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Modelling of Geomechanics for Informed Hydraulic Fracturing Operations

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Modelling of Geomechanics for Informed Hydraulic Fracturing Operations

by

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A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
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Abstract

Multistages hydraulic fracturing of horizontal wells has been an integral part of natural Canadian resources, such as shales and tight gas reservoirs. In the hydraulic fracturing process, long horizontal well divided into several stages to access much larger volume of oil and gas in low permeability/porosity formations. Then the hydraulic fracture fluid is pumped into each stage to initiate and propagate the fractures around the well which increase the porosity and permeability of the formation. Although, the technology has greatly improved in the past decade to enhance the production from unconventional reservoirs, still several uncertainties can cause failure. Therefore, without geomechanical considerations, the predicted design of hydraulic fractures may not be completely accurate. Then understanding the reservoir rock mechanics and their spatial heterogeneity as well as stress profiles have a major impact on the reliable decisions in fracturing design optimization. In most simulation models, geomechanical properties are assumed to be homogeneous throughout the reservoir. In this study, the heterogeneity of geomechanical properties is demonstrated by using geomodeling. A three-dimensional (3D) earth model was built by integrating both petrophysical and geological log data using more than 200 wells in the study area. Then, the state-of-stress prior to hydraulic fracturing is estimated by using geological log data to create a geomechanical model from near surface to below the Montney FormationFormation. The model includes dynamic elastic properties and rock strength property distributions in both vertical and horizontal directions within the reservoir. To determine elastic rock properties, changes in compressional and shear velocity through all the layers of the reservoir rock were taken into consideration. A workflow was developed to constrain well properties to derive realistic rock property values and distributions even in areas where only limited well log
information exist. Then Petrel/Visage software package used to evaluate stress changes within the Montney Formation. Since this formation has very low permeability with complicated geological settings, the knowledge of geomechanical and geological properties, stresses magnitude and orientation, completion and production data is essential to evaluate the fracture volume and conductivity. In this research study, we presented an unconventional reservoir simulator and the critical parameter to quantify multistage hydraulic fracturing in the Montney Formations. Data from a detailed core analysis and various field logs are used to achieve a history match of initial production data from the liquids rich Montney well production within the study field.
Preface

This is a paper-based PhD thesis and the contents of the papers have been formatted to meet the University of Calgary's thesis requirement. I greatly appreciate the contribution of the co-authors in reviewing the work and providing directions. In particular, I would like to acknowledge my supervisor, Dr. Ian Gates for the significant guidance he provided during the process of publishing these papers. The thesis was carried out to present a comprehensive workflow on multistage hydraulic fracturing with considering the geomechanical aspects in Montney Formation, Alberta, Canada. List of original publications arising from the research documented in this thesis:


This paper is presented as appendix I, since its property does not follow the thesis workflow.
Acknowledgements

When I started my PhD studies on geomechanical effects of hydraulic fracturing treatment, I knew very little about the two main aspects involved in the research: Geomechanics and hydraulic fracturing. With completion of this degree, although there's still a lot to learn in these fields, I feel grateful for the given opportunity to explore and learn about this subject which is drawing more attention every day in the oil and gas industry. This would have been impossible without contribution and supervision of Dr. Ian Gates. I would like to express my deepest appreciation to him for all he has taught me, not only in scientific but also in personal life. I want to express my special thanks to Ian for giving me the wonderful opportunities for self-improvement in the warm and friendly environment. I definitely enjoyed the years of studies and research under his supervision whose great support with infinite patience has significantly influenced this work. I would like to sincerely acknowledge his valuable guidance, relentless support, discerning thoughts and loads of inspiration that led me forward to delve deeper into the issue. Deep appreciation is also extended to Dr. Geir Hareland for giving me the opportunity to work as a member of his team. He has helped me learn about the geomechanics aspect of my research. My gratitude is also due to the members of my supervisory committee, Dr. Chris Clarkson, Dr. Hossein Hejazi, Dr. Ron Wong and Dr. Hassan Hassanzadeh for their invaluable comments and suggestions during different stages of this work. I would also like to thank Mr. Li Qiuguo and Dr. Alexey Zhmodik from Schlumberger Company for training the software, step by step, also special thank for their helpful advices during completion of the Geomechanical study. I would like to thank Dr. Ahmed Abou-Sayed, Technical director production and
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Dedicated to……

My husband
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List of Symbols, Abbreviations and Nomenclature

\( E \) = Young’s Modulus, GPa
\( \nu \) = Poisson Ratio
\( \rho \) = Bulk Density, g/cm\(^3\)
\( \varphi \) = Porosity, m\(^3\)/m\(^3\)
\( K_I \) = Fracture toughness, kPa.m\(^{0.5}\)
\( \text{UCS} \) = Unconfined Compressive Strength, MPa
\( \mu \) = Friction Coefficient
\( C_t \) = Rock Compressibility, KPa\(^{-1}\)
\( p(x, y) \) = fluid pressure, MPa
\( \sigma_h(x, y) \) = minimum in-situ stress, MPa
\( C(x, y, x', y') \) = complex stiffness function
\( W(x', y') \) = fracture opening width, L, mm
\( A \) = surface area of the fracture, m\(^2\)
\( q_x, q_y \) = flow rate/unit length in the fracture
\( c_t \) = fluid leakoff coefficient
\( c \) = volume concentration of the proppant, kg/m\(^3\)
\( v_p \) = the velocity of proppant, m/min
\( h_i \) = L, m
\( P_{cp} \) = fluid pressure at a reference depth, MPa
\( \rho_f \) = fluid density, g/cm\(^3\)
\( E' \) = plane strain modulus, MPa
\( m \) = total number
\( \sigma_1 \) = maximum horizontal stress, MPa
\( \sigma_2 \) = minimum horizontal stress, MPa
\( \tau \) = shear stress, MPa
\( C \) = cohesive strength, MPa
\[ \tau(t) = \text{shear stress}, \text{MPa} \]
\[ \sigma_m(t) = \text{effective normal stress}, \text{MPa} \]
\[ \phi = \text{friction angle}, \text{deg} \]
\[ \alpha = \text{Biot's constant} \]
\[ \Delta t_c = \text{compressional travel time, \mu s/ft} \]
\[ \Delta t_s = \text{shear travel time, \mu s/ft} \]
\[ M = \text{compressional modulus, MPa} \]
\[ G = \text{shear modulus, MPa} \]
\[ \bar{\rho} = \text{mean overburden density, g/cm}^3 \]
\[ S_{H0} = \text{tectonic stress parallel to the maximum horizontal stress, MPa} \]
\[ S_{ho} = \text{tectonic stress parallel to the minimum horizontal stress, MPa} \]
CHAPTER ONE: INTRODUCTION

Recently, unconventional tight resource plays have attracted more companies particularly in North America. These reservoirs require hydraulic fracturing to be commercially productive. At this point, it remains unclear as to the influence of geomechanical properties on fracture stimulation and its effective permeability, nature of the fractured zone (whether single extensive fracture or a network), and extent of fractured zone. An understanding of the geomechanical properties and their spatial heterogeneity can be used to guide productivity in these reservoirs. In most simulation models, geomechanical properties are assumed to be homogenous throughout the reservoir.

