Faculty of Science and Engineering
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Hydraulic Fracture Productivity Performance in Tight Gas Sands, A Numerical Simulation Approach

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Of
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Declaration

To the best of my knowledge and belief this thesis contains no material previously published by any other person except where due acknowledgment has been made. This thesis contains no material which has been accepted for the award of any other degrees or diploma in any university.

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Abstract

Hydraulically fractured tight gas reservoirs are one of the most common unconventional sources being produced today, and look to be a regular source of gas in the future. Tight gas sands by definition have extremely low permeability and porosity, and are most often uneconomical to produce without the aid of some form of reservoir stimulation. Hydraulic fracturing is one of the most common forms of commercially extracting gas from tight gas sands and is becoming increasingly popular in America, Canada and the rest of the world, with some projects in Australia.

Along with the low productivity, tight gas sands are faced with other additional challenges if compared to conventional reservoirs, such as near wellbore damage due to water blocking, mechanical damage, fluid invasion and wellbore breakouts. In addition, inaccuracy of conventional build-up and draw-down well test results is common. 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. This leads to the need for accurate simulation of tight gas reservoir well tests or a reduction in analysis time.

The primary aim of this research project is to use early time well test and production data to determine insights into hydraulic fracture productivity performance. The work is presented with reference to two published peer-reviewed papers published as lead author and one peer-reviewed paper published as co-author. The two main methods of analysis used will be Horner plot and a semi-log plot of production rate vs. log-time. Sensitivity analysis on fracture number, size and orientation with respect to the wellbore are conducted.

The production and pressure buildup data is generated using commercial 3-D reservoir simulation software, Eclipse. A box model with generic tight gas properties is created with realistic hydraulic fracture and well completion simulated. Data is either compared to an unfractured tight gas sand model, or to a model with different number of fractures but comparable overall fracture volume.

Acknowledgments

I would like to express my sincere thanks to my supervisors Associate Professor Reza Rezaee and Dr. Mofazzal Hossain and Hassan Bahrami for all their help and patience throughout this project. They dedicated their time unselfishly and willingly to help me finish this project to a level I am proud of. They provided me with the guidance I needed to organize this project and present it in a meaningful and useful way.

I would also like to thank my family and friends who supported me in various ways throughout my university life, it has made the process infinitely easier.

List of Publications Included as Part of the Thesis

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*Production Performance of Hydraulic Fractures In tight Gas Sands, A Numerical Simulation Approach.*Ostojic, J., Rezaee, R., and Bahrami, H.

2011 JPSE:

Hydraulic Fracture Productivity Performance In Tight Gas Sands – A Numerical Simulation Approach. Ostojic, J., Rezaee, R., and Bahrami, H.

2011 SPE:

Evaluation of Damage Mechanisms and Skin Factor in Tight Gas Reservoirs. Hassan Bahrami., Reza Rezaee.,JakovOstojic., DelairNazhat/ Curtin University, Ben Clennell/ CSIRO

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Nomenclature

σ_{eff} = Effective Stress

$\sigma = Stress$

$\alpha = Effective\ Stress\ Coefficient$

$P_P = Pore\ Pressure$

$N_P = Proppant\ Number$

$I_x = Fracture\ Penetration\ Ratio$

$C_{fD} = Absolute\ Fracture\ Conductivity$

$k = Reservoir\ Matrix\ Permeability$

$k_f = Fracture\ Permeability$

$w_f = Fracture\ Width$

$x_f = Fracture\ Half\ Length$

$x_e = Half\ Length\ of\ Square\ Drainage\ Area$

$V_p = Propped\ Fracture\ Volume$

$V_e = Well\ Drainage\ Volume$

$GIIP = Gas\ Initially\ In\ Place$

$OIIP = Oil\ Initially\ In\ Place$

$m(p) = Pseudo\ Pressure$

$P = Pressure$

$Z = Gas\ Compressibility\ Factor$

$\mu = Viscosity$

$t = Time$

$t_a = Pseudo\ Time$

$C_t = Total\ Compressibility$

$\Delta P = Change\ in\ Pressure$

$q = Flow\ Rate$

$B = Formation\ Volume\ Factor$

$\Phi = Porosity$

$\Delta t = Change\ in\ Time$

$\Delta t = Change\ in\ Time$

$t_p = Production\ Perdio\ Time$

$h = Height/Thickness$

$r_w = Wellbore\ Radius$

$m = Slope$

$S = Skin$

$b = Constant$

$S_w = \ Water\ Saturation$

$k_{rg} = Gas\ Relative\ Permeability$

$S_{ch} = Choke\ Skin\ Effect$

$Mscf/d = Thousand\ Standard\ Cubic\ Feet\ per\ Day$

1.0 Introduction and literature review

The increasing global demand for energy along with the reduction in conventional reserves has led to the increasing demand and exploration of unconventional 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 commonly classified as low permeability (less than 0.1mD) and low porosity, with high irreducible water saturation and high capillary pressures (Addis and Yassir, 2010). Naturally these sub-optimal reservoir properties have a significant impact on reservoir productivity and production performance. Shanley et al., (2004) describe this poor productivity as "permeability jail" (Figure 1).

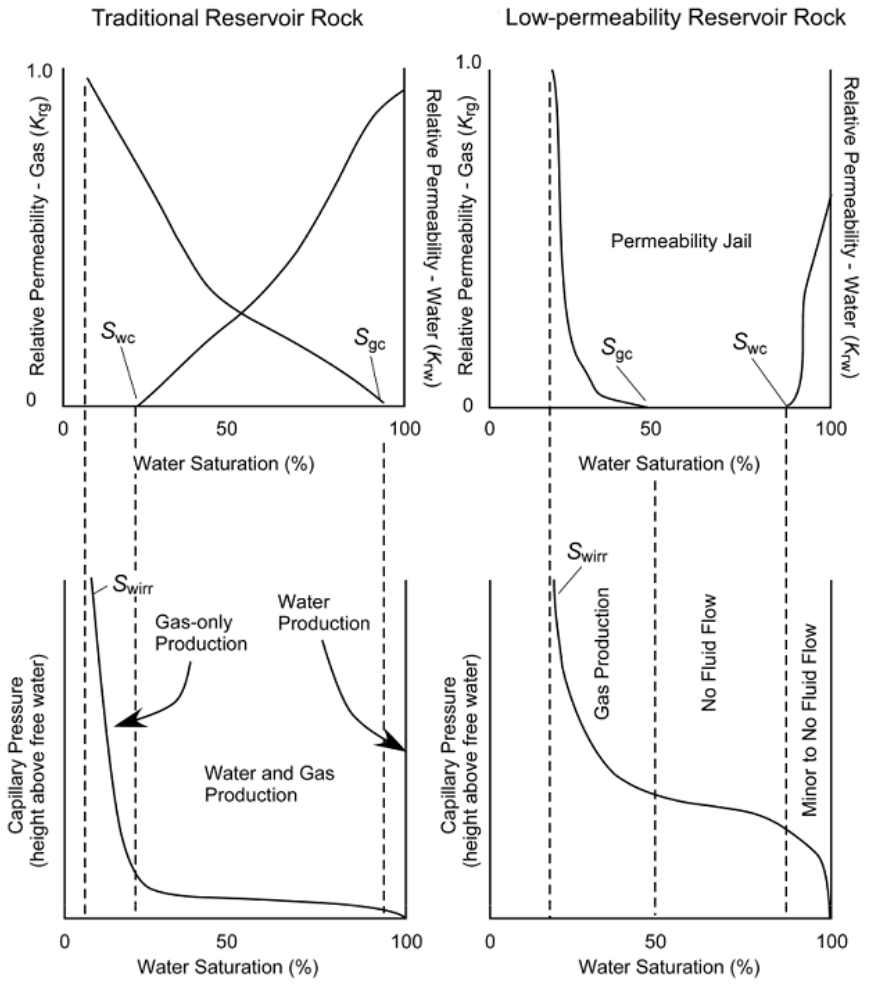

Figure 1: Schematic of "permeability jail" on typical tight gas relative permeability curves (Shanley et al., 2004)

In general tight gas formations are not economical to produce without having aid from some form of artificial productivity increase. Holditch (2006) defines tight gas sands to be "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 define tight gas sands as requiring "man-made" permeability systems for economic production.

This research project, however, aims to: investigate the sensitivity of various reservoir and hydraulic fracture parameters, such as multiple hydraulic fractures, fracture spacing, fracture orientation on productivity performance; and serve as a guide for further optimization work based on numerical reservoir simulation. The results gathered are outputs from a simulated 3-D tight gas reservoir with multiple hydraulic fractures, with the primary focus on fracture spacing, number and orientation. Section 1.2 details previous research focuses on this area of hydraulic fracture optimization and the conclusions reached.

Due to the low productivity and permeability of tight gas sands, the reservoir response is significantly delayed compared to conventional reservoirs, thus reducing the economic appeal of conventional well testing (Pankaj and Kumar, 2010). The study also focuses on gathering insights from well tests via pressure derivative response and early time production data, with the aim to analyse fracture performance. In order to asses hydraulic fracture performance the process through which hydraulic fractures are initiated and propagate must be understood. Mechanical properties of the reservoir and surrounding rock have the most significant impact on hydraulic fracture behavior. This is elaborated in section 1.1.

1.1 Significance of Mechanical Rock properties on hydraulic fracturing in tight gas sands

The vast majority of tight gas reservoirs are multilayered sands, with relatively poor connectivity between the gas bearing layers. Hydraulic fracturing is often the most effective way to produce this form of gas at economical rates (Pankaj and Kumar, 2010). Green et al., (2009) notes that previous work has been done to suggest that mechanical rock properties are secondary factors in hydraulic fracture containment. However, results generated by simulation software "GHOFER" showed that rock mechanical properties do have a substantial impact on hydraulic fracture growth, and overall the differences are greater for varying Young's modulus compared to Poisson's ratio. Pankaj and Kumar (2010) state that hydraulic fracture design is in fact highly dependent on the mechanical properties of the rock, such as, Young's modulus, Poisson's ratio and fracture toughness and shear modulus, even though they may not have as a significant effect as other reservoir properties.

Hydraulic fracturing most often contains two stages of fluid pumping, a mini-frac to establish injectivity and gather necessary reservoir data for the main fracture job. The main fracture job involves the pumping of fluid and proppant to keep the fracture open and provide a higher permeability flow path for the fluid (Pankaj and Kumar, 2010). The details of the mini-frac process is elaborated in section 1.2.3.

The process of drilling through a rock mass and injecting it with a fluid at high rates causes significant stress concentrated in a relatively small area. When production occurs from this

stress augmented portion of the reservoir rock it can lead to the development of a stress reversal region (Aghighi et al., 2009).

