Faculty of Science and Engineering
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Numerical Modeling of Well Test Analysis for Hydraulically Fractured Wells in Tight Gas Reservoirs

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Declaration

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DEDICATION

I would like to dedicate my thesis to my parents, for their encouragement, sincere wishes and prayers

To my lovely wife Nuha and son (Musa who have supported me and believed that I would do it

To my brothers, sisters and all family members for their love and support

Abstract

As conventional gas resources continue to deplete, there is a growing interest in finding better ways to extract unconventional resources, especially from tight gas reservoirs (TGRs). However, understanding how to efficiently produce gas from fractured wells in these reservoirs remains a huge challenge. This thesis has several goals. First, it explores the latest advancements in science and technology related to tight gas resource extraction. Then, it aims to develop methods for in-depth analysis of production data, ultimately leading to improved productivity. Additionally, it focuses on enhancing the overall performance of tight gas reservoirs, from estimating reserves to comprehensive field development through numerical reservoir simulations using data from a representative tight gas field in Australia.

The thesis utilises various numerical tools to refine existing approaches and adapt them to the unique conditions of tight gas reservoirs. These tools help accurately identify flow patterns and predict essential reservoir parameters, including drainage area with high accuracy essential to minimise the uncertainties. Pressure transient analyses consistently remain a fundamental tool for evaluating and determining key parameters related to both the well and reservoir. These analyses play a critical role in predicting pressure behaviour and facilitating reserve estimation for reservoir characterization and management. In the context of tight gas reservoirs, pressure transient analyses become notably challenging due to the incorporation of fracturing techniques. These techniques are used to enhance the limited productivity of such reservoirs, which result from their

inherently low or even ultra-low permeability. Consequently, the complexities introduced by fracturing strategies necessitate a more sophisticated approach when conducting pressure transient analyses in this specific reservoir type. Fracturing in tight gas reservoirs, whether for horizontal or vertical wells, introduces complex and challenging-to-determine flow regimes.

In summary, this thesis contributes significant insights to the analysis of transient pressure data in tight gas fields and proposes simplified analytical tools. Through numerical simulation and analytical studies, the thesis addresses the numerous challenges involved in accurately predicting various parameters encountered during the appraisal and early development stages of tight gas reservoirs. The research also addresses the complexities of the field and offers valuable solutions/approaches to enhance accuracy in parameter prediction and minimise uncertainties. This thesis work can serve as a valuable resource for professionals and researchers seeking to navigate the challenges associated with the accurate analysis and prediction of tight gas reservoirs' performance.

List of Publications as a result of This Thesis

1. Hossain, M. M., Al-Fatlawi, O., Brown, D., & **Ajeel, M.** (2018, March). Numerical Approach for the Prediction of Formation and Hydraulic Fracture Properties Considering Elliptical Flow Regime in Tight Gas Reservoirs. In Offshore Technology Conference Asia. Offshore Technology Conference.

2. **Ajeel, M**., Hossain, M., & Al-Fatlawi, O. (2017). An Analytical Approach to Identify the Time Separating the Linear Flow and Elliptical Flow in a Fractured Vertical Well in Tight Gas Reservoir. In *Proceedings of One Curtin International Postgraduate Conference (OCPC) 2017*. Curtin University, Miri, Sarawak, Malaysia.

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Nomenclature

A	: Drainage area, ft^2.
A_1, A_2	: Constants.
AAPE	: Average absolute percentage error, dimensionless.
B	: Constant, Dimensionless.
b_{Dpss}	: pseudo-steady-state parameter, dimensionless
C_i	: gas initial compressibility (psi-1).
d	: Average distance between two fractures, ft.
F_{CD}	: the dimensionless fracture conductivity, dimensionless
Fr	: Fracture properties constant
G	: Gas in place, SCF
h	: bay thickness (ft),
k	: permeability (mD)
m_e and m_{wf}	: are reservoir and flowing well pseudo pressure (psi2/cp)
n	: Number of the fractures
N_f	: Number of the fractures
q	: Flow rate, MScf/D
r^2	: Coefficient of determination, dimensionless
r_{eD}	: the dimensionless well radius, dimensionless
r_w	: Well radius, ft
r_w’	: Equivalent well radius, ft
S	: Skin factor, Dimensionless

T	: Temperature, °R
TGR	: Tight gas reservoir
WR	: Whicher Range
WRTGF	: Whicher Range Tight Gas Field
x_f	: fracture half-length (ft),
$\bar{y}$	: Average value of the tested parameter.
y	: actual value of the tested parameter
y_c	: Calculated value of the tested parameter
Δt	: production time (hr),
μ_{gi}	: initial gas viscosity, cP
μ_i	: Initial viscosity, cP
σ	: Standard deviation, dimensionless
φ	: Porosity, Dimensionless

Chapter 1: **Introduction**

1.1 Background

Unconventional reservoirs, typically characterized by extremely low permeability, often necessitate special recovery techniques that go beyond standard practices to be commercially viable. These unique methods encompass reservoir stimulation, such as hydraulic fracturing, as well as the utilization of horizontal wells or horizontal wells with multiple fractures. However, the definition of unconventional resources has continuously evolved due to the rapid advancements in technology and ongoing scientific research and development aimed at discovering new sources of hydrocarbon reserves. The progress in drilling technology has enhanced the capability to extract hydrocarbons from ultra-deep formations, enabling the exploration and exploitation of potential hydrocarbon resources in these reservoirs. These resources are predominantly categorized as unconventional reservoirs.

There exists a multitude of classifications for unconventional resources, as documented and published by various societies and organizations across the globe. Unconventional hydrocarbon resources, such as tight gas and oil, shale oil and gas, gas hydrates, and coalbed methane, fall under the classification of unconventional resources of hydrocarbons according to the Canadian Association of Petroleum Producers (CAPP) and the Society of Petroleum Engineers (SPE). According to Information Handling Services (HIS), unconventional resources encompass various types of hydrocarbons such as shale oil, shale gas, tight oil shale, extra heavy oils, tight sands gas, coal gas, coal mine gas, syngas coal, and hydrates gas.

Chinese National Standards and China's oil and gas industry standards have established six classification criteria and definitions for unconventional gas and oil resources. These include heavy oil, tight oil, tight gas, oil shale, coalbed methane, and tar sand. Heavy oil refers to oils that exhibit challenges in flowing through porous media due to their high viscosity. These oils have a thicker consistency compared to conventional crude oil, making their extraction and transportation more complex. On the other hand, tar sand is defined as oil with a viscosity exceeding 10,000 centipoises (cP) at the temperature of the reservoir. Tight oil, which is specifically suited for porous media with low permeability, hinders the natural production of wells at an economically viable flow rate. Due to the low permeability of the reservoir, the oil does not flow easily through the rock, making it challenging for wells to produce oil naturally at a rate that is economically feasible. As a result, special techniques such as hydraulic fracturing are often employed to enhance the flow of tight oil and maximize its extraction from the reservoir.

According to Ahmed and Meehan (2016), they propose a definition of unconventional resources that relies on the classification of wells and the specific completion techniques necessary for their exploitation. According to their classification, conventional resources are defined as reservoir fluids that can be economically produced through vertical wells without the need for hydraulic fracturing lengths exceeding 200 feet or unfractured horizontal wells. Therefore, unconventional resources are characterized as hydrocarbon reserves that cannot be economically produced unless specific advanced techniques are employed. These techniques typically involve the use of vertical wells with long hydraulic fractures or horizontal wells with multiple hydraulic fractures.

1.2 Tight gas reservoirs

Shale gas (especially natural gas) has garnered considerable attention in recent times owing to its abundant reserves, economic feasibility, and potential as a cleaner energy source. Nevertheless, tight sandstones also hold significant importance as an essential hydrocarbon resource, especially for natural gas. In fact, developing shale gas reservoirs can be more challenging than tight gas sandstone resources due to their generally lower quartz content and the difficulties associated with completing them for production (Moore, Ma, Pirie, & Zhang, 2016).

A tight gas reservoir, which is a type of unconventional reservoir, has a low value of permeability which makes the production of gas more difficult and uneconomical. Hydraulic fracturing has been used worldwide to enhance the permeability to increase gas recovery and to achieve economic production.

The success of the fracturing process can be measured by enhancing the dimensionless fracture conductivity. The dimensionless fracture conductivity (F_{CD}) is a function of fracture half-length and width, proppant pack permeability, and flow type (e.g. laminar or turbulence) and it has the most significant effect on the pre and post-fracture treatment. The value of dimensionless fracture conductivity is practically determined through well testing. When analysing post-fracture data, it is often observed that the dimensionless fracture conductivity value is lower than the predicted value calculated from the well test and pressure transient analysis.

Nowadays, there has been significant global exploration of tight oil and gas resources. To economically produce hydrocarbons from these reservoirs, advanced and expensive technologies are required. One such effective technology is hydraulic fracturing, which has been employed in the oil and gas industry for the past few decades to create highly conductive channels in formations with low to ultra-low permeability values. In the realm of horizontal drilling, the use of hydraulic fracturing with multiple fractures has proven to be a highly successful method for enhancing production from tight reservoirs (Kumar & Goswami, 2019).

1.3 Scope and objective of the research

The behaviour of the pressure transient response to the flow for hydraulically fractured wells in tight gas reservoirs can be divided into two regions. The early time region represents the flow through fractures which tends to be linear, while the late time region represents the semi-steady state flow in the matrix (Da Prat, 1990).

A numerical model has been developed using simulation software (CMG and Ecrin Rubis) to simulate the tight gas reservoir with a hydraulically fractured well. Depending on the production data of the numerical model, an analysis of the well test data has been conducted using Ecrin-Saphir software to determine the conductivity of the reservoir both before and after the fracturing. The reasons for anomalous conductivity obtained from the model and post-fracture data have been investigated through sensitive studies. The model has been tested for validation based on history matching for real field cases. The sensitivity study is important to check the sensitivity of each parameter on the results of conductivity to analyse the effect of each parameter on the results; and develop the models/methods. Analysing the proposed solutions to enhance the conductivity using the whole information received from modelling, well testing, numerical tools and software. Accordingly, the main objectives of this research are:

- Develop a sophisticated numerical model to effectively analyse the well test data obtained from a hydraulically fractured well in a tight gas reservoir. This numerical model employs advanced computational methods to interpret and make sense of the complex data obtained from the well test. By utilizing this model, operators and engineers can gain valuable insights into the behaviour and performance of the fractured well, enabling them to optimize production strategies and maximize the recovery of gas resources. The development and application of such a robust numerical model can greatly contribute to the understanding and efficient management of tight gas reservoirs, ultimately leading to enhanced production and economic benefits.
- Study the sensitivity of various parameters involved in the design of fracturing techniques that impact fracture conductivity. By analysing the effect of each parameter, valuable insights can be gained to enhance the overall conductivity. Through this analysis, a better understanding of the relationship between these parameters and fracture conductivity can be achieved, enabling the identification of optimal design configurations and techniques that can effectively improve conductivity.

To analyse the behaviour of a fractured well, numerical methods can be employed using specialized numerical software. These methods involve the use of mathematical models and predict the performance of the fractured well under various conditions.

Through this numerical analysis, the required behaviour of the fractured well can be determined, including factors such as production rates, pressure behaviour, and overall productivity. Sensitivity analyses can also be performed to evaluate the impact of different parameters on the well's behaviour.

1.4 Research significance

This study focuses on the development of a sophisticated numerical model that will analyse the behaviour of hydraulically fractured wells in tight gas reservoirs (TGRs), leading to improved strategies for reservoir management and production optimization.

As tight gas evolves into a crucial energy asset for energy firms, accurate reserve assessments and efficient production enhancement remain imperative and ingrained in advancing the significance of tight gas resources. Natural gas is unequivocally acknowledged as a prevailing primary energy resource, carrying substantial importance in addressing the ongoing global energy demand for the foreseeable future. Its significant role in the energy landscape remains vital due to its versatile applications and environmentally favourable characteristics.

Customers have indeed been motivated to prioritize natural gas as a leading energy source for several reasons. One of the key drivers behind this shift is the positive environmental impact of natural gas. Compared to other fossil fuels like oil and coal, burning natural gas results in significantly lower emissions of pollutants. This makes natural gas an attractive option for those concerned about reducing their carbon footprint and addressing climate change. The economic benefits of natural gas, including its cost-effectiveness and abundant availability, also contribute to its appeal as a paramount energy source. Overall, the combination of environmental advantages, economic benefits, and ample availability has incentivized customers to consider natural gas as a primary energy choice. In addition, it is worth noting that the emissions generated through the process of combusting natural gas are significantly less harmful to the environment when compared to the emissions produced by the combustion of other types of fossil-derived fuels (O. F. Al-Fatlawi, 2018; Shah, 2017).

Moreover, the utilization of natural gas comes with a range of positive economic incentives. This is evident through the steady and consistent growth rates of both consumption and production on a global scale. In contrast, the consumption and production of oil and coal have experienced fluctuating and unpredictable growth patterns. These trends highlight the stability and reliability of natural gas as an energy source, which has contributed to its attractiveness in the economic landscape. The future outlook for oil and coal has witnessed a discernible and significant decline in recent times. Projections and analyses indicate a downward trajectory in terms of their anticipated relevance and prominence in the energy landscape. This noticeable decline underscores the shifting dynamics and growing concerns surrounding the sustainability, environmental impact, and long-term viability of these fossil fuel resources (O. F. Al-Fatlawi, 2018; BP., 2018).

In addition, the U.S. Energy Information Administration (EIA) (EIA (2018)) provides insightful projections up until 2050 showing that natural gas occupies the most substantial portion of the overall spectrum of energy production in the United States. This finding highlights the dominant role played by natural gas in meeting the energy demands of the nation, signifying its significance and contribution to the energy mix. This recognition of natural gas as a prominent source of energy underscores its importance for the present and future energy landscape of the United States. The abundance of natural gas reserves in both conventional and unconventional reservoirs serves as a significant factor driving its prominence as a prime energy source. According to the U.S. Energy Information Administration (EIA), the substantial size of these reserves is expected to contribute to the continuous growth in natural gas production. This confirms the long-term sustainability and potential expansion of natural gas as a crucial component of the energy landscape (EIA, 2018).

1.5 Outline of the thesis

The well-test analysis plays a crucial role in the development of successful field development plans as it provides essential data on key parameters such as formation permeability, hydraulic fracture half-length, and initial reservoir pressure. However, pressure data analysis in fractured wells within Tight Gas Reservoirs (TGRs) is challenging due to the low permeability of tight formations and the extended duration of the build-up test.

Additionally, the time required for the build-up test, which is essential for gathering pressure data, can be impractically long in TGRs. These factors contribute to the complexity of pressure data analysis in fractured wells within TGRs, necessitating innovative approaches and techniques to overcome these challenges. Consequently, normal analysis techniques often struggle to yield successful results in TGRs. Furthermore, inaccurate estimation of the reservoir's initial pressure can have a significant impact on reservoir simulation outcomes, production data analysis, and field development planning.

It is crucial to address these challenges and develop alternative methodologies that can provide more accurate and reliable results for effective decision-making in TGRs (Ilk, Anderson, Stotts, Mattar, & Blasingame, 2010). However, the current publications on pressure transient analysis of hydraulic fractured vertical wells in TGRs are insufficient, considering the significance of this practical problem (Amini, Ilk, & Blasingame, 2007; Badazhkov, Ovsyannikov, & Kovalenko, 2008; Bahrami, Jayan, Rezaee, & Hossain, 2012; Borges & Jamiolahmady, 2009; Branagan & Cotner, 1982; Cheng, Lee, & McVay, 2009; Gochnour & Slater, 1977; S. Holditch, Lee, Lancaster, & Davis, 1983; Ilk et al., 2010; Jahanbani & Aguilera, 2008; Kazemi, 1982; Pankaj & Kumar, 2010). Therefore, Chapter 3 of the thesis aims to address this knowledge gap by introducing a simplified numerical approach. This approach focuses on calculating hydraulic fractures and reservoir parameters using well-test data from hydraulically fractured vertical wells in tight gas reservoirs, considering an elliptical flow regime.

Recently, the petroleum industry has witnessed a significant shift in recent times, with conventional reservoirs depleting rapidly. As a result, unconventional reservoirs have emerged as a replacement for conventional reservoirs (Al-Fatlawi, Vimal Roy, Hossain, & Kabir, 2017; M. M. Hossain, Al-Fatlawi, Brown, & Ajeel, 2018). Tight gas reservoirs (TGRs) are a significant type of unconventional reservoir characterized by low to extremely low permeability and porosity, along with high heterogeneity. The analysis of TGRs presents considerable complexity due to the uncertainties associated with reservoir properties, particularly permeability and porosity(Al-Fatlawi, Hossain, & Saeedi, 2017).

Due to the low permeability, a stimulation technique is necessary to improve productivity. Hydraulic fracturing is indeed the most commonly used stimulation technique in such reservoirs (S. A. Holditch, Jennings, Neuse, & Wyman, 1978). In fractured wells, different flow regimes can occur, including linear, bilinear, formation linear, elliptical, and pseudo-radial flow (Heber Cinco-Ley & Samaniego-V, 1981) and they are explained in Chapter 2.

The literature indicates that many published works in the field (such as: (Shail Apte, 2015; Hale & Evers, 1981; F. Kucuk & W. Brigham, 1979; W. Lee & Gidley, 1989)) have overlooked or neglected the skin effect in their derivations or formulas. In addition, there is a lack of emphasis on studying the impact of the number of fractures and the distance between fractures in many published works (Except for (SS Apte & Lee, 2017)). To fill this gap, new correlations have been developed for the linear and elliptical flow regimes in Chapter 4, considering the influence of factors such as skin effect, number of fractures, and distance between them. These correlations provide a more comprehensive understanding of the behaviour of fractured wells by considering these important parameters.

Examining production information from TGRs stands out as a crucial field of study within unconventional gas resources. Gathering production data can be done continuously and affordably, eliminating the need for well shutdowns. This data analysis serves the purpose of estimating reservoir and well characteristics.

Furthermore, the utilisation of the type curve method not only demands a minimal dataset but can also be accomplished without the need for commercial simulators. This renders it a convenient, rapid, and cost-effective technique for assessing fractured wells in TGRs.

Given these considerations, certain scholars have generated type curves specific to hydraulic fractured vertical wells in TGRs (R. G. Agarwal, Gardner, Kleinsteiber, & Fussell, 1999; Amini et al., 2007; Araya & Ozkan, 2002; T Blasingame & Palacio, 1993; H.-Y. Chen & Teufel, 2000; Cox, Kuuskraa, & Hansen, 1996; M. J. Fetkovich, 1973; Pratikno, Rushing, & Blasingame, 2003; Soliman, Venditto, & Slusher, 1984; Wattenbarger, El-Banbi, Villegas, & Maggard, 1998; Xu, Li, Haghighi, Cooke, & Zhang, 2013).

Nonetheless, these simplified type curves frequently yielded inaccurate outcomes and led to misinterpretations of results. In light of this, the current study enhances this methodology by presenting a new collection of type curves for the examination of production data from fractured horizontal wells in TGRs. The creation of this new set of type curves is based on an original statistical correlation, as clarified in Chapter 5.

Additionally, the stimulation techniques of hydraulic fracturing of horizontal well drilling have emerged as the leading and economically feasible technological approach for effectively extracting resources from reservoirs with low permeability and tight geological structures.

This innovative fusion of methods enhances both resource recovery and cost efficiency, playing a crucial role in fully tapping into the potential of these complex reservoirs (Al-Fatlawi, Vimal Roy, et al., 2017; O. F. Al-Fatlawi, 2018; M. Hossain, Rahman, & Rahman, 2000b). Because tight gas reservoirs exhibit substantial diversity in properties like porosity and permeability, acquiring accurate data to adequately represent reservoir characteristics presents a challenge.

This precision is fundamental for constructing an effective numerical simulation model. Introducing a fractured horizontal well into such a model, characterized by significant heterogeneity, is not only intricate but also poses considerable difficulties, particularly with conventional computing resources. Consequently, this undertaking requires extensive computational time and access to expensive, advanced computing facilities.

However, the need for prolonged computation and costly facilities often clashes with standard industry practices and constrained budgets. Industries must respond to strict deadlines while seeking cost-effective solutions, especially in an unstable gas market marked by tight financial limits.

Chapter 6 explains how to tackle the noted challenge of reservoir heterogeneity by developing a reservoir simulation model that employs an equivalent well radius derived from a combination of well radius and fracture properties, instead of utilising the actual well radius. This model aims to predict the production behaviour of a fractured horizontal well within a heterogeneous tight gas reservoir.

Chapter 7 provides comprehensive conclusions and insightful recommendations based on the in-depth findings and practical implications explored throughout the thesis. This chapter also summarises detailed perspectives and actionable recommendations for future research endeavours. It also compiled the list of references provided in the reference list that acknowledges the valuable contributions of previous scholars.

Chapter 2: **Literature Review**

2.1 Background

In today's world, there is significant global exploration of tight oil and gas resources. To achieve the goal of economically producing hydrocarbons from these reservoirs, it is imperative to utilize and implement advanced and sophisticated technological solutions, often accompanied by significant costs. Hydraulic fracturing technology has proven to be a prominent and effective technology that has been widely adopted in the oil and gas industry for several decades. Its primary objective is to create highly conductive channels within formations with low or ultra-low permeability. This technique has transformed the industry by enabling the economical production of oil and gas from unconventional reservoirs, such as shale formations. In horizontal drilling, hydraulic fracturing with multiple fractures for the oil and gas industry stands out as an exceptionally efficient technique, leading to significant advancements in enhancing production from these challenging reservoirs (Kumar & Goswami, 2019).

Among the available techniques, a hydraulic fracturing design undoubtedly emerges as one of the most potent and efficacious methods to attain highly satisfactory production outcomes from unconventional reservoirs, notably tight gas reservoirs. For designing and executing the operation of hydraulic fracturing, many parameters and factors should be considered. Some of these factors are pump rate, size and concentration of propping agent, fracture half-length and number of fractures. Furthermore, it is crucial to acknowledge the existence of other paramount factors that wield a considerable and noteworthy impact on the designing an effective and efficient fracturing plan such as the flow back and shut-in period, pay zone thickness, availability of faults and their distance from the well, and natural fractures (if available) which has a great effect on production results, fluid and rock properties. It is of significance to recognize and take into account that these aforementioned parameters possess the potential to undergo noteworthy variations across a multitude of distinct locations across the world. There isn't a one-size-fits-all hydraulic fracturing technique that can be universally applied worldwide without conducting a thorough evaluation of the underground formations holding hydrocarbons (Kumar & Goswami, 2019).

2.2 Unconventional hydrocarbon reservoirs

Tight gas sandstone reservoirs can be considered as an extension of conventional reservoirs but have extremely low permeability and low value of effective porosity. Hydrocarbons are typically produced from conventional reservoirs that possess high values of permeability and porosity. These characteristics enable the efficient flow of fluids, such as oil and gas, through the reservoir rock. Hydrocarbon reservoirs that have an average permeability of a value equal to or less than 0.1 milliDarcy (mD) had no feasible economic production, but recently, they have proved to have a feasible production when stimulated using one of the effective stimulation methods.

In the research conducted by Meckel and Thomasson (2008), it was conclusively pointed out that the "tight gas reservoir" presents a notable lack of a standardized and universally accepted definition across the industry. This discrepancy in definition has led to varying interpretations and classifications of such reservoirs, thereby contributing to the complexity and challenges encountered in the study and exploitation of these specific types of gas reservoirs. Sometimes, they are referred to as deep-basin, pervasive sandstone reservoirs, or basin-centered gas accumulation. According to the United States Gas Policy Act of 1978, tight gas formations are classified as reservoirs with an average permeability of less than 0.1 mD (millidarcy). This classification was established to differentiate tight gas reservoirs from conventional reservoirs based on their permeability values (Kazemi, 1982).

Accordingly, a sandstone gas reservoir with a permeability value of less than 0.1 mD is classified as a tight gas reservoir. This classification is irrespective of the depositional environment of the reservoir. These reservoirs may exist in different settings, such as channelized fluvial systems (e.g., the Greater Green River basin, (Law, 2002; Ma et al., 2011; Shanley, 2004)), delta fan, alluvial fans, slope and submarine fan channel deposits (e.g., Granite Wash, Wei and Xu (2015)), or shelf margin (e.g., Bossier sand, Rushing, Newsham, and Blasingame (2008)), among others.

Tight gas reservoirs can indeed exhibit a variety of depositional facies. The Cotton Valley formation, for instance, is known to have stacked shoreface/barrier bar deposits, tidal delta, inner shelf, tidal channel, and back-barrier deposits. S. A. Holditch (2006) stated that there is no typical tight gas reservoir due to the high variety of their depositional environment of sandstones and other different variations. The sandstone reservoirs are similar to shale gas reservoirs in drilling, well design, and completion techniques, but they are quietly different in exploration and resource evaluation (Kennedy, Knecht, & Georgi, 2012).

The dimensionless reservoir radius, which is one of the dependent parameters for the pseudo-steady state parameter, is a function of the radius of reservoir, r_e, and fracture half-length, x_f. However, According to a study by O. Al-Fatlawi (2018), a method was proposed that replaces the reservoir radius with the radius of investigation, r_i. This substitution was made because the radius of investigation is easier to determine and has been proven to yield highly accurate results.

$$r_{eD} = \frac{r_i}{x_f} \qquad 2.1$$

For developing a new correlation for b_{Dpss}, the data of b_{Dpss}, r_{eD} and F_{CD} as input for a statistical model, and based on non-linear regression analysis, a new correlation for b_{Dpss} is developed as a function of r_{eD} and F_{CD} as expressed in Equation(2.2).

Table 2-1 Constant coefficients of Equation (2.2).

Constant	Value
a1	3.52
a2	-3.13
a3	0.722
a4	0.52
a5	8.84
a6	1.04
a7	0.495
a8	0.53
a9	0.097
a10	0.29
a11	1.36
a12	0.9
a13	1.1

$$b_{Dpss} = a_1 r_{eD}^{a_2} + a_3\, ln(r_{eD}) + a_4 + \frac{a_5 + a_6 u + a_7 u^2 + a_8 u^3 + a_9 u^4}{1 + a_{10} u + a_{11} u^2 + a_{12} u^3 + a_{13} u^4} \qquad 2.2$$

Where u is a function of F_{CD} and will be defined later in Equation (5.4).

To find the best correlation that fits the available data, several forms of equations are suggested and the confidence level of each equation is observed. The best-fit equation is selected which has the minimum absolute percentage error between the calculated b_{Dpss} and the actual value of b_{Dpss}.

Naik (2003) specified that the San Juan Basin in the western United States was the first region to witness significant development in tight gas production. Tight gas sandstone reservoirs have a long-standing history of large-scale development, predating the widespread development of shale gas reservoirs. Naik mentioned that the United States was producing approximately 1 trillion cubic feet (Tcf) of natural gas annually by the year 1970. Meckel and Thomasson (2008) identified three distinct periods in the evaluation and production of tight gas sandstone reservoirs: the pre-paradigm period (1920-1978), the paradigm period (1979-1987), and the mop-up period (1988-present). Master's article marked the paradigm period by the recognition and argument of the availability of hydrocarbon resources in tight reservoirs. In North America, tight gas sandstones have played a significant role in the exploration and production of energy resources. These reservoirs, characterized by low permeability, have been actively explored and developed to contribute to North America's energy production.

Tight gas sands play an important resource worldwide as classic formations which are found in many parts of the world (Moore et al., 2016). Rogner (1997) stated an approximation of tight gas resources to be 7500 Tcf worldwide, while Naik (2003) mentioned a much larger number for tight gas plays without giving a specific value. However, for comparison, Rogner (1997) specified an estimation of the worldwide shale gas resource of about 16,100 Tcf.

The most important part of the current study is the type curves. These type-curves are generated through numerical simulations, employing the proposed correlations. This approach follows a methodology similar to that proposed by O. F. Al-Fatlawi (2018) for various values of dimensionless fracture conductivity and dimensionless reservoir radius.

The dimensionless reservoir radius and dimensionless fracture conductivity values that are assumed and encompassed in the creation of the type curves are:

r_{eD}: 4, 12, 20, 60, 100

F_{CD}: 5, 20, 40, 60, 100

In the process of generating type curves, simulations were executed for a spectrum of dimensionless reservoir radius (r_{eD}) and flow capacity dimensionless (F_{CD}) values. These simulations entailed capturing the bottom hole flowing pressure and flow rates over time. Subsequently, the recorded values of flow rates, pressures, and time were utilized as inputs for Equations 2.3, 2.4

, 2.5

and 2.6 which are presented below, to construct the type curves.

$$t_{DA} = 0.000264 \frac{kt}{\emptyset(\mu C_t)_i A} \qquad 2.3$$

$$P_D = \frac{2.88\times10^{-4} kh(\Delta m(p))}{qTC_f} \qquad 2.4$$

$$t_{Dd} = \frac{2\pi t_{DA}}{b_{Dpss}} \qquad 2.5$$

$$P_{Dd} = P_D / b_{Dpss} \qquad 2.6$$

The results of the above calculations are then plotted as P_{Dd} versus t_{Dd} for different values of dimensionless fracture conductivity and dimensionless reservoir radius to match the form of Fetkovich's type curves as shown in Figure 5.6 to Figure 5.10 in Chapter 5.

Two example cases are presented to confirm the application methodology to use the technique in an actual representative case.