The research documented in this thesis focuses on the heterogeneity of geomechanical properties of tight rock reservoirs and in particular, the Montney Formation in Alberta, Canada and its impact on hydraulic fracturing. Formation heterogeneity, together with the bounding loads, results in the spatial distribution of stress in the reservoir. Under loading, microfractures may nucleate within the reservoir rock and eventually coalesce to form conductive channels which change the flow properties of the formation. Efficient management and production of these types of reservoirs require access to the underlying spatial distribution of geomechanical and flow properties and for predictive design, an accurate tool to simulate both the mechanical and flow behavior. In this research, geospatial models of the mechanical properties of rock will be constructed and examined to map the stress properties in three dimensions and to model fracture onset and growth and its resulting permeability variations and production properties of the reservoir rock. A workflow was developed to constrain well properties to derive realistic rock property values and
distributions even in areas where only limited well log information exist. Well log data has been collected from more than 250 horizontal and vertical wells in 15 by 15 kilometers to obtain a sufficient number of wells to construct the earth model. However, we report on the mechanical properties of tight siltstone reservoir rocks collected from eighteen wells in the Montney Formation, located in Western Alberta, Canada. We present a data set describing the mechanical behavior of Montney rocks, including dynamic elastic properties and their anisotropy within the reservoir. We also display these data in the context of three-dimensional (3D) earth models to better understand the spatial distribution of rock geomechanical properties. Gamma ray/ Density log as well as sonic logs are the main properties log which used in this study. Then the minimum and maximum horizontal stresses map have been created using Visage/ Petrel software package. Stress magnitude as well as elastic and plastic rock properties dictate the mode, orientation, and size of the hydraulic fracture network which is created by Mangrove/Petrel software package. Figure 1.1 shows the workflow of the presented study.
Figure 1.1 Thesis workflow.

Input:
- Sonic Logs/ Density and Gamma ray Logs

Estimate the petrophysical/Geological and Rock Mechanical Data

Create the Maximum/Minimum and Vertical Stresses Profiles

Hyrdaulic Fracturing Data

Gas/Oil flow rates for last few years

Evaluate the Fracture Conductivity

Evaluate the Permeability Data

History Matching of Production Data

Output:
- Improve Performance Prediction Based on the New Fracture Geometry
1.1 Background

Hydrocarbon production from unconventional reservoirs has transformed the oil and gas industry in North America. The unconventional reservoirs common attribute is that the permeability of the matrix is ultra-low where the permeability often has been improved by natural fractures or induced hydraulic fractures. Hydraulic fracturing creates highly conductive pathways for hydrocarbons from the reservoir into the wellbore. At high pressure, fracturing fluid which includes proppant, water, and chemicals is pumped downhole to the wellbore. Once the pressure exceeds the fracture initiation pressure, the fluid begins to break the rock and fracture form and propagate perpendicular to the direction of the minimum stress. After pumping has terminated, the pressure falls below the fracture pressure and the generated fractures close. Proppant is used to sustain the fracture and keep the channel open. Due to the complexity of unconventional reservoirs, it is challenging to predict the initiation and propagation of induced hydraulic fractures. For example, the complex principal stresses state and distribution as well as the heterogeneity of rocks properties, which may change the profile of hydraulic fractures (Gu, Siebrits, and Sabourov 2008); the existence or the arbitrary pre-existing interfaces may diversify or arrest hydraulic fractures (Zhang et al. 2010); the temperature effect (Ribeiro and Horne 2013); and the fluid loss and transport of proppant (Adachi et al. 2007). Thus, it is crucial to explore how hydraulic fracturing process will happen in complex geological settings. Geological data and its response to hydraulic fracturing can be obtained from experiments or/and field study. Since the laboratory study can perform on small-scale rock samples with several centimetres to large ones with one metre or more, it is easy to control the stress conditions and make
artificial structures. Especially in large scale experiments, it is possible to build a full size borehole, or to control the development of hydraulic fractures, and the hydraulic fracture geometries can be obtained (Haimson 1981). Field study is much more complex because the mechanical behaviours and geologic conditions and in-situ stress fields are different (Warpinski 1996). Although the laboratory experiments can be controlled easily and repeated several time getting the samples from some formation like Montney are difficult and expensive. Many methods can be used to evaluate hydraulic fractoring directly from field data. For example, historical production data such as bottomhole pressure and wellbore pressure losses have been used to understand the fracturing process (Johnson and Greenstreet 2003); sonic anisotropy and radioactive tracer logs have been used to analyse hydraulic fracture geometry (Scott et al. 2010); and integrating resistivity and acoustic imaging have been used to evaluate dominant fracture azimuths and borehole features (Johnson et al. 2010). Besides of these methods, some commercial codes which can apply the field or logs data are available to predict the fracture geometry and fracture behavior (Taheri Shakib 2013; Zhang et al. 2010; Mahabadi et al. 2012; Morris and Johnson 2007; Settari 1980).

In unconventional reservoirs the productivity of a well increases as a result of improved fracture conductivity with increasing the fracture permeability and fracture width. Based on the literature, it is widely known that formation properties and rock elastic properties have a strong impact on the hydraulic fracture conductivity. Therefore, knowledge of formation properties as well as completion procedures are necessarily to design the hydraulic fracture treatment. There are several critical parameters which affect the successful and sustained fracture conductivity. Among them the most important ones are: proppant type and
concentration, rock mechanical properties, and closure stress. More specifically, surface roughness, hardness, and elastic properties are rock mechanical properties that have been studied in connection to fracture conductivity (Zoorabadi et al. 2015). Although proppant is usually applied to sustain the generated fracture width, its embedment is a common phenomenon that has an adverse effect on the rock’s surface and fracture conductivity. The soft and ductile feature of shale formations often leads to proppant embedment and decrease in fracture conductivity (Mueller, Amro, and Freiberg 2015). Therefore, designing the best proppant type, proppant concentration, proppant durability, and fracture fluid are considerable factors that affect this improved conductivity (Chapman and Palisch 2014). The rock mechanical properties have a significant impact on fracture conductivity as well as the behavior of proppant used to sustain the fracture.

The study of the relationship between the rock mechanical properties and fracture conductivity is meaningful because a better understanding will improve productivity and reduce costs of operation, specially when the cost of hydraulic fracturing treatment per well is routinely millions of dollars (Knorr 2015).

1.2 Research Objectives

The main goal of the proposed research is to simply model the fracture propagation in unconventional reservoir shale gas. To elaborate more, the objectives of the research study may be listed as follows:
1. To investigate rock mechanical properties at different depth using different existing models and generate a 3D earth model to build a map of these properties through the reservoir.

2. To determine stress direction and orientation at different depths of reservoir and build a three-dimensional (3D) earth model to map stress values and directions at any point of the reservoir.

3. To model a single stage of hydraulic fracturing using the Universal Fracture Model based on the 3D earth model based on the stress distribution and rock properties in the reservoir and then history match the reservoir model with field production data.

4. To model nineteen stages of hydraulic fracturing us to determine the variability of hydraulic fractures in the reservoir.

5. To establish a workflow for analysis of hydraulic fracturing in tight reservoirs.

1.3 Thesis organization

This thesis is based on a collection of papers, submitted or published during the course of this study. All chapters with the exception of Chapter 1, 2 and 8 are extracted from the research papers.

Chapter 1 provides a background on this research work by stating the objectives and describing how this thesis is structured. Chapter 2 deals with the literature review and comprises of nine sections. In the first section hydraulic fracturing history is briefly touched upon. Since the main purpose of this work project revolves around unconventional
reservoirs, formation properties of this reservoir type is reviewed next. The third part focuses on the geomechanical characterization of the reservoir. Because most hydraulic fracture simulator use basic two-dimensional (2D) models to create the fracture plane, the fourth section describes use of the most commonly-used 2D hydraulic fracturing models in details. In the fifth section, the history of multistage hydraulic fracturing technology history is presented. The sixth section focuses on shale gas productivity and seventh part reviews the available commercial methods. In Section eight, the fracture model input parameters are presented. The last section highlights missing gaps in the literatures.