Benedict and Miskimins (2009) discuss the impacts of re-fracturing and hydraulic fracture reorientation in tight gas sands. Traditionally, the goal of re-fracturing was to repair or replace initial hydraulic fractures which had below expected production performance. Fracture reorientation provides a new reason for re-fracturing, which is to intersect and produce from new sections of the reservoir via reoriented hydraulic fractures (Figure 2). Conventional radial drainage patterns are not often observed in tight gas sands, rather an elliptical drainage pattern surrounding the fracture is often observed.

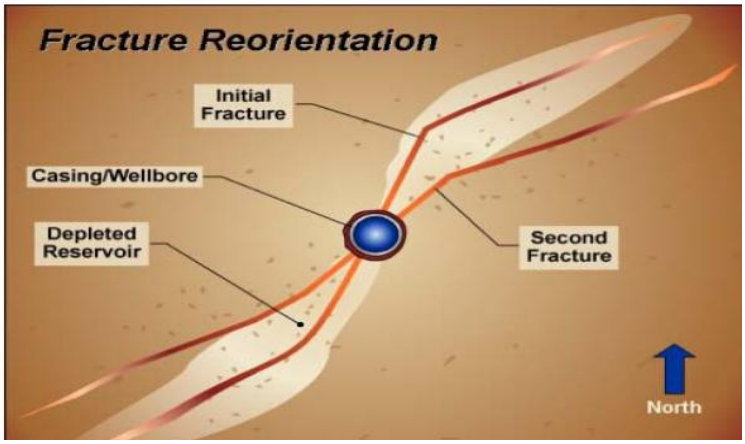

Figure 2: Fracture reorientation schematic, highlighting growth of re-orientated fracture in depleted reservoir section (Benedict and Miskimins, 2009)

In order for hydraulic fracture reorientation to occur, the direction of near wellbore stress must be different to the original stress orientation at the time of the initial hydraulic fracture. There are generally two scenarios which can cause this phenomenon;

- Production of hydrocarbons resulting in a localized change in pore pressure and stress reorientation.
- Hydraulic fracturing process impacts the original effective stress such that maximum horizontal stress changes orientation (Shah et al., 2010).

Effective stress within a reservoir is defined by Equation 1:

$$\sigma_{eff} = \sigma - \alpha P_P \qquad (1)$$

Where:

$\sigma_{eff} = Effective\ Stress$ $\sigma = Stress$

$\alpha = Effective\ Stress\ Coefficient$ $P_P = Pore\ Pressure$

From Equation 1, it is clear that the pore pressure will have a direct impact on effective stress within a reservoir system.

Previous work has been done to show that the stress reversal phenomenon, required for fracture re-orientation, can be used to instigate a fracture along a different azimuth plane from the primary fracture. The new fracture can be rotated up to 90^{o} compared to the primary fracture, hence allowing production from regions not contacted by the primary fracture (Aghighi et al., 2009).

Morrill and Miskimins, 2012, analysed the minimum fracture spacing required to eliminate the possibility of stress interference from nearby fractures. Each hydraulic fracture creates an envelope of high stress in its direct surround area. When a subsequent fracture is placed too close, the initiation pressure, propagation and conductivity of the subsequent fracture can be greatly affected. The stress envelope created by hydraulic fractures and its impact on subsequent fractures is referred to as “stress shadowing”.

From the variables investigated by Morrill and Miskimins (2012), the ratio of minimum versus maximum horizontal stress proved to be the most sensitive in terms of its impact on the stress shadow of a hydraulic fracture (Figure 3).

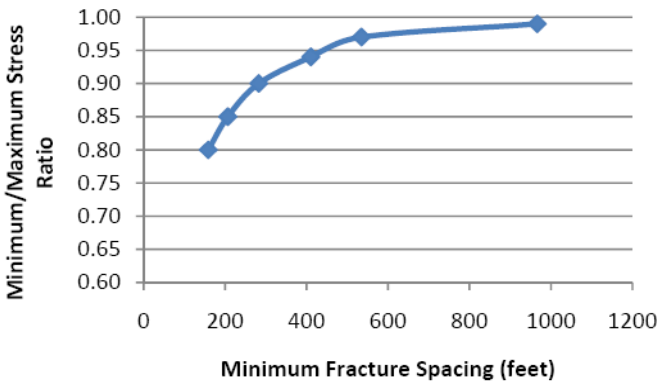

Figure 3: Minimum/Maximum stress ratio impact on minimum fracture spacing requirements as a result of "Stress shadowing" (Morrill and Miskimins (2012)

Figure 3 shows that minimum fracture spacing for different minimum/maximum stress ratios can influence the minimum recommended fracture spacing by several hundred feet. Thus for multiply fractured reservoirs, the impact on minimum/maximum stress ratio of each previous fracture must be assessed prior to any future fracture design.

Similarly Poisson's ratio was found to have a substantial impact; whereas the Biot’s parameter and net fracture pressure were found to have a smaller impact on minimum fracture spacing. However, all these factors are secondary in terms of hydraulic fracture productivity compared to other reservoir and fracture properties.

Akrad et al., 2011, conduct laboratory experiments to analyse the impact on reservoir rock mechanical properties when exposed to fracturing fluids, and how these changes impact the proppant embedment process. Reservoir rock Young's modulus is one of the key criteria used to select the most appropriate fracturing fluid, as it provides an indication of how much fracture conductivity can be expected. Experimental studies show that maximum reduction in Young's Modulus occurs when high reservoir temperatures are observed, and the reservoir rock contains high carbonate content. The reduction in Young's Modulus can result in a significant reduction in fracture conductivity and therefore production performance. The reduction in fracture conductivity is believed to be a result of increased proppant embedment, shown in Figure 4:

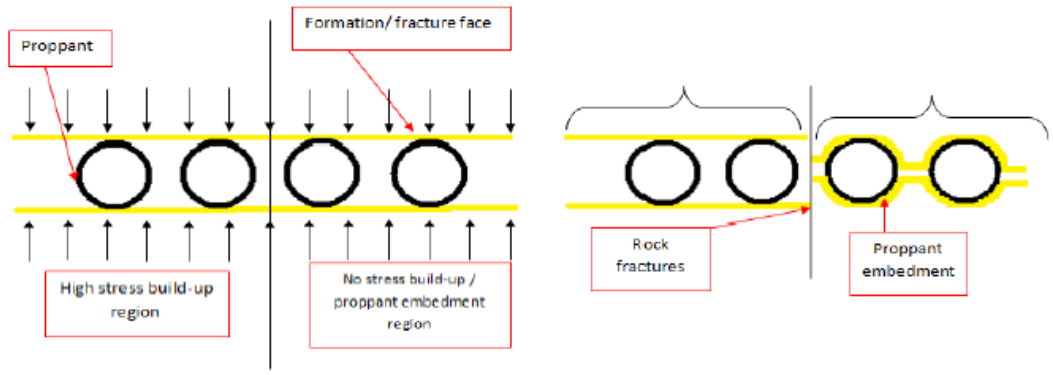

Figure 4: Schematic representation of proppant embedment (Akradet, al. 2011)

The example above depicts the scenario where the fracture separates the rock, such that, on either side of the fracture the rock stiffness is different. The stiffer rock on the left hand side of the fracture can handle the pressure buildup, where as the softer rock breaks and proppant embedment occurs. From Figure 4 it is evident that due to the reduction in fracture area open to flow, proppant embedment can have adverse effects on hydraulic fracture productivity performance.

1.1.1 Hydraulic fracture initiation and propagation

Hydraulic fractures are created by pumping fracture fluid into the reservoir formation at a pressure larger than the in-situ formation pressure until a fracture is initiated. Fracture propagation is enhanced by continuous high pressure fracture fluid injection. The fracture will begin to close if the pressure within the fracture (governed by proppant properties and injection rate) falls below the formation in-situ pressure. Once the fracture is closed, i.e. fracture width is zero; the fracture closure pressure is understood, which is of great importance in terms of hydraulic fracture design and optimization. Figure 5 displays typical bottom-hole pressure response during hydraulic fracturing over time (Pankaj and Kumar, 2010).

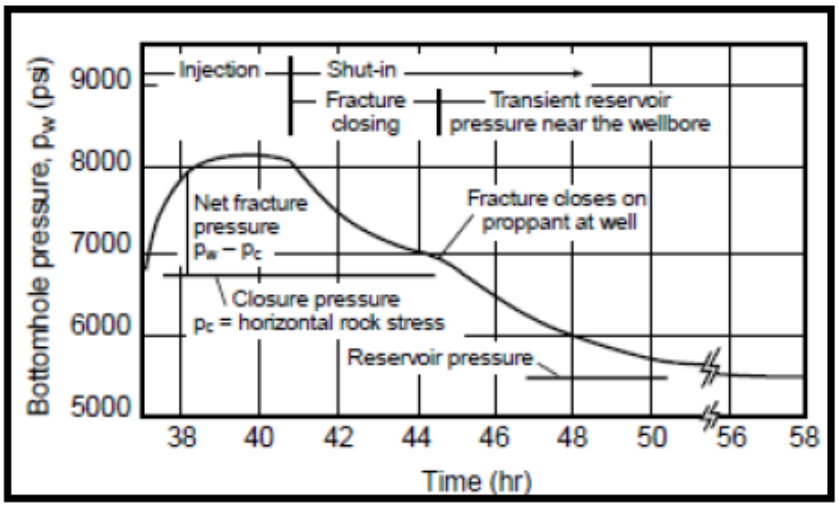

Figure 5: Typical bottom hole pressure response vs time during hydraulic fracturing(Pankaj and Kumar, 2010)

1.1.2 Previous work on fracture productivity and optimization

There have been many documented studies regarding optimization of various fracture properties, such as fracture length and aperture, to improve reservoir production performance. Prats, (1961) was the first to discuss hydraulic fracture optimization and since then numerous engineers and scientists have researched the topic; including fracture size and number sensitivity in terms of cumulative gas production and reservoir sweep.

Pankaj and Kumar (2010) analyse 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. Furthermore, no correlations or conclusions regarding fracture productivity are reached; rather the basic reservoir response is monitored and documented.

Shah et al., 2010, discusses the theoretical difference between hydraulic fracture performance based on orientation, comparing fractures perpendicular and parallel to the wellbore. Hydraulic fractures created along 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 and therefore resulting in more turbulent flow. Again, no universal fracture optimization technique is presented, but rather a discussion on the theoretical expectation of hydraulic fracture design based on fracture orientation.