The reservoirs have been categorized as per the value of normal permeability into three major kinds: the first case is conventional reservoirs which have a permeability value (greater than 1 mD), and near tight reservoirs which have a medium value of permeability (0.1-1mD), as well as the tight reservoirs which has less value of permeability and it needs massive stimulated procedures for commercial extraction of gas (Rezaee, Saeedi, & Clennell, 2012). In conventional reservoirs, the typical pore sections of the rocks are well connected and quite large, and that allows the fluid to flow smoothly in the porous medium. Adversely, the pores in the other two types of reservoirs appear to be isolated and narrow which may restrict the fluid flow and lead to a non-feasible production rate. So, these reservoirs required massive stimulation procedures to enhance the flow rate.

Tight gas constitutes a substantial and noteworthy portion of the world's overall gas reserves (Al-Fatlawi, Hossain, & Essa, 2019). This gas reserve is located in different parts all around the world (Al-Fatlawi, Hossain, Patel, & Kabir, 2019; Dong, Holditch, McVay, & Ayers, 2012; S. A. Holditch, 2013; Rogner, 1997). Various industrial sectors are continuously evolving and expanding to meet the increasing global population's demands. Currently, global energy consumption stands at approximately 550 quadrillion BTUs (quads), while the world's population is estimated to be around 7.4 billion people. In 2030, the world population is predicted to reach 8.2 billion while the energy consumption is predicted to be 722 quads (Abdullah, 2017; Aguilera, Harding, & Krause, 2008; Al-Fatlawi, Mofazzal, Hicks, & Saeedi, 2016).

Accordingly, the tight gas resources are expected to play an important role in covering the scarcity of energy to meet the population's consumption. Anyway, the development of tight gas reservoirs to achieve a feasible production rate is a very challenging task that requires fields of technology, science and planning to work together (Pankaj & Kumar, 2010). To achieve this objective, research endeavours have been focused on developing scientific technologies and methodologies that enable the comprehensive study of tight gas reservoirs. The assessment of tight gas reservoirs takes priority even in the conventional gas-rich areas in the Middle East (Al-Fatlawi, Hossain, & Essa, 2019; Aly, Bukhamseen, Ramsey, & Mesdour, 2009; Forsyth, Al Musharfi, & Al Marzooq, 2011; Shehata, Aly, & Ramsey, 2010). The research trends that concentrate on tight gas reservoirs aim to analyse, evaluate and make production easier. Figure 2.1 illustrates the steady increase in the number of research publications related to tight gas reservoirs over the past four decades, totalling 8,242 according to the Curtin University library catalogue database. This rising volume of studies underscores the critical importance of research and development in the field of tight gas reservoirs.

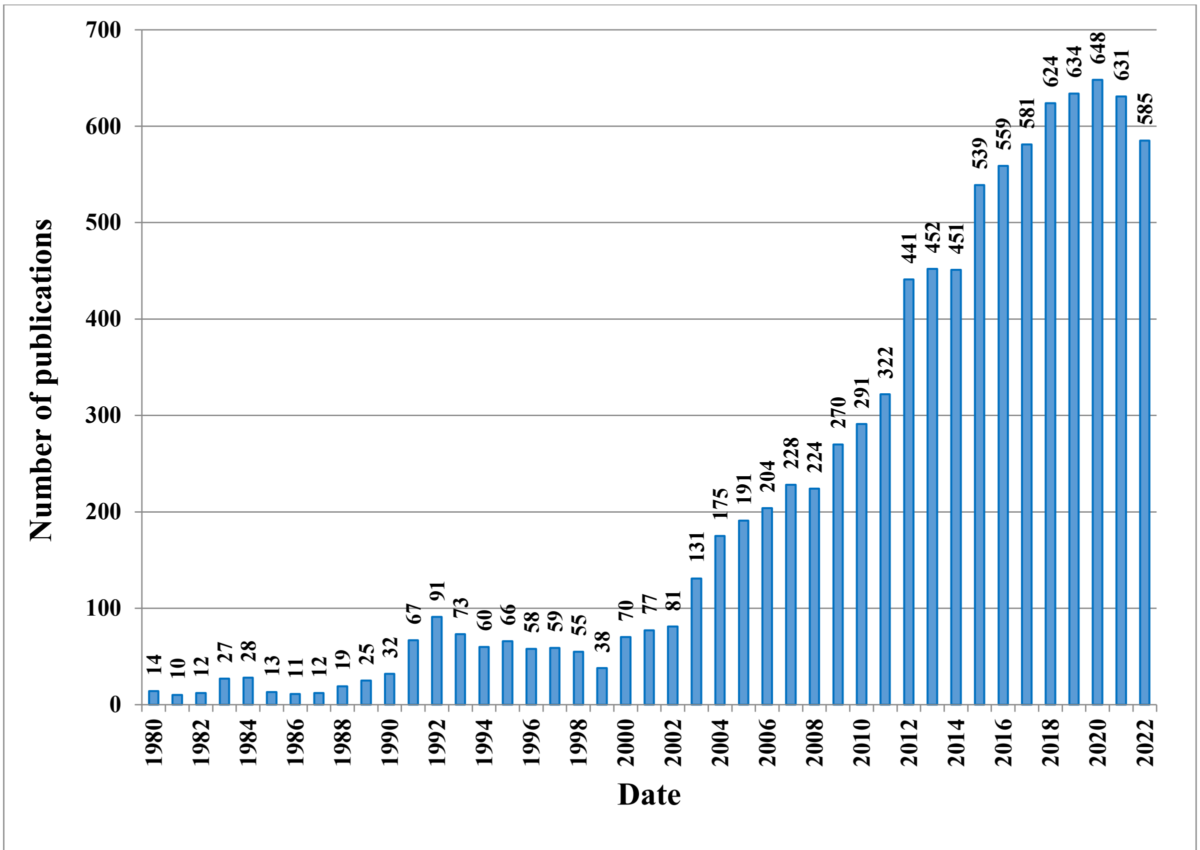

Figure 2.1 The quantity of publications addressing tight gas reservoirs from 1980 to 2022 (Curtin University library catalogue database).

2.3 Pressure transient analysis of unconventional reservoir, issues, complexities, technical, and practical constraints

Generally, one of the main goals of well testing of gas reservoirs is estimating the original gas in-place and recoverable volumes. Initial reservoir pressure (p_i) is a very critical parameter and important for estimating gas in place, as well as detecting the accurate required field development. Well-testing provides an estimate of permeability and skin in addition to the initial reservoir pressure.

The primary challenge in conducting well testing for tight gas reservoirs is the extended time required to attain radial flow due to the low or ultra-low permeability. Consequently, conventional well-test analysis can result in inaccuracies when estimating field parameters. Moreover, achieving an economically viable production rate at the outset often necessitates the application of stimulation technologies, with hydraulic fracturing being the prevalent method employed in such scenarios.

Hydraulic fracturing is widely used to enhance the productivity of gas reservoirs with low permeability (Dmour, 2008). Many studies have been conducted to develop models for analysing vertically fractured gas wells. However, the performance of fractured wells is significantly affected by non-Darcy flow occurring within the fractures. Several authors (H Cinco-Ley, Samaniego V, & Kucuk, 1985; M. J. Fetkovich, 1980; Horne, 1995) agree that the most crucial factor influencing the permeability of the proppant pack is the presence of non-Darcy flow. W. Lee and Holditch (1981) highlight that the high-pressure drop resulting from high velocities, which can be attributed to turbulence and inertial resistance, further exacerbates this effect. They also emphasize that neglecting the impact of non-Darcy flow on the gas well's productivity index, without considering the type of proppant used, can lead to incorrect interpretations of well tests.

The literature review unveils that the discussion of pressure transient analysis for both hydraulically and naturally fractured reservoirs was first originated by Pollard (1959). Pollard's primary focus lay in determining fracture volume through pressure build-up tests. In deep reservoirs, induced fractures generally exhibit a vertical orientation and follow a single plane of weakness. The presence of a vertical fracture near the wellbore introduces complexity to the transient flow behaviour of low-permeability gas wells. Furthermore, the flow becomes even more intricate when turbulence occurs in proximity to the wellbore (Dmour, 2008; Pollard, 1959).

Russell and Truitt (1964) introduced transient drawdown solutions for vertically fractured liquid wells. These solutions were developed through numerical simulation and provided a basis for drawdown and build-up testing methods. Building upon the work of Russell and Truit, Clark (1968) applied their solutions to analyse fractured water injection wells using falloff tests. Their research contributed to the understanding and analysis of fractured well behaviour in water injection scenarios.

The works of Garcia, Pooladi-Darvish, Brunner, Santo, and Mattar (2006) provide a comprehensive collection and summary of significant advancements in pressure transient analysis. They specifically focus on the practical application of these developments in the design and analysis of fractured well tests. Their research serves as a valuable resource for understanding and implementing the latest techniques and approaches in this field.

The study conducted by A. Gringarten and Witherspoon (1972) involved a review of the theory related to transient pressure analysis in both hydraulically and naturally fractured reservoirs. This work provided a comprehensive understanding of the subject matter.

In a later publication, De Swaan O (1976) presented an analytical solution for the unsteady state behaviour of a well producing at a constant flow rate in naturally fractured reservoirs. This solution was significant as it introduced new definitions of diffusivity that proved to be useful in characterizing the reservoir.

The study by Crawford, Hagedorn, and Pierce (1976) is recognized for presenting notable field examples of pressure transient tests conducted on both hydraulically and naturally fractured reservoirs. Their work provides valuable insights into the behaviour and analysis of fractured wells in real-world scenarios.

In the case of hydraulic fractured wells, Pratikno et al. (2003) observed that the pressure transient tests often matched the type curves of early fractured wells. However, they found that the apparent fracture length yielded a value of 10 ft, significantly lower than the design lengths exceeding 1000 ft. S. Holditch and Morse (1976) initially attributed this discrepancy to high-velocity flow within the fracture. However, the work by Ramey Jr (1965) suggested that the finite-fracture permeability-width was a more plausible cause of this issue, utilizing a finite element solution.

A classic study on steady-state flow by Michael Prats (1961) provided crucial insights into understanding and addressing this problem. Furthermore, H Cinco-Ley et al. (1985) introduced a seminal semi-analytical solution in the real domain for wells with a finite conductivity vertical fracture in an Infinite Acting Reservoir (IAR). Although this solution may require precise calculations, it is known for its accuracy in analysing such well configurations.

Dmour (2008) proposed an analytical model obtained from various sources without considering the impact of equation selection on the final results. The study focused on the systematic evaluation of the Modified Isochronal test for two hydraulically fractured gas wells. Its objective was to investigate the effect and magnitude of non-Darcy flow on the pseudo-steady state productivity index of stimulated gas wells. The paper also demonstrates the application of the adopted technique to a low permeability tight gas reservoir that has been hydraulically fractured. It highlights how the build-up and drawdown data, which are predominantly influenced by bilinear flow, can be rigorously evaluated using his concept and computer models.

Gao, Rahman, and Lu (2021) introduced a practical mathematical framework for multi-fractured horizontal wells within naturally fractured reservoirs. This model relies on the fractal system, the theory of permeability modulus, and time-fractional calculus, serving as an expansion of the traditional trilinear flow model.

The thorough sensitivity analysis they performed indicates the impact of crucial parameters, including fractal dimension, hydraulic fracture permeability modulus, conductivity, inter-porosity flow coefficient, and more, on transient pressure responses. They mentioned that the analysis provides insights into the reasons behind the observed changes in behavior. The application of their model to a field case study not only affirms its validity but also positions the presented results as valuable guides in interpreting well tests.

Zhong et al. (2022) explored the influence of various factors on the production of multilayer tight gas through numerical simulation, establishing compatibility thresholds. They developed the variable weightbased fuzzy comprehensive evaluation (VW-FCE) method and introduced a co-production compatibility index for assessing multilayer tight gas reservoir co-production. The study highlighted that when two co-production layers have similar properties, their compatibility is primarily affected by changes in formation pressure and gas saturation. Conversely, if the properties differ, compatibility is governed by formation thickness and permeability. The researchers validated their approach by comparing it with actual production data from typical wells engaged in tight sandstone gas co-production.

2.4 Identification of flow regimes

The main flow regimes accompanied by the hydraulically fractured well in tight gas reservoirs include Bi-linear flow, linear flow, and elliptical flow. Each has its peculiarities and thus influences various findings in testing.

2.4.1 Bi-Linear flow:

H Cinco-Ley et al. (1985) explain that the existence of an artificial fracture has a significant impact on the fluid dynamics near the wellbore. Their research delves into the different flow regimes that can emerge around a well with an artificial fracture, including the occurrence of bilinear flow.

Bilinear fracture flow manifests in hydraulically fractured wells when the fracture's conductivity is finite. In this flow regime, two distinct linear flows transpire in the normal direction: one from the matrix to the fracture and another from the fracture to the wellbore. This phenomenon is typically observed in extended fractures, which are challenging to maintain in an open state effectively, or in natural fractures that contain fracture fill minerals (Dmour, 2008).

W. Lee and Gidley (1989) introduced a formula for representing the pressure drop over time in dimensionless form. It can be represented as follows:

$$p_D = \frac{1.38}{\sqrt{C_r}} t_{x_{fD}}^{\frac{1}{4}} \qquad 2.7$$

and

$$t_{x_{fD}} \frac{dp_D}{dt_{x_{fD}}} = \frac{0.345}{\sqrt{C_r}} t_{x_{fD}}^{\frac{1}{4}} \qquad 2.8$$

where:

$$t_{x_{fD}} = \frac{0.002637kt}{\varphi\mu C_t x_f^2} \qquad 2.9$$

$$C_r = \frac{w_f k_f}{\pi k x_f} \qquad 2.10$$

and

$$p_D = \frac{kh(p_i - p)}{141.2qB\mu} \qquad 2.11$$

Equation (2.7) shows that in the log-log plot of pressure derivatives vs time, a quarter slope will be detected when bi-linear flow exists. These bi-linear flows thus occur earlier when it was not usually observed as it may be accompanied by wellbore storage and skin effect.

2.4.2 Linear flow:

Linear flow in TGR exists when the flow from the reservoir to fractured-well and it can be clearly detected and determined in the wells having infinite conductivity fractures (Shail Apte, 2015; SS Apte & Lee, 2017). The exceptionally low permeability in TGRs could extend the linear flow regime for over a decade (Nobakht & Clarkson, 2012). The most crucial chart for examining the linear flow regime and calculating the product of fracture half-length and the square root of permeability is the graph depicting normalized pressure against the square root of time, as presented in the work of Anderson, Nobakht, Moghadam, and Mattar (2010).

Numerous research papers and studies have indicated that analyzing the slope of the graph depicting normalized pressure against the square root of time is a method used to determine the product of fracture half-length and the square root of permeability (A. C. Gringarten, Ramey Jr, & Raghavan, 1974; M. Ibrahim & R. Wattenbarger, 2006a; Nobakht, Mattar, Moghadam, & Anderson, 2010). A. C. Gringarten et al. (1974) proposed a solution for linear flow around a fractured well in the square reservoir. Wattenbarger, El-Banbi, Villegas, and Maggard (1998) have also provided a linear flow solution for situations involving a constant flow rate and consistent pressure within a rectangular reservoir. They provide an example of a real field by explaining the calculation method.

The equation below thus represents an example of the linear form (W. Lee & Gidley, 1989) is given by:

$$p_D = \left(\pi t_{x_{fD}}\right)^{\frac{1}{2}} \qquad 2.12$$

$$t_{x_{fD}} \frac{dp_D}{dt_{x_{fD}}} = \frac{1}{2}\left(\pi t_{x_{fD}}\right)^{\frac{1}{2}} \qquad 2.13$$

Therefore, Equation (2.13) provides a clear description of the log-log plot of pressure derivative vs time which provides the slope of a half (0.5) in the linear flow regime. Later, A. C. Gringarten et al. (1974) provided the type curves that will be used to analyse the transient pressure behaviour associated with the infinite conductivity of hydraulic fractures. The concept incorporates a third flow regime known as elliptical flow, which holds significant importance in the overall understanding of the system.

2.4.3 Elliptical flow:

The well test confirmed the existence of an elliptical flow regime in formations characterized by low to ultra-low permeability (Amini et al., 2007). F. Kucuk and W. E. Brigham (1979) introduced an analytical solution designed for the analysis of the elliptical flow regime, specifically addressing fractures with infinite conductivity in elliptical or an-isotropic reservoirs. Hale (1979) developed dimensionless type curve solutions based on a simulation of the elliptical flow regime observed during well testing in TGR. Riley (1991) presented an analytical solution for a finite-conductivity fracture in an infinite-acting reservoir in elliptical coordinates. Liao (1993) studied the effects of different wellbore storage and skin factors on pressure tests of hydraulically fractured wells and stated a general model for elliptical flow in fractured wells for these cases.

SS Apte and Lee (2017) provide an approximate pressure solution for elliptical flow for a constant rate case, and it can be written as:

$$p_{wD} = \left(\frac{\left(\frac{\pi \sinh(2\epsilon_0)}{2}\right)^{-\frac{3}{8}}}{\left(e^{-\left(\frac{3}{4}\right)\epsilon_0}\right)} \right) \sin\left(\frac{3\pi}{8}\right) t_{Dxf}^{\frac{3}{8}} \quad . \tag{2.14}$$

And provides another formula for the rate solution for constant bottom hole pressure, and it can be written as:

$$q_D = \left(\frac{8}{3\pi}\right)\left(e^{-\left(\frac{3}{4}\right)\epsilon_0}\right) \frac{t_{Dxf}^{-\frac{3}{8}}}{\left(\frac{\pi \sinh(2\epsilon_0)}{2}\right)^{-\frac{3}{8}}} \quad , \tag{2.15}$$

Where:

$$\epsilon_0 = \sinh^{-1}\left(\frac{x_e}{2x_f}\right) \tag{2.16}$$

For both linear and elliptical flow regimes, there is no formula in the published study to define the effect of the skin factor. In addition, there is only one author (Shail Apte, 2015; SS Apte & Lee, 2017) studied the effect of the number of fractures and distance between these fractures in multi-fractured wells and even this study stated this effect for horizontal wells only not vertical wells.

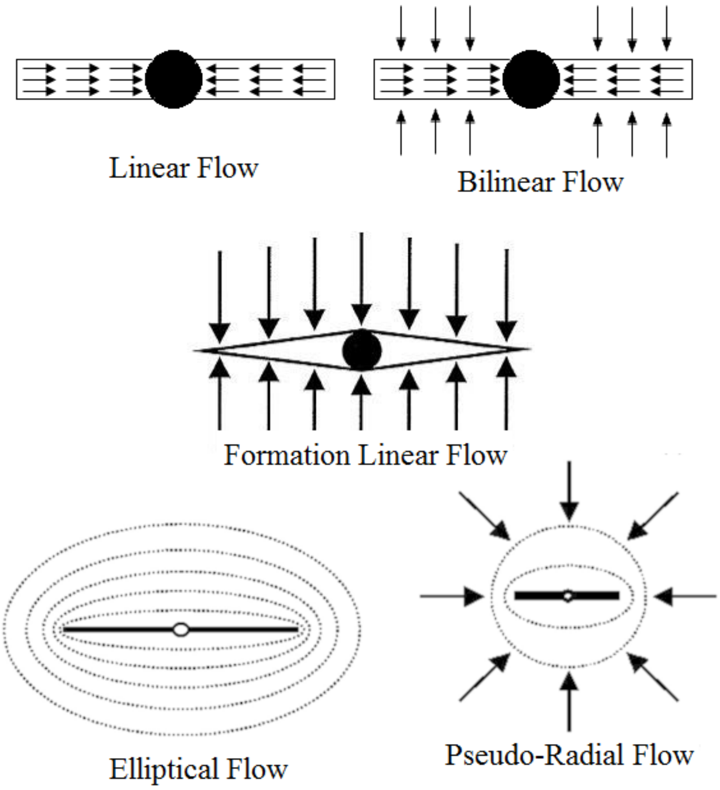

Figure 2.2 Flow regimes around hydraulically fractured well (after Heber Cinco-Ley and Samaniego-V (1981))

In the above cases, the assumptions are made that the fluid and rock properties remain constant throughout the analysis. The assumption of constant fluid and rock properties may not be applicable in cases involving gases. Unlike liquids, gases are highly compressible and their properties, such as density and viscosity, can vary significantly with changes in pressure and temperature. This has changed the equations hence making diffusivity equation for gases to be non-linear, it can be linearised by taking pseudo pressures. R Al-Hussainy and Ramey Jr (1966) and Rafi Al-Hussainy, Ramey Jr, and Crawford (1966) proposed an idea aimed at expanding the analytical solutions originally derived for oil reservoirs to gas reservoirs, particularly when dealing with real gas pseudo-pressure considerations. Based on the background information, Raghavan, Chen, and Agarwal (1997) and C.-C. Chen and Raghavan (1997) further developed analytical pressure transient solutions specifically tailored for situations involving multiple fractured horizontal wells within homogeneous reservoirs. The possibility of occurrence in regards to the compound linear flow wherein a linear flow is established beyond the fracture tips.

Chapter 3:

Identifying Transition from Linear to Elliptical Flow in Tight Gas Reservoirs: An Analytical Approach

3.1 Introduction

The tight gas reservoirs (TGRs) have been playing a prominent role while conventional reservoirs have been depleting rapidly (Al-Fatlawi, Roy, Aswin, Hossain, & Kabir, 2017). However, the characteristics of tight gas reservoirs are significantly heterogeneous resulting in a high level of variability in reservoir properties, such as porosity and permeability, which introduces complexity and challenges when attempting to describe and analyze the reservoir.

Given the exceedingly low permeability encountered in TGRs, fracture stimulation techniques are unequivocally recognized as the optimal and imperative methods to exploit these reservoirs and significantly enhance production rates (S. A. Holditch, Jennings, Neuse, & Wyman, 1978). During production from a fractured well in TGR, five discernible flow regimes or patterns in the vicinity of the fractures are observed, which encompass linear, bilinear, formation linear, elliptical, and pseudo-radial flow, as outlined by Heber Cinco-Ley (1981), and shown in Figure 2.2.

The fundamental flow regimes are categorized according to the time frame during which they are likely to occur, the type of wellbore (e.g., vertical or horizontal) that penetrates the reservoir, and the method by which the well is completed (e.g., open hole completion). Precisely identifying the flow regimes, particularly through pressure transient analysis, commonly referred to as well-test analysis, is of high importance for accurately predicting reservoir parameters, including those related to boundary effects.

In the context of a vertical well, the radial flow regime is defined by the flow occurring in a horizontal radial direction. This flow pattern can exist during a specific time period before the pressure transient has propagated to the reservoir boundaries. Understanding this specific time period allows for the identification of the characteristics of the reservoir boundary and the actual drainage area. The characteristics become evident when analysing the relatively short duration of drawdown or pressure build-up data associated with a vertical well in an unconventional reservoir.

However, achieving radial flow in TGR would indeed demand an impractically long duration, necessitating extended shut-in periods that may not be feasible in practical terms. This timeframe can span from several years to well over a decade, contingent on the specific permeability and attributes of the TGR. Furthermore, wells in TGR often need stimulation methods like hydraulic fracturing and the use of fractured horizontal wells to enhance their productivity.

In the context of horizontal or fractured vertical wells, the flow regime near the wellbore can initially exhibit linear behaviour, transition into an elliptical flow pattern, and ultimately evolve into a radial flow regime as conditions change over time. The precision of interpreting well-testing data for such scenarios heavily relies on the precise identification of these flow regimes, demanding extensive periods of flowing or shut-in data, especially in tight gas reservoirs (TGR), to achieve accuracy. Frequently, obtaining such extensive well-testing data is unfeasible.

Among the numerous studies focusing on flow regimes around fractured wells in TGR, the analysis of the transition between linear and elliptical flow has not been extensively explored. This is due to the need for a lengthy dataset of pressure (or pseudo-pressure function) versus time history in fractured wells within TGR, which is often challenging to obtain. However, in this study, the primary focus lies in identifying the transition time between two flow regimes (linear and elliptical) using numerical modelling, especially in situations with limited production data. Accordingly, In this study, an analytical method is devised to accurately determine the transition moment when the linear flow pattern concludes and the elliptical flow pattern commences in a fractured vertical well within a TGR (Nobakht & Clarkson, 2012). The key plot for analysing this flow regime is the relationship between normalized pressure and the square root of time (Anderson et al., 2010). This plot typically takes the form of a straight line, and by determining the slope of this line, it becomes possible to calculate the product of the fracture's half-length and the square root of permeability.

Published studies have documented that, the analysis of the slope of the plot between normalized pressure and the square root of time enables the determination of the product of fracture half-length and the square root of permeability (M. Ibrahim & R. Wattenbarger, 2006a; Nobakht et al., 2010). M. Ibrahim and R. Wattenbarger (2006a) and M. Ibrahim and R. A. Wattenbarger (2006) introduced a correction factor to enhance the accuracy of the calculation for the product of fracture half-length and the square root of permeability. Under constant flowing pressure conditions, they established an empirical correlation for determining the correction factor.

Miller (1962) introduced a solution for linear flow occurring within a confined aquifer in an infinite-acting reservoir. A. C. Gringarten et al. (1974) presented an analysis of linear flow occurring around a fractured well situated within a square reservoir. Wattenbarger et al. (1998) provided solutions for linear flow rate in a rectangular reservoir under both constant flow and constant bottom hole pressure conditions. They elucidated a calculation method along with a practical field example to illustrate their approach.

3.2 Elliptical Flow in TGR

During well-testing analysis, it has been verified that the elliptical flow regime is present in formations characterized by low to ultra-low permeability (Amini et al., 2007).

F. Kucuk and W. E. Brigham (1979) introduced an analytical solution designed to describe elliptical flow occurring in fractures with infinite conductivity within elliptical or anisotropic radial reservoirs. Hale (1979) presented type curve solutions, depicted in dimensionless form, which were derived from simulations of the elliptical flow regime observed during well testing in TGR. Riley (1991) examined the scenario of a finite conductivity fracture situated within an infinite-acting reservoir. He adopted an analytical solution for this specific case, utilizing elliptical coordinates. Liao (1993) proposed a comprehensive numerical model designed for elliptical flow patterns in fractured wells, considering various factors such as wellbore storage and skin effects in pressure tests.

3.3 Type Curves in TGR

Type curve methods prove valuable for indirectly identifying flow regimes in TGR (tight gas reservoirs). Numerous studies involving type curves have been conducted within TGRs (R. Agarwal, Carter, & Pollock, 1979; Cinco, Samaniego, & Dominguez, 1978; M. Fetkovich, Fetkovich, & Fetkovich, 1996). Cinco et al. (1978) utilized a type curve method to analyze low permeability gas reservoirs with finite conductivity fractures, considering a constant flow rate within TGR. R. Agarwal et al. (1979)

introduced type curves specifically tailored for tight gas reservoirs with finite-conductivity fractures, focusing on scenarios with constant bottom-hole pressure. M. Fetkovich et al. (1996) recommended the use of a decline curve method to analyse gas-layered reservoirs, under the assumption that there is no crossflow between the individual layers.

This study aims to develop an analytical approach that can precisely identify the exact moment when the linear flow regime transitions into the elliptical flow regime. This is a critical endeavour because it holds the potential to significantly improve our understanding of reservoir parameters. With a more accurate description of these parameters, we can enhance our ability to forecast future pressure trends over considerably longer timeframes.

3.4 Theoretical Background

W. Lee and Holditch (1981) introduced an analytical method for assessing pressure decline in the linear flow regime near a hydraulically fractured well within a low-permeability gas reservoir. Their approach assumed that the fracture exhibited high conductivity, although not infinite, and disregarded the impact of wellbore storage. They provided the following equation to describe linear flow:

$$m_e - m_{wf} = \frac{40.785 \times 10^3 qT\sqrt{\Delta t}}{h.x_f\sqrt{k\phi\mu_{gi}C_i}} \qquad 3.1$$

Where:

m_e and m_{wf} : are reservoir and flowing well pseudo pressure (psi^2/cp),

q : the gas production rate (SCF/D),

T : the temperature (°R),

Δt : the production time (hr),

h : the bay thickness (ft),

x_f : the fracture half-length (ft),

k : the permeability (mD),

φ : the porosity (dimensionless),

μ_{gi} : the initial gas viscosity (cP)

C_i : the initial gas compressibility (psi^{-1}).

Hale and Evers (1981) formulated a series of equations to characterize the elliptical flow pattern within a fractured well in a tight gas reservoir (TGR). They devised equations applicable to flow tests under both constant rate and constant pressure conditions. The equation they presented for a constant rate test is as follows:

$$m_e - m_{wf} = \frac{1422.QT.ln\left(\frac{A+B}{x_f}\right)}{kh} ln\left(\sqrt{\frac{B^2}{x_f^2}} + \sqrt{1 + \frac{B^2}{x_f^2}}\right) \quad 3.2$$

Where A and B can be calculated from the following equations:

$$B = 0.02878\sqrt{\frac{kt}{\phi \mu C_t}} \quad 3.3$$

$$A = \sqrt{B^2 + x_f^2} \quad 3.4$$

Where:

m_e and m_{wf} : are reservoir and flowing well pseudo pressure respectively (psi^2/cp),

Q : is gas production rate (SCF/D),

T : is the temperature (°R),

t : is production time (hr),

h : is pay thickness (ft),

x_f : is fracture half-length (ft),

k : is permeability (mD),

φ : is porosity (dimensionless),

μ : is gas viscosity (cP),

C_t : is gas compressibility (psi^{-1}),

A : is half of large axis of elliptical shape (ft)

and

B : is the half of the small axis in the elliptical shape.