Chapters 3 is included of the publications abstracts. In Chapter 4, we present integrated geological, geophysical, and geomechanical data in order to characterize the rock properties in our Montney study area which is located in Northwest of Alberta, Canada. The variation of stresses at different depth of the reservoir investigates and the stress state in the reservoir before hydraulic fracturing is modeled in Chapter 5. Geomechanical effects on one stage hydraulic fracture conductivity disclose in Chapter 6. Multistage hydraulic fracturing (nineteen stages) and history matching with the production field data is discussed in Chapter 7. Chapter 8 summarizes the main conclusions and recommendations for future work.
CHAPTER TWO: LITERATURE REVIEW

2.1 Introduction

Hydraulic fracturing of tight rock reservoirs is critical for economical extraction of oil and natural gas. This technology was introduced to the oil and gas industry in the 1930s when Dow Chemical Company found that cracks formed when fluid pressure was applied within a rock formation (Adachi et al. 2007). Later, in 1947, the first hydraulic fracturing stimulation treatment was conducted to increase well productivity in the Hudson gas field in the state of Kansas, U.S.A. (Howard and Fast 1957). By 1955, there were about 3,000 fractured well treatments conducted each month to stimulate increased petroleum production from tight rock reservoirs (Hubbert and Willis 1957). In the last decade, hydraulic fracturing has revolutionized oil and gas production and the technology has developed rapidly with deployment of multistage hydraulic fracturing in unconventional oil and gas reservoirs.

2.2 Unconventional reservoirs

In general, unconventional reservoirs refer to low mobility oil and gas reservoirs. This can be due to both high viscosity of oil (e.g. heavy oil and oil sands reservoirs) or low permeability formations (e.g. tight rock oil and gas reservoirs). More recently, the term ‘unconventional reservoirs’ has referred to tight rock reservoirs where the permeability of the rock is typically less than 1 mD and often lower than 0.1 mD (Byrnes 1996). Tight rock reservoirs often have complex geological properties and in situ stress behavior since they
tend to be deep (ENB 2011; Pang, Jia, and Wang 2015; Li et al. 2015). To release the petroleum that is held in the pore space of these tight rocks, these reservoirs have to be artificially fractured to provide sufficient permeability so that economic rates of petroleum fluid production can occur.

In general, unconventional gas resources are divided into two broad types: 1. shale gas (sometimes referred to as tight gas) and 2. coal seam gas (Gu, Siebrits, and Sabourov 2008). Coal seam gas, also referred to as coal bed methane, is contained within tight coal seams whereas shale gas is usually found in mudstone and shale. In these reservoirs, there are often interlayers of sandstone and/or limestone and the gas is often stored in these surrounding rocks as well. The focus of the research documented in this thesis is on tight shale and in particular, shale gas reservoirs. In shale, the permeability typical ranges from 0.00001 to 1 mD.

It is a real challenge to optimize hydraulic fracturing in tight rock. This is because models are complex integrating geomechanics, fluid flow, fluidization of proppant, mass and heat transfer, and dynamics and take extensive computation run time. Also, experiments are difficult to conduct – often the rock pressures for tight formations is high, typically greater than 50 MPa and thus fracturing experiments to optimize the operation is very difficult since it is hard to use physical models with the initial state of stress on the rock (as is in the reservoir) and crack it in a lab especially at realistic length scales. The prediction of initiation and propagation of hydraulic fractures in a target formation is challenging since the physics of these processes are not fully resolved and there are many uncertain parameters that have
to be determined for unconventional reservoirs. For example, not only are the initial state-of-stress uncertain in these formations but so too are the spatial distributions of geomechanical properties such as the Young’s modulus and Poisson’s ratio. Thus, populating geospatial models with both geological properties (e.g. porosity, initial permeability, fluid saturations), rock-fluid properties (e.g. relative permeability and capillary pressure curves), and geomechanical properties inherently includes uncertainty and thus predictive modelling is difficult. Thus, design and modelling of hydraulic fracturing treatment is challenging and optimization of production from tight rock resources is an ongoing difficulty faced by operators.

Figure 2.1 presents shale basins through North America sourced from the U.S. Energy Information Administration. The map reveals that there are substantial shale resources within North America and this is why hydraulic fracturing has changed petroleum production globally. The U.S. over the past few decades was importing oil and gas to supply its needs but due to the ability to produce petroleum from tight rocks, the U.S. is now an exporter of petroleum and this will likely remain the case for many years.

For analysis of tight shale gas reservoirs, the specific reservoir that has been focused on in this thesis is the Montney Formation in Northwest Alberta, Canada. The properties of this resource is described in the following sections.
2.2.1 Properties of Shale

The mineralogy of the formation is a primary control of the pore network in unconventional tight rock reservoirs. In general, the porosity increases with more clay and detrital quartz content and decreases with more carbonate and biogenic quartz content (Euzen 2011). Mineralogy also has a major impact on the mechanical properties of the rock which
consequently presents a major control on the size, orientation, and effective permeability of the fracture network created during hydraulic fracturing.

In general, shale refers to sedimentary rocks made up of clay-size particles (less than 4 microns) although, typically, the mineralogy varies widely within a single resource and especially between different shale gas plays (Ghanizadeh et al. 2014). There are several factors which affect the mineralogical composition of shales: the source of clastics, mechanical and chemical weathering during erosion, transport and deposition of sediments, as well as biogenic production, and digenetic transformations. These parameters vary both horizontally and vertically within the rock (Euzen 2011). Shale is a mixture of quartz, feldspars, clays, carbonates and additional minerals (pyrite, apatite, hematite, anhydrite, etc.). The relative amounts of these components vary in different shale formations; some shales have low quartz content but are clay-rich such as the Ohio Formation and carbonate-rich such as the Second White Specks, Utica, or both like the Eagle Ford and Haynesville Formations. Other shales such as the Montney Formation in Alberta, the Devonian in Northeast British Columbia, and Mancos have relatively low carbonate content (Muki 2012). In the other formations such as the Barnett and Marcellus shales, a wide range of mineralogical composition exists with siliceous mudstone, calcarceous mudstones, and clay-rich shales (Mitra, Warrington, and Sommer 2010). Clay-rich shales are more ductile and tend to deform instead of breaking under stress (Rickman et al. 2008).

Castle et al. (2006) collected rock mechanical data from 23 laboratory measurements of Young’s modulus and 32 measurements of fracture intensity factor from different
formations. They reported that the Young’s modulus of shale ranged from 0.06 to 9.9 Mpsi (0.41 to 68.25 MPa) with an average of 2.5 Mpsi (17.23 MPa). The shale fracture toughness ranges from 220 to 1177 psi (1.5 to 8.11 MPa) with an average of 721 psi (4.97 MPa) (Castle et al. 2007).

2.2.2 Characterization of the Montney Formation

The Montney Formation, in western Alberta and northeast British Columbia, consists of shallow water sandstone in the east and deep-water mudstone in the west (Ghanizadeh et al. 2015b). Since the lithofacies of the Montney Formation are mostly shale and siltstone with varying degrees of dolomitization, it is not truly a shale gas reservoir in the strictest sense. Fine-grained sandstones and coquinas are also found in the upper part of the siltstone-dominated succession (Rivard et al. 2014). The Doig Formation sits above the Montney Formation and consists mostly of water sands and muds that filled the remainder of the Montney Basin.

The lithology of the Montney Formation consists of organic-rich and organic lean sandy siltstone to silty sandstone with occasional thin shale with thin coquina and phosphate layers (Muki 2012). Therefore, the most accurate description of the Montney “shale” is that it is generally considered a siltstone. The Montney siltstone has low porosity (<10%) although the associated sandstone porosity can be as high as 35%. The Montney lithofacies are clay-poor with content values less than 20% with high content of quartz, carbonates and feldspars (Rivard et al. 2014). In some areas of BC, the Montney is being actively developed for
liquids, with gas being a by-product (Rivard et al. 2014). The Montney Formation is divided into two major parts based on its lithology: the Upper Montney and the Lower Montney. In the East, the sequence boundary separating the Upper and Lower underlies a laterally discontinuous dolomitic coquina, and basinward toward the West, this boundary underlies the turbidite coarser facies of the lowstand systems tract in the Upper Montney (Moslow 2001).