Valko and Economides (1998) propose a widely used and refined model called the Unified Fracture Design method (UFD). A cornerstone in the theory behind the UFD method is that “penetration and dimensionless fracture conductivity are competing for the source: propped volume”. The UFD method is centred around what is now referred to as the “proppant number” ,N_p, which is defined as a permeability weighted number equal to two times the ratio

propped fracture volume vs reservoir volume, given by Equation 2 below(Jamiolahmady et al., 2009).

$$N_P = I_x^2 C_{fD} = \frac{k_f}{k}\frac{w_f X_f}{X_e^2} = 2\frac{k_f}{k}\frac{V_p}{V_e} \quad (2)$$

Where:

$N_P = Proppant\ Number$

$I_x = Fracture\ Penetration\ Ratio$

$C_{fd} = Absolute\ Fracture\ Conductivity$

$k_f = Fracture\ Permeability$

$k = Reservoir\ Matrix\ Permeability$

$w_f = Fracture\ Width$

$x_f = Fracture\ Half\ Length$

$x_e = Half\ Length\ of\ Square\ Drainage\ Area$

$V_p = Propped\ Fracture\ Volume$

$V_e = Reservoir\ Matrix\ Volume$

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

Tudor et al., (2009) conducted simulations of different fracture numbers in the same tight gas system. No correlation is presented between productivity performance and fracture number. However, it is presented and shown that after that first fracture, all additional fractures have a lesser impact on initial productivity.

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 increased connectivity with high permeability natural fractures. In addition, the impact of depletion effects on is-situ stress within a tight gas reservoir is studied and significant changes observed. The changes in stress direction and magnitude have severe effects on hydraulic fracture design, propagation and productivity once depletion has occurred.

Rushing and Blasingame (2003) use 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 are used to history match the results against real tight gas reservoir data.

Rietman (1998) also use decline curves to analyse the sensitivity of optimum fracture length to different reservoir parameters. The findings show that reservoir porosity and pay thickness are more influential in terms of performance than permeability and drainage area.

1.2 Evaluation of hydraulic fracture performance using transient well testing

Pressure-transient testing has been well regarded in the industry as a valid method of predicting key reservoir parameters (e.g. permeability, skin, average reservoir pressure, reservoir shape, flow conditions/regimes etc.), and can provide additional information which cannot be achieved via static interpretation. In basic terms, a transient well test involves the measurement of flow rate, pressure and time under controlled conditions. One of the most common forms of transient well testing is a production and pressure buildup test.

1.2.1 Production and pressure build up test

A production and pressure buildup up test consists of a period of well production, to allow transient reservoir effects to occur, followed by a buildup period which describes the reservoir response.

Figure 6 shows reservoir response during a constant flow rate production period followed by a pressure build up period. The two most common methods of running the production period are either constant production rate or constant pressure draw-down.

The following information can be derived from production and buildup transient well testing:

- *Permeability* – The dynamic reservoir response and resulting permeability represent in-situ average permeability over a large portion of the reservoir, and is therefore considered more useful than core evaluated permeability.

- *Skin* – Negative reservoir impacts (positive skin) often result during completion, and positive reservoir effects (negative skin) can result from successful reservoir stimulation, such as hydraulic fracturing.

- *Average Reservoir Pressure* – Used to calculate the volume of hydrocarbons initially in place (GIIP or OIIP) via material balance calculation.

- *Deliverability Potential* – Both Inflow Performance Relationship (IPR) and Absolute Open Flow (AOF) can be derived from transient well tests. AOF refers to the maximum flow rate a well can achieve if exposed to atmospheric pressure. Both values can be determined using known correlations such as the Vogel or Fetkovich methods.

- *Reservoir description* – reservoir shape, boundaries and heterogeneities can be understood from transient well test analysis.

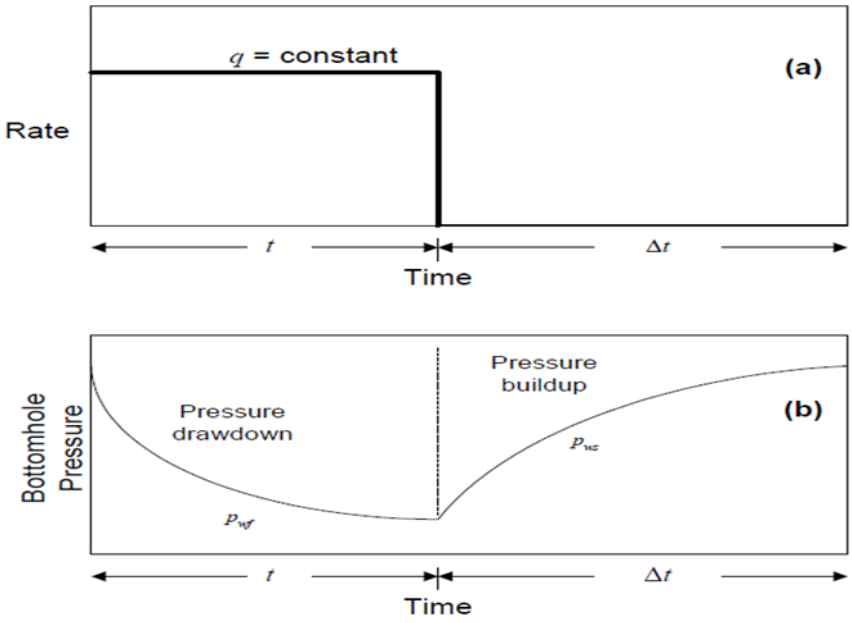

Figure 6: Typical production and pressure buildup test (Drawdown and buildup test) (Jayan, 2010)

Transient well testing can be described simply as the analysis of reservoir pressure response with change in production rate; a generic reservoir response is outlined below (Mattar et al. 2008):

- At initial production the wellbore pressure decreases quickly, causing a pressure pulse, and the near wellbore fluid to expand and migrate towards the localized low pressure region.
    - The radius of the reservoir matrix impacted by this pressure pulse increases with the square root of time and reservoir permeability. Hence the longer the welltest, the more complete the reservoir characterization is in terms of portion of overall reservoir volume contributing to the reservoir response.
- Fluid migration from a low pressure region at its original location, causing nearby fluid to replace the previously occupied pore space.
- Fluid transfer toward the low pressure region continues until the reservoir pressure reaches equilibrium.
- At shut-in conditions, the reservoir fluid continues to expand and increase reservoir pressure, until steady state is reached.

1.2.2 Pressure derivative diagnostic plot analysis of well test data

For oil wells the diffusivity equation (Equation 5) is used for Horner plot analysis, for gas wells the Horner Plot analysis is very similar. Instead of pressure plotted against Horner Time, Pseudo Pressure is plotted against Pseudo Horner Time. This allows the same form of slope analysis to be conducted for oil wells and gas wells via a Horner Plot. Figure 7 displays a typical Horner plot for well test analysis, displaying three distinct phases. Initial reservoir response can be seen on the Horner plot through wellbore storage (WBS in Figure 7), transitional flow period followed by radial flow (RF in Figure 7).

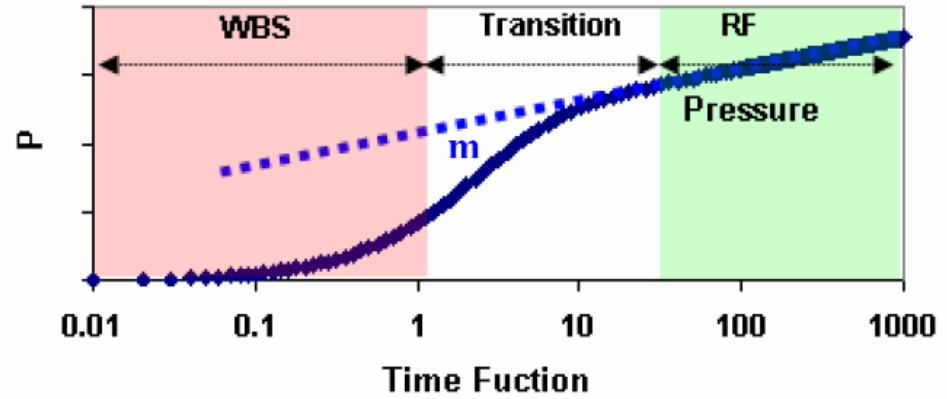

Figure 7: Semi-log Horner Plot of pressure response during the buildup section(Bahrami et al., 2011)

Pseudo pressure is a mathematical function created to account for changing compressibility and viscosity of gas with pressure. Certain key assumptions underpin the analysis of transient well test data, such as;

- Total system compressibility is constant
- Fluid viscosity is constant
- Porosity is constant
- Fluid saturations are constant.

The assumptions listed above are quite accurate for liquids, whereas gases tend to violate the first two constraints with changing pressure. Philippe et al., 2008, discusses pseudo pressure to account for the compressibility and viscosity inconsistency of gas compared to liquids described by Equation 3.

$$m(p) = 2\int_0^P \frac{PdP}{\mu Z} \qquad (3)$$

Where:

$m(p) = Pseudo\ Pressure$ $P = Pressure$

μ = Viscosity $Z = Gas\ Compressibility\ Factor$

This form of pressure measurement ensures that pseudo-pressure is equal to a constant multiple of logarithmic time. A similar relationship is developed for pseudo time defined by Equation 4.

$$t_a(t) = \int_0^t \frac{dt}{\mu C_t} \quad (4)$$

where:

$t_a = Pseudo\ Time$ $t = Time$

$C_t = Total\ Compressibility$ μ = Viscosity

The pressure derivative diagnostic plot approach follows similar principles as the Horner method, and is centred on the diffusivity equation, which describes the radial flow regime in a homogeneous porous system under constant flow rate (i.e. well test shown in Figure 6).

The diffusivity equation and derivative diagnostic plot method can be described via the derivation of a commonly used equations (Bahrami et al., 2010).

