. Input data used for well performance modelling of well ZZ-01 in the stimulated tight gas reservoir.

Porosity	%	7
Permeability	md	0.01
Skin	-	-3
Reservoir pressure	psia	5,000
Reservoir thickness	ft	300
Horizontal well length	ft	1,000
Initial gas production rate	MMSCFD	12
Tubing ID	inch	4
Initial water gas ratio	STB/ MMSCF	20
Gas S.G. (air=1)	-	0.65
Water density	Kg/m^3	1,000

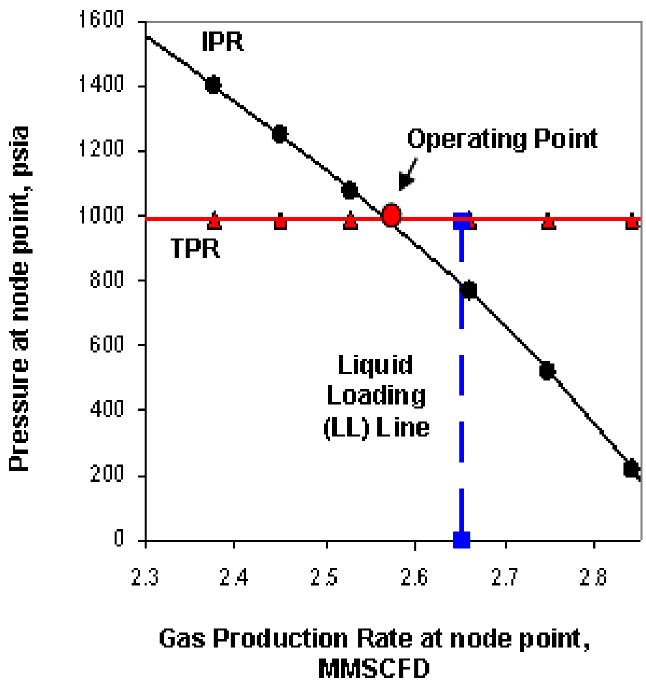

Figure 8. Well performance modelling results of water loading in well ZZ-01.

Figure 10 shows use of tubing size optimisation for water unloading. In this case, a 2.8-inch coiled tubing is run inside 4-inch ID well tubing, and gas can flow to the surface via the area between the 2.8-inch and 4-inch pipes. As a result of the reduction in area in the wellbore and an increase in gas velocity, the minimum gas flow rate to avoid water loading is reduced from 2.55 MMSCFD [LL1] to 1.32 MMSCFD [LL2]. In other words, successful removal of water from the wellbore and a single phase gas production can be achieved using the system; however, it should be noted that due to a reduction in the wellbore flowing area, there is a slight decrease in the gas production rate using the method. When using the coiled tubing system, gas injection into the coiled tubing can also be considered to enhance the process of water lifting to the surface and to unload the well from circulating liquids downhole.

DISCUSSION

Water loading can be an important factor in controlling the productivity of tight gas reservoirs, especially in late time when the reservoir driving energy and gas flow rate declines. Based on the simulation and modelling study, to have optimum productivity in tight gas reservoirs it is important to minimise the amounts of water or other liquids to be invaded into the reservoir matrix and fracture during drilling and well completion. The tight gas strategy is recommended to be focussed on under-balanced drilling

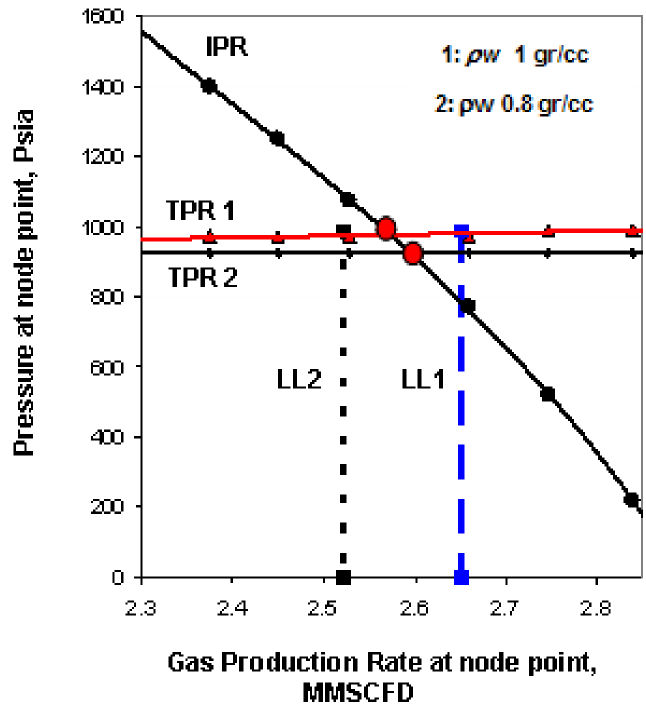

Figure 9. Well performance modelling results of water unloading in well ZZ-01 for reduced liquid density.