The thickness of the Montney Formation increases from 0 m (surface) in the West up to 300 to 400 m in both Alberta and British Columbia. The depth to the top of the Montney increases in the same direction from approximately 500 m in the east to over 4000 m in the west (Rivard et al. 2014). The average of total hydrocarbon content of the Montney is 0.8%, with a range of 0.1 to 3.6% (Muki 2012). Figure 2.2 displays the major intervals in the Montney unit located in the provinces of British Colombia and Alberta.
Figure 2.2 Cross section H-H’, northeastern British Columbia to west-central Alberta. Datum is the top of Halfway Formation, except at the extremities, where the sub-Jurassic unconformity is used as datum (Edwards et al. 2003).

2.3 Geomechanical characterization

For tight rock reservoirs, an understanding of geomechanics is important to optimize drilling, completion and stimulation of shale gas reservoirs. Knowledge of rock properties and in situ stresses in the target formation are necessary to predict the characteristics of hydraulically induced fractures. In typical practice, two elastic properties, the Young’s modulus and Poisson’s ratio, are used by the industry to quantify shale fracability. Poisson’s ratio is the ratio of transverse strain over axial strain and Young modulus is the ratio of stress over strain.
Rock with lower Poisson’s ratio is more brittle whereas rock with higher Young modulus requires more stress to achieve a given amount of strain. (Euzen 2011).

Shale brittleness, defined as the ratio of quartz content and quartz+carbonates+clay content, is an important factor for hydraulic fracture stage design because it has a direct impact on the geometry of the fracture network generated by hydraulic fracturing (Sondergeld et al. 2010). There are some methods to extract the brittleness from Young’s modulus and Poisson’s ratio (Rickman et al. 2008). Rock properties are divided into two types: static and dynamic. Static rock properties can be obtained from laboratory measurements while dynamic elastic properties are calculated from compression velocity, shear velocity and density and gamma logs (Mullen et al. 2007, ). In the absence of sonic logs, Mullen et al. (2007) proposed a method to derive dynamic rock mechanical properties from conventional logs using multiple petrophysical relationships and neural network methods. Vishkai et al. (2017) proposed a method to estimate dynamic rock mechanical properties from the gamma and neutron density logs. Static Poisson’s ratio and Young modulus can be measured in the lab by triaxial compression tests on core samples. Gray et al. (2010) used seismic inversion to calculate rock elastic properties and in situ state of stress within the Colorado shale in central Alberta. In their method, they used seismic inversion of hydraulically fractured region to generate visualizations of the network and to estimate fractures directions.

Other important geomechanical parameters are the three principal stresses: vertical stresses and minimum and maximum horizontal stresses. These stresses can change during well drilling, the fracturing treatment, as well as the production process. Fracture network
evolution, both direction and extent, is controlled by the stress profile which in turn, depends on the rock’s elastic properties, lithostatic pressure (vertical stress), tectonic stress, and pore pressure.

Closure pressure as well as break down pressure are other significant factors in hydraulic fracturing design. Closure pressure is the minimum pressure theoretically needed for opening fractures in the reservoir whereas the breakdown pressure is higher than closure pressure and represents the pressure at which unstable fracture propagation away from a wellbore occurs. The in situ stress distribution can control fracture orientation and geometry and determine the fluid pressure required to open a fracture (or fracture width) during the hydraulic fracturing process. In an isotropic media, the fracture will always open against the minimum horizontal stress and propagate in parallel with the maximum horizontal stress (Fox et al. 2013; Zoback et al. 2003). The minimum horizontal stress is also affected by the fluid pressure which controls the fracture opening (fracture width).

Current stress regimes have a strong impact on the magnitude and orientation of the tectonic stress. Figure 2.3 shows the influence of the stress regime on stress anisotropy in Barnett shale (Figure 2.3a), Marcellus shale (Figure 2.3b), and Montney shale (Figure 2.3c) (Euzen 2011). In the Barnett shale, as shown in Figure 2.3a, the normal faulting regime induces limited stress anisotropy and breakdown pressure varies only slightly with azimuth while in the Montney shale, the strike slip/reverse stress regime results in the highest stress anisotropy and well orientation will have a strong impact on wellbore stability and hydraulic fracturing.
Figure 2.3 Stereo plot shows the influence of stress regime on stress anisotropy and magnitude. Color scale is proportional to fracture breakdown pressure.

Shale reservoirs are often heterogeneous with several planes of weakness such as bedding planes and natural fractures. Reactivation of bedding planes and natural fractures can divert the induced hydraulic fracture growth when the normal growth path is parallel to the maximum horizontal stress (Gale et al. 2007).

2.4 Hydraulic fracturing

Although the presence of gas in shale has been known for many years, it was not possible to produce the gas volume hosted in these resources until the combination of horizontal drilling and hydraulic fracturing made it technically and commercially recoverable. In conventional hydraulic fracturing, the target interval is isolated initially and then fracturing fluid is injected with high flow rate into the target interval until tensile fracturing occurs. Thereafter,
the slurry containing proppant is injected into the opened fractures to continue fracture propagation as well as to provide sufficient space for fracture conductivity after fracture closure (Nassir et al. 2013).

Unconventional fracturing applications are usually characterized by high fluid leak-off from the fracture into the reservoir which substantially alters the stress profile, pore pressure, permeability, and porosity around the main fractures in the reservoir (Cottrell 1983; Settari and Warren 1994). Therefore, the interactions of geomechanical aspects of the porous media and reservoir fluid flow have to be investigated to understand hydraulic fracturing.

The first model to demonstrate a coupled relationship between fluid flow and elastic response of the rock formation was presented by Khristianovich and Zeltov (1955). Later in 1957, Hubbert and Willis revealed how to define the state of in-situ stress as well as the preference of fracture propagation direction, in the plane perpendicular to the minimum stress (Hubbert and Willis 1957). In 1957, Howard and Fast and Carter provided the framework for the current understanding of fluid leak-off volume (Howard and Fast 1957). Shortly after, Perkins and Kern published their analysis of radial, penny shaped vertical fractures. They also considered turbulent flow and non-Newtonian fluids as well as the role of rock toughness (Perkins and Kern 1961). In 1972, Nordgren added leak-off and storage width to fracture models and presented the PKN model (Nordgren 1972). Another significant early work on fracture modeling was accomplished by Geertsma and de Klerk in 1969 which is called the KGD model. They used the Carter equation to include leak-off in the fractures
model (Geertsma and De Klerk 1969). The KGD and PKN models are two-dimensional (2D) models and are typically referred to as first generation fracture models.

Given the relationship of injected volume versus fracture extent as indicated by first generation fracture models, fracture treatments evolved into massive hydraulic fracturing treatments. Massive hydraulic fractures (MHF) are designed to enhance oil and gas recovery from low permeable reservoir formations where the treatments are designed to create fractures as far as 1000 m radially from the wellbore and generally require up to 1000 m$^3$ of fracture fluid (Teufel and Clark 1984). MHF was developed by trial and error and results from the treatment were often uncertain where some operations were successful whereas others were failures. Among the many technological problems encountered in MHF, one of the most important issues was the determination of the geometry and volume of the stimulated reservoir volume (Eekelen 1982).

TipScreenOut (TSO) was another generation of hydraulic fracturing technology sometimes referred to as third generation hydraulic fracturing operations (Oberwinkler et al. 2013). Screenout is defined as the condition which happens when the proppant creates a bridge across a restricted flow area creating a sudden and significant restriction to fluid flow that causes a rapid rise in pump pressure (Oberwinkler et al. 2013). The purpose of TSO is to generate short and wide fractures which have high permeability (Nolte and Morris 2000). In this method, the slurry is pumped into the rock at high flow rate. The tip of the fracture fills with sand, retarding fracture propagation. Therefore, the process screens out the tip of the fracture with sand. The slurry continues to be pumped into the fracture increasing fracture
width and packing the fracture with proppant to obtain high conductivity (Smith and Haga 1987). But this method may not be successful because of the early screenout or failure to achieve screenout. Both of these failure conditions can cause well damage or undesirable consequences.

To avoid fracture failure, pretreatment tests need to be conducted to accurately determine fracture design variables. Although the above models are effective at estimating fracture geometry, they also have assumptions that limit the applicability of the models. Therefore, three-dimensional (3D) models were developed to design fracture treatment procedures to address the limitation associated with the 2D models (Castle et al. 2007).