Equation 5 describes the pressure change with respect to log delta time:

$$\Delta P = \frac{162.6q\mu B}{kh}\left[\log(\Delta t) + log\left(\frac{l}{\phi\mu C_t r_w^2}\right) - 3.23 + 0.875\right] \quad (5)$$

Where:

$q = Flow\ Rate$ $\Phi = Porosity$

$B = Formation\ Volume\ Factor$ $r_w = Wellbore\ Radius$

$\Delta P = Change\ in\ Pressure$ $h = Thickness$

$\mu = Viscosity$ $t = Time$

$k = Reservoir\ Matrix\ Permeability$ $\Delta t = Change\ in\ Time$

$\Phi = Porosity$ $C_t = Total\ Compressibility$

From equation 5, it is clear that a plot of pressure change versus log of elapsed time will result in a straight line, allowing equation 5 to be simplified to a generic form such as equation 6:

$$\Delta P = mlog(Time\ function) + b \quad (6)$$

The derivative of equation 6 with respect to Δt gives the following derivative equation:

$$m = \frac{d(\Delta P)}{d(log\Delta t)} \qquad (7)$$

Equation 7 can be re-written as:

$$Log\left[\frac{d(\Delta P)}{d(log\Delta t)}\right] = 0log(\Delta t) + log(m) \qquad (8)$$

Where:

$b = Constant$ $\qquad$ $m = Slope$

Time Function $(Drawdown) = \Delta t$ $\qquad$ $Time\ Function\ (Production) = \frac{\Delta t + t_p}{\Delta t}$

$\Delta t = Change\ in\ Time$ $\qquad$ $t_p = Production\ Time$

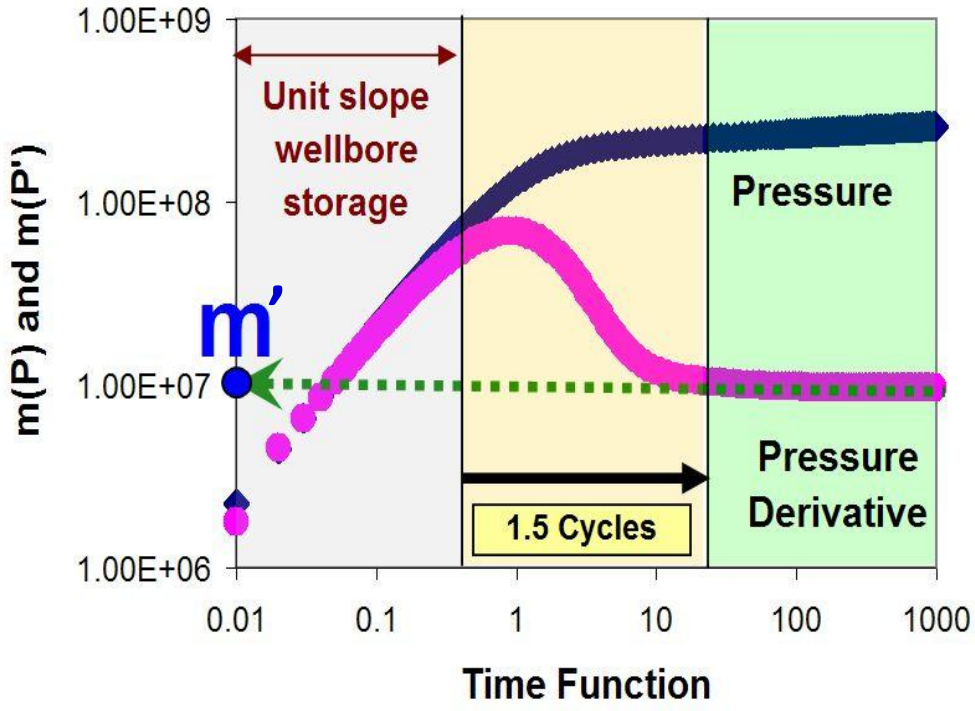

Figure 8: log-log Plot of pressure derivative vs log time (Bahrami et al., 2010)

From equation 8, it can be deduced that a log-log plot of the pressure derivative vs elapsed time will results in a slope equal to 0 for a radial flow regime, Figure 8. Furthermore, extrapolation of the zero slope to the y-axis (m') can be used to determine skin and permeability using equations 9 -10:

Using m' calculated from a pressure derivative plot as shown in Figure 8, it can be used in equations 9 and 10 to determine permeability and skin respectively.

$$kh = 162.6\frac{q\mu B}{m'} \quad (9)$$

$$S = 1.1513\left[\frac{\Delta P_{1hr}}{m'} - Log\left(\frac{k}{\phi\mu C_t r_w^2}\right) + 3.2275\right] \quad (10)$$

Where:

$q = Flow\ Rate$ $\Phi = Porosity$

$B = Formation\ Volume\ Factor$ $r_w = Wellbore\ Radius$

$\Delta P = Change\ in\ Pressure$ $h = Thickness$

$\mu = Viscosity$ $S = Skin$

$k = Reservoir\ Matrix\ Permeability$ $C_t = Total\ Compressibility$

Generally the derivative plot can be analysed via three main sections; early, middle and late time response which can yield the following information (Mattar et al. 2008)

- Early time is often dominated by wellbore storage and skin effects, recognized by a fixed linear slope. The slope and duration of this period is dependent on stimulation such as hydraulic fracturing and acidizing.
- Middle time represents radial flow; at this stage the average reservoir permeability can be calculated.
- Late time data can yield the impact of skin, as the delta between the derivative and original data, Figure 8. In addition this can determine reservoir boundaries and heterogeneity in the reservoir system.

In addition different flow types can be interpreted and analysed from pressure derivative results based on the slope observed at different flow periods (Figure 9).

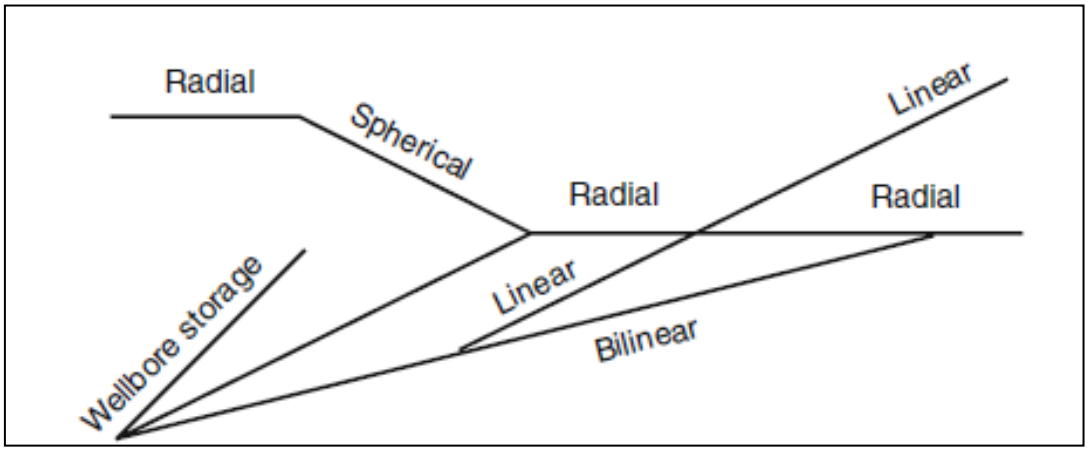

Figure 9: Different flow types interpretation based on Horner plot slope (Philippe et al., 2008)

Figure 10 displays a schematic illustration of the most common near wellbore flow regimes that can be identified during transient well testing. As displayed in Figure 8, the first stage of production is typically dominated by wellbore storage and skin effects.

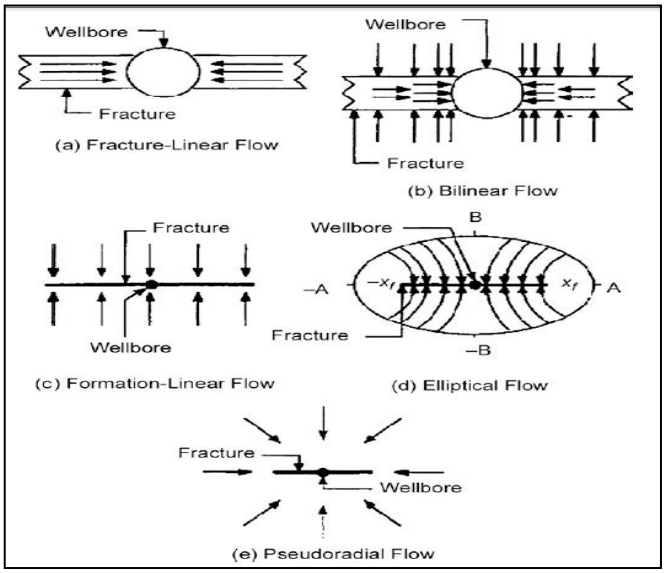

Figure 10: Schematic representation of different flow types
(Magalhaes et al., 2007)

Wellbore storage effects can cause distortion of well test data on a single derivative diagnostic plot, leading to a reduction of interpretation accuracy (Jayan, 2010). Bahrami et al. (2010) describes a method of using a plot of the second derivative to account for such effects and can be used to determine a more precise end of wellbore storage effects. This approach also outlines the method of using a combination of the first and second derivative diagnostic plots to gain further clarity form well test data.

1.2.3 Mini-Fall-Off technique:

As mentioned above, hydraulic fracturing is the primary method of increasing productivity and therefore economic viability of tight gas formations. To offset the many challenges associated with using conventional well testing methods for tight gas analysis, the Mini-Fall-Off technique (MFO) can be used to help determine various reservoir properties during hydraulic fracturing. This is achieved by analysing the pre-fracture closure and post-fracture closure reservoir response. Although not originally invented by Behrmann and Nolte (1998), they developed the method into what the industry now refers to as a MFO.

As seen in Figure 5, there is an initial injection period (required to initiate a mini-fracture) followed by a shut-in period in order to analyse pressure decline. The two key periods for MFO analysis are the pre-closure and post-closure reservoir response periods. The pre-closure period can be separated in two further sections for analysis, during injection and post injection propagation. The reservoir response during injection (and fracture initiation) is used to analyse fracture propagation, where as the post injection response can yield insights into pressure dependent leak-off and near wellbore effects (Pankaj and Kumar, 2010).

The post-closure reservoir response is independent of the fracture properties, as the fracture is no longer open and contributing to the productivity of the formation. This period in the MFO consists of pseudo linear flow followed by pseudo radial flow and can be used to determine transmissibility, reservoir pressure and fracture closure time.

The post closure pressure decline can be interpreted in a similar method to a derivative diagnostic Plot analysis, via a log-log plot of pressure decline. The post-closure radial flow time is a function of the following properties (Pankaj and Kumar, 2010)

- Injected volume
- Reservoir pressure (P_r)
- Formation transmissibility
- Closure time (t_c)

1.3 Tight gas challenges

Tight gas sands have additional issues compared to conventional reservoirs, with different forms of damage sustained during drilling, completion, stimulation and production. One such form of damage is liquid invasion, which is more severe for tight gas sands than conventional sands. This is due to the low matrix porosity, resulting in a weaker and less secure mud cake and high capillary pressure, causing deeper fluid invasion (Figure 11).