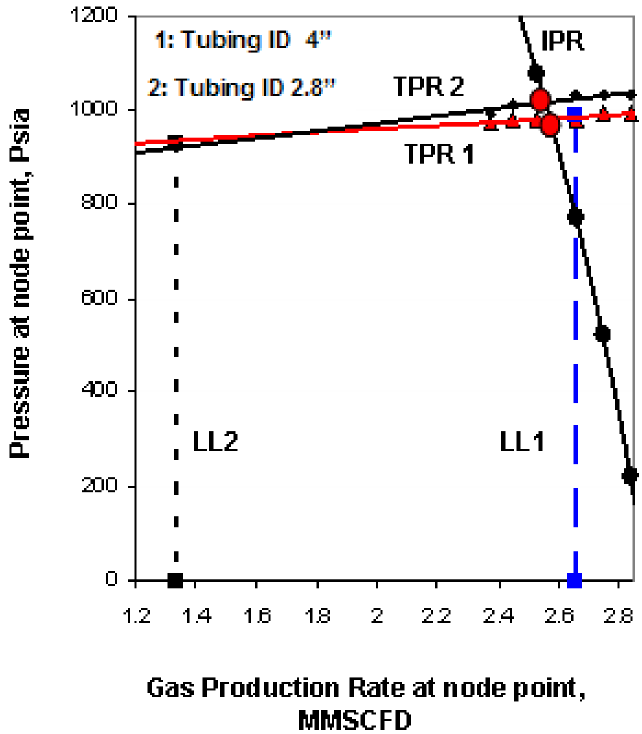

Figure 10. Well performance modelling results of water unloading in well ZZ-01 for optimised tubing size.

to reduce the damage to near wellbore region by liquid invasion, and also lessen the significant amounts of water filtrate production during cleanup.

Tubing size optimisation can help in production at optimum gas velocity. During the cleanup period of tight gas wells, a coiled tubing can be temporarily run in the wellbore through the well tubing to lessen the wellbore area and increase gas velocity to lift the circulating liquids downhole. Partially injection of the produced gas to the bottom of the well via the coiled tubing can further improve the water unloading process. After the cleanup process is completed, the coiled tubing can be removed and the well can continue with normal production.

The use of an oil-based mud system can also help reduce the detrimental impact of liquid loading on tight gas wells' productivity. As shown for well ZZ-01, the well could have no liquid loading problem if the invaded liquid was oil (density of 0.8 gr/cc), instead of water filtrate (1 gr/cc filtrate density). Use of the oil-based mud system can also reduce the problems related to shale intervals.

To further reduce damages to formation and avoid any liquid loading, feasibility of drilling using foam or gas needs to be studied for tight gas reservoirs. Theoretically, this approach can help the well to produce to its maximum potential, since near wellbore reservoir region is exposed to the lowest damage and there will be no liquid in the wellbore.

CONCLUSION

According to the simulation modelling results performed in the study for stimulated gas wells in tight sand reservoirs, there might be significant production of filtrate with gas during the cleanup period, which can cause a water loading problem. The very low permeability in the tight gas reservoirs result in a long clean-up period.

A tight gas well might have a water loading problem downhole, although no water may come to the surface. Production logging in tight gas wells can help detect possible liquid loading in the wellbore.

Water loading can have a negative impact on the productivity of gas wells in tight formations, especially in late time when gas flow rate declines. Therefore in addition to the decline of production rate in late time production history of a gas well, the liquid loading can cause a further reduction in a well's productivity.

The use of an oil-based mud system instead of water-based mud during the drilling of tight sand formations can help reduce liquid loading problems in a wellbore, since oil has less density than water.

Tubing size optimisation and the use of foaming agents can help unload re-circulating liquids. As a result, the cleanup period will speed up and productivity is improved.

NOMENCLATURE

P	Pressure
Y_w	Water hold-up
Y_g	Gas hold-up
Q	Flow rate
ρ_w	Water density
ρ_g	Gas density
μ	Viscosity
V	Velocity
ID	Internal diameter
t	Time
K	Permeability
S	Skin
L	Length
WGR	Water gas ratio
$MMSCFD$	Million standard cubic feet per day

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APPEA