2.4.1 Fracture models

Fracture models have been developed to integrate critical formation data to predict fracture geometry so as to optimize well placement and stage design to achieve the maximum possible oil and gas productivity. Mack and Warpinski (2000) described that historically that there are four main reasons that hydraulic fracturing models have been created: (1) to simulate fracture geometry and proppant placement; (2) to design a pumping schedule; (3) evaluate how hydraulic fractures affect well performance, and (4) to perform an economic optimization.

There are many studies that have been conducted to simulate fracture geometry and fracture network size. 2D models represent the first generation of fracture models and they assume
that the height is constant and the fracture only varies in length and width (Veatch and Moschovidis 1986). Those models include major assumptions and limitations. For example, constant fracture height and homogeneous rock properties and no input for the initial state of stress. Although 3D models were developed to account for vertical fracture growth, the fundamental assumptions of 2D models have been often applied in 3D models.

2.4.1.1 Two-Dimensional Fracture Propagation Models

The simplest analytical models for fracture propagation were developed in the 1940s and 1950s, and followed by development of the most used 2D models in the 1960s. In general, 2D fracture models are based on the assumption that the fracture surface deforms in a linear elastic manner. Fracture mechanics specifies the fracture shape as a function of fluid pressure in that fracture (Howard and Fast 1957). The continuity equation for transient fluid flow in one dimension for the rectangular fracture is given by (McClure 2012):

\[
\frac{\partial Q}{\partial x} + \frac{\partial A}{\partial t} + Q_{\text{loss}} = \frac{\partial Q}{\partial x} + \frac{\pi h_f}{4} \frac{\partial w}{\partial t} + Q_{\text{loss}} = 0
\]  

(2.1)

where \( h_f \) is a fixed fracture height, \( Q \) is the flow rate (volume per unit time) through a cross section which is related to the fluid pressure gradient, and \( A \) is the cross-sectional area of the fracture. \( Q_{\text{loss}} \) is the volume rate of fluid loss to the formation per unit length of fracture which is determined by the flow fluid of the losses into the surrounding porous medium as governed by Darcy’s law (Perkins and Kern 1961). Equation 2.1 is a general equation used in all models while the width, \( W \), is estimated from different models each with its own
assumptions. The fracture is driven by an incompressible Newtonian fluid injected at a constant rate at the perforation zone as shown in Figure 2.4. A description of different models is presented in the following.

![Figure 2.4 Sketch of a Plane-strain fluid-driven fracture.](image)

- **Sneddon & Elliot Model**

In 1946, Sneddon and Elliott modified the theory of cracks in a two-dimensional elastic medium which was developed by Griffith who succeeded in solving the equations of elastic equilibrium in two dimensions for a space bounded by two concentric coaxial ellipses. (Sneddon and Elliott 1946). They solved the equations for the stress field and pressure associated with static pressurized cracks:

\[
W_{\text{average}} = \bar{W} = \left(\frac{\pi}{4}\right) W(0, t) \tag{2.2}
\]

\[
W(0, t) = \frac{2P_{\text{net}} hf(1-v^2)}{E} \tag{2.3}
\]
where $\bar{W}$ is the average value of the fracture width, $W(0,t)$ is the fracture width at the wellbore, $P_{\text{net}}$ is a fracture net pressure, $h_f$ is the fracture half-length, $E$ is the rock Young’s modulus and $\nu$ is Poisson’s ratio. They showed that the width of a static penny-shaped crack of radius $R$ under constant pressure is given by the expression:

$$W(r) = \frac{8P_{\text{net}} R (1-\nu^2)}{\pi E} \sqrt{1 - \left(\frac{r}{R}\right)^2}$$

(2.4)

and volume is given by:

$$V = \frac{16(1-\nu^2)R^3}{3E} P_{\text{net}}$$

(2.5)

and

$$P_{\text{net}} = \sqrt{\frac{\pi \gamma F E}{2(1-\nu^2)R}}$$

(2.6)

where the net pressure $P_{\text{net}}$ is defined as the pressure in the crack minus the stress against its opening, $\gamma_F$ is the specific fracture surface energy, $\nu$ is Poisson’s ratio, and $E$ is Young’s modulus. The specific fracture surface energy represent the combined effect of the fracture toughness and the viscous pressure drop in the fracture (Cipolla et al. 2010). The main assumption of this model were the distribution of stress in vicinity of a Griffith crack which caused by internal pressure, changed along the length of the crack in a semi-infinite two-dimensional medium (Sneddon and Elliott 1946).
• Carter Model

In 1957, the Carter 2D fracture model was developed. It assumed that the fracture length grows with constant height and width along the fracture propagation as shown in Figure 2.5. The pressure drop along the fracture length is negligible and the 1D fluid leak-off at any point of fracture is a function of the exposure time of the point to the fracturing fluid. For a vertical fracture with a constant height, Carter’s equation gives fracture length \( u(x, t) \) as a function of time:

\[
u_L(x, t) = C_l/\sqrt{(t - \tau(x))}
\]

\[(2.7)\]

\[
C_l = \left(\frac{kC_t\phi}{\pi\mu}\right)^{0.5} (P_f - P_R)
\]

\[(2.8)\]

where \( t \) is time, \( \tau(x) \) is the time when the fracture tip gets to point \( x \), \( C_l \) is the leak-off coefficient, \( k \) and \( \phi \) are the reservoir permeability and porosity, respectively, \( C_t \) is the total compressibility, \( \mu \) is the fluid viscosity, and \( P_f \) and \( P_R \) are the fracture and reservoir pressures, respectively.
Figure 2.5 Carter Assumptions for fracture propagation.

The assumptions of the Carter model are that the fracture grows with constant height and width, and only the fracture length increases along the fracture propagation. These assumptions are not realistic (Nordgren 1972).

- PKN model

Perkins and Kern (1961) with Nortgren’s (1972) modification focused on fluid flow with the assumption that fracture mechanics is relatively unimportant. Figure 2.6 shows a schematic diagram of the PKN model. Perkins and Kern’s assumptions are as follows (Perkins and Kern 1961):

1. The fracture has a fixed height.
2. The fracture fluid pressure is constant in the vertical cross sections perpendicular to the direction of propagation.
3. Each vertical cross section deforms individually and it is not hindered by its neighbors.

4. The cross sections obtain an elliptical shape with the maximum width in the center.

5. The fluid pressure gradient is determined by the flow resistance in the narrow, elliptical flow channel in the propagation direction.

6. The fluid pressure in the fracture decreases toward the tip of the fracture.

The Perkin and Kern’s original theory together with Nortgren’s modification is now referred to as the Perkins-Kern-Nortgren (PKN) model. In the original model, the influence of the growth rate of the fracture width on the flow rate was neglected. Then in the absence of fluid losses, the term \( \frac{\partial p}{\partial x} \) is equal to zero. Although this assumption is acceptable if fluid loss dominates the material balance, but causes a significant error in the case of little or no leak-off. Then Nortgren corrected this growth-rate effect and rewrote the continuity equation in the form of (Nordgren 1972):

\[
\frac{\partial p}{\partial x} = - \frac{\pi h_f \frac{\partial w}{\partial t}}{4} \tag{2.9}
\]
By incorporating the new equation from Perkins-Kern-Norgren (PKN) model can be derived as follows (Nordgren 1972). Let x, y, z be a system of rectangular Cartesian coordinates with x axis in the direction of fracture propagation, z axis parallel to the well axis, and origin at the well face. The fracture lies in the x-z plane with $0 < x < L$ and $|z| \leq 1/2L$. Before fracture initiation, a compressive stress acts on planes parallel to the fracture. According to the Perkins-Kern theory, the different values for stress in the rock surrounding the reservoir should have a small effect on the fracture geometry. The fluid in the fracture is under a pressure $\sigma + \Delta p$, and the variation of $\Delta p$ with z has been neglected, so $\Delta p$ is a function of $x$ and $t$. Then, via the plane-strain solution for a crack under constant pressure, the fracture is elliptical and the width is given by:

$$W(x,t) = \frac{(1-v)}{\sigma} (h^2 - 4z^2)^{1/2} \Delta p \quad |z| \leq 1/2h$$

(2.10)

$$W = 0 \quad |z| \geq 1/2h$$

(2.11)
where $G$ and $\nu$ are the bulk shear modulus and Poisson’s ratio of the formation respectively.