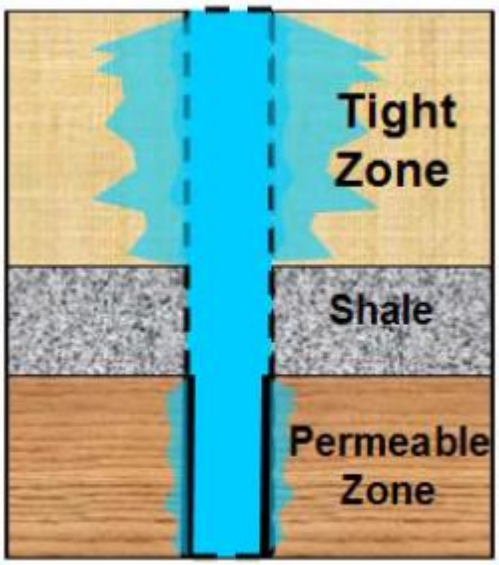

Figure 11: Schematic representation of increased water invasion in tight formations(Bahrami et al., 2011)

Once the fluid enters the wellbore other negative impacts, such as, water blocking, phase trapping and unfavourable relative permeability effects reduce the already low tight gas sand productivity. Filtrate invasion can have negative impacts on relative permeability and hence reduce productivity. Similarly, fracture and drilling fluid invasion (due to the abovementioned weaker mud cake) can lead to significant reduction in permeability of the rock matrix surrounding natural or hydraulic fractures (Bahrami et al., 2011).

Tight gas sands have significantly larger horizontal and vertical stress anisotropy compared to conventional sands; this disproportion can lead to severe wellbore breakouts. These breakouts occur in the direction of minimum stress and propagate in the direction of maximum principal stress (least resistance to opening). Hence drilling in the direction of maximum stress is advised for avoiding wellbore breakouts (Bahrami et al., 2011).

Another key damage mechanism is solid particle invasion resulting in mechanical damage impacting gas relative permeability and water saturation (Figure 12). This can also occur during the various phases of drilling, production and hydraulic fracturing. Very simply, invading solid particles can reduce productivity by blocking pore spaces and fluid flow paths. In addition, solid particles such as clays, can swell and cause further blocking of the already low porosity and permeability formation (Figure 13).

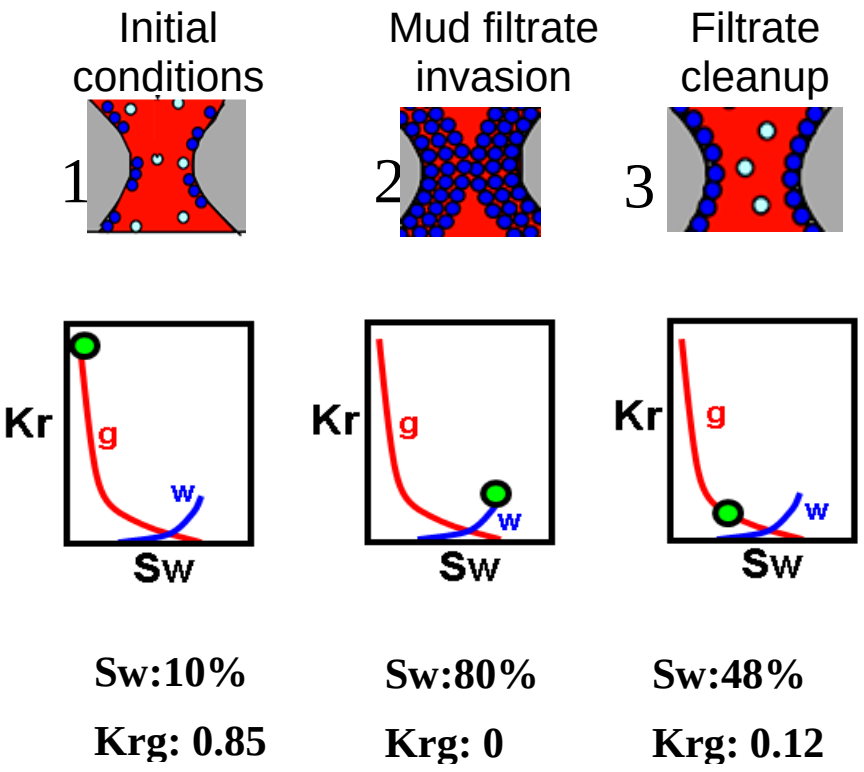

Figure 12: Different forms of invasion and impact on Sw and Krg (Bahrami and Rezaee, 2010)

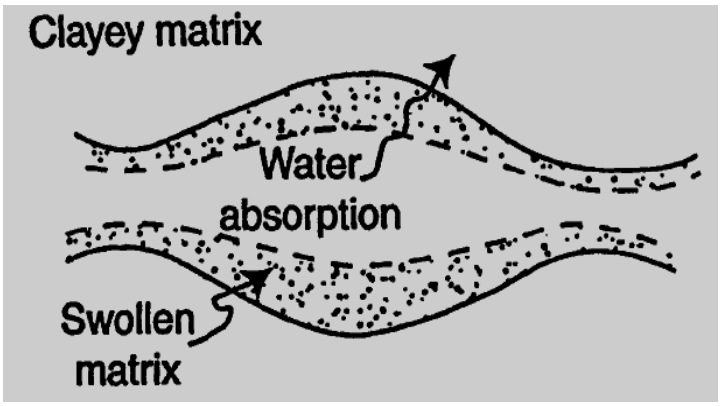

Figure 13: Schematic representation of reduction in flow path area as a result of clay swelling (Bahrami and Rezaee, 2010)

Insufficient contact between the fracture and wellbore results in a flow restriction that can be described as choke skin effect outlined by the following formula with respect to dimensionless fracture conductivity(Meyer et al., 2010):

$$S_{ch} = \frac{kh}{k_{fw_f}}\left[ln\left(\frac{h}{2r_w}\right) - \frac{\pi}{2}\right] = \frac{h}{x_{fC_{fd}}}\left[ln\left(\frac{h}{2r_w}\right) - \frac{\pi}{2}\right] \qquad (10)$$

Where:

$S_{ch} = Choke\ Skin\ Effect$ $k_f = Fracture\ Permeability$

$w_f = Fracture\ Width$ $r_w = Wellbore\ Radius$

$x_f = Fracture\ Half\ Length$ $h = Thickness$

$k = Reservoir\ Matrix\ Permeability$ $C_{fD} = Absolute\ Fracture\ Conductivity$

A smoother transition between the high permeability fracture and low permeability tight sand via the use of appropriate proppant can reduce the amount of pressure drop and negative skin effects (Meyer et al., 2010).

The drawdown during tight gas production is higher than conventional reservoirs; hence the gas velocity is also higher, resulting in a higher Reynolds number. At high Reynolds number, inertia (non-Darcy) effects can be the same order of magnitude as viscous (Darcy) effects. Cooke was the first to analyse the impact of non-Darcy effects in fractured/propped reservoir systems (Rahman, 2008). However these mechanical damage issues have been elaborated in Appendix C for the benefit of readers.

This research project focuses on the analysis of various hydraulic fracture and reservoir properties on hydraulic fracture productivity performance via 3-D reservoir simulation of well tests and short term production. The primary focus being to gather insights into production performance from short term data, and how significantly factors such as fracture size, number, spacing orientation and reservoir permeability effect the productivity of a hydraulically fractured tight gas sand. The majority of research discussed so far has focused on long term fracture optimization, whereas this research project aims to address the benefits from short time data insights.

2.0 Model description and discussion of results

This research project presents the results from various 3-D reservoir simulations conducting a sensitivity analysis on different reservoir and hydraulic fracture properties. The sensitivity analysis covers four major hydraulic fracture and reservoir properties;

- Fracture size
- Fracture number
- Fracture orientation
- Average reservoir permeability

The details of results including, necessary plots and results are provided in the published peer reviewed article enclosed in Appendix A and B. As mentioned in section 1.1, these reservoir and hydraulic fracture properties have been previously simulated and analysed, however the

different conclusions and interpretations are reached in this manuscript. The primary aim of this paper is to use early production and buildup production data to determine fracture productivity performance and aid in hydraulic fracture design and analysis. The results discussed in this paper are analysed using transient well test data from consecutive production and pressure buildup tests. The two forms of analysis used are the previously described derivative diagnostic plot method (Section 1.2.2), and early time normalised production rate data plotted against log-time.

Commercial simulation software (Eclipse) is used to generate a 3-D homogeneous model with tight gas properties (Table 1). A single vertical well is simulated in the centre of the reservoir to ensure symmetrical depletion throughout the production periods. Numerous simulations are run to examine the effects of fracture orientation, size and number on welltest response in terms of early time production rate and cumulative production (Ostojic et al., 2011).

Table 1: Model description and inputs for various simulation runs (Ostojic et al., 2011)

	Unit	Value		Unit	Value
Number of Cells	x, y, z	50, 50, 71	Reservoir Constraint	Gas rate, MSCFD	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	175 - 575
Permeability	mD	0.1-0.001	Number of Hydraulic Fractures	-	0 – 10
Reservoir Pressure	Psia	4000	Fracture Porosity	%	80
Well Type	-	Vertical, Single Well	Fracture Permeability	mD	28,000
Reservoir Thickness	Ft	180	Perforation Length	Ft	180

To analyse the effect of fracture orientation, two simulations with fractures having equal fracture volume and perpendicular to one another are run. One model simulates a single fracture perpendicular to the wellbore, and the other model with a single fracture along the wellbore. The hydraulic fracture along the wellbore is simulated with the expectation to achieve greater production, as per the theoretical findings of (Tudor et al., 2009). The

"perpendicular fracture" is simulated in the centre of the box model, with the hydraulic fracture 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 the size of the grid-blocks used for these simulations, however the difference in fracture volume is negligible compared to the overall 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. For example, the first scenario compares one 1150 ft horizontal fracture to four 550 ft horizontal fractures (Figure 14); with the single fracture and four fracture models having similar fracture volume. This analysis aims to determine which scenario is more beneficial in terms of production performance and analysis of fracture effectiveness, numerous smaller fractures or fewer larger fractures (Ostojic et al., 2011).