Determining the transition point from linear flow to elliptical flow is crucial. This transition point should satisfy both the linear and elliptical flow equations, and the pressure values should also match. Figure 3.1 provides a visual representation of this transition with a plotted curve. The time at which these conditions are met on the plot corresponds to the required transition point.

3.5 Modelling of Solution Criteria

The model has been constructed using the fundamental equations for linear flow (as per Equation (3.1) suggested by W. Lee and Holditch (1981)) and elliptical flow (as per Equation (3.2) suggested by Hale and Evers (1981)), and solved numerically by employing the false position iterative method. This method allows for the determination of transition time from the solution of these two non-linear equations. The solution approach is illustrated in Figure 3.1. Figure 3.1 is conceptual, illustrating the theoretical framework to showcase the patterns of both linear and elliptical flow. It shows the significance of the transition point from a linear to an elliptical flow regime, and the method of the determination of this tranistion point elaborated in the following sections of this chapter.

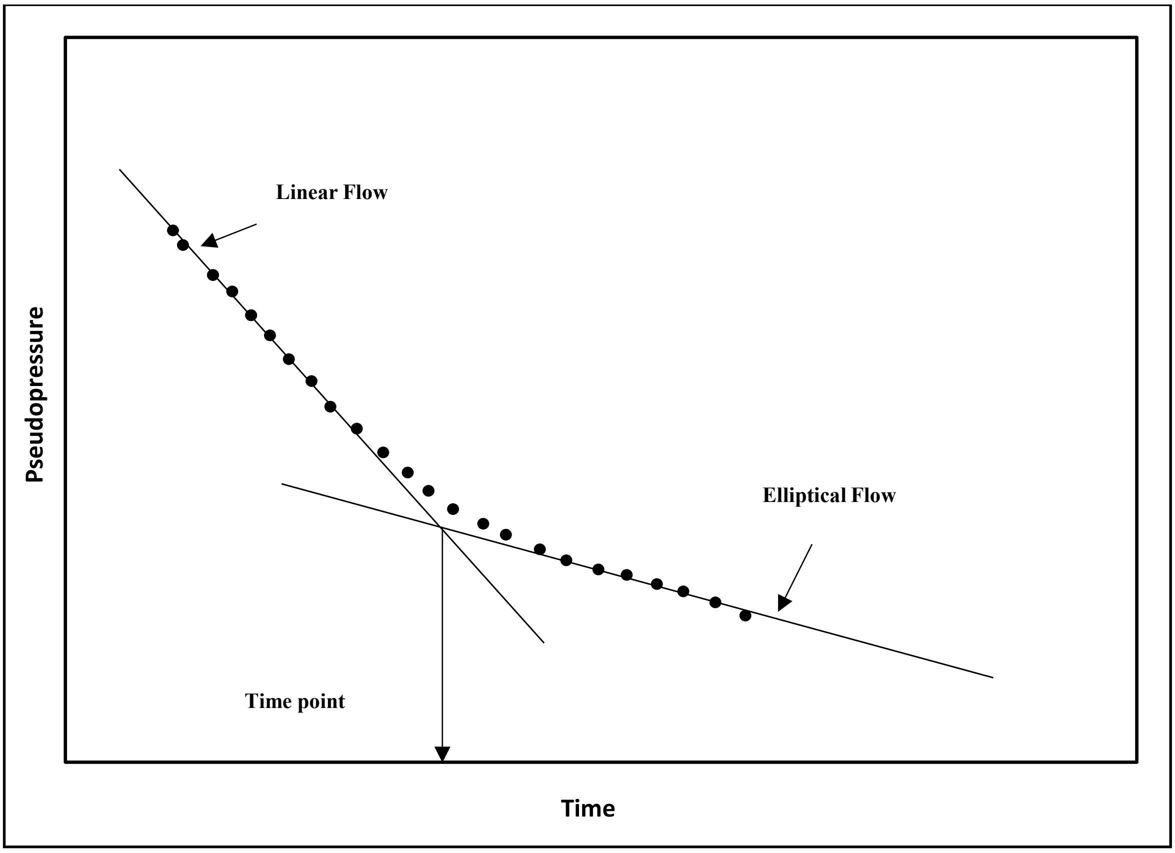

Figure 3.1 Illustrate the method of determination of the transition of Linear and Elliptical flow regimes.

The convergence criteria of the numerical solution are outlined below:

Assume the first equation is:

$$\Delta m_1 = f_1(t) \tag{3.5}$$

And the second equation is:

$$\Delta m_2 = f_2(t) \tag{3.6}$$

Iteratively determining the intersection for specific data values involves subtracting one of the equations from the other:

$$\Delta m_2 - \Delta m_1 = f_2(t) - f_1(t) \tag{3.7}$$

To solve this, we need to find the value of (t) that satisfies the following conditions:

$$|\Delta m_2 - \Delta m_1| \leq \varepsilon \tag{3.8}$$

The final solution to this problem involves solving the last equation numerically, and various methods like the Newton-Raphson method, False position method or the Secant method can be applied. However, this study considered the False position method as it provides fast convergence with high accuracy. This solution will determine the specific time (*t*) at which the transition from linear flow to elliptical flow occurs. Visual Basic-based computer program was developed to solve the problem.

3.6 Computer Code

A computer program has been created using the Visual Basic Dot Net (VB.Net) programming language, implementing the model discussed above. The visual basic script is provided in Appendix A. Figure 3.2 displays the program's main window, which includes fields for inputting time history data required to run the program. Figure 3.3 illustrates the specific data entered for case 2, as further elaborated below.

The "pressure vs Time" combo box can be modified by clicking on it, which will then display a list with three additional options, as demonstrated in Figure 3.3.

Choosing the option related to the Pseudo-pressure function will trigger the appearance of three additional fields that need to be filled out. These fields include Gas specific gravity, Z-factor, and viscosity calculation method selection. After completing these fields, clicking on "Continue" will display the final results, as shown in Figure 3.3.

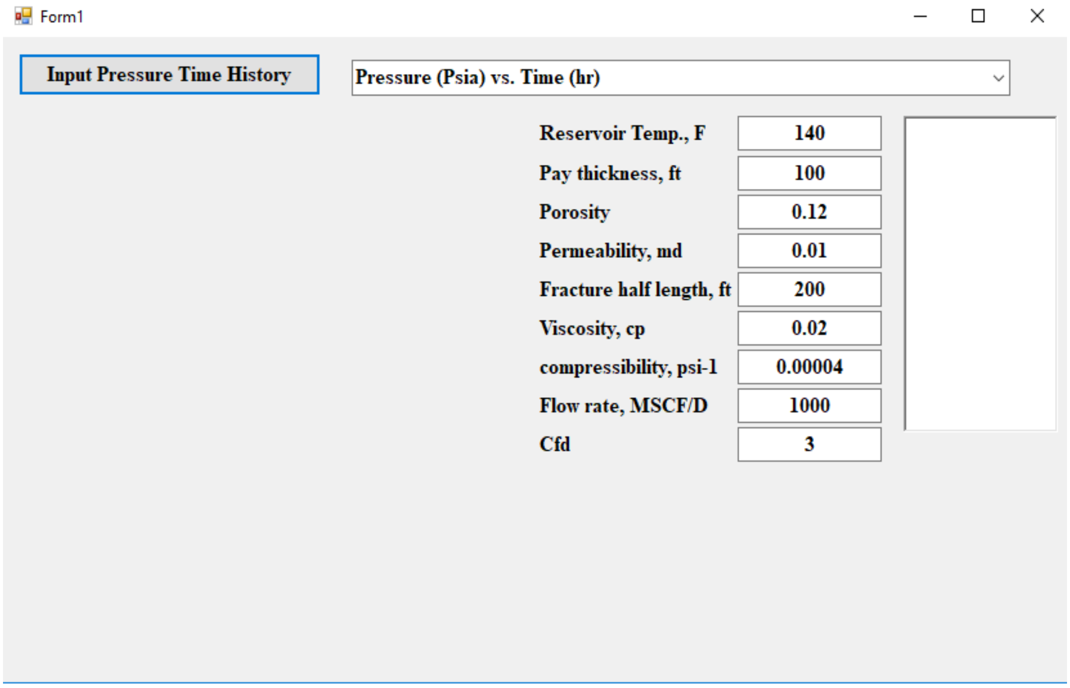

Figure 3.2 The primary input window of the executable file for the developed code.

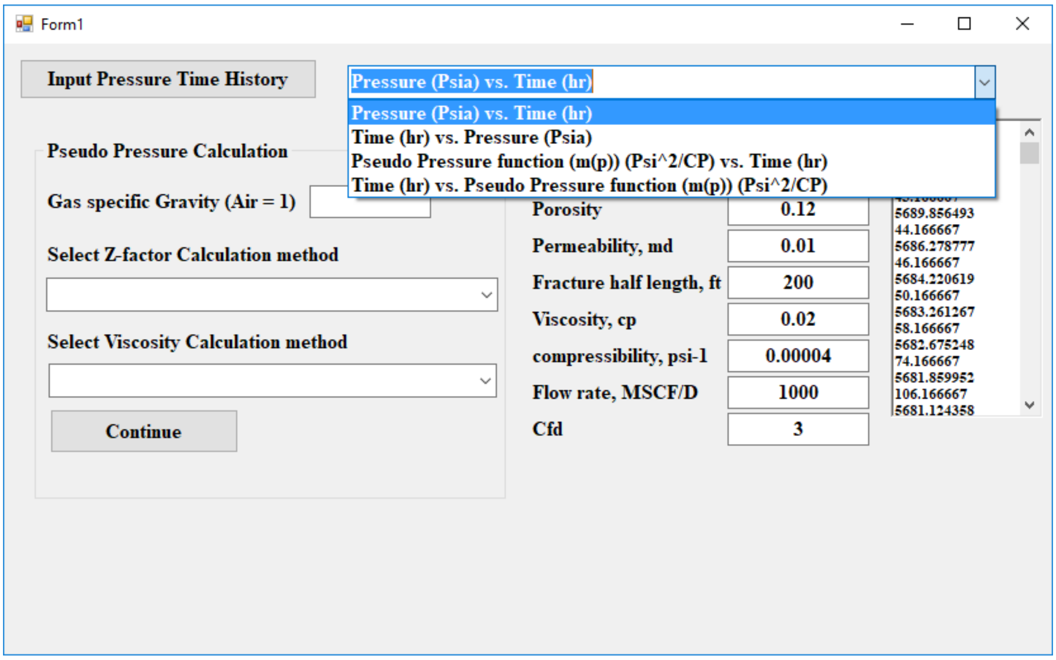

Figure 3.3 The input window of the executable file for the developed model displays the available input data options.

3.7 Model Validation

Two cases have been examined to validate the model and the developed code. Case 1 utilizes field data obtained from published literature, representing real-world conditions. Case 2, on the other hand, employs synthetic data generated through numerical reservoir simulation using the industry-standard commercial package ECRIN, which is provided by KAPPA Engineering (Houzé et al., 2011).

3.7.1 Case 1

The first case incorporates data obtained from the literature published by (Hale & Evers, 1981) specifically for a fractured well in a tight gas reservoir (TGR). The input data for this case are presented in Table 3.1 and Table 3.2. The developed code is employed to compute the pseudo-pressure function as a function of time, and the results are visualized in Figure 3.4, in which it can be seen that the transition time between two flow regimes, namely the end of the linear flow and the start of the elliptical flow regime, occurs at approximately 4649 hours. This closely matches or is similar to what was demonstrated in (Hale & Evers, 1981).

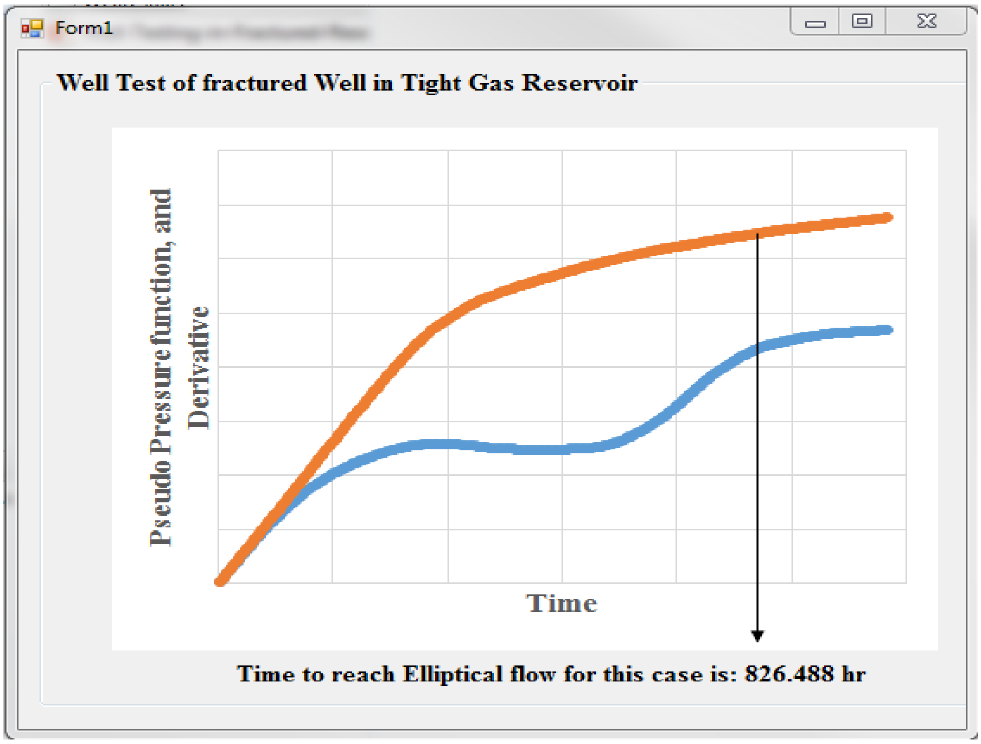

Figure 3.4 The graphed result from the developed model's executable file.

Table 3-1 Basic data of San Juan Mesaverde Well (Hale & Evers, 1981).

Final Rate, m^3/D (Mcf/D)	65900 (2326)
Net pay, m (ft)	8.8 (29)
Porosity-thickness, m (ft)	0.664 (2.18)
Permeability md	0.078
Fracture half-length, m (ft)	436 (1430)
Gas gravity	0.591
Reservoir temperature, °C (°F)	60 (140)
Critical pressure, kPa (psi)	4695 (681)
Critical temperature, k (°R)	195 (351)

3.7.2 Case 2

Because of the limited availability of real production or buildup data for tight gas reservoirs, simulation studies have been conducted on the Wicher Range Tight Gas Field (WRTGR). This field is situated in the Canning Basin of Western Australia and is considered one of the promising tight gas fields (Al-Fatlawi, Hossain, & Saeedi, 2017). Up to this point, a total of five vertical exploration wells have been drilled in the Wicher Range Tight Gas Field, with two of them undergoing hydraulic fracturing operations. Well-test data is accessible for the two hydraulically fractured wells in this field, but unfortunately, the data covers only a short period and is insufficient for conducting a comprehensive pressure transient analysis (PTA) to predict reservoir parameters with a high degree of confidence. Therefore, a simulation model has been constructed using ECRIN-Rubis and subsequently validated through history-matching processes. The simulation model is then utilized to generate synthetic data spanning 10 years, which is shown in Figure 3.6.

Following the generation of synthetic data, the resultant data was exported for further study and analysis. Two methods were employed for analysis: the first method utilized the proposed analytical model, and the second method utilized the developed code. Through these analyses, the calculated transition time was determined to be 826 hours, as illustrated in Figures 3.7 – 3.9.

Table 3-2 Pressure time and pseudo-pressure data of San Juan Mesaverde Well (Hale and Evers 1981).

Well head pressure, kPa	Pseudo-pressure, kPa.s	Elapsed time, hours	Flow rate, m^3/D
8060	5.37×10^5	0	0
7867	5.13×10^5	2	27400
7957	5.28×10^5	4	0
7605	4.85×10^5	6	44000
7846	5.13×10^5	8	0
7322	4.55×10^5	10	58900
7695	4.94×10^5	12	0
7026	4.23×10^5	14	73300
6274	3.46×10^5	26	65900
6481	3.67×10^5	26.08	0
6557	3.74×10^5	27.17	0
6612	3.80×10^5	26.25	0
6647	3.83×10^5	26.33	0
6681	3.86×10^5	26.42	0
6715	3.90×10^5	26.50	0
6750	3.94×10^5	26.58	0
6764	3.96×10^5	26.75	0
6805	4.00×10^5	27.00	0
6846	4.04×10^5	27.25	0
6881	4.08×10^5	27.50	0
6909	4.11×10^5	27.75	0
6950	4.15×10^5	28.00	0
6964	4.16×10^5	28.25	0
6984	4.18×10^5	28.50	0
7012	4.22×10^5	28.75	0
7033	4.24×10^5	29.00	0
7060	4.26×10^5	29.50	0
7080	4.29×10^5	30.00	0
7108	4.32×10^5	30.50	0
7136	4.34×10^5	31.00	0
7184	4.40×10^5	32.00	0
7536	4.80×10^5	51.00	0
7681	4.94×10^5	75.00	0
7763	5.04×10^5	100	0

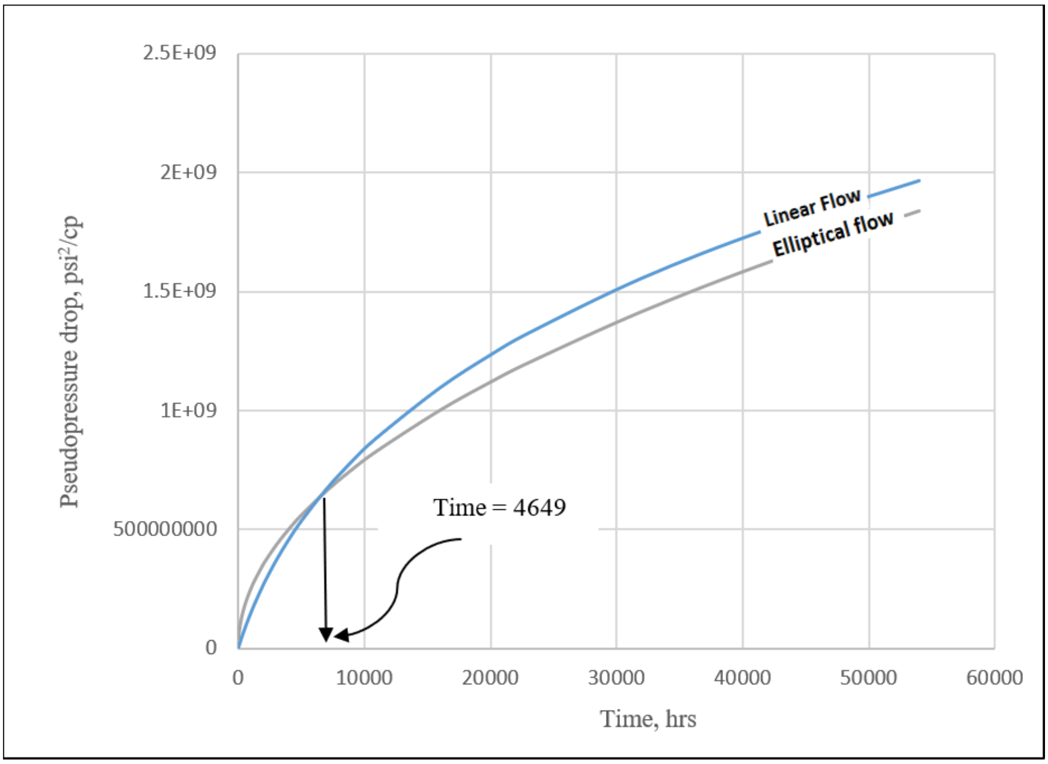

Figure 3.5 Identification of the transition time between the linear and elliptical flow regimes.

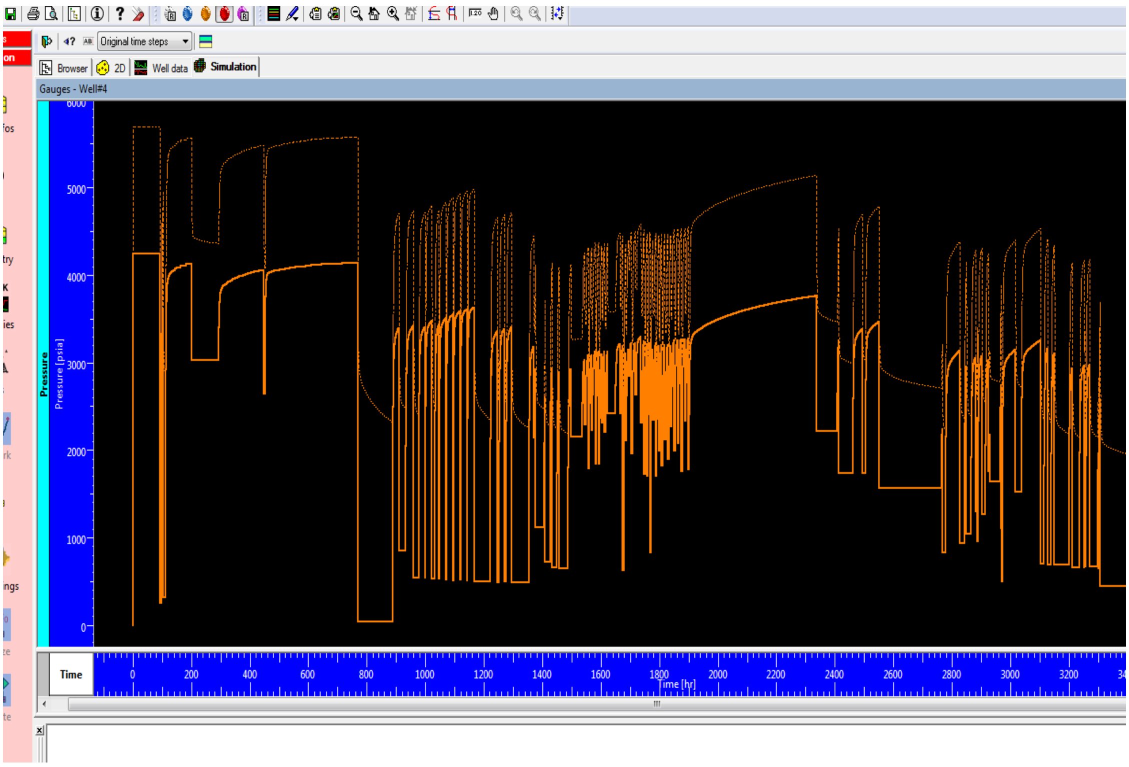

Figure 3.6 Pressure vs. Time Simulation data using ECRIN-Rubis simulator.

The second method relied on the widely accepted industry-standard pressure transient analysis software ECRIN-Saphir. The result obtained from this software is 800 hours, as displayed in Figure 3.5. This level of agreement between the developed code and the standard simulation tool is considered to be quite close. This case study serves as an illustration of how the proposed analytical model and the developed code can serve as valuable alternatives to the use of commercial tools, providing reliable and accurate results in pressure transient analysis.

Furthermore, this model and the developed tool can be effectively utilized to predict the transition time between the linear flow and elliptical flow regimes in fractured vertical wells. This capability is particularly crucial for enhancing the interpretation of pressure transient analysis (PTA) in the context of tight gas reservoirs (TGR), especially when there is a shortage of available test data.

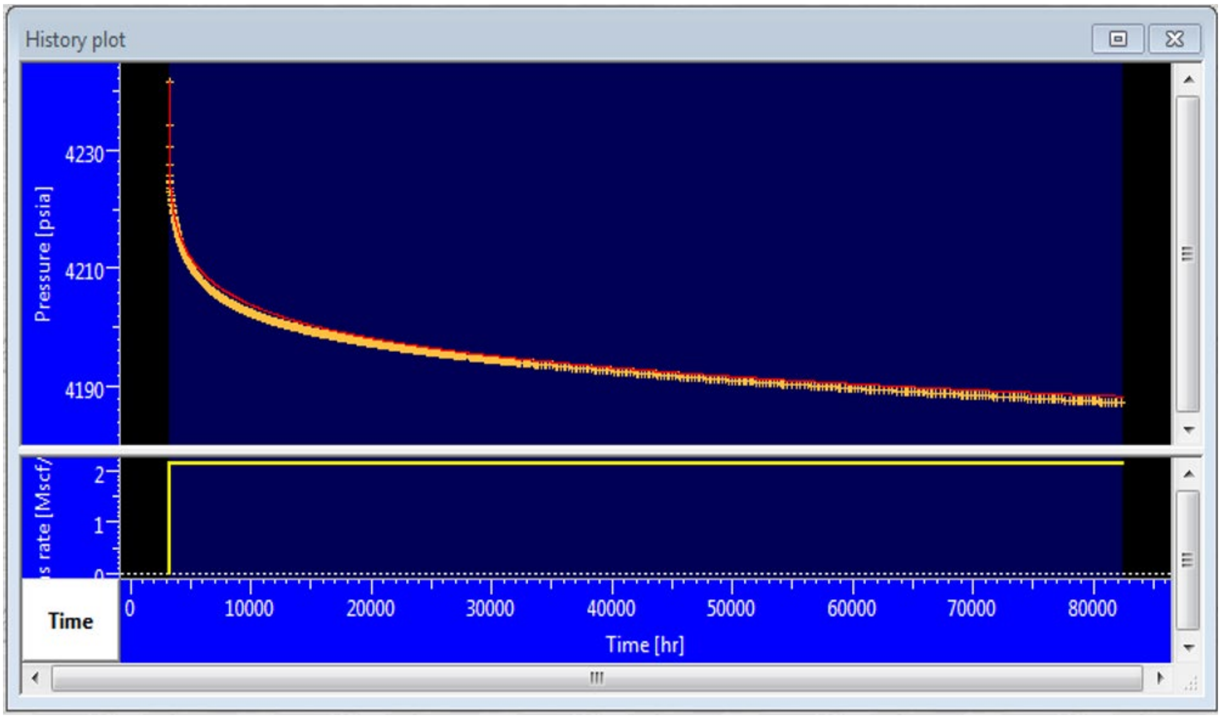

Figure 3.7Well-test analysis results using the ECRIN-Saphir software Pressure vs time and gas rate vs time.

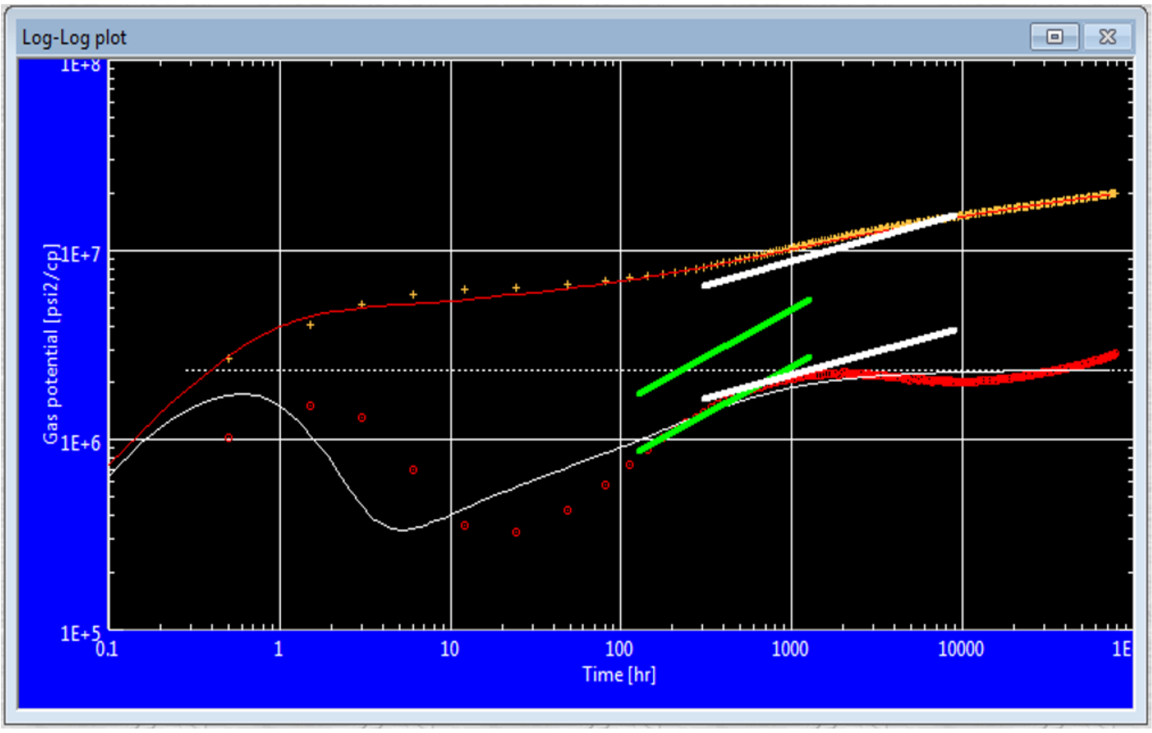

Figure 3.8 Well test analysis results using the ECRIN-Saphir software. Pseudo pressure function vs time in log-log plot

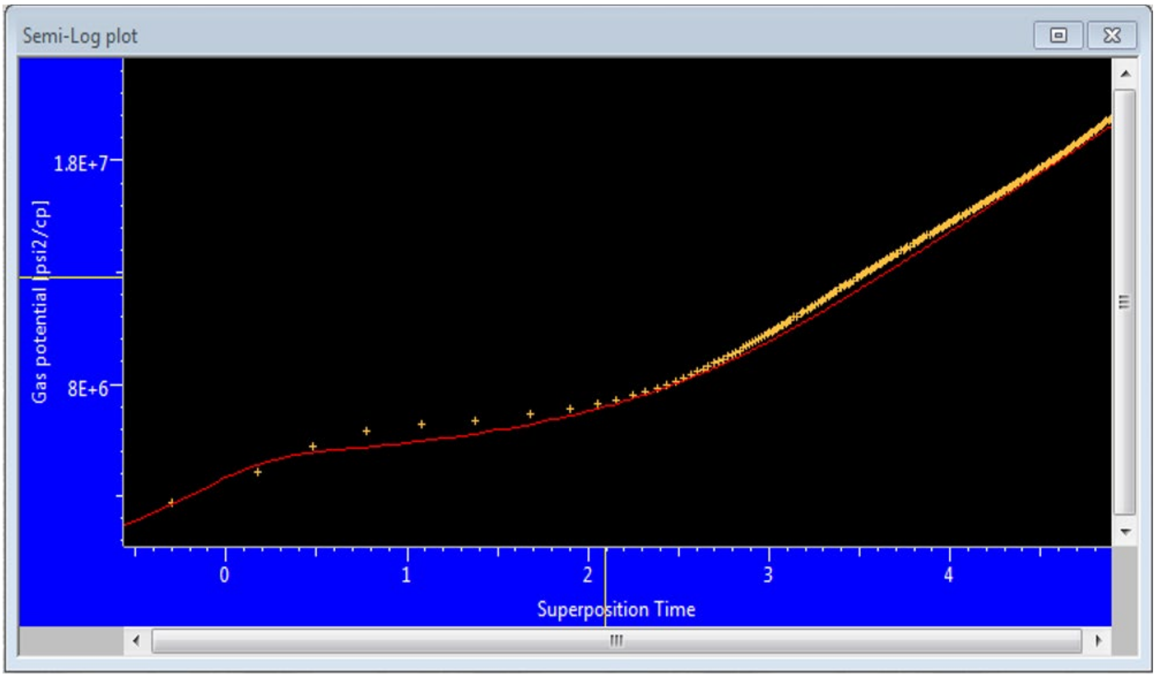

Figure 3.9 Well test analysis results from the ECRIN-Saphire software. The pseudo-pressure function vs superposition time (Semi-log plot)

Figure 3.7 displays well test history data through two distinct plots. The first plot depicts pressure (psia) against time (hrs), while the second one (below the pressure plot) illustrates gas flow rate (Mscf/day) against time (hrs). In Figure 3.8, a log-log diganostic plot showcases the pseudo pressure function and its derivative over time, with two lines indicating specific flow regimes: the green line denotes linear flow, and the white line signifies elliptical flow. Additionally, Figure 3.9 presents a semi-log plot (superposition plot) of the pseudo-pressure function (m(p)) in relation to superposition time. All these flow warrant very good history matching of the rate data.