For fluid flow in the fracture, the continuity equation is as follows:

$$\frac{\partial q}{\partial x} + \frac{\pi h_f}{4} \frac{\partial w}{\partial t} + q_{loss} = 0$$

(2.12)

where $q$ is the flow rate (volume per unit time) through a cross section which is related to the fluid pressure gradient and

$$q_{loss} = \frac{2h_f C_l}{\sqrt{t-\tau(x)}}$$

(2.13)

where $q_{loss}$ is the volume rate of fluid loss to the formation per unit length of fracture which is determined by the fluid flow losses into the surrounding porous medium as governed by Darcy’s law (Perkins and Kern 1961), $C_l$ is the leak-off coefficient, $t$ is the time as pumping starts, and $\tau(x)$ is the arrival time of fracture tip at location $x$. It has been assumed that $q$ is related to the pressure gradient by the classical solution for laminar flow of the Newtonian viscous fluid in the elliptical tube of semiaxes $1/2h$, $1/2w_{max}$, and $h \gg w_{max}$:

$$q = -\frac{\pi w^3 h_3}{64 \mu} \frac{\partial \Delta p}{\partial x}$$

(2.14)

where $w = w_{max}$ (or $z = 0$) and

$$w = \frac{(1-\nu)h}{G} \Delta p \text{ at } z=0$$

(2.15)

Then the following equation is realized by eliminating of $\Delta p$:

$$q = -\frac{\pi G}{256(1-\nu)} \frac{\partial}{\partial x} W^4$$

(2.16)
The pressure drop along the fracture length is negligible and the 1D fluid leak-off at any point of fracture is a function of the exposure time of the point to the fracturing fluid. The leak-off velocity function has been considered to be the same for all points and calculated from Equation 2.7 and 2.8.

The fracture width is calculated by assuming that the fracture surface deforms in a linear elastic manner. Now by incorporating Equations 2.13 and 2.16 into Equation 2.12:

\[
\frac{G}{64(1-v)\mu h} \frac{\partial^2}{\partial x^2} W^4 = \frac{8c_l}{\pi \sqrt{t - \tau(x)}} + \frac{\partial w}{\partial t}
\]

(2.17)

where \( \tau(x) = \tau[L(t')] = t', 0 \leq t' \leq t \) is the time that the fracture opened at \( x \). Initially, the fracture is closed and thus, the initial condition is defined as:

\[
t = 0, w(x, 0) = 0
\]

Furthermore, the fracture is closed for \( x \geq L(t) \), and therefore, the boundary condition is given by:

\[
x \geq L(t), w(x, t) = 0 \quad \text{(first boundary condition)}
\]

By knowing \( q(0, t) = q_i = constant \), then

\[
-\left[ \frac{\partial}{\partial x} W^4 \right]_{x=0} = \frac{256(1-v)\mu}{\pi G} q_i \quad \text{(second boundary condition)}
\]

Now the problem given by non-linear partial differential equation, Equation 2.17, with initial and boundary conditions is fully specified. The governing equation can be converted into the dimensionless form as follows:

\[
x = \pi \left[ \frac{(1-v)\mu q_i^5}{245c_l^2Gh^4} \right]^{1/3} x_D
\]

(2.18)
\[ L = \pi \left[ \frac{(1-\nu)\mu q_i^2}{245C_i^4 h^4} \right]^{1/3} L_D \]  \hspace{1cm} (2.19)

\[ t = \pi^2 \left[ \frac{(1-\nu)\mu q_i^2}{32C_i^5 g h} \right]^{2/3} t_D \]  \hspace{1cm} (2.20)

\[ w = \left[ \frac{16(1-\nu)\mu q_i^2}{C_l^2 g h} \right]^{1/3} w_D \]  \hspace{1cm} (2.21)

Equation 2.17 is then simplified to:

\[ \frac{\partial^2}{\partial x_D^2} (w_D^4) = \frac{1}{\sqrt{t_D-\tau_D(x)}} + \frac{\partial w_D}{\partial t_D} \]  \hspace{1cm} (2.22)

\[ -\left( \frac{\partial}{\partial x_D}(w_D^2) \right) \bigg|_{x_D=0} = 1 \quad w(x_D, 0) = 0 \]

\[ w_D(x_D, t_D) = 0 \quad \text{when } x_D > L_D \]

\[ \tau_D[L_D(t_D)] = t_D \quad \text{when } 0 \leq t_D \leq t_D \]

Equation 2.24 cannot be solved analytically and thus a numerical method must be used to solve for \( w_D(x_D, t_D) \); Nortgren used the finite difference method.

England and Green also tried to derive an equation for fracture width starting from the PK model in plane strain. Their method yields the following result (Economides and Nolte 1989).

\[ w(x) = \frac{4(1-\nu)L}{\pi G} \int_{x/L}^{1} \frac{f_{L2}df_{L2}}{\sqrt{(f_{L2}^2-t^2)}} \int_{L}^{f_{L1}} \frac{\Delta P(f_{L1}) df_{L1}}{\sqrt{(f_{L2}^2-f_{L1}^2)}} \]  \hspace{1cm} (2.23)

where \( G \) and \( \nu \) represent the elastic properties of rock, shear modulus and Poisson’s ratio, respectively, \( \frac{E}{2(1+\nu)} = G \) where \( E \) is the Young’s Modulus, \( 2L \) can be replaced by \( h_y \) in their model, and \( x/L, f_{L2} \) and \( f_{L1} \) are fractions of the fracture half length. The simplest case is a uniformly distributed load, \( \Delta P = \text{constant over the full fracture length (2L)} \). Therefore:
\[ W(x) = \frac{2(1-v)L\Delta P}{G} \sqrt{1 - x^2} \]  \hspace{1cm} (2.24)

or

\[ W(x,t) = \frac{2(1-v)h_f(P-\sigma_H)}{G} \]  \hspace{1cm} (2.25)

and

\[ \frac{\partial (P-\sigma_H)}{\partial x} = -\frac{64}{\pi} \frac{q\mu}{w^2 h_f} \]  \hspace{1cm} (2.26)

By incorporating Equations 2.7, 2.25, and 2.26 into Equation 2.12, the result is:

\[ \frac{G}{64(1-v)h_f\mu} \frac{\partial^2 w^4}{\partial x^2} - \frac{\partial w}{\partial t} - \frac{8C_i}{\pi \sqrt{t-\tau(x)}} = 0 \]  \hspace{1cm} (2.27)

To solve the above equation, the initial condition is \( w(x, 0) = 0 \) with boundary conditions \( w(x, t) = 0 \) for \( x > L \) and \( -\frac{\partial w^4(0,t)}{\partial x} = \frac{256\mu(1-v)q_i}{\pi G} \) for a one side of the fracture (England and Green 1963). The final presented results for fracture width, length and pressure by Nortgren are as follows (Garagash and Detournay 2005):

\[ w(0, t) = 4\left(\frac{2}{\pi^2}\right)^{1/4} \left[\frac{\mu(1-v)q_i^2}{G h_f C_i}\right]^{1/4} t^{1/8} \]  \hspace{1cm} (2.28)

\[ w(x, t) = w(x, 0) \left(1 - \frac{x}{L}\right)^{1/4} \]  \hspace{1cm} (2.29)

\[ \Delta P(0, t) = 8\left(\frac{2}{\pi^3}\right)^{1/4} \left[\frac{\mu G q_i^2}{h_f^2(1-v)^2 C_i}\right]^{1/4} t^{1/8} \]  \hspace{1cm} (2.30)