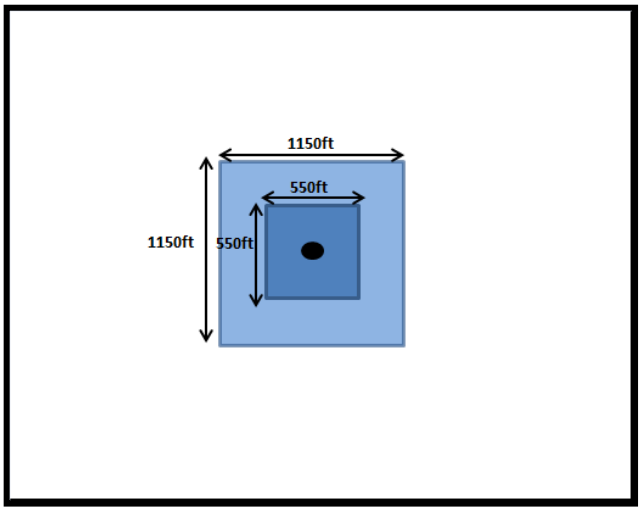

Figure 114: Schematic of fracture dimensions used for fracture size vs. fracture number analysis (Ostojic et al., 2011)

For all simulations, 3 production-buildup periods are simulated with a constant gas production rate of 500 MScf/d. Different time steps and durations are set for each set of production-buildup periods, with the first production period the shortest and the third production period the longest (Table 2). Results from the third buildup and production periods are the only one that is analysed to ensure that the results are not based on initial reservoir pressure response (Ostojic et al., 2011). Additional plots and detail discussion of results are provided in Appendix A and B.

Table 2: Different duration and time steps used for production and pressure buildup simulation (Ostojic et al., 2011)

Period	Duration (days)	Number of time steps
Production 1	10	10
Buildup 1	60	30
Production 2	190	40
Buildup 2	120	50
Production 3	500	170
Buildup 3	500	150

2.1 Simulation result interpretation via Derivative Diagnostic Plot analysis:

As mentioned in section 2.0, early time derivative diagnostic plot data and slope is analysed to investigate the impact of various reservoir and hydraulic fracture properties on production performance. The use of early time data is key, as it eliminates the need for extensive well test duration and hence reduces cost (if not conducted via reliable and accurate reservoir simulation).

2.1.1 Average reservoir permeability sensitivity analysis:

Three models are created for this sensitivity analysis, all with the basic reservoir properties as outlined in Table 1, with the one variable being the average reservoir permeability, ranging from 0.1 mD, 0.01 mD and 0.001 mD (Table 3). All reservoir permeability variations are run with a different number of hydraulic fractures in the system, 1, 5 and 10. When plotted on a log-log Horner Plot, all results display a linear period of flow with a slope ranging from 0.75 – 0.95 respectively for all models with more than 1 hydraulic fracture simulated (Table 3 and Figure 15). The single hydraulic fracture models with varying permeability all display a common linear slope section of ½.

Table 3: Horner Plot linear slope section during early time production (Ostojic et al., 2011)

Average reservoir permeability (mD)	Derivative diagnostic Plot linear slope - early time
0.1	0.75
0.01	0.85
0.001	0.95

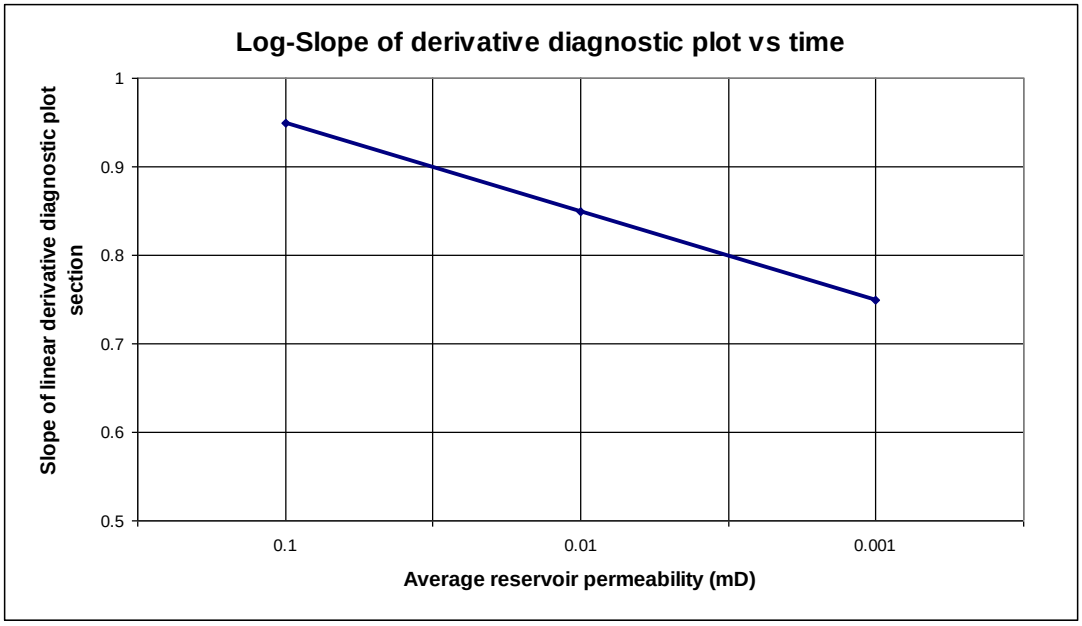

Figure 15:Plot of Horner non-linear slope section vs log average reservoir permeability (Ostojic et al., 2011)

The use of this relationship is important when analysing the increased productivity or effective increase in average reservoir permeability as a result of introducing hydraulic fractures into a tight gas system. The fact that this is early time analysis allows insights regarding fracture productivity performance to be determined sooner after completion.

The above analysis method allows for the true magnitude increase in average reservoir permeability to be compared to the expected average permeability increase, via early time derivative diagnostic plot analysis (Ostojic et al., 2011).

2.1.2 Fracture size sensitivity analysis:

Four scenarios are simulated in total for this analysis; no fracture base case, single fracture 350 ft, single fracture 550 ft and single fracture 1150 ft. In order to maintain consistency between simulations all other reservoir and fluid parameters are kept constant, and the fracture size is increased symmetrically away from the wellbore. Similar to the finding in section 2.1.1, a common slope is identified on the derivative diagnostic plot for all simulated production and pressure buildup tests. This common slope is ½ which identifies a period of linear flow on

derivative diagnostic plot (Medeiros, Ozkan et al. 2008). However, in this case the duration of the linear flow section is found to increase with fracture size (Figure 16).

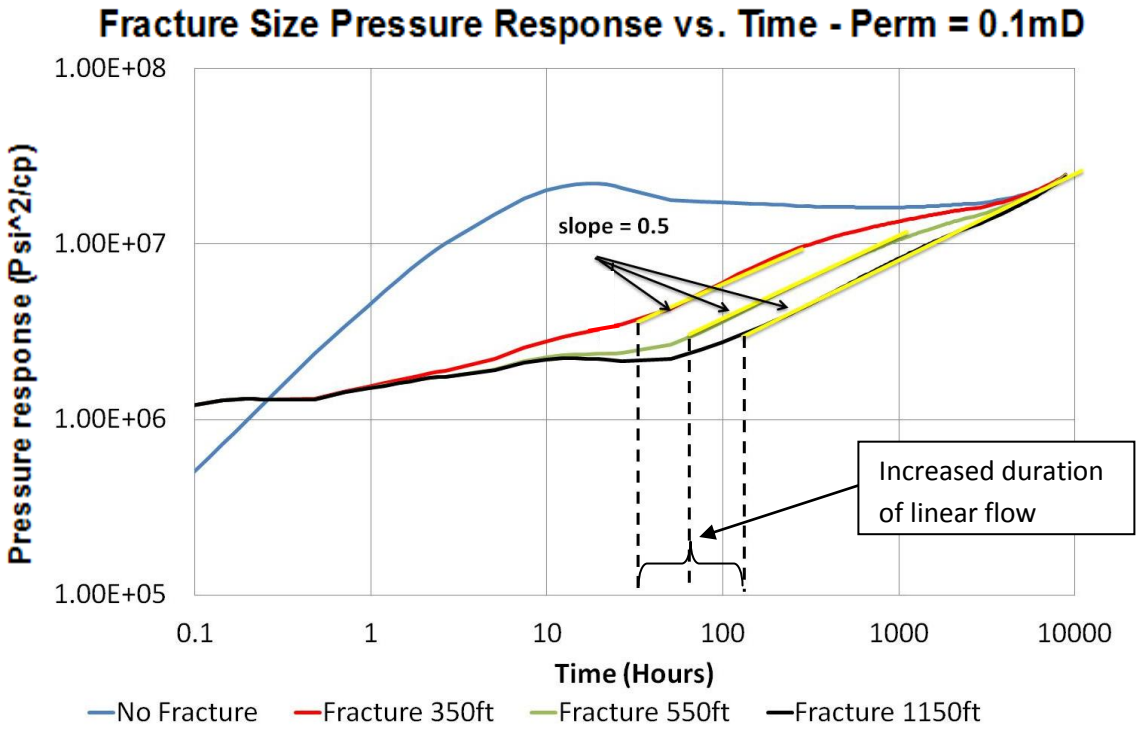

Figure 16: Increased duration of linear flow on derivative diagnostic plot with increasing fracture size

Although a direct relationship is not concluded, the results show that effective hydraulic fracture length can be determined from early time derivative diagnostic plot analysis compared to previous early time fracture performance. I.e. for a new planned fracture, designed with a longer half-length than the previous fracture but results in a shorter duration of linear flow on a derivative diagnostic plot implies that poor clean-up or proppant distribution has occurred and impacted the fracture effective length (Ostojic, 2011). Tudor et al., (2009) discuss the importance of good post-fracture clean up and the potential negative effects which result from having a low effective fracture length compared to the proposed/designed fracture length. The early diagnostic plot analysis method outlined above can be implemented as a first pass gauge of the fracture cleanup efficiency, and give insights for future hydraulic fracture work for the tight gas system.

2.1.3 Fracture number sensitivity analysis

As in section 2.1.2, a similar analysis is conducted for different number of equal sized fractures. All reservoir and hydraulic fracture properties are maintained; the only variable is fracture number, ranging from 0, 1, 5 and 10. Results are analysed via a derivative diagnostic plot and

the number of fractures is again found to have an impact on the duration of linear derivative diagnostic plot section (Figure 17).