3.8 Summary

Addressing the challenges and devising alternative methodologies that yield more accurate and reliable results is crucial for informed decision-making in Tight Gas Reservoirs (TGRs). Despite the practical significance of pressure transient analysis for hydraulic fractured vertical wells in TGRs, current publications on this subject are inadequate. This Chapter aims to fill this knowledge gap by presenting a simplified numerical approach. The focus of this approach is on deriving hydraulic fractures and reservoir parameters from well-test data of hydraulically fractured vertical wells in tight gas reservoirs, specifically considering an elliptical flow regime. A key aspect involves determining the start of the elliptical flow regime and the end of the linear flow regime. Once this critical time is identified, the subsequent data analysis can be facilitated through conventional and simple calculations as explained above.

Chapter 4:

Numerical Modelling and Development of Correlations for the Prediction of Multistage Hydraulic Fracture Parameters in Tight Gas Reservoir

4.1 Introduction:

Horizontal wells employing the multistage hydraulic fracturing technique have gained prominence for economically exploiting and enhancing productivity in tight gas reservoirs (TGRs), as discussed in previous chapters (Chapters 1-3). In such wells, both horizontal and hydraulic fractures can exhibit various flow regimes, including linear, bilinear, and elliptical, though achieving stable flow rates can be challenging. Identifying the transition time between these different regimes becomes crucial for accurate well-test data analysis, especially when obtaining stabilized drawdown or shut-in data is practically unattainable.

Chapter 3 delves into the methodologies for using short-term data to pinpoint the transition time. This information can then be leveraged to extrapolate short-term data, predicting stabilized drawdown or buildup data, ultimately leading to offering more precise well-test data analysis and a reduction in uncertainty. Chapter 4 therefore, focuses on linear and elliptical flow regimes, which happened relatively early, to analyse the reservoir characteristics and associated parameters, especially in the case of multistage horizontal fractures.

Many research works (such as: (Shail Apte, 2015; Hale & Evers, 1981; F. Kucuk & W. E. Brigham, 1979; W. Lee & Gidley, 1989)) were conducted to develop a model to describe flow regimes around the fractured vertical and horizontal wells. However, most of these works considered simplified ideal cases and neglected the skin effect. These models also did not capture the effect of the number of fractures and distance between the fractures. The recent work conducted by SS Apte and Lee (2017) considered a multi-fractured horizontal well in the tight gas reservoir and analysed it using linear and elliptical flow regime correlations. They presented an analysis of a real field case and showed that their approach resulted in a value of the product ($k^{5/8}x_f^{3/4}$). They assumed infinite conductivity for fractures and considered the effect of multi-fracturing in their analysis (i.e. the number of fractures and distance between them). However, the model of SS Apte and Lee (2017) offers high-accuracy results for the ideal case when skin=0, and multi-fractured horizontal well interpretation. Nevertheless, the approach lacks accuracy in a real case when the skin has a value other than zero or when applied to fractured vertical wells.

Most of the previous works on the analysis of the well-test data from multiple hydraulic fractured vertical wells in tight gas reservoirs showed a lack of accuracy because they ignored at least one of the dependant variables affecting the pressures transient analysis (mostly ignored the multiple hydraulic fracturing effects and/or skin effect), which leads to erroneous results in estimation of reservoir parameters (e.g. permeability, initial reservoir pressure, drainage radius, types of reservoir boundaries), near wellbore formation damage (e.g. skin), and fracture parameters (e.g. fracture half-length, length, number of fractures etc.), and lack the accuracy in sensitivity analysis. However, the details of the numerical model developed as a part of this study are presented in this chapter, which can provide a better interpretation of well-test data from the hydraulic fracturing well with higher accuracy in real cases (i.e. skin $\neq 0$) considering the linear and elliptical flow regimes, especially when very limited test data are available. Accordingly, new correlations of linear and elliptical flow regimes are formulated to analyse the reservoir and well characteristics considering all the parameters mentioned earlier.

Numerical Modeling

The main step for the accurate analysis of well test data of a hydraulically fractured well in TGR is to identify the flow regimes (M. M. Hossain, Al-Fatlawi, Brown, & Ajeel, 2018; Stotts, Anderson, & Mattar, 2007). The pressure transient analysis is the key method to identify the period of each flow regime and to analyse the well test data in order to predict reservoir properties and fracture parameters such as permeability, fracture half-length and skin factor (W. J. Lee & Wattenbarger, 1996).

As discussed in Chapter 3, there are five distinct flow regimes that may exist near a hydraulically fractured well. Linear flow regime (Figure 2.2a, in Chapter 3)) occurs in a short time and may be accompanied by a wellbore storage effect. During this time, the fluid flow from the fracture to the wellbore and the flow regime are mostly linear (Heber Cinco-Ley, 1981).

The bilinear flow regime (Figure 2.2b) occurs only around the fractured well with finite-conductivity fractures when the flow from the formation into the fracture is linear and before the fracture sides affect the well behaviour (Heber Cinco-Ley, 1981).

Formation linear flow regime (Figure 2.2c) occurs only in fractured wells with high-conductivity fractures when the fluid flows linearly and perpendicular to the fracture (Heber Cinco-Ley, 1981).

The elliptical flow regime (Figure 2.2d) is a transition flow period that exists between linear flow at early times and radial or pseudo-radial flow regime at late times. It may continue for several years or even a decade (Heber Cinco-Ley, 1981).

Pseudo-radial flow regime (Figure 2.2e) takes place around a fractured well in TGR after a very long time (i.e. several years or a decade). At this flow regime, the drainage area can be assumed as a circle for practical analysis (M Prats, Hazebroek, & Strickler, 1962).

Analysis of the reservoir around a hydraulically fractured well in a TGR previously depended on linear flow, bilinear flow, and pseudo-radial flow, but this requires analysing all three flow regimes for accurate results (M. M. Hossain et al., 2018).

The analysis based on the pseudo-radial flow regime is the most accurate analysis for the prediction of the permeability, but this flow regime requires a very long time to occur in the TGR and this is not economically feasible (M. M. Hossain et al., 2018).

Therefore, in this study, the analysis has been done depending on two flow regimes that happened in early times of the production which are linear and elliptical flow regimes.

4.2 Linear flow regime:

Linear flow in TGR occurs when there is a clear and detectable flow from the reservoir to a fractured well with infinite conductivity fractures (Shail Apte, 2015; SS Apte & Lee, 2017). It can extend for a considerable duration, often surpassing a decade. This prolonged flow regime is primarily attributed to the remarkably low permeability exhibited by these reservoirs. As a result, the flow from the reservoir to the fractured well remains detectable and sustained over an extended period, contributing to the reservoir's long-term productivity (Nobakht & Clarkson, 2012).

The plot of normalized pressure against the square root of time, as introduced by (Anderson et al., 2010) is a crucial tool for analyzing the linear flow regime and for calculating the product of the fracture half-length and the square root of permeability. Anderson et al. (2010) solution was derived only for horizontal wells, and its results non unique as it provides several solutions for a single case.

Numerous published studies have emphasized that the slope of the plot of normalized pressure against the square root of time is instrumental in determining the product of the fracture half-length and the square root of permeability (M. Ibrahim & R. Wattenbarger, 2006a, 2006b; Nobakht et al., 2010). However, all of these studies ignore the skin factor and multi-fracturing effect in their solutions.

A. C. Gringarten et al. (1974) proposed a solution for linear flow around a fractured well in a square reservoir. A. C. Gringarten et al. (1974) provided the solution, which appears to be easy to apply using tables provided for solving numerical integrations in his model, but it is limited for square reservoir, and its accuracy is found be low when it applies for tight gas reservoirs. It also fails to take into account of the effect multi-fracturing and skin.

A solution of linear flow is also presented by (Wattenbarger et al., 1998) for a constant flow rate; and for a constant pressure in a rectangular reservoir. They provide an example of a real field by explaining the calculation method. The solution provided by Wattenbarger et al. (1998) is restricted to a rectangular reservoir, and it ignores the effect of skin factor and multi-fracturing.

4.3 Elliptical flow regime:

The elliptical flow regime exists in the low and ultra-low permeable formation (Amini et al., 2007). F. Kucuk and W. E. Brigham (1979) proposed an analytical solution to analyze the elliptical flow regime for the infinite conductivity fractures in the elliptical or an-isotropic reservoir. F. Kucuk and W. E. Brigham (1979) assume that the reservoir has an elliptical boundary, and they derived their mathematical model according to that for the un-fractured vertical wells. Therefore, there is a lack of fracturing properties in their model.

Depending on a simulation of the elliptical flow regime in a well test in TGR, Hale (1979) provides some type of curve solution in dimensionless form. Hale (1979) model is derived for a fractured well in the tight gas reservoir, and it gives reasonably high accuracy when applied to the single fractured vertical wells. However, the accuracy suffers when applied to multi-fractured vertical wells.

Riley (1991) presented a solution for a finite-conductivity fracture in an infinite-acting reservoir within elliptical coordinates. The solution of Riley (1991) was complex and in Laplace space, therefore, it is very difficult to apply to real cases.

Liao (1993) studies the effects of different wellbore storages and skin factors on pressure tests of hydraulically fractured vertical wells based on numerical simulation for elliptical flow in fractured vertical wells for these cases. Liao did not present any formula as his solution depends on the simulation technique.

To the best of the authors' knowledge, no definite correlations are found in the published studies for both linear and elliptical flow regimes capturing the effect of the skin factor, number of fractures and distance between the fractures. SS Apte and Lee (2017) and Shail Apte (2015) studied the effect of the number of fractures and distance between these fractures in multi-fractured horizontal wells - the studies conducted by numerous authors (Shail Apte, 2015; SS Apte & Lee, 2017; Hale & Evers, 1981; F. Kucuk & W. E. Brigham, 1979; W. Lee & Gidley, 1989; W. Lee & Holditch, 1981) were focused on fractured vertical wells in TGR. Although their works appeared to provide results with a high degree of accuracy in the case of an ideal condition (e.g. skin = 0), the degree of accuracy substantially reduced when the skin was taken into consideration, and it reduced also in the case of multi-fractured vertical wells. However, (Shail Apte, 2015) introduced an analytical model to capture multi-fracturing effects in horizontal wells.

4.4 Development of Correlations:

Several parameters have been studied to test their relationship with the pseudo-pressure function by studying the sensitivity of each parameter and then importing the data and studying them with the pseudo-pressure function assuming the other parameters are constants. Upon using this data, it is easy to find the exact relationship between the specified parameter with pseudo-pressure. Therefore, in this section, a general formula will be assumed to define the pseudo-pressure difference in both flow regimes:

$$\Delta m(P)|_{well} = f(q, T, kh, \varphi, \mu_i, C_{gi}, x_f, \Delta t, S) \quad 4.1$$

After that, an intensive study was carried out to understand the relation of each of the parameters with the pseudo-pressure difference.

After knowing the relation of all parameters with pseudo-pressure, the relationship between all parameters and pseudo-pressure, predicting the appropriate formula to represent each flow regime becomes straightforward. In the following part, an explanation of how to find the correct formula with studies of (kh) and x_f effect on pseudo-pressure are used as examples of the calculation procedure. However, some parameters, such as flow rate, porosity, and gas viscosity, appeared to have the same effect as the published studies. As they are commonly available elsewhere, they are not presented in this work.

4.4.1 The product of permeability and thickness (kh):

Figure 4.1 shows a snapshot of the Ecrin-Saphir resulting figures of the sensitivity of the product of the permeability (k) and thickness (h) on the pseudo-pressure for Whicher Range tight gas field (WRTGF). (Time is the x-axis while pseudo-pressure and pseudo-pressure derivatives in the y-axis).

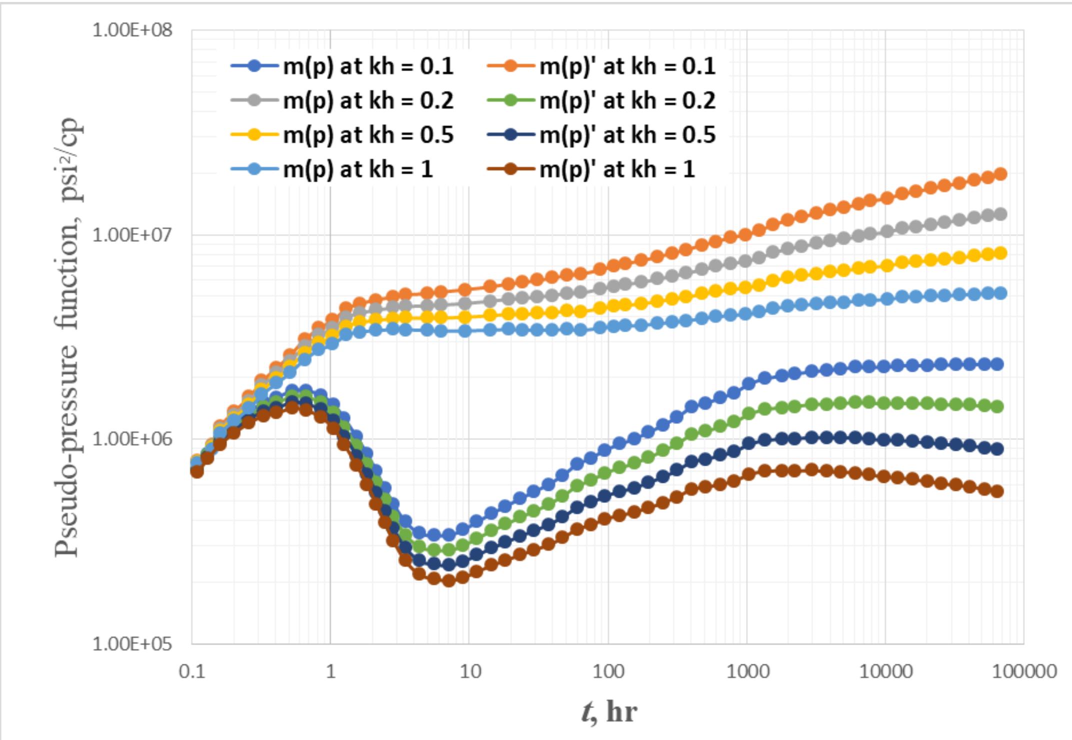

Figure 4.1 Pseudo-pressure vs time for different values of (kh).

After determining the linear flow period and elliptical flow period in Figure 4.1, the data can be imported for analysis. For analysis, the imported data is rearranged and drawn in other curves for only the two mentioned periods (Figure 4.2 and Figure 4.3) then the analysis will show the exact relationship.

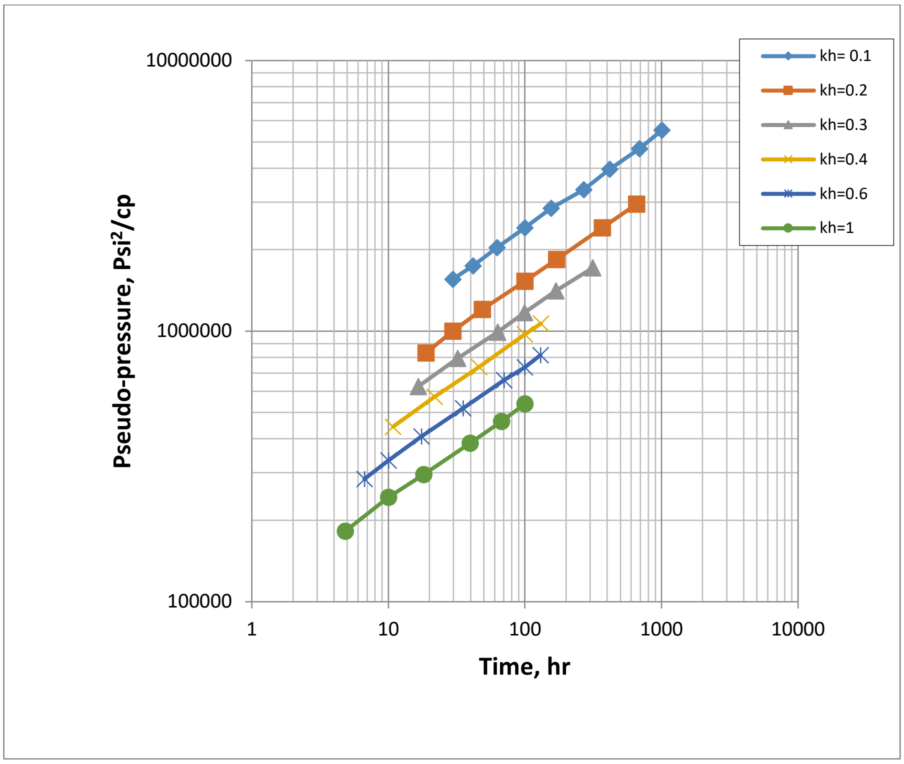

Figure 4.2 Pseudo-pressure vs. time for different values of (*kh*) in linear flow period.

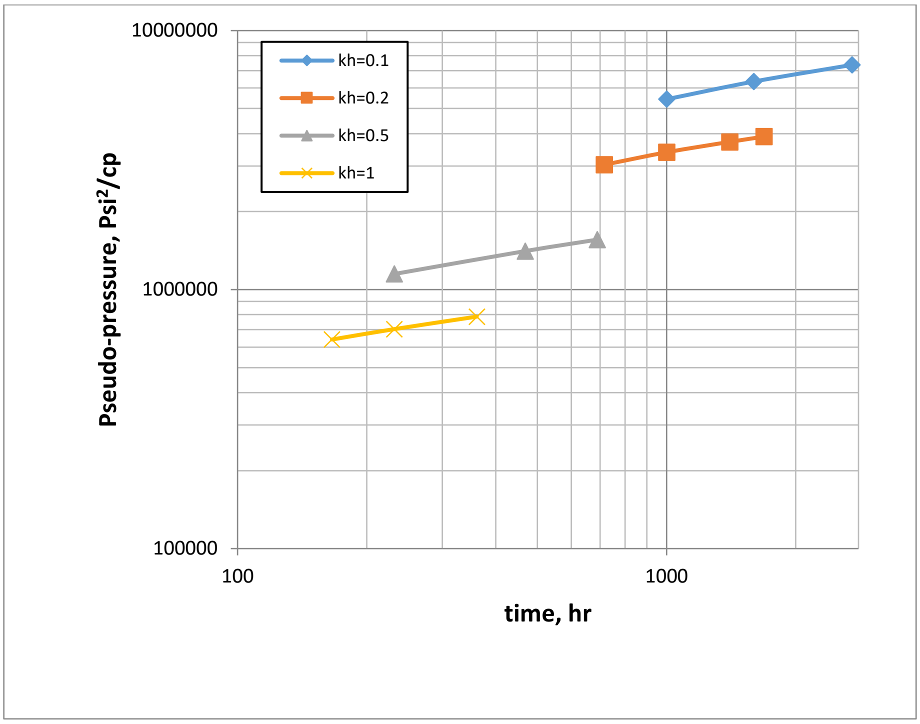

Figure 4.3 Pseudo-pressure vs. time for different values of (kh) in elliptical flow period.

In this stage, all the parameters other than the pseudo-pressure and the (kh) will be treated as constants to find the exact relationship between $\Delta m(p)$ and kh. It can be expressed as:

$$\Delta m(p) = f_1(kh) \qquad 4.2$$

Analysis of the imported data revealed that based on non-linear regression analysis, both linear and elliptical flow regimes, kh exhibits an exponential relationship with the pseudo-pressure function for a specific time value. Other attempted relationships, such as linear and logarithmic, appeared to be unsuccessful, resulting in high levels of errors as shown in Table 4.1 and Table 4.2. The exponents for each relationship were calculated, leading to the derivation of the final formulas for the two flow regimes. Table 4.1 demonstrate that the exponents for (kh), denoted as B, are -0.562 and -0.735 for the linear and elliptical flow regimes, respectively.

The analysis data were assessed to determine the most suitable formula by calculating the Average Absolute Percentage Error (AAPE), favoring the formula with the lowest AAPE.

Table 4-1 Relations for kh with $\Delta m(p)$ for linear flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(kh)$	0.288	215031	-189688
$\Delta m(p) = A + B\, log(kh)$	0.134	36158	-204067
$\Delta m(p) = A(kh)^B$	0.0083	10.949	-0.562
$\Delta m(p) = A + B\sqrt{kh}$	0.227	305147	-278058

Table 4-2 Relations for kh with $\Delta m(p)$ for elliptical flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(kh)$	0.253	880700	-795160
$\Delta m(p) = A + B\, log(kh)$	0.191	114072	-817612
$\Delta m(p) = A(kh)^B$	0.0029	12.098	-0.735
$\Delta m(p) = A + B\sqrt{kh}$	0.305	1223022	-1133585

Therefore, for the linear flow, the function of pseudo-pressure in Equation (4.2) can be rewritten as follows:

$$\Delta m(P) = 10.949(kh)^{-0.562} \qquad 4.3$$

Where: In this context, the constant value of 10.949 in this context is representative of several other factors associated with the well and reservoir other than (kh), including but not limited to the flow rate, fracture half-length, porosity, and the number of fractures, among others.

For the elliptical flow regime, the function can be rewritten as follows:

$$\Delta m(p) = 12.098(kh)^{-0.735} \quad 4.4$$

Where: In this context, the constant value of 12.098 in this context is representative of several other factors associated with the well and reservoir other than (kh), including but not limited to the flow rate, fracture half-length, porosity, and the number of fractures, among others.

4.4.2 The half-length of fractures (x_f):

Figure 4.4 shows the Ecrin-Saphir resulting log-log plot with the sensitivity of the half-length of fracture (x_f) on the pseudo-pressure for WRTGF.

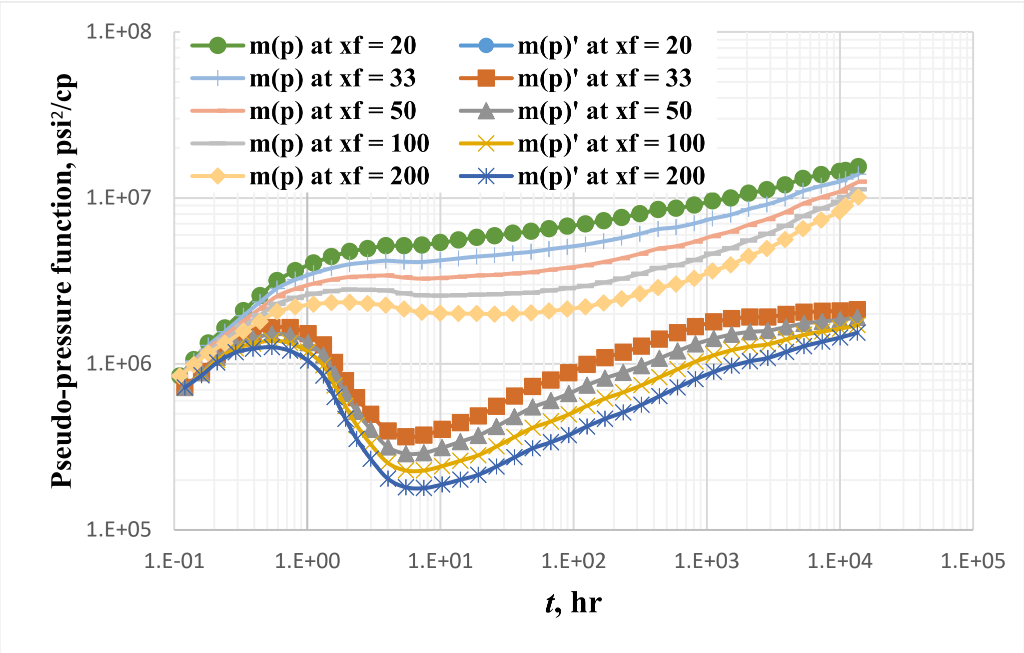

Figure 4.4 Pseudo-pressure vs time for different values of (x_f).

For analysis, the imported data of the elliptical flow period has been rearranged and drawn in other curves for only the two mentioned periods (Figure 4.5 and Figure 4.6). Then, the analysis will show the exact relationship.

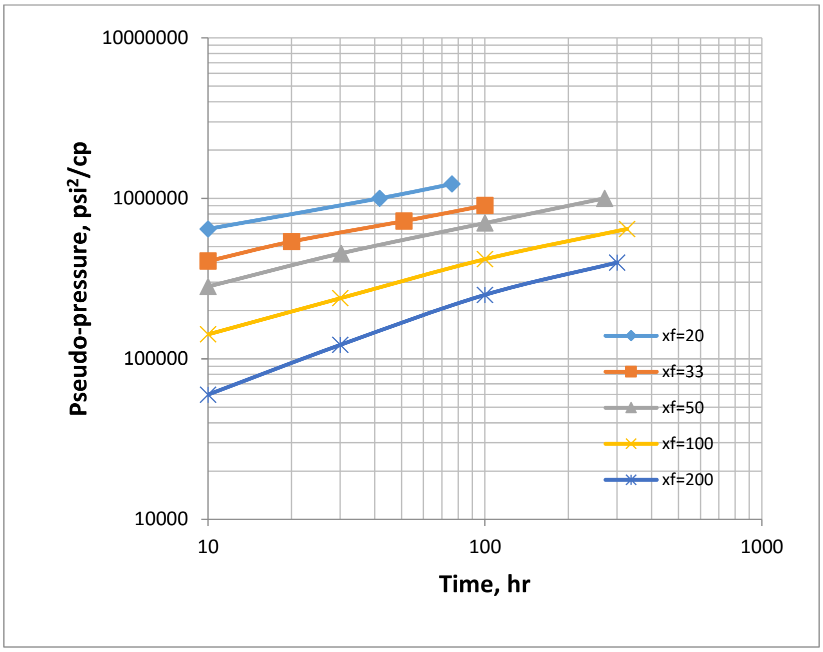

Figure 4.5 Pseudo-pressure vs. time for different values of (x_f) in linear flow period.

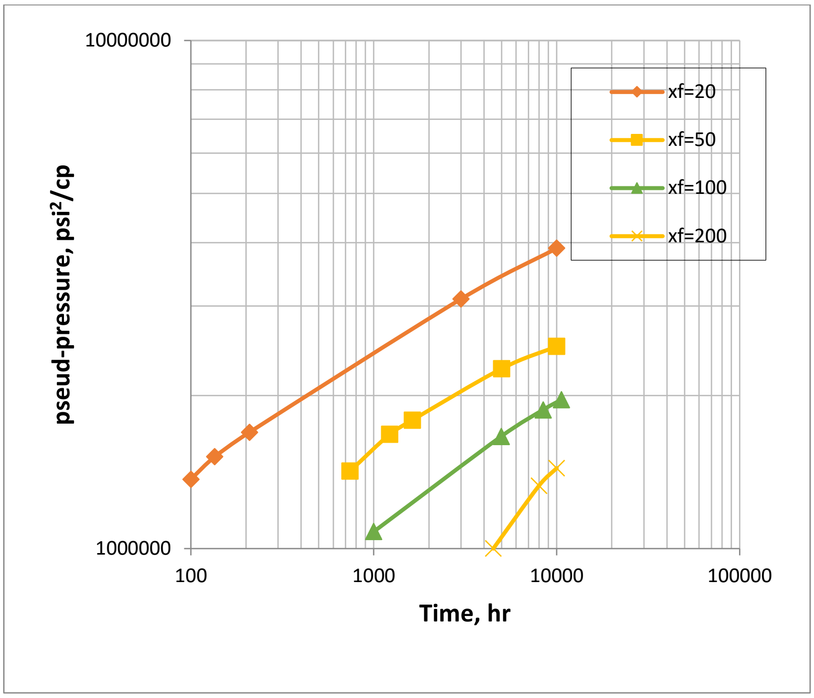

Figure 4.6 Pseudo-pressure vs. time for different values of (x_f) in elliptical flow period.