The fracture fluid pressure is constant over the vertical cross section perpendicular to the direction of propagation. The cross sections obtain an elliptical shape with maximum width in the center. The model also gives the following equation for length as a function of time:

\[ L(t) = 6.8 \left[\frac{G q_i^3}{(1-v)\mu h_f^2}\right]^{1/5} t^{4/5} \]  \hspace{1cm} (2.31)
• **GDK Model**

The Geertsma and de Klerk model assumed that the formation is homogeneous and elastic stress-strain relations can be applied. The GDK model assumes that the vertical cross section perpendicular to flow is rectangular, whereas the horizontal cross section is elliptical. The fracture fluid behaves like a purely viscous liquid and fluid flow is laminar. The pressure gradient along the fracture is inversely proportional to cubic of the fracture width and it is presented by the following Equation:

$$\frac{\partial P}{\partial x} = -\frac{12q\mu}{h_f w_f^3}$$  \hspace{1cm} (2.32)

Except near to the fracture tip, the pressure drop is commonly low along the fracture. A major contribution of the total pressure drop normally occurs at the fracture tip. Therefore, the pressure along the fracture can be taken to be constant. Figure 2.7 shows the GDK schematic diagram. (Gray et al. 2010).

The relationship between the maximum fracture width, length, net pressure and the elastic properties of the surrounding rock is given by the analytical stress solution of a single crack embedded in an infinite plane as follows (Smith and Shlyapobersky 2000):

$$w_{max} = \frac{L_f (P_{wf} - \sigma_{min})}{E} = \frac{L_f P_{net}}{E}$$  \hspace{1cm} (2.33)

$$\bar{E} = \frac{E}{4(1-v^2)}$$  \hspace{1cm} (2.34)
where $E$ is Young’s modulus, $v$ is Poisson’s ratio, and $P_{wf}$ is the wellbore pressure. Equation 2.26 can also be used for GDK model if the term $w$ is substituted by an average width which is related to the GDK maximum width by:

$$w(0, t) = \frac{2(1-v)L(p_f-\sigma_h)}{G}$$

(2.35)

The material balance in differential form is written as follows:

$$\frac{dV_f}{dt} = q_i - q_L$$

(2.36)

**Figure 2.7** GDK fracture schematic diagram.

where $V_f$ is the fracture volume, $q_i$ is the fluid injection rate and $q_L$ is fluid leak-off rate. The fracture volume can be calculated at any time according to Equation 2.36. To calculate fracture dimensions, a specific fracture geometry and pressure distribution in the fracture needs to be assumed. By expanding Equation 2.36, the mass balance along a fracture plane considering the liquid leak-off is:
\[ q_i = 2 \int_0^t u_L(t - \alpha) \frac{dA_f}{d\alpha} d\alpha + w \frac{dA_f}{dt} \]  

(2.37)

where \( u_L(x,t) = C_l/\sqrt{(t - \tau(x))} \) and \( C_l = \left( \frac{K_C t}{\pi \mu} \right)^{0.5} (P_f - P_R) \).

To solve the above equation, the Laplace transform should be taken by knowing the following mathematical rule, Convolution integral:

\[ f \ast g(t) = \int_0^t f(t - \tau) g(\tau) d\tau \]  

(38)

\[ L[f \ast g(t)] = F(s) \cdot G(s) \]  

(39)

then

\[ L[q_i] = 2L[u(t)]L\left[\frac{dA_f}{dt}\right] + wL\left[\frac{dA_f}{dt}\right] \]

\[ L[q_i] = (2L[u(t)] + w)sA_f \]

\[ \frac{q_i}{s} = \left(2C_\sqrt{\frac{\pi}{s}} + w\right)sA_f \]

\[ A_f = \frac{q_i}{s^2 \left(2C_\sqrt{\frac{\pi}{s}} + w\right)} \]

Following formula for the complimentary error function to complete the derivation has been used:

\[ L[e^{ax} \text{erf}(\sqrt{ax})] = \frac{1}{s + \sqrt{as}} \]

So the Laplace form of the mass balance equation can be rewritten as,

\[ A_f = \frac{q_i}{s(2C\sqrt{\pi s} + ws)} = \frac{q_i}{ws} \cdot \frac{1}{\sqrt{\frac{4C^2\pi s}{w^2} + s}} \]
\[ L^{-1} \left( \frac{q_i}{w_s} \right) = \frac{q_i}{w} \]
\[ L^{-1} \left( \frac{1}{\sqrt{\frac{4C^2 \pi t}{w^2} + s}} \right) = e^{\frac{4C^2 \pi t}{w^2}} \text{erfc} \left( \frac{\sqrt{4C^2 \pi t}}{w} \right) \]

To obtain the Laplace inverse, advantage of convolution integral formula has been applied as follows:

\[ L^{-1} \{ F(s) \cdot G(s) \} = f * g(t) = \int_0^t f(\tau) g(t - \tau) d\tau = \int_0^t g(\tau) f(t - \tau) d\tau \]

So,

\[ A_f = \int_0^t \frac{4C^2 \pi t}{w^2} \text{erfc} \left( \frac{\sqrt{4C^2 \pi t}}{w} \right) \frac{q_i}{w} d\tau \]

After integration;

\[ A_f = 2h_f L_f = \frac{q_i w}{4\pi C^2_i} \left( e^{Z^2} \text{erfc}(Z) + \frac{2}{\sqrt{\pi}} Z - 1 \right) \quad (40) \]

where \( L_f \) is the fracture length, \( h_f \) is the fracture height and \( Z \) is a dimensionless time given by \( Z = \frac{2C_i \sqrt{\pi t}}{w} \).

- **Comparison between PKN and GDK Models**

The GDK and PKN models take both mass balance and solid mechanics into consideration simultaneously. These models differ by one basic assumption: the way in which they convert a 3D fracture mechanics problem into a 2D problem. The GDK model expresses fracture width in terms of height whereas the PKN model that expresses fracture width in terms of length (Veatch et al., 1989). In the other word, GDK assumes that the fracture width changes...
much more slowly along the fracture face in vertical direction compare to horizontal direction at any point of the fracture. While, Perkins and Kern assume that the pressure at any section is dominated by the height of the section rather than the length of the fracture. The difference in this one basic assumption in those models leads to two different ways of solving the problem and consequently different fracture geometry will be formed (Settari 2012). According to the literature, each of these two models can be used successfully to design hydraulic fractures (Mack and Warpinski 2000; Karimi-Fard, Durlofsky, and Aziz 2004; Kozicki and Donzé 2008; Nassir, Settari, and Wan 2013).

Figure 2.8 shows a conceptual plot of the pressure and width versus length from the two models. In the GDK model, the fluid pressure decreases with fracture length, whereas in the PKN model increases with length. In general, for the same fracture length, the PKN width is smaller than that of the GDK model which causes a larger fracture length for the same volume of pumped fluid (Settari 2012).
Figure 2.8 Comparison of GDK and PKN fracture models.

Figure 2.8 also displays the net pressure curves; the PKN model predicts an increasing pressure profile whereas the GDK model predicts a decreasing pressure profile. In addition, the PKN model indicates that the higher net pressure could be expected with increasing the fracture length. Fractures calculated using the PKN models generally have smaller widths and are significantly longer than the fractures computed with the KGD model (Brady et al. 1992).
2.4.1.2 3D models

The limitations of 2D models have led to the development of 3D fracture models. The first 3D model was the Pseudo 3D model (P3D) which is a natural extension of the 2D Perkins and Kern model to determine fracture propagation at different fracture height (Settari and Cleary 1984). P3D models include two main categories: “cell-based models” in which fracture has been divided into several self-similar cells along horizontal direction (Simonson, Abou-Sayed, and Clifton 1978) and “lumped models” which assume a fracture consists of two half ellipses of equal lateral extent but different vertical extent (Cleary, Kavvadas, and Lam 1983). As shown by Settari and Warren (1994), P3D models tend to overestimate the fracture height.