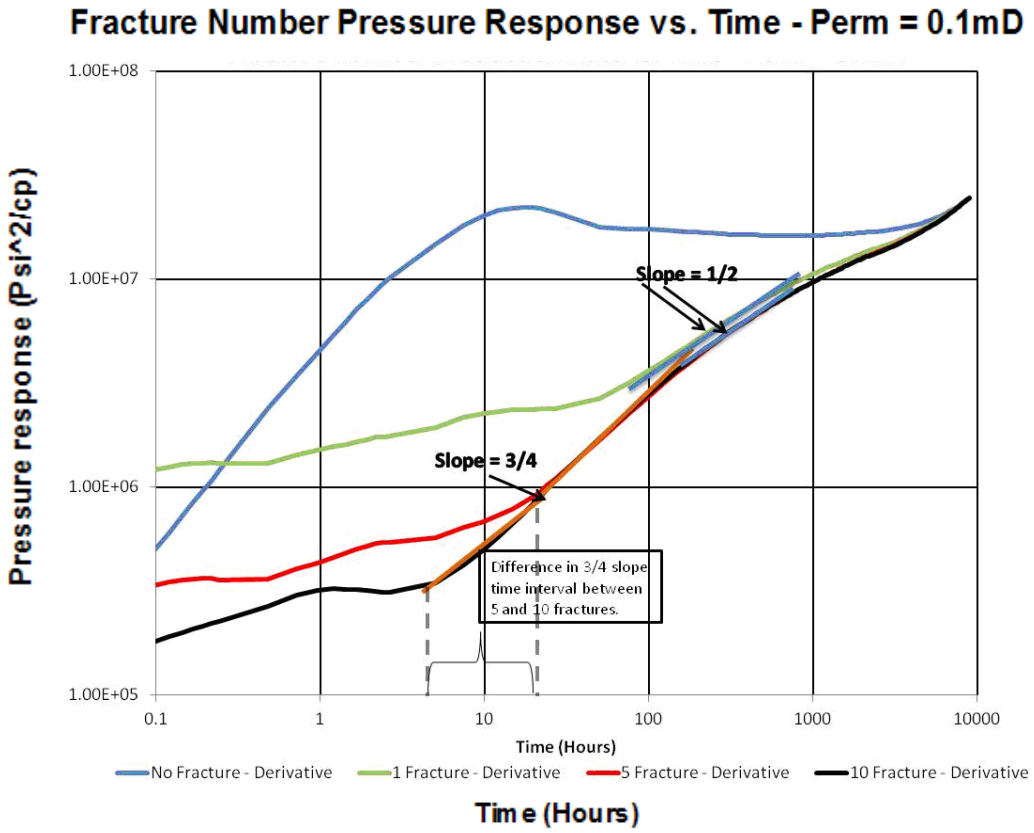

Figure 17: Derivative diagnostic plot for different number of hydraulic fractures in a 0.1mD tight gas sand

Again, this finding can be used to compare future hydraulic fracture performance after an initial hydraulic fracture is completed. Similar to section 2.1.2, this relationship can be used to compare expected/planned hydraulic fracture productivity performance to true productivity performance via early time derivative diagnostic plot slope analysis. The early time data allows any potential problems to be identified sooner rather than later.

2.2 Early time production rate data analysis

Similar to section 2.1, early time production rate data is analysed to investigate the impact of various reservoir and hydraulic fracture properties on production performance. Again the focus is on early time data in order to reduce cost. The recommended practice is to use early time production rate data analysis in conjunction with derivative diagnostic plot analysis to reach any conclusions regarding hydraulic fracture productivity performance.

2.2.1 Fracture orientation with respect to wellbore analysis

Two models with equal fracture volume are simulated, one fracture model intersecting the wellbore perpendicularly, and the other intersecting parallel along the wellbore. Dimensionless

production rate and cumulative gas rate vs. time plots are created and analysed, for the same production and pressure buildup times as outlined in Table 3. The term dimensionless production rate (fold of increase) for this analysis is defined as the fractured simulation production rate divided by the un-fractured simulated production rate. This form of analysis allows for direct productivity comparison with respect to an un-fractured tight gas reservoir. This method of analysis provides insights into proportional productivity increase as a direct result of hydraulic fracturing.

After 500 days of production, the fracture along the wellbore recovers ~60% more cumulative gas, and accelerates production, compared the perpendicular fracture, Figure 18 (Ostojic, 2011). This increased production is due to the higher surface area of wellbore that the fracture intersects if compared to the perpendicular fracture (Tudor et al., 2009).The increased contact area between the wellbore and hydraulic fracture increases average wellbore permeability and hence inflow performance. Similar to the multiple 550 ft fracture model results, the parallel fracture model experiences a large decrease in production rate over the first few days of production.

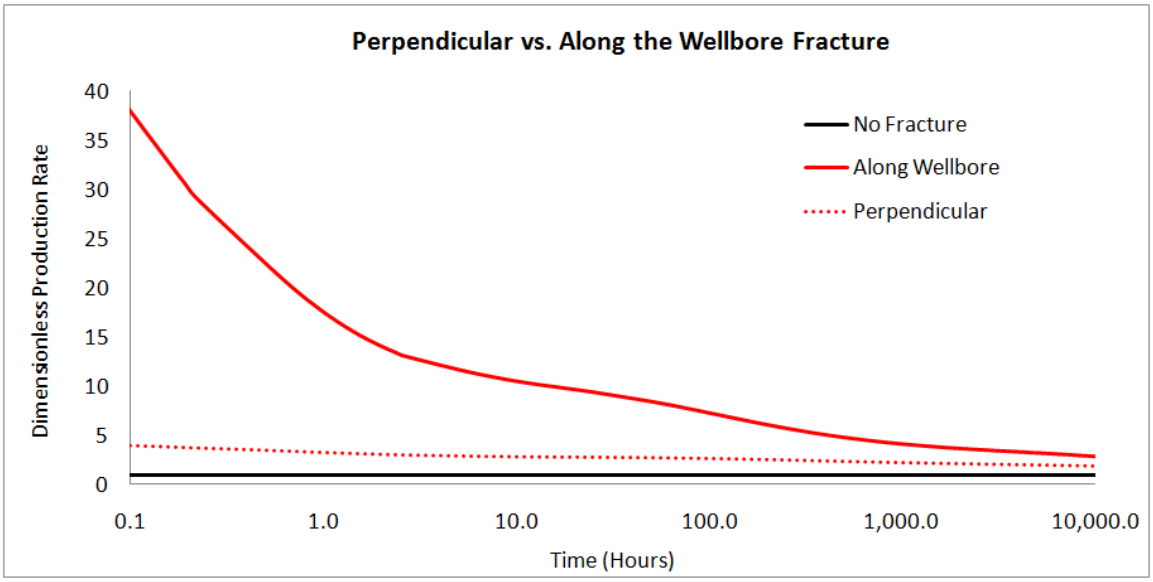

Figure 18: Dimensionless production rate vs log-time for two fracture orientation scenarios (Ostojic, 2011)

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 cumulative production (Figure 19). Additional plots and detail discussion on this portion of the analysis are elaborated in Appendix B.

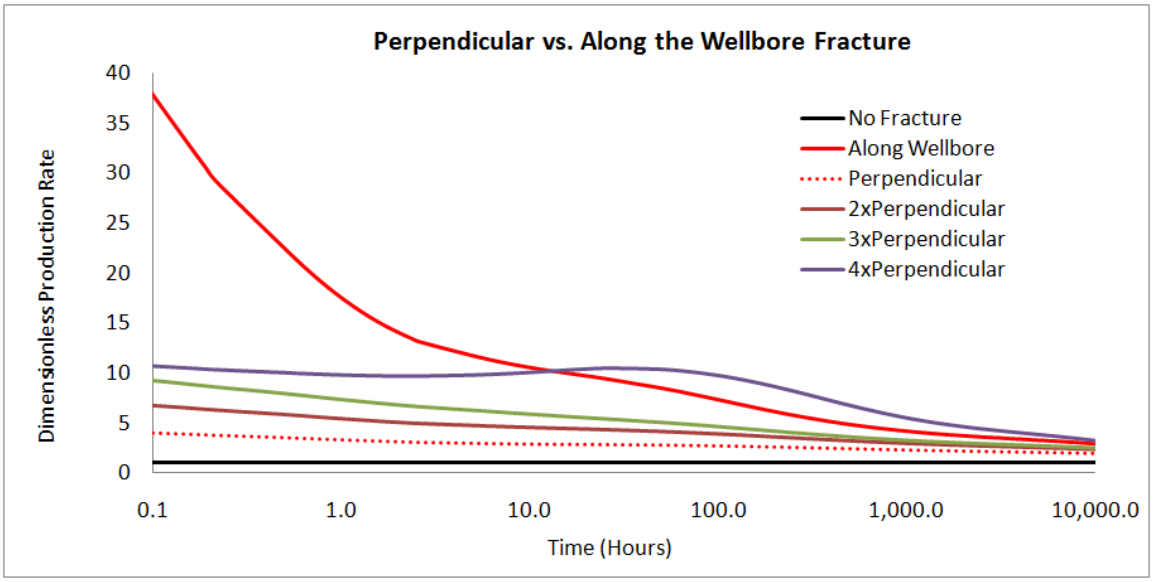

Figure 19: Dimensionless production rate comparison of numerous perpendicular hydraulic fractures compared to single along the wellbore hydraulic fracture (Ostojic, 2011)

The simulation results have shown that only the 4 perpendicular fractures achieve a higher cumulative production over the simulated time interval. 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 (Tudor et al., 2009), 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 the in-situ stress magnitude and orientation with respect to the wellbore must be analysed prior to planning hydraulic fracture performance, as discussed in section 1.1.1.

2.2.2 Fracture number sensitivity vs. fracture size analysis:

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 simulated. However, as shown in Table 4, the difference in fracture volume is negligible compared to the overall volume.

Table 4: Fracture volume and initial gas rate for simulation models used (Ostojic, 2011)

Fracture number and size	1x1150 ft	2x1150 ft	3x1150 ft	4x550 ft	8x550 ft	12x550 ft
Fracture Volume (ft^3)	4,338	8,676	13,013	3,969	7,938	11,906
Delta Initial Gas Rate Per Additional Fracture (Mscf/d)	-	9,294	7,223	9,165	8,189	8,187
Fracture Spacing (ft)	90	60	45	36	20	14

The fractures simulated are symmetrical, and have equal length and width. All fractures also have equal aperture of 1mm. 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 4). Hence, the results of a 1x1150 ft, 2x1150 ft and 3x1150 ft fracture models are compared to 4x550 ft, 8x550 ft and 12x550 ft fracture models, respectively. The comparison of dimensionless production rate with respect to an un-fractured model is implemented for this analysis (Figure 20).