In this stage, all the parameters other than the pseudo-pressure and the (x_f) will be treated as constants to find the exact relationship between $\Delta m(p)$ and x_f. It can be represented as:

$$\Delta m(p) = f_2(x_f) \qquad 4.5$$

Analysing the imported data showed that for a specific value of time, both for linear and elliptical, (x_f) has an exponential relationship with the pseudo-pressure function. Other attempted relationships, such as linear and logarithmic have resulted in a high value of error as shown in Table 4.3 and Table 4.4. The exponent of each relation was calculated and the final formulas of the two flow regimes were derived according to these exponents. As shown in Table 4.3 and Table 4.4, the exponents of x_f (which is defined as B) are -0.8695 and -0.494 for linear and elliptical flow regimes respectively.

Table 4-3 Relations or x_f with $\Delta m(p)$ for linear flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(x_f)$	0.115	164955	-1319
$\Delta m(p) = A + B\,log(x_f)$	0.0802	369466	-166581
$\Delta m(p) = A(x_f)^B$	0.0024	14.5	-0.8695
$\Delta m(p) = A + B\sqrt{x_f}$	0.088	236133	-20248

Table 4-4 Relations for x_f with $\Delta m(p)$ for elliptical flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(x_f)$	0.0518	55602	-346
$\Delta m(p) = A + B\,log(x_f)$	0.0348	105695	-41817
$\Delta m(p) = A(x_f)^B$	0.0004	12.38	-0.494
$\Delta m(p) = A + B\sqrt{x_f}$	0.0726	73396	-5207

Therefore, for the linear flow, the function of pseudo-pressure in Equation (4.5) can be rewritten as follows:

$$\Delta m(p) = 14.5(x_f)^{-0.8695} \tag{4.6}$$

Where: In this context, the constant value of 14.5 in this context is representative of several other factors associated with the well and reservoir other than fracture half-length, including but not limited to the flow rate, porosity, and the number of fractures, among others.

For the elliptical flow regime, the function can be rewritten as follows:

$$\Delta m(p) = 12.38(x_f)^{-0.494} \tag{4.7}$$

Where: In this context, the constant value of 12.38 in this context is representative of several other factors associated with the well and reservoir other than fracture half-length, including but not limited to the flow rate, porosity, and the number of fractures, among others.

4.4.3 The skin factor effect (S):

Figure 4.7 Pseudo-pressure vs time for different values of (*S*).shows the simulated result of the sensitivity of the skin factor (S) on the pseudo-pressure for WRTGF. The simulation was conducted using widely accepted commercial software, Kappa-Saphir (formerly named as Ecrin-Saphir)

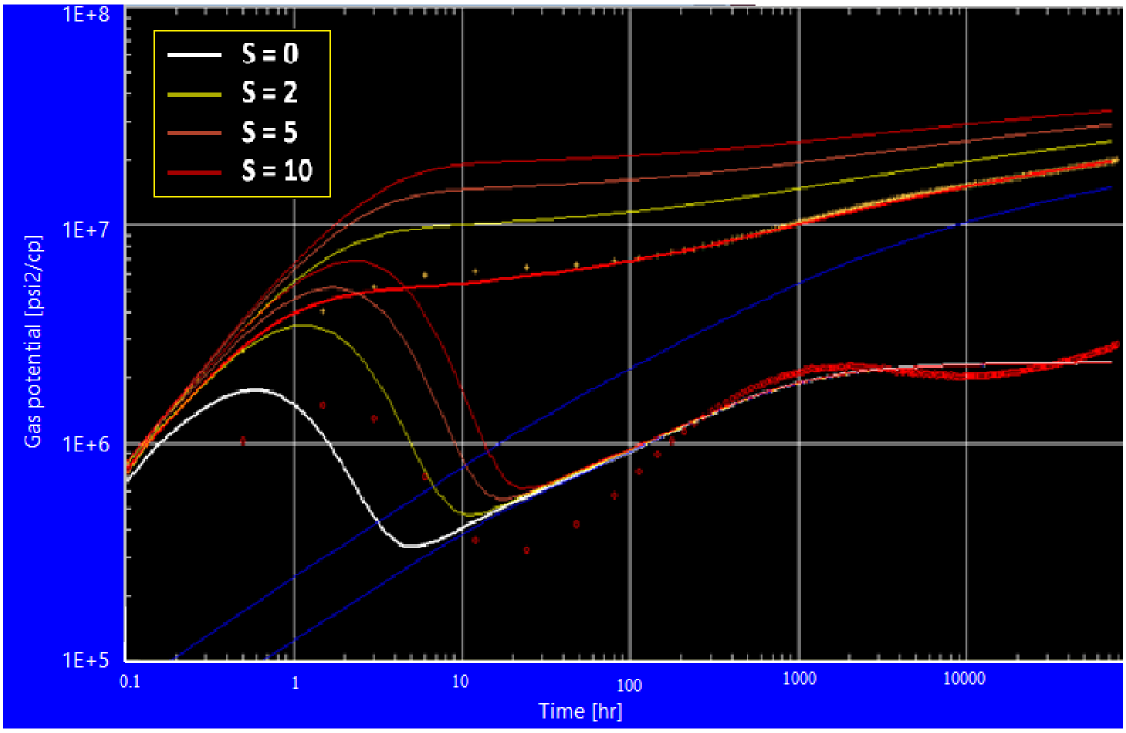

Figure 4.7 Pseudo-pressure vs time for different values of (*S*).

Importing data for this case is a delicate and challenging process because certain curves appear almost coincident, even though they are not truly overlapping. This distinction becomes apparent only when the Figure is significantly enlarged. Nonetheless, for analysis, the imported data associated with the elliptical flow period has been precisely reorganised, and subsequent analysis will show the exact relationship.

In this stage, all the parameters other than the pseudo-pressure and the (S) will be treated as constants to find the exact relationship between $\Delta m(p)$ and S. It can be represented as:

$$\Delta m(p) = f_3(S) \qquad 4.8$$

Analysing the imported data showed that for a specific value of time, both linear and elliptical, (S) has a linear relationship with the pseudo-pressure function and the other relationships tried such as exponential and logarithmic appeared to be unsuccessful as these relationships resulted in a high level of error as showed in Table 4.5 and Table 4.6. The final formulas of the two flow regimes are derived according to the detected relationship.

Table 4-5 Relations for S with $\Delta m(p)$ for linear flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(S)$	0.014	6122843	25796
$\Delta m(p) = A + B\ log(-S)$	0.155	6005278	1225058
$\Delta m(p) = A + B\sqrt{-S}$	0.085	6082719	445823

Table 4-6 Relations for S with $\Delta m(p)$ for elliptical flow with average absolute error value

The formula	AAPE	Value of A	Value of B
$\Delta m(p) = A + B(S)$	0.015	7533892	53789
$\Delta m(p) = A + B\ log(-S)$	0.178	7429713	891778
$\Delta m(p) = A + B\sqrt{-S}$	0.046	7485173	111857

Therefore, for the linear flow, the function of pseudo-pressure in Equation (4.8) can be rewritten as follows:

$$\Delta m(p) = 6122843 + 25796(S) \qquad 4.9$$

Where: In this context, the constant values of (6122843 and 257961) are representative of several other factors associated with the well and reservoir other than skin factor, including but not limited to the flow rate, porosity, and the number of fractures, among others.

For the elliptical flow regime, the function can be rewritten as follows:

$$\Delta m(p) = 7533892 + 53789(S) \qquad 4.10$$

Where: In this context, the constant values of (7533892 and 53789) are representative of several other factors associated with the well and reservoir other than the skin factor, including but not limited to the flow rate, porosity, and the number of fractures, among others.

4.5 Linear flow regime formulation:

Rewriting Equations (4.3), (4.5) and (4.8):

$$\Delta m(P) = 10.949(kh)^{-0.562} \qquad 4.11$$

$$\Delta m(P) = 14.5(x_f)^{-0.8695} \qquad 4.12$$

$$\Delta m(P) = 6122843 + 25796(S) \qquad 4.13$$

From the above three equations and the fact that the other parameters (such as flow rate, gas viscosity, gas compressibility, average porosity … etc.) have the same effect as the published works. With the other fact that the slope of the linear flow is (0.5), the equation can be written as:

$$\Delta m(P)|_{well} = A_1(kh)^{-0.562}(x_f)^{-0.8695} qT\sqrt{\frac{\Delta t}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.14$$

Where A_1 and C_2 are constants depending on the well and reservoir properties. The equation can be rewritten as follows by adding the effect of multi-fracturing:

$$\Delta m(P)|_{well} = \frac{A_2(kh)^{-0.562}(C_f)^{-0.886}}{(x_f)^{0.8695}} qT \sqrt{\frac{\Delta t}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.15$$

Where A_2 is a constant and can be determined easily with C_2 using linear regression depending on the data described in the above sections.

After finding the value of A_2 which is 3.86×10^{-5}, we can rewrite the equation to be:

$$\Delta m(P)|_{well} = C_1 \frac{qT}{kh} \sqrt{\frac{\Delta t}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.16$$

Where:

$$C_1 = \frac{3.06 * 10^{-4} k^{-0.062} h^{0.438} C_f^{0.886}}{(x_f)^{0.8695}} \qquad 4.17$$

4.6 Elliptical flow regime formulation:

Rewriting Equations (4.4), (4.7) and (4.10):

$$\Delta m(p) = 12.098(kh)^{-0.735} \qquad 4.4$$

$$\Delta m(p) = 12.38(x_f)^{-0.494} \qquad 4.7$$

$$\Delta m(p) = 7533892 + 53789(S) \qquad 4.10$$

From the above three equations and the fact that the other parameters (such as flow rate, gas viscosity, gas compressibility, average porosity … etc.) have the same effect as the published works. With the other fact that the slope of the elliptical flow is (0.3), the equation can be written as:

$$\Delta m(P)|_{well} = A_1(kh)^{-0.735}(x_f)^{-0.494} qT \sqrt{\frac{\Delta t^{0.6}}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.18$$

Where A_1 and C_2 are constants depending on the well and reservoir properties. The equation can be rewritten as follows by adding the effect of multi-fracturing:

$$\Delta m(P)|_{well} = \frac{A_2 (kh)^{-0.562} (C_f)^{-0.886}}{(x_f)^{0.8695}} qT \sqrt{\frac{\Delta t}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.19$$

Where A_2 is a constant and can be determined easily with C_2 using linear regression depending on the data described in the above sections.

After finding the value of A_2 which is 8.53×10^{-5}, we can rewrite the equation to be:

$$\Delta m(P)|_{well} = C_1 \frac{qT}{kh} \sqrt{\frac{\Delta t^{0.6}}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.20$$

Where:

$$C_1 = \frac{3.06 * 10^{-4} k^{-0.062} h^{0.438} C_f^{0.886}}{(x_f)^{0.8695}} \qquad 4.21$$

4.7 The impact of the parameters on the results:

Highlighting the influence of individual input parameters on correlation results is crucial. Inaccuracies in determining these variables can introduce errors in the procedure, impacting both early and later-stage estimations of gas in place. It is imperative to identify which variables contribute to larger errors for accurate assessments.

Certain parameters significantly influence the calculation procedure, while others do not. Among the most crucial factors affecting pressure behaviour is the product of permeability and thickness (*kh*), displaying high sensitivity to pressure, as observed in Figures 4.1, 4.2 and 4.3. This is also clearly illustrated in the previously derived correlations in this chapter, where their mathematical power is notably high.

Fracture properties also have a notable impact on the calculations especially fracture half-length (x_f), though somewhat less than the influence of the product of permeability and thickness (kh). This observation is evident in figures 4.4, 4.5, and 4.6, indicating a moderate to high impact. Notably, this impact tends to diminish as the value of fracture half-length increases.

The skin factor (S) moderately influences the pressure trend, though to a lesser extent than the aforementioned parameters. Additional factors like well radius and fluid properties exhibit a moderate to low impact on the pressure trend. Exploring into detailed discussions on these parameters may not be particularly valuable in this context.

Table 4-7 illustrates the influence of certain parameters on the pressure (or pseudo-pressure function).

Table 4-7 the impact of some parameters on the pressure

The Parameter	Effect
kh	High
Fracture half-length, x_f	Moderate to high
Skin factor, S	Moderate to low
Well radius, r_w	Low
Gas viscosity, μ_g	Low
Gas compressibility, C_g	Low

4.8 Validation of Proposed Correlations:

After deriving all correlations, testing its validity is an important part to ensure that it can be applied to other works having the same conditions. Therefore, the two following methods are used:

4.8.1 Validation using the statistical approach:

The formulas were validated based on statistical methods to determine the level of accuracy. The following statistical tools are used.

a) The coefficient of determination (r^2) was found to be about (0.95) for linear flow and about (0.97) for elliptical flow regimes, which warrants excellent correlations as they are close to (1). The equation coefficient of determination (r^2) used is given below:

$$\boldsymbol{r^2} = \frac{\sum(\boldsymbol{y_c}-\bar{\boldsymbol{y}})}{\sum(\boldsymbol{y}-\bar{\boldsymbol{y}})} \qquad 4.22$$

Where:

y: the actual value of the tested parameter (pseudo-pressure in our case).

y_c: Calculated value of the tested parameter.

$\bar{y}$: Average value of the tested parameter.

b) The average absolute percentage error (AAPE) was found to be about (0.022) for linear flow and about (0.017) for elliptical flow regime, which are excellent results as they are close to (0). The equation of (AAPE) is as below:

$$\boldsymbol{AAPE} = \frac{\boldsymbol{1}}{\boldsymbol{n}}\sum\frac{|\boldsymbol{y}-\boldsymbol{y_c}|}{\boldsymbol{y}} \qquad 4.23$$

Where: n: is the number of tested points.

4.8.2 Validation with actual field data:

The model was validated against the real field data obtained from WRTGF, located in Western Australia. The field is a highly faulted tight gas field. The results are shown in Figure 4.8 and Figure 4.9 resulted in a value of AAPE of (0.055) with respect to the actual values and showed a very good match for both linear and elliptical flow regimes which means that the formulas can be applied for future works with high accuracy.

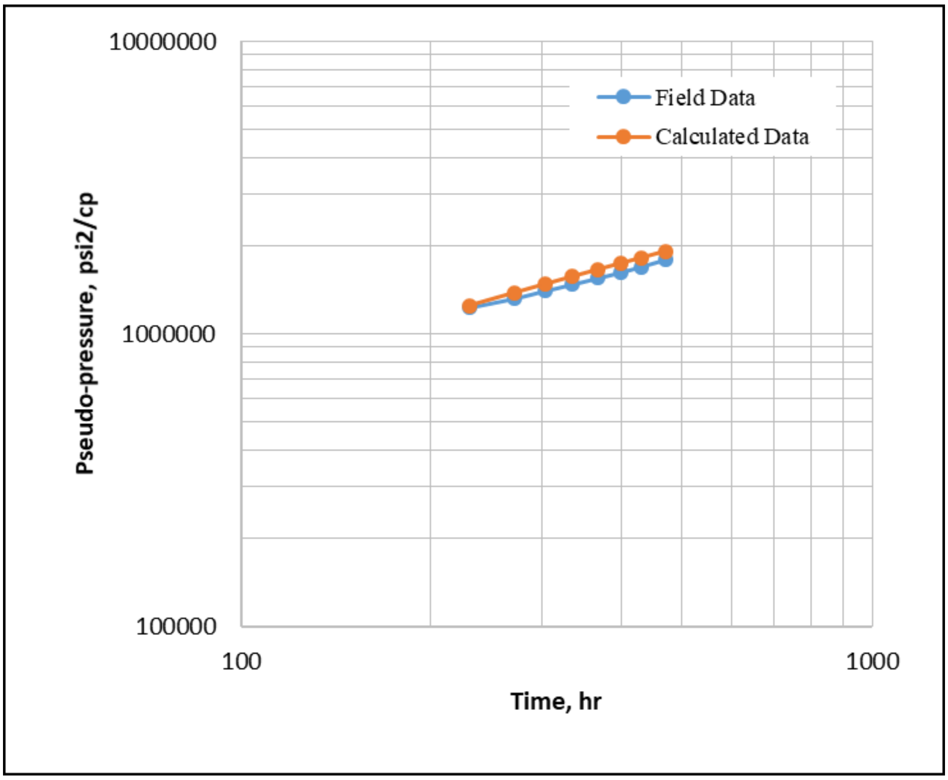

Figure 4.8 Comparison of the field data with correlation calculated data for linear flow period

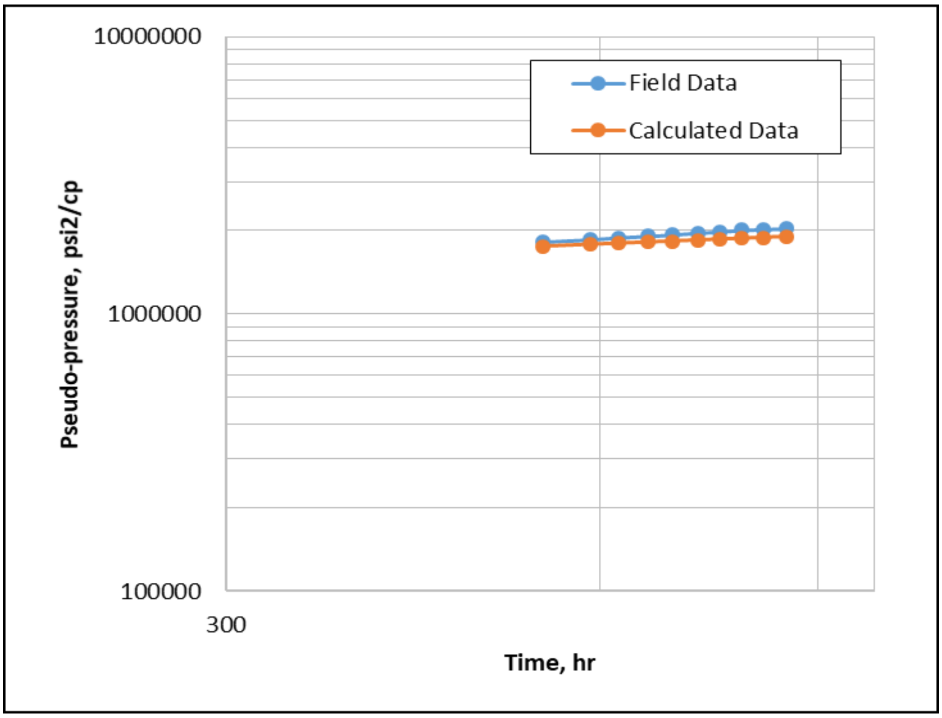

Figure 4.9 Comparison of the field data with correlation calculated data for elliptical flow period

4.9 Real Field Case Study

WRTGF in Canning Basin in Western Australia (Al-Fatlawi, Hossain, & Saeedi, 2017). Five wells have been drilled in the field so far, and two of them are hydraulically fractured.

Most of the available well test data for these two wells are limited to a short period of time and not long enough to predict the reservoir parameters with an acceptable value of accuracy. However, there is only one case detected that has data enough to reach an elliptical flow regime which is for well number 4. The basic reservoir and well parameters are presented in Table 4.7.

Table 4-8 Reservoir and well parameters for Case study

Final Flow Rate, MScf/D	5000
kh, mD.ft	4.35
φ_{avg}	0.08
Fracture half-length, ft	33.1
Reservoir Temperature, ºF	200
Gas gravity (Air=1)	0.7
Number of fractures	4
Distance between fractures, ft	100
Initial Gas viscosity, cP	0.001
Skin factor	-2.5
Initial Gas Compressibility, Psi^{-1}	0.001
Pay net thickness, ft	400

Pressure and time data can be shown in Figure 4.10 and Table 4-9 and the Pseudo-pressure difference vs. time for well number 4 (which is a fractured vertical well) in WRTGF is shown in Figure 4.11.

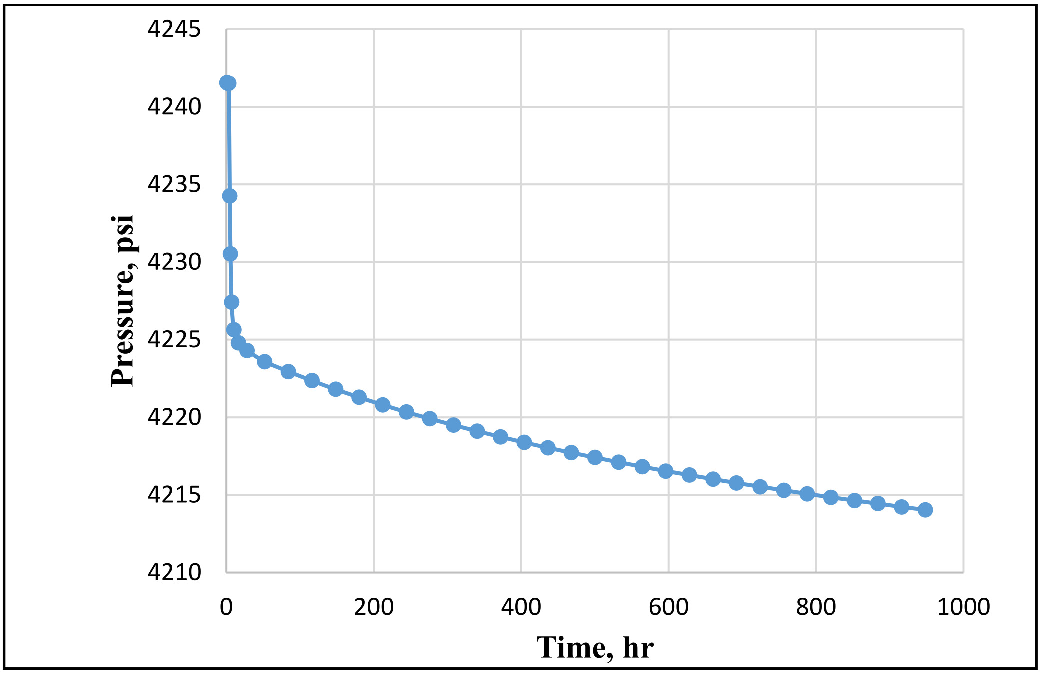

Figure 4.10 Pressure vs time data for well 4 in Whicher Range Tight Gas Field

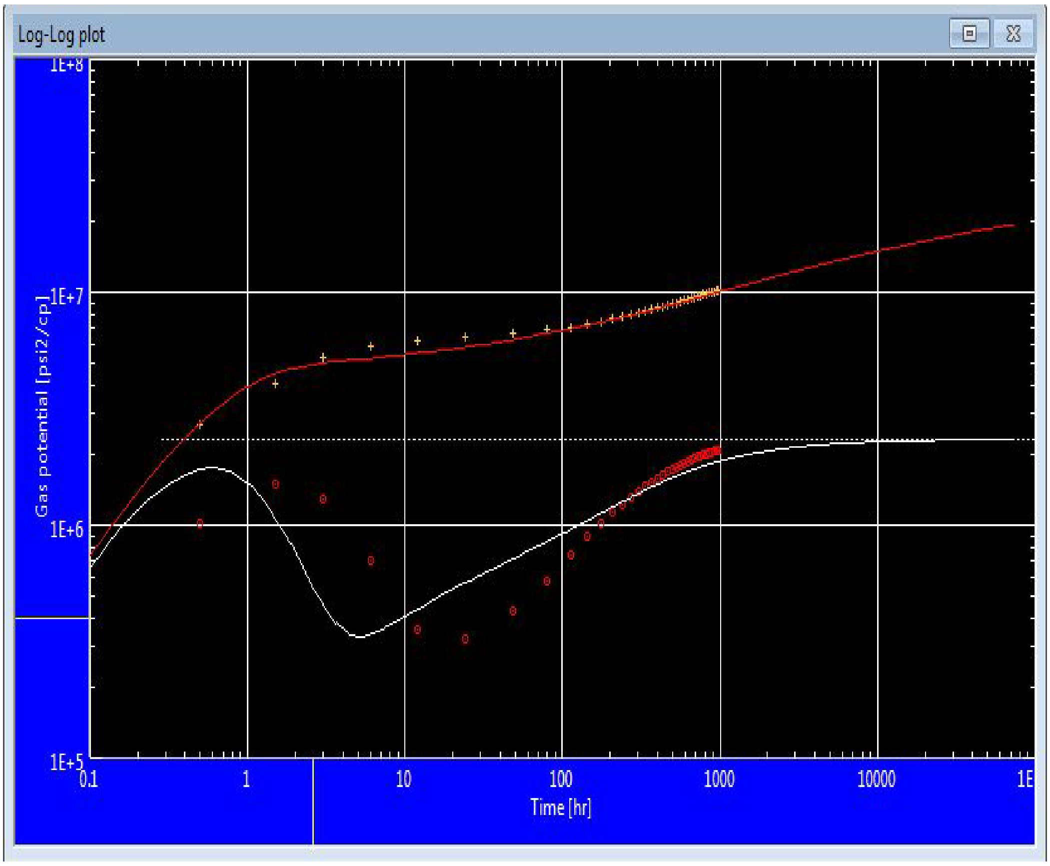

Figure 4.11 Pseudo-pressure difference vs time for well 4 in Whicher Range Tight Gas Field.

Table 4-9 Well test data for well-4 in WRTGF

Pressure, psi	Time, hr
4241.56	0.93
4234.27	4.67
4230.53	5.68
4227.42	7.17
4225.64	10.18
4224.81	16.2
4224.3	28.22
4223.59	52.21
4222.95	84.19
4222.36	116.18
4221.8	148.17
4221.29	180.16
4220.8	212.18
4220.34	244.17
4219.91	276.19
4219.5	308.21
4219.11	340.2
4218.74	372.17
4218.38	404.22
4218.04	436.21
4217.72	468.2
4217.41	500.21
4217.11	532.19
4216.82	564.22
4216.54	596.23
4216.28	628.31
4216.02	660.33
4215.77	692.35
4215.53	724.38
4215.3	756.17
4215.07	788.4
4214.85	820.42
4214.64	852.44
4214.44	884.46
4214.23	916.5
4214.04	948.56

For linear interpretation, the period with a slope of 0.5 is detected to be between about 200 to 400 hr. Therefore, any point in this period can be applied in the linear flow equation. The pseudo-pressure at the selected point is about 900000 Psi^2/cP and the time is about 120 hr. Apply it in Equation (4.15).

$$\Delta m(P)|_{well} = \frac{A_2(kh)^{-0.562}(C_f)^{-0.886}}{(x_f)^{0.8695}} qT \sqrt{\frac{\Delta t}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.15$$

$$900000 = \frac{3.06\times10^{-4}(k*400)^{-0.562}C_f^{0.886}}{x_f^{0.8695}}(5000)(660)\sqrt{\frac{120}{0.08*0.001*0.001}} + 0.007817(-2.5)(5000)(660)$$

$$C_f = \ln\sqrt{\frac{d}{3n}} = \ln\sqrt{\frac{100}{3*4}} = 1.06\ ,$$

substitute C_f value in the above equation and simplify to get:

$$k^{0.562}x_f^{0.8695} = 1.49 \qquad 4.24$$

For elliptical analysis, the period with a slope of 0.3 was detected to be between about 500 to 900 hr. Therefore, any point in this period can be applied to the elliptical flow equation. The pseudo-pressure at the selected point is about 1600000 Psi^2/cP and the time is about 800 hr. Apply it in Equation (4.25).

$$\Delta m(P)|_{well} = \frac{A_2(kh)^{-0.735}(C_f)^{-0.886}}{(x_f)^{0.494}} qT \sqrt{\frac{\Delta t^{0.6}}{\varphi \mu_i C_{gi}}} + C_2 SqT \qquad 4.25$$

$$1600000 = \frac{2.88\times10^{-4}(k*400)^{-0.735}C_f^{0.886}}{x_f^{0.494}}(5000)(660)\sqrt{\frac{800^{0.6}}{0.08*0.001*0.001}} + 0.0163(-2.5)(5000)(660)$$

$$C_f = \ln\sqrt{\frac{d}{3n}} = \ln\sqrt{\frac{100}{3*4}} = 1.06,$$

Substitute C_f value in the above equation and simplify to get:

$$k^{0.735}x_f^{0.494} = 0.183 \qquad 4.26$$

This result is for elliptical flow and it can accept a set of solutions, but we have another solution for linear flow which is described above (see Equation 4.24) and from these two Equations (4.24 and 4.26), it is easy to find the unique solution because we have 2 equations with two variables. Solving this system of equations is as follows:

Rewrite Equation (4.24):

$$k^{0.562} x_f^{0.8695} = 1.49 \qquad 4.24$$

It can be simplified to solve for k as follows:

$$k^{0.562} = 1.49\, x_f^{-0.8695}$$

$$k = 2.033\, x_f^{-1.55} \qquad 4.27$$

Now rewrite Equation (4.26):

$$k^{0.735} x_f^{0.494} = 0.183 \qquad 4.26$$

It can be simplified to solve for k as follows:

$$k^{0.735} = 0.183\, x_f^{-0.494}$$

$$k = 0.1\, x_f^{-0.672} \qquad 4.28$$

Dividing Equation (4.27) on (4.28) to get:

$$1 = 20.33\, x_f^{-0.878}$$

Then x_f = 30.9 ft which is close to the real value.

Substitute this value into Equation 4.27 (or 4.28) to find the permeability:

$$k^{0.562} 30.9^{0.8695} = 1.49$$

$$k = 0.01 \text{ mD}$$

Which is also very close to the average of the real field value.

Drawing from the extensive validations presented earlier, it is evident that the proposed developed models and correlations presented in the thesis are well-suited for the analysis of short-term well-test data. These tools offer a high degree of accuracy while simultaneously minimizing uncertainties, all without the need for costly simulation packages. Importantly, their utility extends to scenarios where expensive simulation packages may not be necessary, making them a cost-effective and reliable choice for well-test data analysis, and can be used as important tools for front-line engineers for routine industry tasks.

Chapter 5: **Development of New Type Curves with Simulation Technique**

5.1 Introduction

The analysis of production data from tight gas reservoirs remains a challenging endeavour. This difficulty arises from the inherent heterogeneity of the porous medium and the extremely low permeability, particularly in the case of hydraulically fractured wells (Ilk, Rushing, & Blasingame, 2011; Mahadik, Bahrami, Hossain, & Mitchel, 2012). Various studies have been published to analyze the production data for oil and gas reservoirs. The studies that have gained the highest level of prominence are: R. G. Agarwal, Gardner, Kleinsteiber, and Fussell (1998); Arps (1945); TA Blasingame, Johnston, and Lee (1989); TA Blasingame, McCray, and Lee (1991); Doublet, Pande, McCollum, and Blasingame (1994); M. Fetkovich et al. (1996); Michael J Fetkovich (1980); Fraim and Wattenbarger (1987); Mattar and McNeil (1998); Palacio and Blasingame (1993).

Arps (1945) stated a new methodology based on an empirically derived mathematical relationship at a constant flowing bottom hole pressure to forecast the future production for dominated boundary conditions. The main benefit of the Arps method is it does not need the rock and fluid properties and the main demerit is it has no theoretical and scientific bases. Michael J Fetkovich (1980) combined a solution of analytical flow equations with Arps' decline curve equations and based on this combination, Fetkovich created new type curves.

These type-curves can be applied when analyzing a well that maintains a constant flowing hole pressure during transient and boundary-dominated flow periods. R. G. Agarwal et al. (1998); TA Blasingame et al. (1991); McCray (1990); Palacio and Blasingame (1993) presented production decline analysis by introducing innovative concepts.

These concepts, namely the rate integral, rate-integral derivative, and material balance time, enable the analysis of data from wells that produce at varying flowing bottom hole pressures. Pratikno, Rushing, and Blasingame (2003) presented an analytical solution for constructing various type-curves applicable to fractured vertical wells situated at the centre of circular bounded reservoirs.

Pratikno et al. (2003) employed the rate integral and the rate integral derivative, as derived by McCray (1990) to mitigate the influence of inaccurate data when fitting type curves.

Pratikno et al. (2003) introduced a novel parameter known as the pseudo-steady constant (b_{Dpss}). This parameter is dependent on the dimensionless fracture conductivity (F_{CD}) and dimensionless radius (r_{eD}). They also provided a correlation for calculating (b_{Dpss}) across a wide range of (F_{CD}) and (r_{eD}) values.

They formulated (r_{eD}) as a function dependent on both reservoir radius (r_e) and fracture half-length (x_f). This definition holds for conventional reservoirs as well as reservoirs with high or moderate permeability, especially when the pressure wave reaches the reservoir boundary relatively quickly.

However, in low or extremely low permeability reservoirs, the pressure wave may require an exceedingly long time to reach the reservoir boundaries, rendering practical determination unfeasible. Consequently, this model lacks the necessary accuracy for tight gas reservoirs characterized by ultra-low permeability values. O. Al-Fatlawi (2018) introduced a novel correlation for the pseudo-steady constant (b_{Dpss}) designed specifically for fractured wells in tight gas reservoirs featuring low permeability.

Al-Fatlawi et al. (2017) suggested a modification to (r_{eD}). They incorporated the radius of the investigation into the (r_{eD}) correlation instead of the reservoir radius. This modification eliminates the need for the pressure wave to reach the reservoir boundary, making it more practical. Importantly, their approach demonstrates high accuracy when applied to real-field cases.

The developed correlation was subsequently applied to ascertain the reservoir permeability and fracture half-length for a tight gas reservoir in Australia. Additionally, the research extended to the creation of new type curves based on the (b_{Dpss}) correlation, simplifying the analysis of production data from fractured wells in tight gas reservoirs.

Nevertheless, the prior work was predominantly tailored for single fractures. This work, however, is focused on developing a fresh correlation for the pseudo-steady constant (b_{Dpss}) specifically designed for multi-fractured vertical wells in low-permeability tight gas reservoirs. The correlation is then used to evaluate fracture half-length, average reservoir permeability and the gas reserve in a tight gas reservoir. Then it is employed to generate new type curves to analyse the fractured vertical well in the tight gas reservoir for the case of single and multi-fractures based on the (b_{Dpss}) correlation.

5.2 Methodology:

The Fetkovich-type curves and the mentioned correlation suggested by Pratikno et al. (2003) are given in Equation (5.1):

$$b_{Dpss} = \ln(r_{eD}) - 0.049298 + 0.43467 r_{eD}^{-2} + \frac{a_1 + a_2 u + a_3 u^2 + a_4 u^3 + a_5 u^4}{1 + b_1 u + b_2 u^2 + b_3 u^3 + b_4 u^4} \quad 5.1$$

Where:

$$r_{eD} = \frac{r_e}{x_f} \quad 5.2$$

$$u = \ln{(F_{CD})} \quad 5.3$$

Table 5.1 represents the values of the constant coefficients of Equation (5.1).

Table 5-1 Values of coefficients used in Pratkino correlation

Coefficients	**Value**
a1	0.936268
a2	-1.00489
a3	0.319733
a4	-0.04235
a5	0.002218
b1	-0.38554
b2	-0.06989
b3	-0.04847
b4	-0.00814

The pseudo-steady-state parameter (b_{Dpss}) remains constant for a well and is contingent upon the dimensionless radius (r_{eD}) and dimensionless fracture conductivity (F_{CD}). Importantly, it remains unaffected by changes in pressure and time.

Equation (5.1) is a correlation that relies on the variables F_{CD} and r_{eD}. These specific variables can be determined using Equations (5.4) and (5.5) respectively.

$$F_{CD} = \frac{k_f w_f}{k\, x_f} \quad 5.4$$

$$r_{eD} = \frac{r_e}{x_f} \qquad 5.5$$

Where:

x_f : is the fracture half-length, ft,

w_f : is the fracture width, in,

k_f : is the fracture permeability, mD and

r_e : is the reservoir radius, ft.

O. Al-Fatlawi (2018) generated a simple modification of b_{Dpss} correlation by redefining one of its dependent variables. He used the radius of investigation, r_i, instead of the reservoir radius, r_e in the definition of r_{eD}. According to that, new type curves have been created for a vertical well with a single fracture in a TGR reservoir depending on multiple values of r_{eD} and F_{CD}.

In this ongoing research, further adjustments and enhancements have been implemented to account for the complexities introduced by multiple fractures when analyzing the fractured horizontal wells within tight gas reservoirs. To construct the new correlation, a comprehensive reservoir simulation was undertaken. The simulation model was specifically designed to replicate conditions within a circular reservoir, where a hydraulically fractured horizontal well was strategically situated at the central point of the reservoir. To generate the necessary data, a total of twenty-five simulation scenarios were carefully designed and executed to facilitate the development of the correlation.

Table 5.2 provides a comprehensive overview of the data considered for the reservoir model, as well as the constraints associated with the well.

The following range of dimensionless reservoir radius and dimensionless fracture conductivity has been covered in the simulation scenarios:

r_{eD}: 4, 12, 20, 60, 100.

F_{cD}: 5, 20, 40, 60, 100.

Table 5-2 Reservoir model properties

Property	Value
Reservoir Area, Acre	2650
Pay zone thickness, ft	300
Permeability, mD	0.01-0.1
Porosity, %	3-9
Initial reservoir pressure, psi	4000
Reservoir fluid	Gas
Fracture half-length, ft	50-2000
Minimum bottom hole flowing pressure, psi	1000
Number of fractures	1-20

Dimensionless pressure, P_D, and dimensionless time, t_{DA}, are calculated based on the results of simulation scenarios. Then, based on the new empirical modification b_{Dpss} can be calculated from the following correlation.

$$b_{Dpss} = P_D C_f - 2\pi t_{DA} \quad 5.6$$

Where:

Where: C_f = 1 for a single fracture and can be calculated from Equation (5.7) for multiple fractures:

$$C_f = \ln\left(\frac{104d}{n}\right) \quad 5.7$$

Where:

d: Average distance between two fractures, ft.

n: Number of the fractures.

Figure 5.1 to Figure 5.5 presents the P_D vs t_D for different values of r_{eD} and F_{CD}, which are used to calculate b_{Dpss} using Equation (5.1) for all the scenarios.

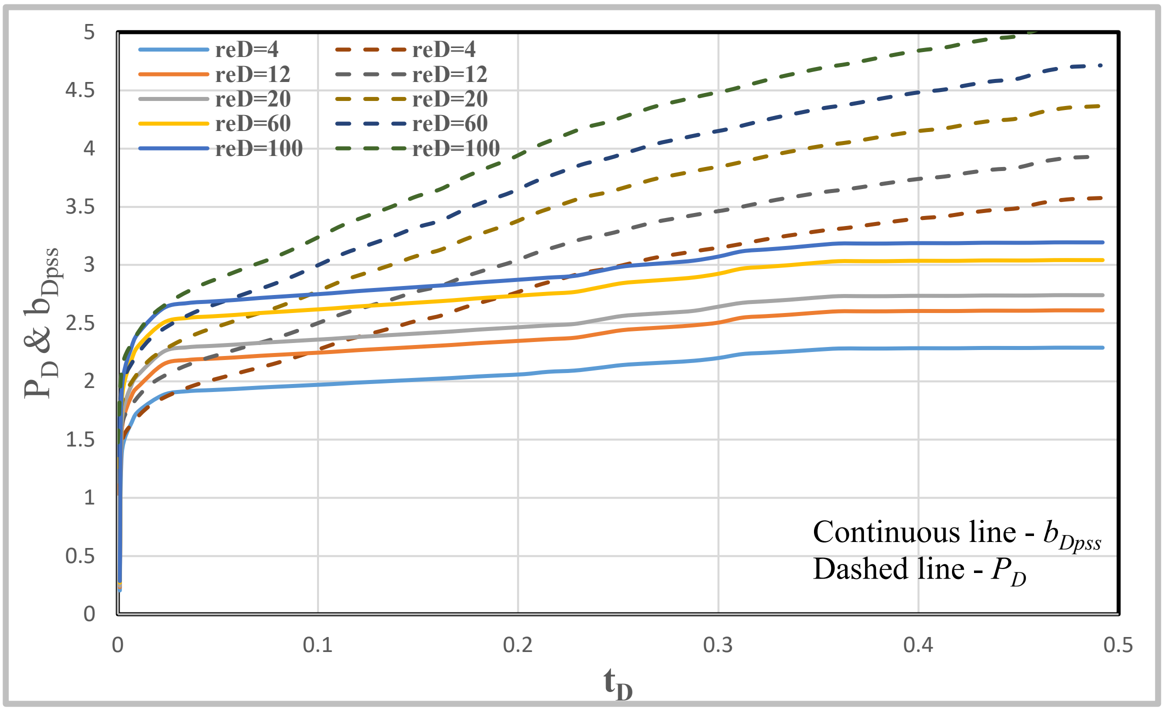

Figure 5.1 P_D and b_{Dpss} versus t_{DA} for a fractured horizontal well in TGR with a dimensionless fracture conductivity of 5

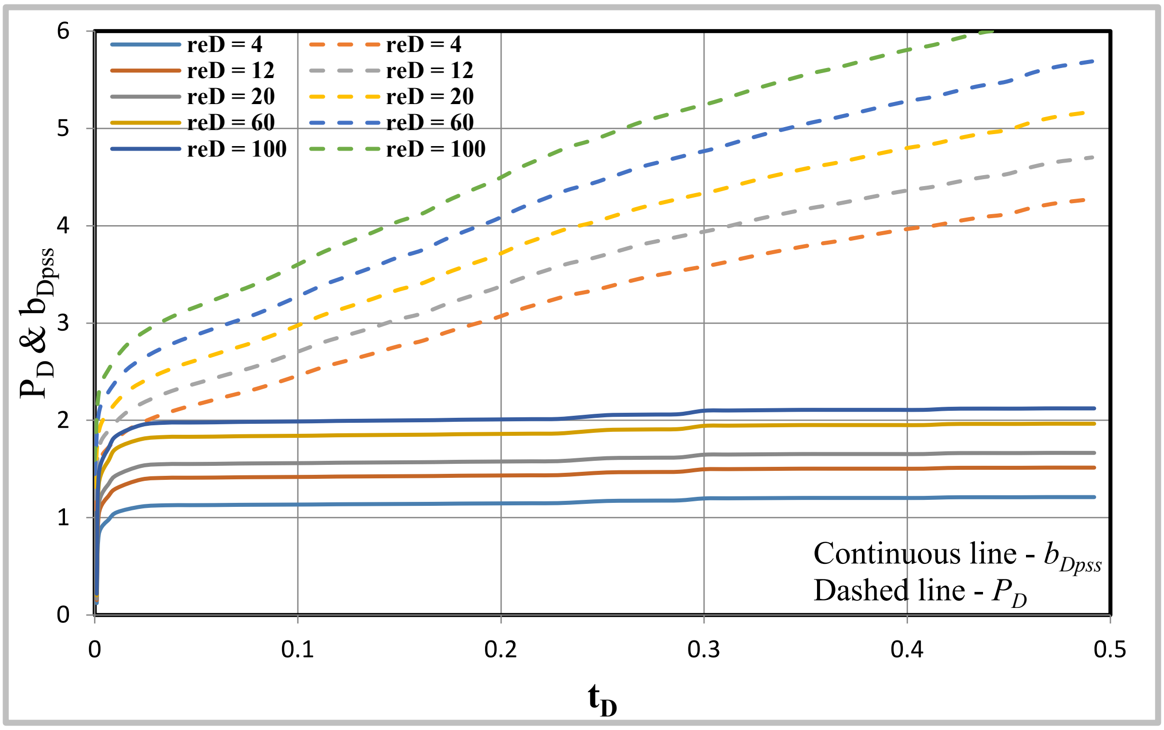

Figure 5.2 P_D and b_{Dpss} versus t_{DA} for a fractured horizontal well in TGR with a dimensionless fracture conductivity of 20.

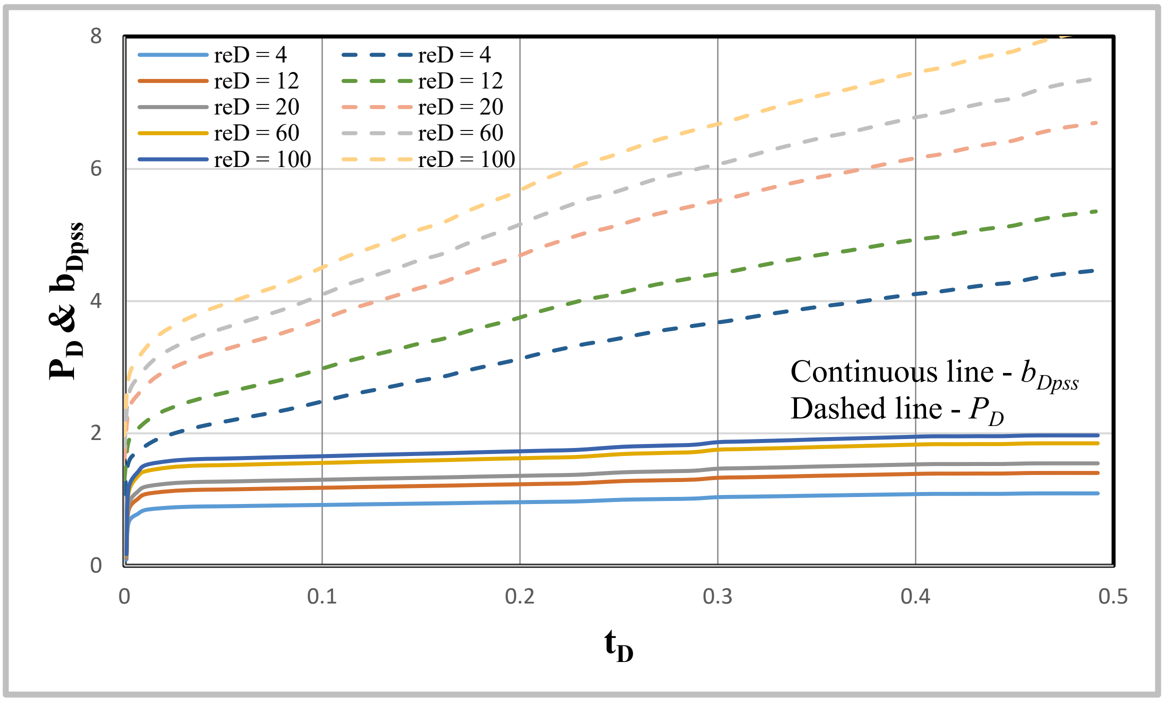

Figure 5.3 P_D and b_{Dpss} versus t_{DA} for a fractured horizontal well in TGR with a dimensionless fracture conductivity of 40.

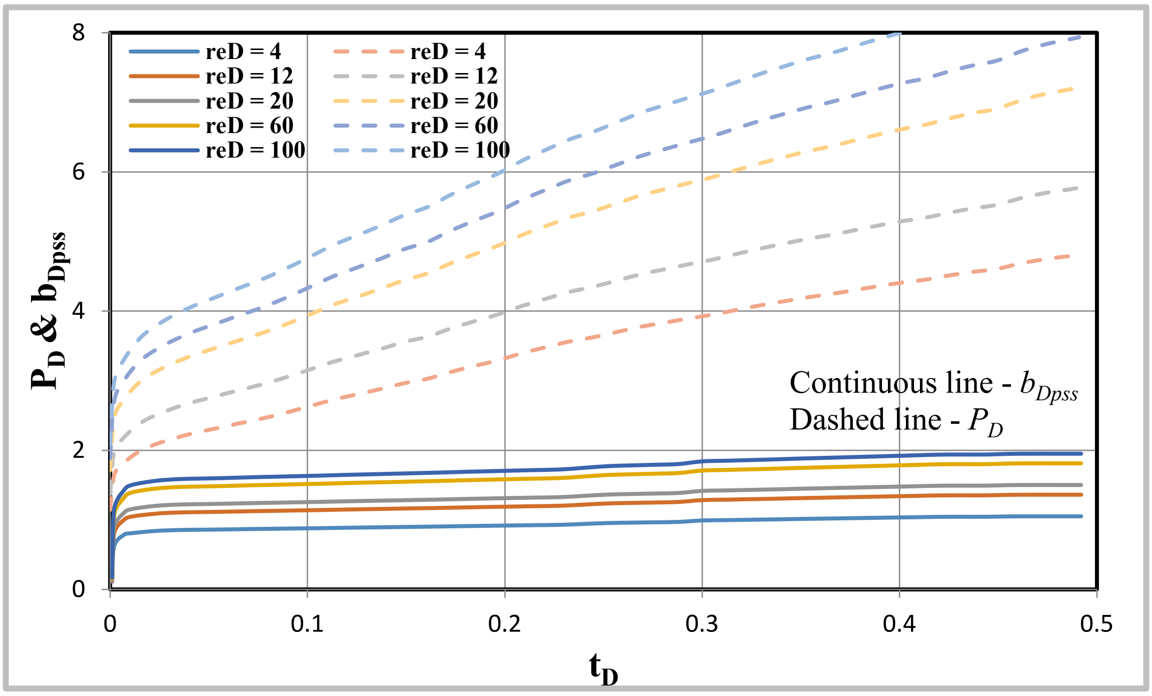

Figure 5.4 P_D and b_{Dpss} versus t_{DA} for a fractured horizontal well in TGR with a dimensionless fracture conductivity of 60.

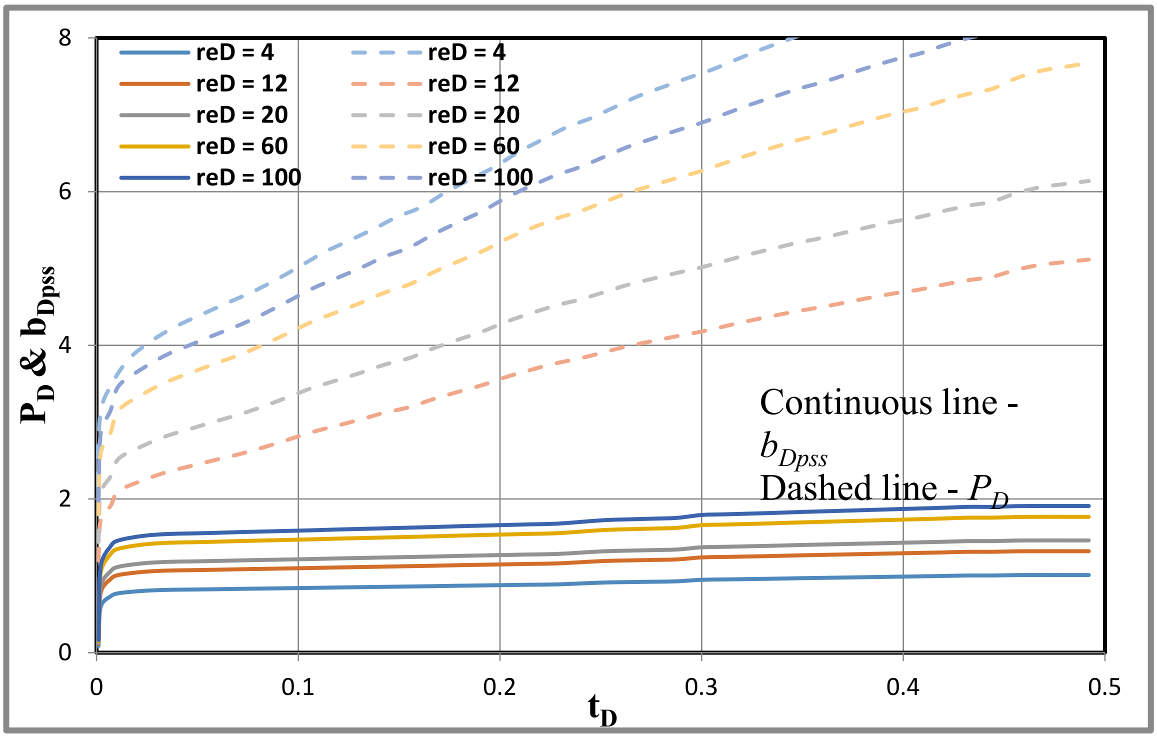

Figure 5.5 P_D and b_{Dpss} versus t_{DA} for a fractured horizontal well in TGR with a dimensionless fracture conductivity of 100.

Table 5-3 Calculated dimensionless pseudo-steady state parameter at different values of Dimensionless radius and Dimensionless fracture conductivity.

b_{Dpss}		r_{eD}				
		4	12	20	60	100
F_{CD}	100	1.01	1.32	1.46	1.77	1.91
	60	1.05	1.36	1.50	1.81	1.95
	40	1.09	1.40	1.54	1.85	1.99
	20	1.21	1.52	1.67	1.97	2.12
	5	2.29	2.60	2.74	3.05	3.19

The dimensionless reservoir radius, which is one of the dependent parameters for the pseudo-steady state parameter, is a function of the radius of reservoir, r_e, and fracture half-length, x_f. However, in this study, the radius of investigation is used instead of the reservoir radius and this was determined by (O. Al-Fatlawi, 2018) and proved that it gives a high accuracy results.

$$r_{eD} = \frac{r_i}{x_f} \qquad 5.8$$

For developing a new correlation for b_{Dpss}, the data of b_{Dpss}, r_{eD} and F_{CD} as input for a statistical model, and based on non-linear regression analysis, a new correlation for b_{Dpss} is developed as a function of r_{eD} and F_{CD} as expressed in Equation (5.9).

$$b_{Dpss} = a_1 r_{eD}^{a_2} + a_3 \ln(r_{eD}) + \frac{a_5 + a_6 u + a_7 u^2 + a_8 u^3}{1 + a_9 u + a_{10} u^2 + a_{11} u^3} \qquad 5.9$$

Where u is a function of F_{CD} and was previously introduced and defined in Equation (5.3).

Table 5-4 Constant coefficients of Equation (5.9).

Constant	Value
a1	0.0001
a2	-1.5
a3	0.28
a4	0.34
a5	9.95
a6	1.05
a7	0.47
a8	0.701
a9	-0.18
a10	0.718
a11	1.37

To find the best correlation that fits the available data, several equation forms are suggested and the confidence level of each equation is observed. The best-fit equation is selected which has the minimum absolute percentage error between the calculated b_{Dpss} and the actual value of b_{Dpss}.

5.3 Confidence Level Test Using Mathematical Expressions:

The proposed correlation is tested for confidence level using two different mathematical expressions:

5.3.1 Average Absolute Percentage Error (AAPE):

The calculation of the average absolute percentage error can be performed using Equation (5.10).

$$AAPE = \frac{1}{n}\sum_{1}^{n}\frac{\left|(b_{Dpss})_{Actual}-(b_{Dpss})_{Calculated}\right|}{(b_{Dpss})_{Actual}} \qquad 5.10$$

Where: n is the number of points.

The proposed correlation in this work has an *AAPE* value of (1.79 %) which is very good because it is so low.

5.3.2 Coefficient of the Determination of Correlation (R-squared):

The Coefficient of the Determination of Correlation (R-squared coefficient) can be calculated from Equation (5.11).

$$r^2 = \sum \frac{(b_{Dpss})_{Calculated} - \overline{b_{Dpss}}}{(b_{Dpss})_{Actual} - \overline{b_{Dpss}}} \quad 5.11$$

Where: $\overline{b_{Dpss}}$ is the average value of b_{Dpss}, and it can be calculated from Equation (5.12).

$$\overline{b_{Dpss}} = \frac{\sum (b_{Dpss})_{Actual}}{n} \quad 5.12$$

The proposed correlation in this work has an R-squared value of (0.933) which is very good because it is close to 1 (1 is the ideal value).

5.4 Generation of Type Curves:

The most important part of the current study is the type curves. The type curves are generated depending on the proposed correlation based on the Al-Fatlawi format (O. F. Al-Fatlawi, 2018) for different values of dimensionless fracture conductivity and dimensionless reservoir radius.

The values of dimensionless reservoir radius and dimensionless fracture conductivity suggested and covered in generating the type curves are:

r_{eD}: 4, 12, 20, 60, 100

F_{CD}: 5, 20, 40, 60, 100

Simulation processes were done for the above range of r_{eD} and F_{CD} to record the bottom hole flowing pressure and flow rates versus time to generate the type curves. The recorded values of flow rates, pressures and time are then used as input to Equations (5.8), (5.9), (5.13), (5.14), (5.15) and (5.16) to create the type curves.

$$t_{DA} = \frac{0.000264kt}{\varphi(\mu C_t)_i A} \tag{5.13}$$

$$q_D = \frac{1424\, qTC_f}{kh(\Delta m(p))} \tag{5.14}$$

$$t_{Dd} = \frac{2\pi t_{DA}}{b_{Dpss}} \tag{5.15}$$

$$q_{Dd} = q_D b_{Dpss} \tag{5.16}$$

The results of the above calculations are then plotted as q_{Dd} versus t_{Dd} for different values of dimensionless fracture conductivity and dimensionless reservoir radius to match the form of Fetkovich's type curves as shown in Figure 5.6 to Figure 5.10.