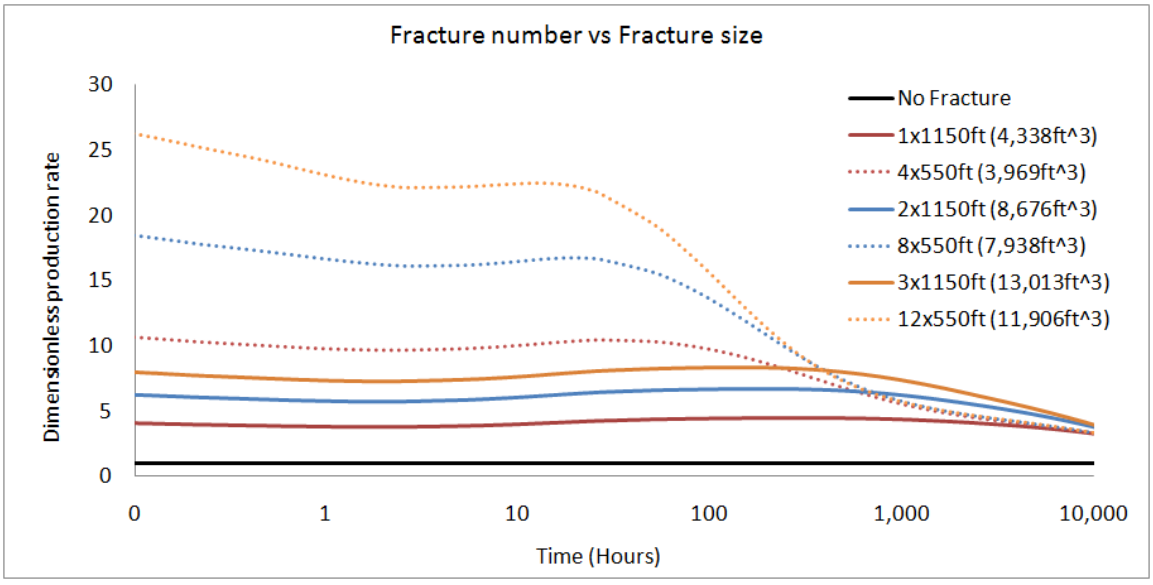

Figure 20: Dimensionless gas production rate vs. Time for all simulated 1150 ft and 550 ft fractures (Ostojic, 2011)

Form Figure 20, it is observed that the increase in the number of fractures intersecting the wellbore drastically impacts the initial flow rate of the tight gas reservoir. Initial production rate increases similarly with fracture number, regardless of fracture volume. For example, the 4x550ft fracture model produces initially at a higher rate than the 3x1150 ft fracture model although it has a substantially lower total fracture volume (Table 3). In terms of immediate drainage of tight gas formations, numerous smaller fractures increase productivity more per volume of fracture, compared to fewer longer fractures. 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.

To be more specific, an almost perfectly linear relationship is found between initial production rate (first 24 hours) and fracture number, as can be observed in Figure21.

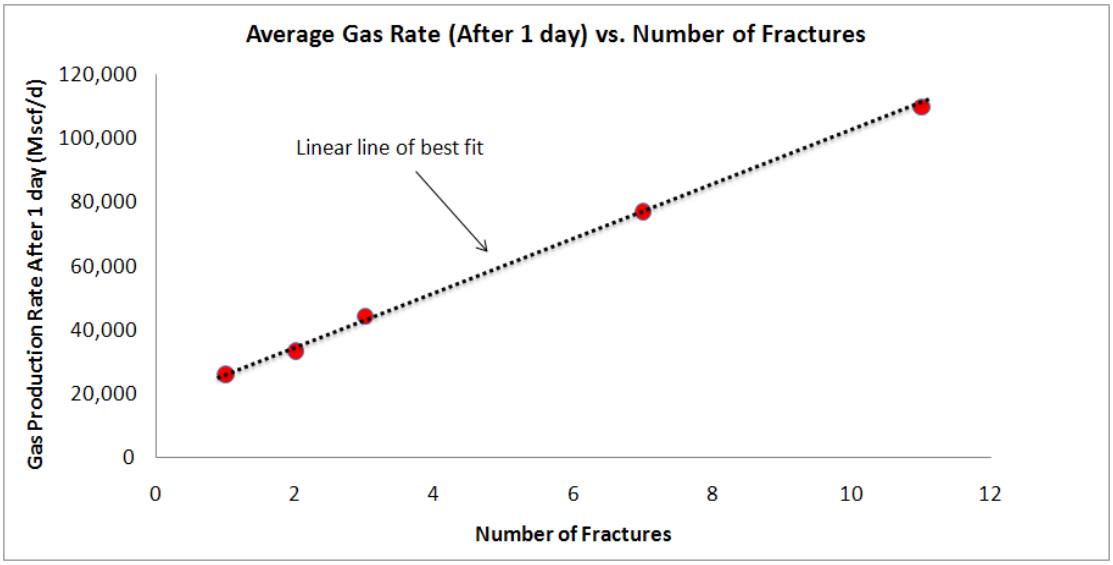

Figure 21: Average gas rate after 1 day vs. Number of Hydraulic Fractures (Ostojic, 2011)

The linear relationship between early time production rate and fracture number can be used as a diagnostic tool to compare hydraulic fracture productivity performance, and hence determine fracture efficiency. These findings agree with work done by (Magalhaes et al., 2007)

The difference in cumulative gas production between the 550 ft and 1150 ft fracture cases is negligible, particularly between the 8 and 12 fracture cases after 500 days, less than 2%. This is due to the fact that with more fractures within the same reservoir shape and volume the fracture spacing is reduced. With reduced fracture spacing several fractures can potentially be producing from the same drainage area. With this in mind, it can be assumed that the 12x550 ft fracture model is not directly comparable to the 3x1150 ft model in terms of cumulative production. Similarly the 8x550 ft model is likely to produce less cumulative gas than the 2x1150 ft fracture model due to multiple fractures producing from a common drainage area. Therefore the 1x1150 ft and 4x550 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 the 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 compared to 4 smaller fractures.

3.0 Conclusion and recommendations

Based on the results as discussed in Sections 2.1.1-2.2.2, a number of useful conclusions are made, that can be used for hydraulic fracture productivity performance analysis from early time data and/or pre-fracture design and evaluation, as described below:

- For tight gas sands with multiple hydraulic fractures, a common slope on the log-log pressure vs time plot is observed. This slope does not identify one of the common flow types defined for fractured reservoir flow. However, the slope was determined to be a linear function of reservoir permeability for a homogeneous tight gas reservoir. It should be noted however that such a perfect linear relationship between the common-slope and reservoir permeability will not be maintained in a real heterogeneous tight gas reservoir. However, the relationship with increasing slope with decreasing reservoir permeability should remain true.

- The duration of the abovementioned common slope is also a function of fracture number, with increasing duration with additional hydraulic fractures present in the reservoir.

- Fracture number has more significant impact on well productivity 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.

- After the initial hydraulic fracture, each subsequent fracture increases the initial gas production rate (within first 24 hours) in a linear fashion, and is independent of fracture length. For immediate feedback regarding possible presence of hydraulic fracture damage, this data could be used as first screening of fracture performance.

- Vertical Fracture (i.e. fractures along the wellbore) are far more effective than transverse or horizontal (i.e. fractures perpendicular to wellbore), based on simulation results, 4 transverse fractures are required to achieve a same performance for a single vertical fracture. However, this is not a direct relationship and would require further investigation to determine a possible correlation.

- The results from section 2.2.1 have showed increased ultimate recovery for hydraulic fractures created along the wellbore compared to perpendicular fractures, for equal total fracture volume between the two cases.

As mentioned in section 2.0 the 3-D model used is a simplified representation of a realistic tight gas reservoir model, and does not cover all real word effects. Further work is suggested to justify the abovementioned findings for fully representative heterogeneous tight gas reservoir models. Furthermore, it would be ideal to match findings from any production data from

Australian tight gas fields and compare findings to the various operational tight gas fields around the world.

Economic analysis regarding the fracture number vs. fracture size (of comparable overall fracture volume) is required to reach a more concrete conclusion regarding the true benefit of either approach. The true benefit of the optimal fracture design, in terms of fracture size vs. fracture number, can only be finalized with a cost comparison. However, such a comparison is heavily dependent on the field location, not only in terms of onshore vs. offshore but globally also.

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Appendix A: 2011 APPEA published paper

Appendix B: 2011 JPSE published paper

Appendix C: 2011 APPEA published paper (Co-Author)

Statement of Contribution of others

APPEA and JPSE peer reviewed articles written by Jakov Ostojic as lead author, Associate Professor Reza Rezaee and Hassan Bahrami contributed as co-author.
Both Dr. Reza and Hassan were involved in building the base reservoir simulation model of tight gas reservoirs, analysis and interpretation of simulation results; in addition they provided guidance and support during the preparation of simulation models.
The rest of the article production and preparation, building the hydraulically fractured reservoirs simulation model, evaluation of the simulation outputs (gas rate and transient pressure) and preparing diagnostic plots for different hydraulically fractured systems, collation and sorting of data was completed by the lead author, Jakov Ostojic.

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Date……. Date…….

Reference:

OSTOJIC, J., BAHRAMI, H. & REZAEE, R. 2011.*Production Performance of Hydraulic Fractures In tight Gas Sands, A Numerical Simulation Approach*. APPEA Journal.

OSTOJIC, J., BAHRAMI, H. & REZAEE, R. 2011.*Hydraulic Fracture Productivity Performance in Tight Gas Sands – A Numerical Simulation Approach*. JPSE.

APPEA peer reviewed article written by Hassan Bahrami as lead author, Associate Professor Reza Rezaee and Jakov Ostojic contributed as co-author.
The contribution of Jakov Ostojic to this paper was the preparation of the simulation model used to generate data for this article.

Reference:

BAHRAMI, H., REZAEE, M. R., OSTOJIC, J., NAZHAT, D. 2011.*Evaluation of Damage Mechanisms and Skin Factor in Tight Gas Reservoirs.* APPEA Journal. 51: pp. 639-652.

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Written Endorsements

I, JakovOstojic, contributed to the model construction, running of simulations and collation/analysis of results and data to the paper “Production Performance of Hydraulic Fractures In tight Gas Sands, A Numerical Simulation Approach” published by APPEA in 2011. Also to the paper “Hydraulic Fracture Productivity Performance In Tight Gas Sands – A Numerical Simulation Approach” published by JPSE 2011.

Reference:

OSTOJIC, J., BAHRAMI, H. & REZAEE, R. 2011.*Production Performance of Hydraulic Fractures In tight Gas Sands, A Numerical Simulation Approach*. APPEA.

OSTOJIC, J., BAHRAMI, H. & REZAEE, R. 2011. *Hydraulic Fracture Productivity Performance in Tight Gas Sands – A Numerical Simulation Approach*. JPSE.

Signature:……

Date:…….

I, as a Co-Author, endorse that this level of contribution by the candidate indicated above is appropriate.

Name:…….

Signature:…….

Name:…….

Signature:…….