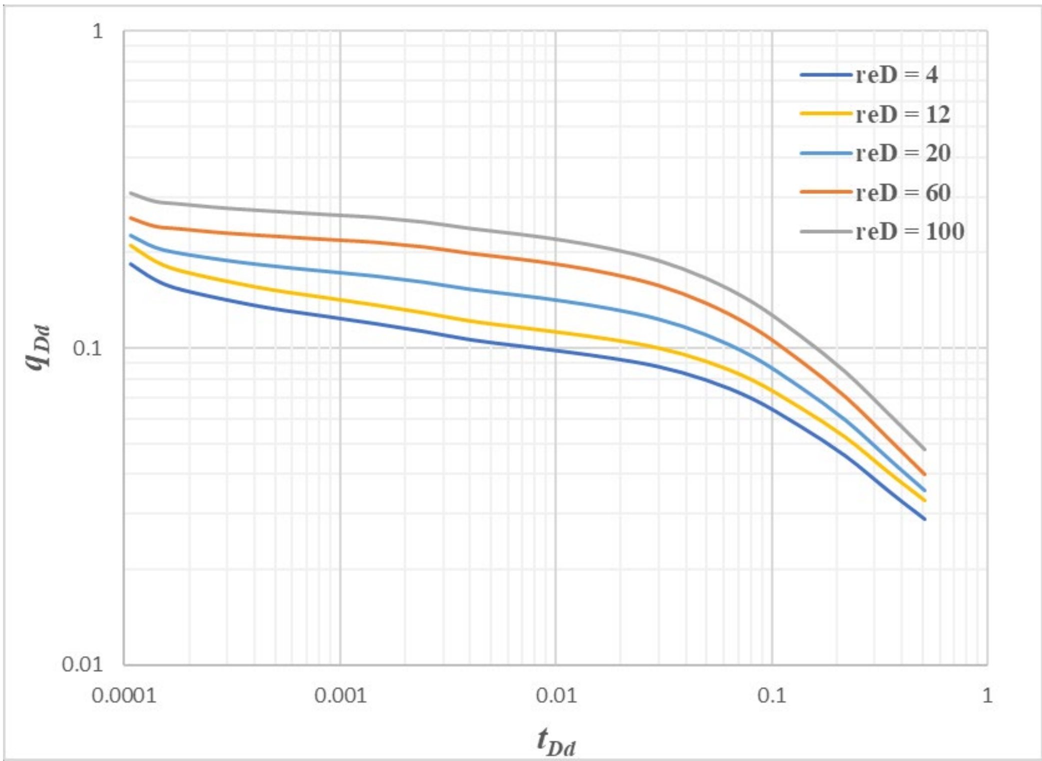

Figure 5.6 Decline type curve - dimensionless decline rate versus dimensionless decline time for a fractured horizontal well with F_{CD} =5

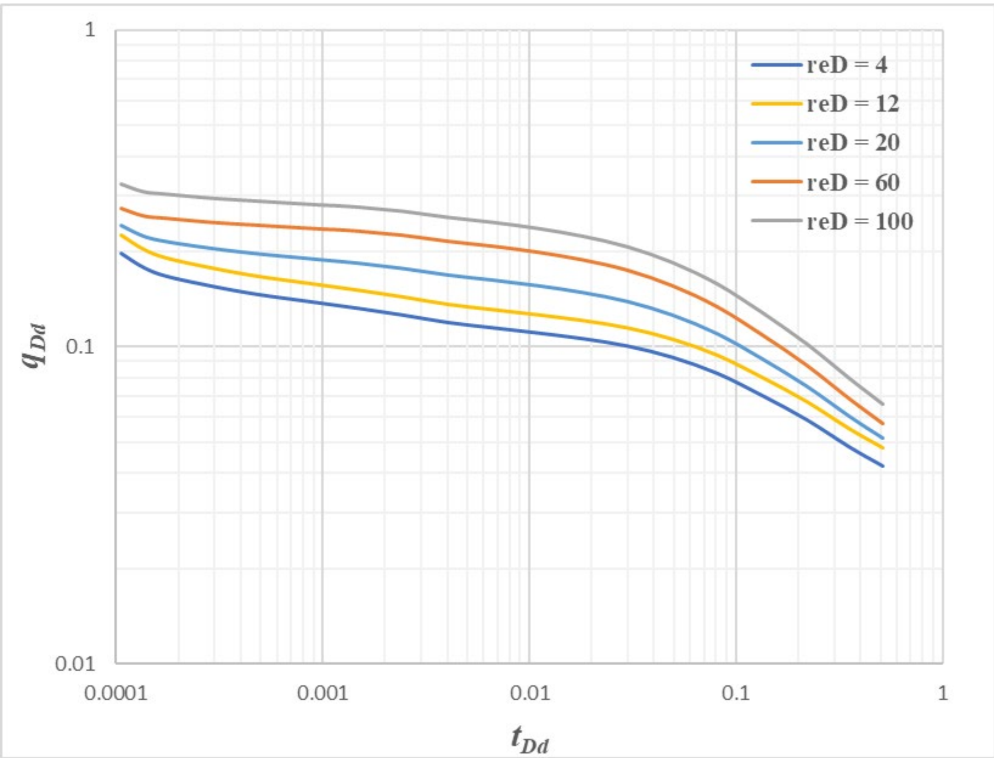

Figure 5.7 Decline type curve - dimensionless decline rate versus dimensionless decline time for a fractured horizontal well with F_{CD} =10

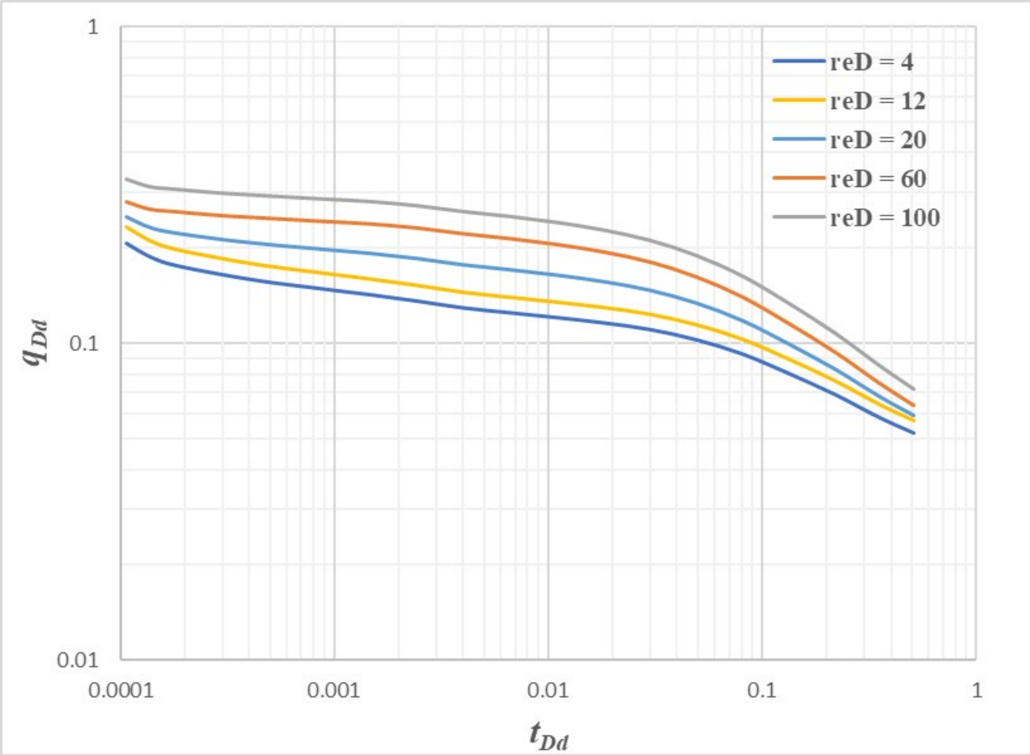

Figure 5.8 Decline type curve - dimensionless decline rate versus dimensionless decline time for a fractured horizontal well with F_{CD} =20

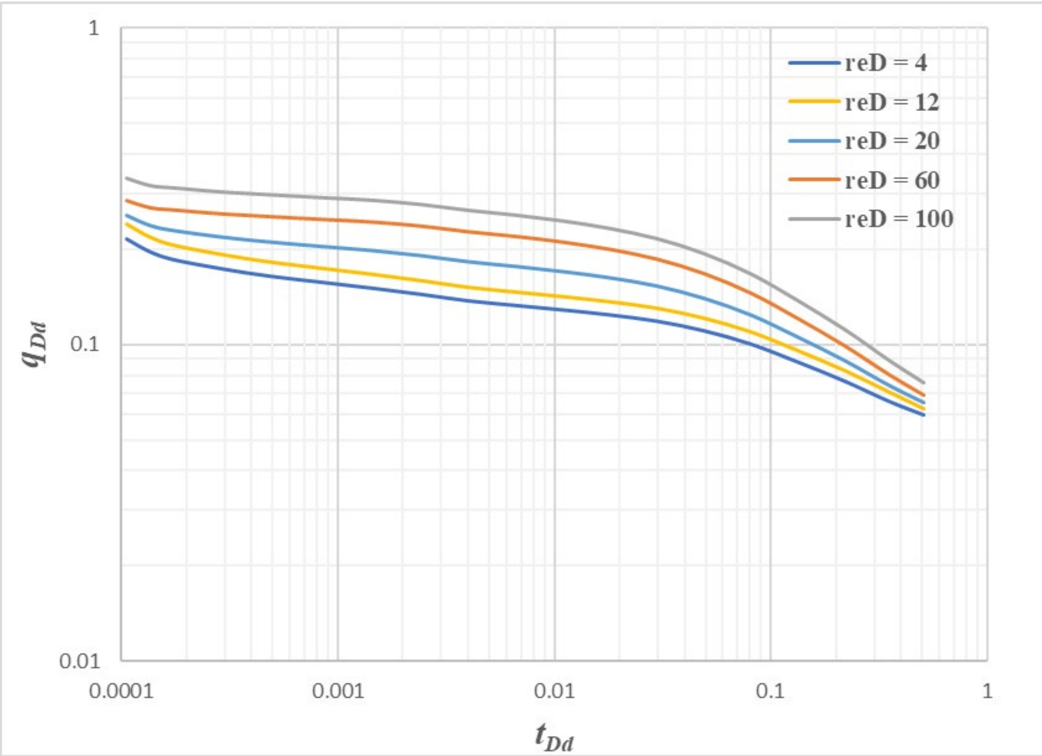

Figure 5.9 Decline type curve - dimensionless decline rate versus dimensionless decline time for a fractured horizontal well with F_{CD} =50

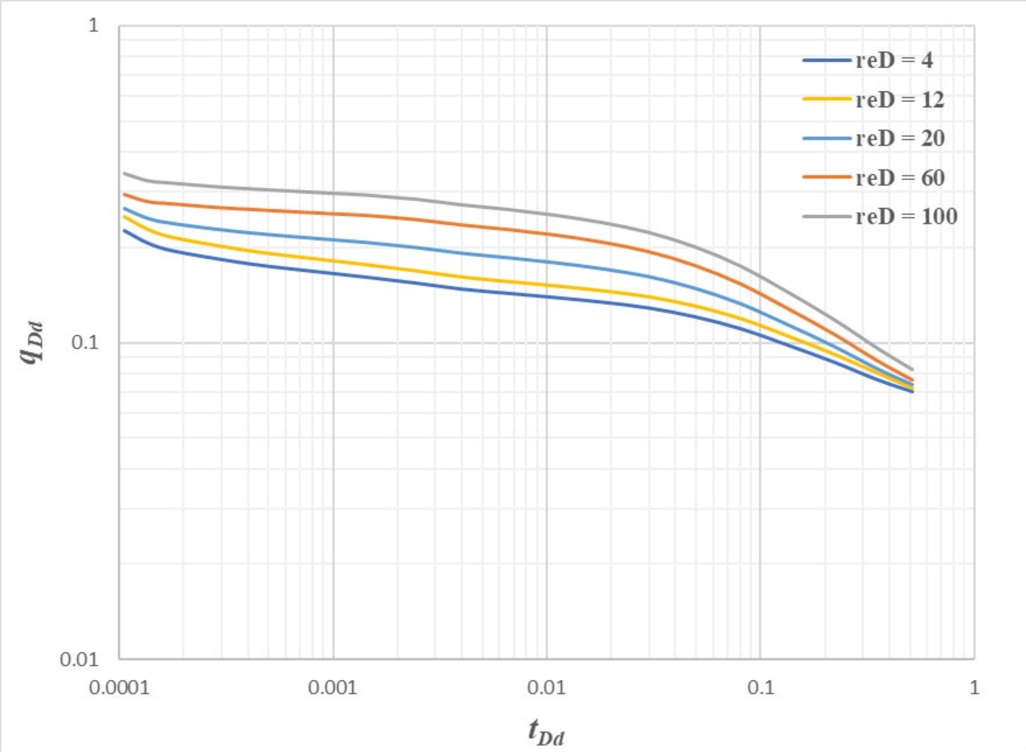

Figure 5.10 Decline type curve - dimensionless decline rate versus dimensionless decline time for a fractured horizontal well with F_{CD} =100

5.5 Validation of the proposed correlation:

The proposed correlation for the pseudo-steady state, b_{Dpss}, and the accompanying set of type curves have been validated using production data obtained from an actual field example. This field example involves a fractured horizontal well situated within a tight gas reservoir (TGR) located in the Middle East. The basic data of the example have been used to determine parameters such as fracture half-length, average reservoir permeability and drainage area are provided in Table 5.5. In addition, Table 5.5 consists of the fracture half-length determined from fracturing jobs.

The equations employed to calculate drainage area, A, permeability to the gas, k_g, and the gas in place, G, are given by Equations 5.17 to 5.19.

Table 5-5 the basic real-field data of the case used for validation

Property	**Value**
Pay zone thickness, ft	250
Porosity (avg), fraction	0.057
Initial reservoir pressure, psia	4000
Permeability (avg.), mD	0.04
Initial flow rate, Mscf/D	4000
Production period, month	8
Drainage area, acres	2560
Fracture half-length, ft	755
Number of fractures	10
Distance between two consecutive fractures, ft	363

$$A = \frac{GB_{gi}}{\varphi h(1-S_{wir})} \quad 5.17$$

$$k_g = 141.2\frac{B_{gi}\mu_{gi}}{hC_f}b_{Dpss}\left(\frac{(P_{Dd})_{MP}}{(\Delta P_P/q)_{MP}}\right) \quad 5.18$$

$$G = \frac{1}{C_{gi}C_f}\frac{(t_{ca})_{MP}}{(t_{Dd})_{MP}}\frac{(P_{Dd})_{MP}}{(\Delta P_P/q)_{MP}} \quad 5.19$$

Pseudo pressure drop normalized rate function $(\frac{q}{\Delta P_P})$ is subsecuently graphed against the material balance pseudo-time function (t_{ca}) for the purpose of conducting the type curve matching. Equations 5.20 to 5.22 are applied to compute the pressure drop normalized rate function and material balance pseudo-time function.

$$\frac{q}{\Delta P_P} = \frac{q}{\left(P_{P_i} P_{P_{wf}}\right)} \tag{5.20}$$

$$P_P = \frac{\mu_i Z_i}{P_i} \int_{P_{base}}^{P} \frac{p}{\mu Z} dP \tag{5.21}$$

$$t_{ca} = \frac{\mu_i C_{gi}}{q(t)} \int_0^t \frac{q(t_{ca})}{\mu(\bar{P}) C_g(\bar{P})} dt \tag{5.22}$$

The two mentioned parameters, ($\frac{q}{\Delta P_P}$ and t_{ca}) are calculated for the two real field cases and plotted on a logarithmic scale as shown in Figure 5.11.

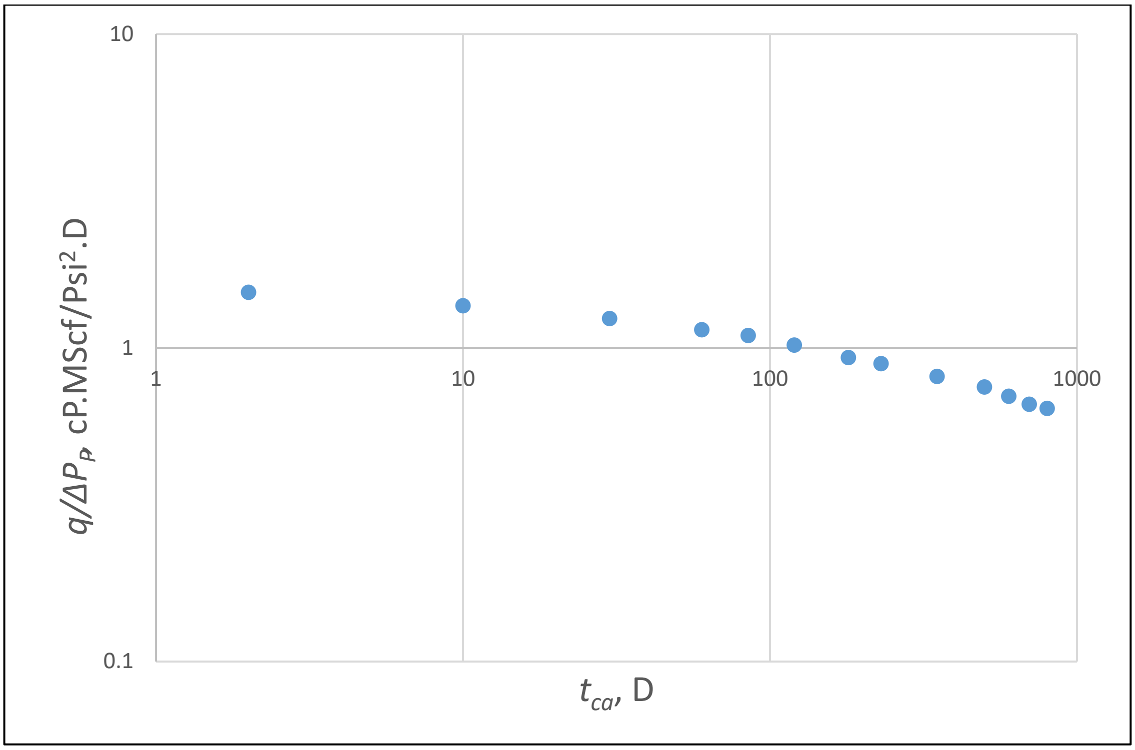

Figure 5.11 Log-Log plot for pseudo-pressure drop normalized rate vs material balance pseudo-time function for the real field case

The graph depicting the pseudo-pressure drop normalized rate function and material balance pseudo-time function for both cases aligned with the suggested type curves, resulting in the identification of a matching point for each case. The resulting values of the match points are listed in

Table 5.6. The type-curves selection depends on the dimensionless fracture conductivity ratio (F_{CD}).

Table 5-6 the extracted data of the match point for the two cases

Match point coordinates	Case.1
F_{CD}	10
q_{Dd}	0.1
t_{Dd}	0.1
r_{eD}	5
$q/\Delta P_P$, $cP.MScf/Psi^2.D$	7
t_{ca}, day	9000

Table 5.7 shows the results of permeability, Gas in place and drainage area, obtained from the calculations for the real field case based on the type curve matching process and Equations 5.5, 5.17, 5.18, 5.19. While fracture half-length can be found from Equation 5.5 by knowing r_i and r_{eD} which can be found from 5.23 and the matching criteria respectively.

$$r_i = \sqrt{\frac{A}{\pi}} \qquad 5.23$$

Table 5-7 the type curve matching results

Property	*G*, BSCF	*A*, Acres	*k*, mD	x_f, ft
Value	355	2457	0.0393	724

The average absolute percentage error (AAPE) has been calculated for each parameter of the resulting data in comparison with the actual field data, and shown in Table 5.8.

Table 5-8 Average Absolute error percentage (AAPE) of the results of type curve matching

Property	***AAPE*, %**			
	***G*, Bscf**	***A*, acres**	***k*, mD**	**x_f, ft**
AAPE Value	1.94	4.62	2.08	4.27

The values of AAPE, as expressed in Table 18, serve as indicators of minimal error levels across both the correlations and calculation methodologies, as well as in the newly developed type curves. The coherence observed between the actual field data and the outcomes derived in the present study underscores a noteworthy degree of confidence in the established correlation connecting the dimensionless pseudo-pressure constant to the newly devised type curves. This confidence is not only confined to the successful correlation but also extends to the efficacy of these curves in determining essential parameters such as permeability (k), fracture half-length (x_f), drainage area (A), and original gas in place (G).

It is imperative to underscore that the methodology employed in this study is centred on a relatively concise period of 24 months of production data for tight gas reservoirs (TGRs). Importantly, it should be acknowledged that this temporal scope is comparatively brief when juxtaposed with the prolonged real-time production often witnessed in reservoirs of this nature, which can span decades (Al-Fatlawi, Hossain, & Saeedi, 2017; Bahrami, Rezaee, & Clennell, 2012; Maley, 1985). As such, this methodological approach positions itself for prospective applications in the ongoing analysis of production data emanating from fractured horizontal wells, equipped with either single or multiple fractures in a TGR. This, in turn, provides valuable insights for the strategic planning and future development of the field.

5.6 Summary:

While the type curve method provides a convenient and affordable way to analyse well test data, requiring little data and avoiding expensive commercial simulators, its simplified curves often lead to inaccurate results and misinterpretations when used with fractured wells in Tight Gas Reservoirs (TGRs). To address these limitations, this study introduces a new set of type curves specifically designed for analysing production data from fractured horizontal wells in TGRs. These improved curves are based on a novel statistical correlation, explained in detail in this chapter. This advancement offers a more accurate and reliable tool for evaluating the performance of fractured wells in TGRs.

Chapter 6:

Development of Method to Analyse Pressure Transient Data for Hydraulic Fractured Horizontal Wells in Tight Gas Reservoir

6.1 Introduction

The unconventional reservoirs have attracted considerable attention owing to their vast and untapped potential for ensuring a clean and environmentally sustainable primary energy source. This is in response to the ever-expanding global demand for energy, as these reservoirs offer a unique opportunity to meet this demand while also prioritizing ecological well-being (Al-Fatlawi, Hossain, & Essa, 2019; Göedeke & Hossain, 2012; S. A. Holditch, 2003; D. Sadeq, Alef, Iglauer, Lebedev, & Barifcani, 2018; D. J. Sadeq, 2018; Sahoo, Gani, Hampson, Gani, & Ranson, 2016).

Significant focus is also directed towards the development of tight gas reservoirs, categorized as a type of unconventional reservoir. This is particularly important in ensuring a consistent supply of clean energy resources, especially as numerous mature conventional gas reservoirs are currently undergoing depletion (O. F. Al-Fatlawi, 2018; Dong et al., 2012; S. A. Holditch, 2006; Khlaifat, Qutob, & Barakat, 2011; Xinhua, Ailin, Jian, & Dongbo, 2012). As a result, there has been a notable upward trajectory in research and development efforts related to the advancement of tight gas reservoirs. This has translated into a substantial rise in the volume of research articles within this domain, with the count escalating from 10 articles per year in 1980 to a significant 668 articles per year by 2017 (Al-Fatlawi, Hossain, Patel, et al., 2019; M. M. Hossain et al., 2018).

The integration of horizontal well drilling techniques with hydraulic fracture stimulation methods has risen to prominence as the foremost viable and economically sound technological strategy for the profitable extraction of resources from reservoirs characterized by low permeability and tight geological formations. This innovative synergy of approaches not only optimizes resource recovery but also ensures cost-effectiveness, thus proving instrumental in unlocking the full potential of such challenging reservoirs (Al-Fatlawi, Vimal Roy, et al., 2017; O. F. Al-Fatlawi, 2018; M. Hossain, Rahman, & Rahman, 1999; Rahman, Hossain, Crosby, Rahman, & Rahman, 2002).

However, the progress in the development of tight gas reservoirs is impeded by significant challenges arising from the intricate nature of reservoir attributes, such as diverse reservoir descriptions and the pronounced heterogeneity exhibited in the distribution of porosity and permeability. These complexities are further compounded by the inherently low permeability of these reservoirs, which collectively pose considerable hurdles in their effective exploitation (Al-Fatlawi et al., 2016; Bahrami, Rezaee, Hossain, et al., 2012; Xinhua et al., 2012). Therefore, to achieve economically viable gas production from these reservoirs, the key strategy entails the drilling of horizontal wells that are subsequently subjected to hydraulic fracturing stimulation. This combined approach is essential for effectively enhancing gas extraction rates and maximizing the economic potential of such reservoirs (Bahrami, Rezaee, & Hossain, 2012; Bocora, 2012; M. Hossain, Rahman, & Rahman, 2000a; Leal, Duarte, Soriano, Lopez, & Fatkhutdinov, 2014; Xinhua et al., 2012). Furthermore, the advancement of extracting gas from tight reservoirs necessitates addressing several challenges concerning the characterization of the reservoir, numerical simulation, and comprehension of production mechanisms. These issues are crucial for accurately predicting the performance of gas production from the reservoir (M. M. Hossain et al., 2018; Moridis, Blasingame, & Freeman, 2010).

In order to accurately forecast and optimize reservoir production performance, numerical simulation is commonly used. However, the accuracy of these simulation studies relies heavily on the precision of the data and information regarding reservoir descriptions. It is crucial to have accurate reservoir characteristics and conditions to ensure the reliability of the simulation results (M. M. Hossain et al., 2018; Moridis et al., 2010). Although 2numerical simulation seems to be the most viable choice for predicting and enhancing reservoir production, the precision of these simulation analyses relies heavily on the accuracy of the data and details pertaining to reservoir characteristics. This is crucial for accurately representing the genuine reservoir properties and circumstances (Al-Jawad, 2004; Mahmood & Al-Jawad, 2010; Temizel, Alklih, Najy, Putra, & Al-Fatlawi, 2018).

Due to the significant variation in reservoir properties such as porosity and permeability, tight gas reservoirs pose a challenge in obtaining precise data required to adequately represent reservoir characteristics. This accurate development is a fundamental requirement for effectively constructing a numerical simulation model. Incorporating a fractured horizontal well into a numerical model characterized by a high degree of heterogeneity is not only a complex task but also presents considerable challenges, especially when using standard computing resources (O. F. Al-Fatlawi, 2018). As a result, this task demands an extensive amount of computational time and access to costly, advanced computing facilities. However, the necessity for such prolonged computation time and high-cost facilities is typically not conducive within the context of standard industry practices and constrained budgets. Industries often need to respond promptly to meet stringent deadlines, while also striving for cost-effective solutions, especially when operating in a fluctuating gas market characterized by tight budget constraints.

This study aims to address the mentioned issue of reservoir heterogeneity by creating a reservoir simulation model by using an equivalent well radius (which is a function of well radius and fracture properties) instead of the real well radius. The original model is proposed by O. F. Al-Fatlawi, 2018, which will be used to forecast the production performance of a fractured horizontal well in a heterogeneous tight gas reservoir. Additionally, the model is used to optimize fracture parameters, including the number of fractures and fracture half-length for heterogeneous tight gas reservoirs. The validity of the simplified model is justified by analyzing multiple cases to predict the production performance of a multistage hydraulic fractured horizontal well in a tight gas reservoir based on cumulative gas production. The validated model is then utilized to optimize various parameters of the well and fractures, including horizontal well length, number of wells, number of fractures, and fracture half-length. These optimizations are specifically tailored for typical tight gas reservoirs. The model may seem simplistic compared to real scenarios, but it offers reliable and highly accurate approximate predictions. Additionally, it significantly reduces computation time and associated costs, making it a valuable tool.

6.2 Preparing the model

The simplified model was developed using the industry-standard commercial simulator ECLIPSE/PETREL. This software is widely recognized and trusted within the field for its capabilities in modelling and simulating reservoir behaviour.

Initially, a reservoir simulation model was developed for a fractured horizontal well in tight gas reservoirs using actual data obtained from petro-physical analysis, which relied on well log and core data. The simulation model was constructed to incorporate the distribution of permeability and porosity throughout the reservoir. This distribution was determined using Sequential Gaussian Simulation, a technique commonly employed in reservoir modelling to simulate spatial variability. By incorporating these key parameters, the simulation model aimed to accurately represent the reservoir's characteristics and behaviour.

Following the initial model, an additional model was constructed using identical fluid and rock properties, as well as reservoir characteristics. However, in this new model, the presence of natural fractures was disregarded, assuming a reservoir without any fracturing. Instead of utilizing the actual well radius, the equivalent well radius was used. This equivalent well radius is determined by considering parameters such as the real well radius, fracture half-length, fracture spacing, and the number of fractures.

$$r'_w = f(r_w, x_f, N_f, d) \tag{6.1}$$

Where:

r'_w : Equivalent well radius (ft)

r_w : Real well radius (ft)

x_f : Fracture half-length (ft)

N_f : Number of fractures

d : Fracture spacing (ft)

In order to determine the actual function of the equivalent well radius with the specified parameters, various scenarios were assumed and simulated using the commercial simulator ECLIPSE/PETREL. Each scenario was simulated for a period of 30 years to ensure the accuracy and reliability of the results. By running these simulations, the relationship between the equivalent well radius and the other parameters could be determined.

The above-described reservoir model was utilized to perform numerical simulations for a range of fracture half-lengths (ranging from 300 to 1000 ft) and number of fractures (ranging from 4 to 50) in order to forecast the pressure trend. The objective was to compare and analyze the discrepancies between the results obtained from the real model and the equivalent model.

By examining the differences in the simulation outcomes, the aim was to identify the acceptable equivalent model that could be considered as the best alternative to the real model. The selection process was based on minimizing the discrepancy (ε) between the two models. In other words, the model that exhibited the smallest differences in results compared to the real model was deemed as the acceptable equivalent model. Where ε is given by the following equation:

$$\varepsilon = \left| \frac{P_{wf,real} - P_{wf,model}}{P_{wf,real}} \right| \qquad 6.2$$

Where:

ε : The discrepancy (dimensionless)

$P_{wf,\ real}$: Real flowing well pressure at the end of the simulation period (psi)

$P_{wf,\ model}$: Calculated flowing well pressure at the end of the simulation period (psi)

The acceptable value of discrepancy (ε) is considered to be equal to or less than 5%.

6.3 Building the models

In this work, a reservoir simulation model was constructed to address over two hundred simulation scenarios; each ran for 30 years to get the best formula for the equivalent well radius (r'_w).

In all scenarios considered in this study, it is assumed that the hydraulic fractures in a horizontal well have an equal spacing along its horizontal length of 4000 ft. For example, the spacing between fractures in the scenario of 10 fractures is 350 feet for every two consecutive fractures. To accurately describe the gas PVT properties, such as the gas formation volume factor and viscosity, it is important to consider the underlying principle that governs these properties, which is the gas compressibility, Z-factor (AL-Jawad & Hasan, 2012; Ekundayo & Rezaee, 2019; Hassan & Al-Jawad, 2005). The Z-factor was accurately calculated under different pressure conditions. To achieve this, a comprehensive approach was employed by utilizing the lookup tables of the Z-factor provided by Al-Fatlawi in their 2017 publication (Al-Fatlawi, Hossain, & Osborne, 2017). These tables serve as a valuable resource in determining the precise values of the Z-factor at different pressure levels.

Table 6.1 provides a comprehensive overview of the specifications for all the models, including the horizontal well and the hydraulic fractures.

Table 6-1 The considered properties of reservoir and fractures

Reservoir temperature	220 °F
Initial reservoir pressure	4000 psi
True vertical depth (TVD)	5800 ft
Measured depth (MD)	8420 ft
Permeability in the z-direction (k_z)	0.00001 mD
Horizontal well length	4000 ft
Reservoir area	2250 acres
Fracture half-length	200 – 1000 ft
Fracture height	180 ft
Fracture permeability	10000 mD
Fracture orientation	90°
Fracture width	0.25 inch

6.4 Methodology

Simply, our methodology entails inputting reservoir and well data, including fracture details, into the commercial software ECLIPSE/PETREL. Subsequently, we conduct two simulations to monitor pressure trends over an extended period, specifically 30 years in this case. The selection of a 30-year simulation period is based on established knowledge that within this timeframe, the drainage area exhibits constraints, assuming an elliptical shape, as indicated by M. M. Hossain et al. (2018) findings. Subsequently, we carry out a second simulation with identical properties and specifications, but with the removal of fractures and adjustments made to the well radius. The outcomes are then assessed at the conclusion of the simulation period.

Following the above approach, we conducted an additional simulation using a different scenario. This time, we made adjustments to the properties of the fractures, such as altering the fracture half-length or spacing. We will revisit the results to observe the impact of these modifications. This iterative process involves calculating (ε) each time until we achieve identification or convergence (ε equal to or less than 5%). Afterwards, we analyzed the relationship between fracture properties and the equivalent well radius. The goal of this analysis is to develop a general equation that can be easily applied in future studies for practical and simplified purposes. The established model can serve as an alternative method for simulating fractured horizontal wells in tight gas reservoirs, where fracture properties and the actual well radius are replaced by the equivalent well radius (Al-Fatlawi, Hossain, Patel, et al., 2019).

Figure 6.1 to Figure **6.3** display the the pressure wave for a horizontal well with 6 fractures and a fracture half-length of 500 feet, as depicted by the original model after 5, 15 and 30 years of production respectively.

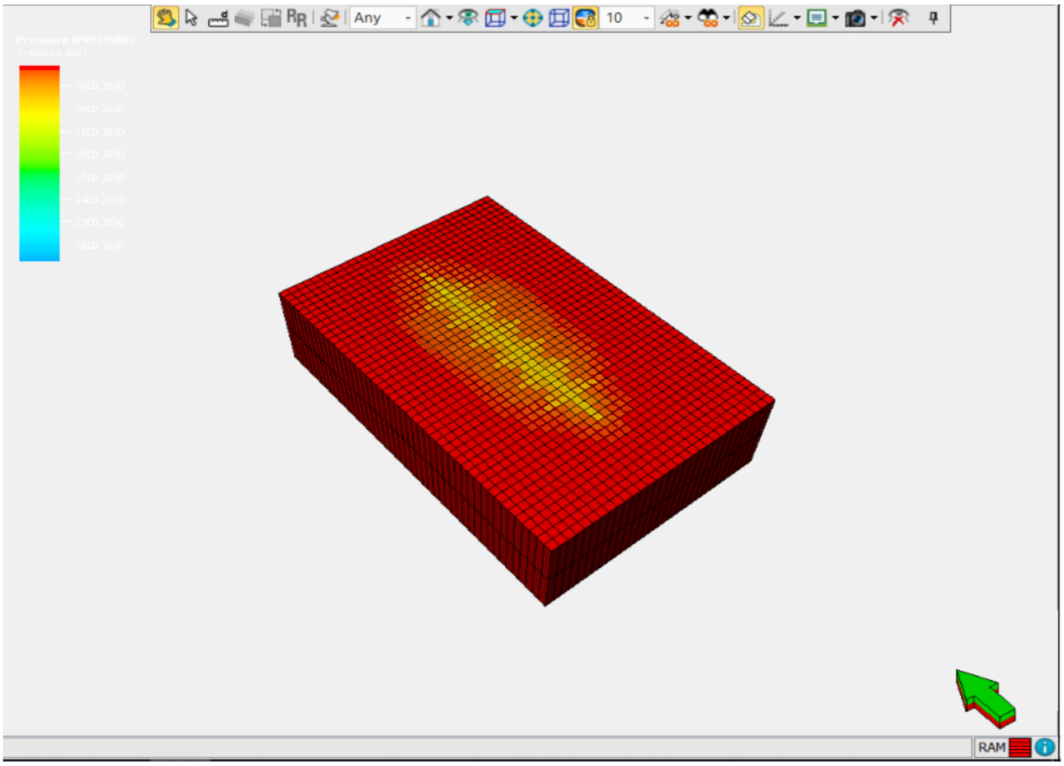

Figure 6.1 The pressure wave of the original model after 5 years of production

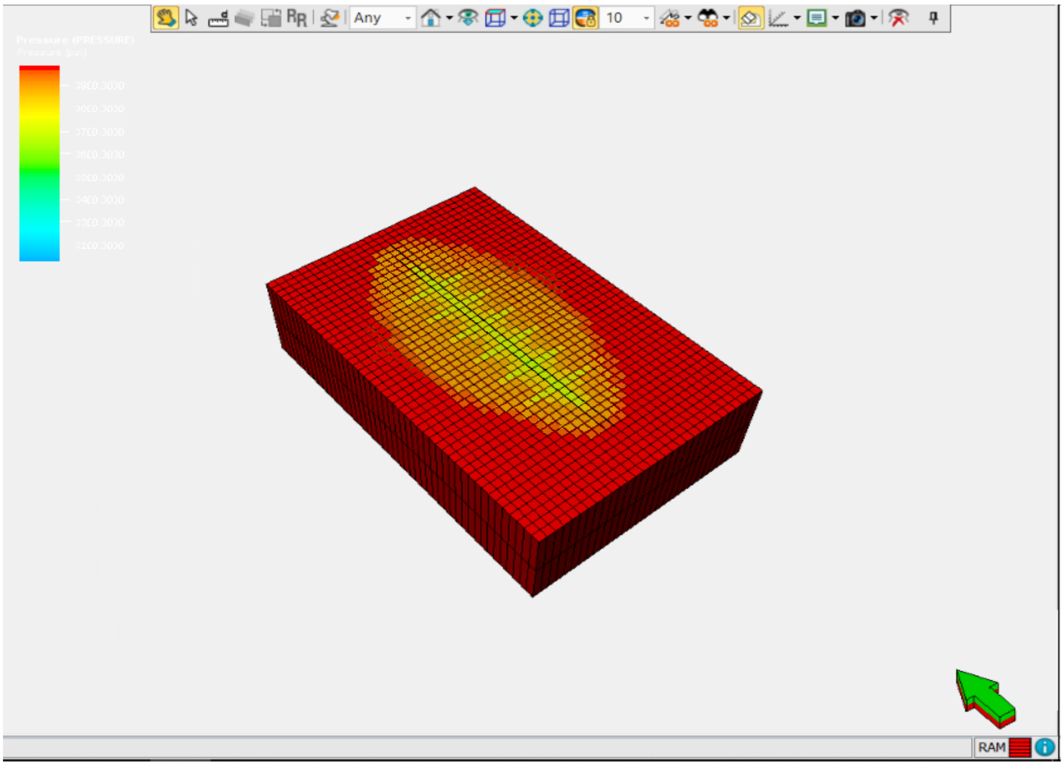

Figure 6.2 The pressure wave of the original model after 15 years of production

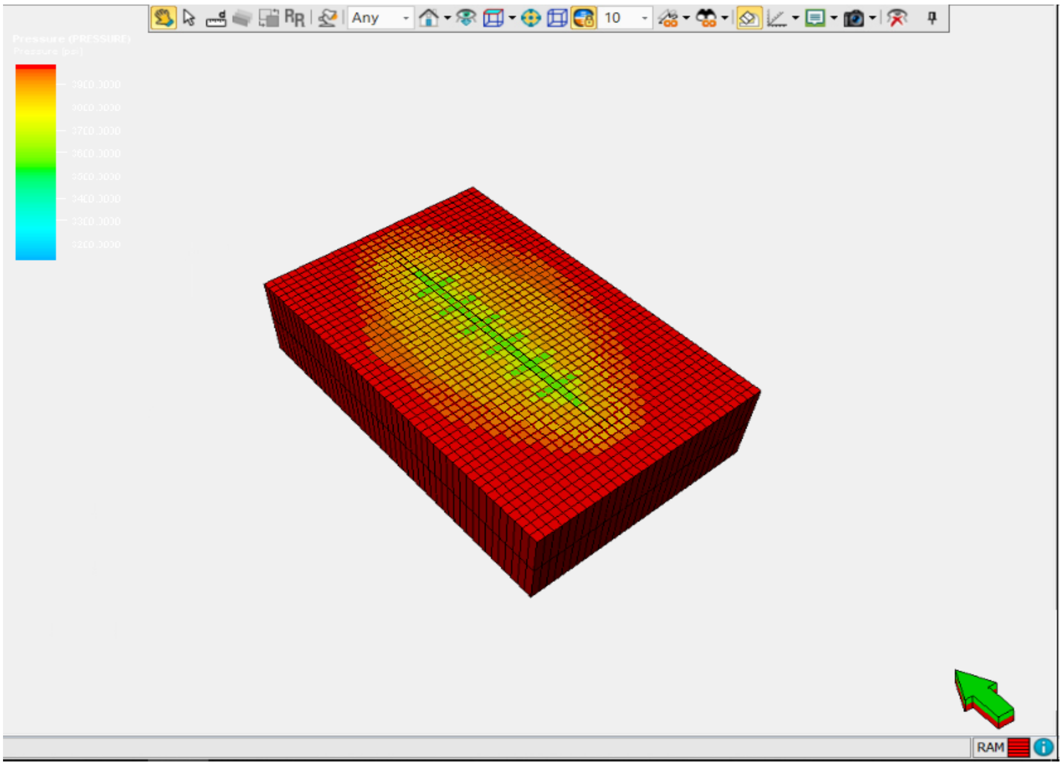

Figure 6.3 The pressure wave of the original model after 30 years of production

Upon analysing the imported data from the commercial software ECLIPSE/PETREL, it was observed that the correlation between fracture properties and the equivalent well radius is intricate and exhibits non-linear behaviour. To determine the most accurate correlation with minimal discrepancy (ε), several equations were tested using non-linear regression analysis. After rigorous evaluation, a complex final formula was derived to represent the relationship of the equivalent well radius and it can be expressed as follows:

$$F_r = \frac{N_f . \sqrt{x_f}}{d^{0.2}} \qquad 6.3$$

$$r'_w = r_w(0.0315\, F_r + 0.935) \qquad 6.4$$

Where:

Fr : Fracture properties constant

N_f : Number of fractures

x_f : Fracture half-length

d : Average distance between two consecutive fractures

r_w : Well radius

r'_w : Equivalent well radius

6.5 Results and validation

The proposed correlation has been validated using production data from an actual field example. This data was collected from a fractured horizontal well situated in a Tight Gas Reservoir (TGR) in the Middle East. By utilising this real data, the accuracy and reliability of the correlation have been tested and confirmed. This validation process enhances the confidence in the proposed correlation's applicability and effectiveness in similar scenarios.

Table 6.2 provides a representation of the corresponding input values, along with the results obtained from the models. It includes the fracture properties used in the simulation and the resulting equivalent well radius, along with the calculated discrepancy.

Upon examining the information presented in Table 6.2, it becomes evident that all the discrepancy values fall below the 5% threshold, indicating a high level of accuracy in the results obtained. However, to further validate the accuracy, an additional method is employed. This method involves comparing the pressure trends of the actual values with those derived from the adopted formula. By plotting these trends, it becomes possible to visually assess the consistency and reliability of the results. This serves as an extra layer of assurance in ensuring the accuracy and validity of the findings. Therefore, Figure 6.4 shows a sample of the results, specifically illustrating the pressure trend of an actual case compared to the calculated data obtained through the utilisation of the equivalent well radius method. According to the figure, the comparison between the pressure trend of the actual case and the calculated data using the method of equivalent well radius reveals a notable agreement during the middle and late stages of production, as indicated by the convergence of the two curves. This suggests a satisfactory level of accuracy in those time periods. However, it is worth noting that during the very early stages of production, the method appears to lack high accuracy.

Table 6-2 Simulation input values and results

r_w, inch	N_f	x_f, ft	D, ft	r_w', inch	ε, %
4	5	500	800	7.44	1.13
4	5	600	800	7.79	2.04
4	10	500	400	12.24	1.95
4	10	600	400	13.05	2.63
6	5	500	800	11.16	1.55
6	5	600	800	11.69	2.38
6	10	500	400	18.36	2.11
6	10	600	400	19.58	2.89
7.5	5	500	800	13.95	2.84
7.5	5	600	800	14.61	3.23
7.5	10	500	400	22.95	2.91
7.5	10	600	400	24.47	3.62

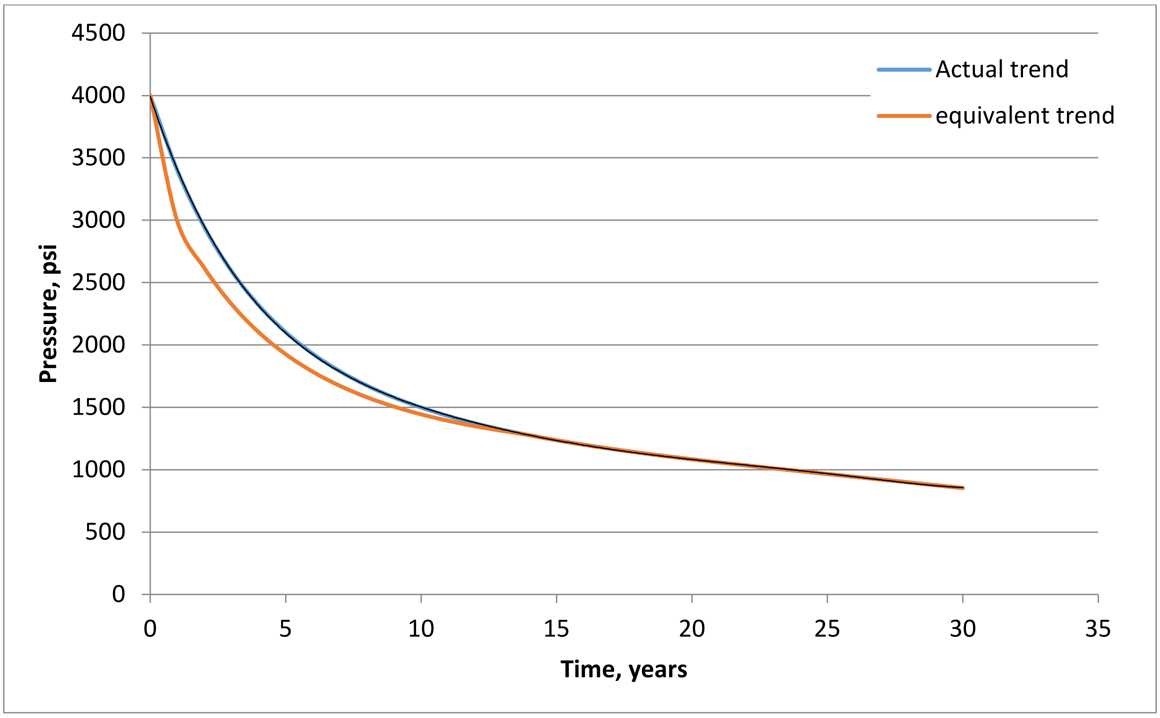

Figure 6.4 The pressure versus time for actual and calculated cases

The aforementioned evidence strongly supports the notion that the proposed methodology can be regarded as a reliable and effective tool for predicting the pressure trend in a fractured horizontal well in a tight gas reservoir. With its straightforward technique and reasonably accurate results, this methodology serves as a valuable guide in analysing the pressure behaviour in such reservoirs. Its simplicity enhances its practicality and applicability, making it a promising approach for industry professionals and researchers alike.

6.6 Summary

Incorporating a fractured horizontal well into a model characterized by significant heterogeneity poses considerable challenges, particularly with conventional computing resources. This task demands extensive computational time and access to expensive, advanced computing facilities. However, the necessity for prolonged computation and costly facilities clashes with standard industry practices and constrained budgets. In industries facing tight financial limits and strict deadlines due to the volatile gas market, cost-effective solutions are crucial.

This chapter addresses the challenge of reservoir heterogeneity by proposing a reservoir simulation model. The model utilizes an equivalent well radius derived from a combination of well radius and fracture properties, rather than relying on the actual well radius. The objective is to predict the production behaviour of a fractured horizontal well within a heterogeneous tight gas reservoir. This approach seeks to balance computational efficiency with the practical constraints of industry practices and budgets.

Chapter 7:

Conclusions and Recommendations

7.1 Introduction

The first part of the chapter presents a brief overview of the accomplishments detailed in the thesis. The subsequent section presents a comprehensive outline of the conclusions drawn from the research described in the preceding chapters. The final section outlines suggestions and recommendations for future work.

7.1.1 Summary of achievements

The accomplishments of the thesis are summarized as follows:

- An analytical method was utilized to ascertain the time threshold marking the transition from linear flow to elliptical flow in a fractured vertical well within a tight gas reservoir. This approach can assist future researchers in precisely predicting the pressure behaviour during this transitional phase.
- Two new correlations were taken into consideration to present the pressure (or pseudo pressure function) in both the linear and elliptical flow regimes observed within a fractured vertical well located in a tight gas reservoir.
- A numerical method was introduced for estimating reservoir permeability and fracture half-length of vertical wells in Tight Gas Reservoirs (TGRs), particularly when there is a scarcity of well test data. This method captures elliptical flow patterns.

- A new set of type curves was developed using the correlation involving the "pseudo-steady constant" specifically designed for horizontal fractured wells in Tight Gas Reservoirs (TGRs), and recommended for estimating reservoir permeability, drainage area, and fracture half-length.
- A simplified methodology for the examination of pressure transient data in a hydraulic fractured horizontal well in a tight gas reservoir was presented. This approach involves employing a straightforward alteration in the fracturing analysis process.

7.1.2 Conclusions

1. The investigation was conducted with the aim of accurately predicting the transition from linear flow to an elliptical flow regime. Identifying this transition time enhances the depiction of reservoir parameters and aids in interpreting restricted data used in Pressure Transient Analysis (PTA). This knowledge enables the utilization of the appropriate method for characterizing flow regimes accurately.
2. The validity of the proposed analytical methodology was substantiated through the examination of two distinct scenarios: one using published data and the other employing synthetic data. In both cases, the outcomes displayed high accuracy when compared to a commercial simulation tool. This validates the potential application of the proposed model and its accompanying code for pressure transient analysis (PTA), thus affirming its credibility.
3. A restricted dataset depicting elliptical flow patterns can be utilised for conducting pressure transient analysis, thereby

acquiring fracture half-length and reservoir permeability for a vertically fractured well within a Tight Gas Reservoir (TGR). The suggested approach can be seamlessly integrated into a typical industrial setting and serves as a potent instrument, particularly beneficial for less-experienced engineers engaged in pressure transient analysis. The operational process of this tool is straightforward, easy to deploy, and capable of functioning effectively even with limited data.

4. Two novel correlations have been put forward for linear and elliptical flow regimes, grounded in actual field data from Western Australia and supported by sensitivity analysis conducted using commercial software. These correlations hold particular importance due to their pivotal role in future pressure-time analyses, facilitating accurate predictions of reservoir parameters with a high level of precision.
5. The validity of the proposed correlations was confirmed through verification using two distinct scenarios – one involving synthetic data generated by commercial software and the other utilizing real field data. In both instances, the correlations exhibited high accuracy with minimal errors. This robust performance suggests the potential application of the proposed correlations in future studies.
6. The introduced methodology involving type curves, built upon a modified correlation for the pseudo-steady constant, surpasses decline curve analysis and comparable pre-existing type curves. This approach stands as a practical substitute for reservoir simulation investigations in Tight Gas Reservoirs

(TGRs), particularly when confronted with restricted data availability.

7. A simplified methodology was proposed in this thesis, which can be considered a practical, credible, and robust approach to forecast the production over time from fractured horizontal wells in tight gas reservoirs, and can predict the pressure trend based on limited data.
8. The validity of the simplified equivalent well radius methodology was confirmed through its application to various reservoir simulation scenarios, which were then compared against a model constructed using actual data. These scenarios encompassed a broad spectrum of the number of fractures and fracture half-lengths. The validation process established that the suggested methodology effectively addresses the impact of fracturing by constructing an equivalent model via statistical analysis. This leads to a reliable approximate production forecast.
9. The drainage areas of wells within Tight Gas Reservoirs (TGRs) no longer exhibit constant boundaries; rather, they fluctuate over time due to the influence of low permeability.
10. The sensitivity analysis inferred that exceeding a certain threshold in the number of fractures would lead to a reduction in the likelihood of achieving incremental productivity. This decrease is primarily attributed to the interference caused by the expansion of the drainage area.

7.1.3 Recommendations

Academic and industrial research will persistently centre around tight gas reservoirs. The majority of existing techniques and tools employed for the analysis of Tight Gas Reservoirs (TGRs), spanning from initial prospect evaluation to the development of these fields, fall short of accurately encompassing the genuine conditions and underlying mechanisms. This is particularly evident in the challenge of precisely modelling the TGRs.

Specifically, the evaluation of prospects and the optimization of production performance in Tight Gas Reservoirs (TGRs) pose significant challenges. Addressing these challenges requires continuous research and development to address multiple gaps. The primary challenge addressed in this thesis revolved around the prolonged time needed for conducting reservoir simulations emphasising the reservoir engineering and practical field development perspectives.

Geomechanics plays a vital role in the effective development of tight gas fields, particularly when hydraulic fracture stimulation is required. Notably, alongside fundamental fracture parameters such as length, width, conductivity, and reservoir permeability, the efficacy of hydraulic fractured wells, whether vertical or horizontal, is closely connected to the aspects of fracture geometry such as size, shape, propagation behaviour, and the inherent characteristics of the fracture geometry itself. To accommodate the impact of these factors, it is imperative to incorporate a rock mechanical model along with the prevailing in-situ stress conditions. By integrating both geomechanical and numerical reservoir aspects, it becomes feasible to capture many of these critical elements that significantly contribute to reducing uncertainties. However, these dimensions are beyond the scope of this thesis. Further exploration is necessary to advance the models and techniques developed in this study while also considering these aspects for improved refinement. With that in mind, the following recommendations are put forth, specifically aimed at enhancing the current work through thorough research:

- Additional research could expand to include considerations of geomechanical factors, contributing to the further enhancement of all proposed developed models.
- All the presented models concentrate on tight gas reservoirs, specifically in tight sand formations, featuring very low permeabilities. Future investigations could be conducted to explore applications of these models in shale gas, shale oil, and/or tight carbonate reservoirs.
- Further avenues of study could encompass a comprehensive evaluation aimed at gauging the efficacy of the recently proposed sets of type curves. This evaluation would involve the analysis of production data specifically in the context of multistage fractured horizontal wells, with the intent of ascertaining the practical utility and reliability of these innovative curves.

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Appendix A: Script code for the VB.net program

The script code is shown below;

```
Imports System.Reflection
Imports System.Security.Cryptography.X509Certificates

Imports System.IO
Imports System.Numerics
Public Class Form1
    Public p(1000), m(1000), z(1000), v(1000), t(1000), ml, mel As Double, h As Double
    Public gg, ppc, tpc, pr, tr, Tf, k1, k2, k3, k4, m1, m2, A, B As Double, n As Integer
    Public k, phi, meo, cg, xf, ta, q, mel1, mel2, mel3, mel4, ml1, ml2, tb As Double
    Private Sub Button1_Click(sender As Object, e As EventArgs) Handles Button1.Click

        Dim i As Integer

        n = 0
        Tf = TextBox3.Text
        Dim lines = File.ReadAllLines("d:/infi.txt")
        For Each line As String In lines
            n += 1
        Next

        'MessageBox.Show(n)

        Dim pr(1000, 2) As String
        'Dim lines = File.ReadAllLines("d:/infi.txt")
        For i = 0 To n - 1
            Dim data = lines(i)
            Dim splits = data.Split(","c)
            For j = 0 To 1
                pr(i, j) = splits(j)
                'MessageBox.Show(i & "   " & j & "   " & pr(i, j))
            Next
        Next

        If ComboBox1.Text = "Pressure (Psia) vs Time (hr)" Then

            For i = 1 To n
                p(i) = pr(i - 1, 0)
                t(i) = pr(i - 1, 1)
            Next

            GroupBox1.Show()
```

```
        ElseIf ComboBox1.Text = "Time (hr) vs Pressure (Psia)" Then
            For i = 1 To n
                t(i) = pr(i - 1, 0)
                p(i) = pr(i - 1, 1)
            Next
        Else
        End If

    End Sub

    Private Sub Button2_Click(sender As Object, e As EventArgs) Handles Button2.Click
        Dim a1, a2, a3, a4, a5, a6, a7, a8, a9, a10, a11, tr2, tr3, tr4, tr5 As Double
        Dim ror, z0, z1, z2, z3, z4, z5, z6, z7, ror2, ror5, mg, x, y, ro As Double

        'MessageBox.Show(p(4))
        If ComboBox1.Text = "Pressure (Psia) vs Time (hr)" Or ComboBox1.Text = "Time (hr)
vs Pressure (Psia)" Then
            tpc = 756.8 - 131.07 * gg - 3.6 * gg ^ 2
            ppc = 169.2 + 349.5 * gg - 74 * gg ^ 2

            For i = 1 To n - 1
                pr = p(i) / ppc
                tr = (t(i) + 460) / tpc
                If ComboBox2.Text = "DAK" Then
                    a1 = 0.3265
                    a2 = -1.07
                    a3 = -0.5339
                    a4 = 0.01569
                    a5 = -0.05165
                    a6 = 0.5475
                    a7 = -0.7361
                    a8 = 0.1844
                    a9 = 0.1056
                    a10 = 0.6134
                    a11 = 0.721
                    tr2 = tr ^ 2
                    tr3 = tr ^ 3
                    tr4 = tr ^ 4
                    tr5 = tr ^ 5
                    z0 = 1
10:                  ror = 0.27 * pr / (z0 * tr)
                    ror2 = ror ^ 2
                    ror5 = ror ^ 5
                    z1 = a1 + a2 / tr + a3 / tr3 + a4 / tr4 + a5 / tr5
                    z2 = a6 + a7 / tr + a8 / tr2
                    z3 = a9 * (a7 / tr + a8 / tr2)
```

```
            z4 = a10 * (1 + a11 * ror2)
            z5 = ror2 / tr3
            z6 = Math.Exp(-a11 * ror2)
            z7 = 1 + z1 * ror + z2 * ror2 - z3 * ror5 + z4 * z5 * z6
            If (Math.Abs((z7 - z0) / z7) > 0.01) Then
                GoTo 10
            Else
                z(i) = z7
            End If
        End If
        If ComboBox3.Text = "Lee et al" Then
            mg = 28.97 * gg
            ro = 0.001494 * p(i) * mg / (z(i) * (Tf + 460))
            k2 = 0.00094 + 2000000.0 * mg
            k3 = (Tf + 460) ^ 1.5
            k4 = 209 + 19 * mg + (Tf + 460)
            k1 = k2 * k3 / k4
            x = 3.5 + 986 / (Tf + 460) + 0.01 * mg
            y = 2.4 - 0.2 * x
            v(i) = k1 * Math.Exp(x * ro ^ y)
        End If
        m1 = 2 * p(i) / (v(i) * z(i))
        If i = 1 Then
            m2 = p(i) - 0
            m(i) = m1 * m2
        Else
            m2 = p(i) - p(i - 1)
            m(i) = m1 * m2
        End If

    Next

End If

k = TextBox1.Text
phi = TextBox2.Text
meo = TextBox3.Text
cg = TextBox4.Text
xf = TextBox5.Text
q = TextBox6.Text
h = TextBox7.Text
Tf = TextBox8.Text



ta = 100
```

```
20:    B = 0.02878 * Math.Sqrt(k * ta / (phi * meo * cg))
        A = Math.Sqrt(B ^ 2 + xf ^ 2)
        mel1 = 1422 * q * (Tf + 460) / (k * h)
        mel2 = Math.Log((A + B) / xf)
        mel3 = Math.Sqrt(B ^ 2 / xf ^ 2)
        mel4 = Math.Sqrt(1 + B ^ 2 / xf ^ 2)
        mel = mel1 * mel2 * Math.Log(mel3 + mel4)
        ml = mel
        ml1 = h * xf * Math.Sqrt(k * phi * meo * cg)
        ml2 = 40785 * q * (Tf + 460)
        tb = (ml1 * ml / ml2) ^ 2

        If Math.Abs((tb - ta) / ta) < 0.01 Then
            GoTo 20
        Else
            Label13.Text = "Time to reach elliptical flow for this case is: " & tb & " hr"
        End If


    End Sub

End Class
```