To improve on P3D models, PLanar 3D (PL3D) models have been developed which couple fracture growth and fluid flow using a moving triangular mesh (Clifton and Wang 1992) or fixed rectangular mesh (Barree 1983). Although this method makes more accurate predictions of fracture geometry than previous methods, it requires a consistency condition between layers and cannot simulate ‘out of plane’ fractures. It is also inappropriate for nonlinear and heterogeneous formation (Li et al. 2015).

Morita et al. (1989) proposed a 3D model that allowed fracture propagation at its perimeter in any direction. In this method, the width of the fracture shrinks to zero at the tip of fracture due to the corresponding energy dissipation and lubrication theory which is used to simulate the fluid flow within the fracture (Morita et al. 1989). Their model could be applied in sand-
production control, casing buckling problems, design of hydraulic fracturing jobs, subsidence, and estimation of formation damage resulting from permeability reduction during hydrocarbon production (Mack and Warpinski 2000).

For a formation that contains weak planes such as natural fractures or faults which are oriented at arbitrary angles to the stress direction, the induced fracture network can be very complex. These types of formations require models that account for fluid flow, geomechanics and crack formation and evolution, and account for interactions between the induced hydraulic fractures and natural fractures (Weng 2015). The Unconventional Fracture Model (UFM), developed by Cipolla et al. (2010), considers the effect of natural fractures, stress distribution, and influence of the mechanical properties of fracture morphology (Cipolla et al. 2010). The UFM model can simulate the propagation of asymmetric fracture networks accounting for fluid flow in the fracture network and elastic deformation of the fractures. The initial assumptions and governing equations (fluid flow in the fracture network, mass conservation and fracture deformation) are similar to the conventional P3D model (Qiu et al. 2015; Weng 2015).

In my research project, the Mangrove hydraulic fracturing simulator is used (Schlumberger, 2017). For the fracture geometry model, in this simulator, the Unconventional Fracture Model (UFM) is used. In this method, the effect of geomechanical properties on the fracture network growth and propagation as well as fluid flow and proppant transport is considered. It is a cell-based model which solves the fully coupled problem of fluid flow in the fracture network and the elastic deformation of the fractures. In this model, stresses increase with
depth but are assumed to be constant at each depth (no variability in a horizontal plane). The UFM fracture models contain four essential components to represent the behaviour of the process: i) fracture creation and aperture dependence on fluid pressure, ii) fluid flow within the fracture, iii) boundary conditions (well and reservoir) and extent of fracture propagation, and iv) proppant transport in the injected fluid (Weng et al. 2014).

2.5 Multistage Hydraulic fracturing

Currently, multistage fracturing of horizontal wells has become widely used to produce hydrocarbon from previously unproductive formations such as shales and tight gas sands. This technology has been performed in an unconventional resource like Montney Formation, but the optimization of the treatment is still unclear because the mutual effect of hydraulic fractures is complex especially when considering the heterogeneities of the Montney Formation. In multistage hydraulic fracturing process, the long horizontal wells divided into many stages to access large volumes of oil and gas bearing formations. Then fracture fluids are pumped down into each stage of the well to generate a channel to increases the porosity and permeability of the formation to allow economic resource extraction (Skomorowski 2016). Figure 2.9 display the hydraulic fracturing treatment schematic.
The hydraulic fracturing technology has greatly improved in the past decade to accommodate industry needs in the development of unconventional reservoirs in Canada. Figure 2.10 shows the most active basins with the most wells drilled located in the northeast of British Columbia. Among the total number of multistage horizontal wells (496), 310 are located in the Montney Formation within the Montney Trend (dark Blue line, Figure 2.10). Since 2005, using the multistage stages hydraulic fracturing technology for the horizontal
wells has been developed. As Figure 2.10 shows, by 2010, the number of multistage horizontal wells in the Montney (dark blue line) was almost five times than the others.

![Figure 2.10 Well count for multistage hydraulic fracturing treatment located in northeast British Columbia by Basin (Johnson and Johnson 2012).](image)

Up to 2010 maximum of 50 stages of hydraulic fractures have been reported for openhole completions in Bakken shale (Themig 2010). It seems that more fracture stages can completely deplete the reservoirs (Soliman, Hunt and Azeri 1999; Ozkan et al. 2009), but is no evidence to confirm that ultimate production increases proportionally with the increase in the number of fracture stages. Thus, it is significantly important to optimize a design in which the necessity of creating each stage has been assessed based on engineering principals and economic justifications. One of the most important factors in performing a successful hydraulic fracturing treatment is the fracture spacing (Cheng 2009).
Based on Johnson et al. data, the number of fracture stages per well has increased in most basins across northeast British Columbia. From 2009 to 2010, operators almost doubled the number of fracture stages per well from 10 to 19 in the Horn River Basin. Fracture stages increased dramatically for the same period in the Deep Basin, from 9 to 15. Increases were modest in the Montney and Montney North trends. Figure 2.11 displays the number of multistage hydraulic fracturing for five active basins drilled in the northeast of British Columbia.

![Figure 2.11 Average number of fracture stages compared in five basins located in northeast British Columbia between 2005 and 2010 (Johnson and Johnson 2012).](image)

An optimized design for fracture placement, along with the wellbore, can help to create large fracture surface area with an effective permeable zone to allow for proppant settling, forming a conductive path from the reservoir into the wellbore. As claimed by Soliman et al. (2010), the stress perturbation caused by induced fractures is an important parameter to control the spacing between fractures. Then perforation location in multistage hydraulic fracturing can
be optimized if the original stress anisotropy is known (Soliman et al. 2010). As a result, the opening of the fractures is highly dependent on the fracture net pressure and the spacing between fractures (Rafiee, Soliman, and Pirayesh 2012). Figure 2.12 displays the plug and perforation horizontal well set up.

Figure 2.12 Schematics of plug and perforation horizontal well set up.

Several studies have been done to investigate stress perturbation around single (Wood and Junki 1970; Warpinski, Wolhart and Wright 2004) and multiple (Cheng 2009; Roussel and Sharma 2011) fractures. However, there is a lack of study on the change of stresses magnitude in heterogeneous formation, like Montney, in different designs of multistage fracturing.

The in situ geomechanical stresses of the formation do not remain constant during the fracturing treatment or afterward. Induced fracture will cause a volume change within the formation which leads to alteration of the stress and strain conditions within the rock mass. The alteration of stress conditions will have an effect on the initiation and propagation of
subsequent stages of the multistage hydraulic fracture operation. This phenomenon is known as ‘stress shadowing’. This special condition happens when the minimum compressive stress in the formation is increased due to the fracturing of the rock. There are some consequences of increasing the minimum compressive horizontal stress, such as rotation or diversion of fracture propagation, stages which cannot initiate, thinner fractures, and reduced porosity and permeability within the fracture stage (Zangeneh, Eberhardt, and Bustin 2015).

2.6 Shale Gas productivity

From 2005 the production of hydrocarbons from Canadian shales reservoir began slowly but developed sharply (Rivard et al. 2014). Figure 2.13 shows the prediction of the Canadian resources volume by 2025. Firstly, natural gas is being produced from Triassic Montney shales and siltstones (2005) and Devonian shales in the Horn River Basin (2007), both located in northeastern British Columbia and then extend to the Devonian Duvernay Formation in Alberta located at western Canada. There are more potential shale resource with natural gas in eastern Canada currently being evaluated. It includes the Upper Ordovician Utica Shale in southern Quebec and the Mississippian Frederick Brook Shale in New Brunswick (Rivard et al. 2014).
As Figure 2.14 shows over 1100 wells have been either drilled for shale gas exploration and production or exploited for gas (gas also being a common by-product of tight oil or tight sand wells) by end of 2012 mostly in British Colombia and Alberta. Alberta shale gas production in 2011 corresponded to about 0.1% of total gas production in the province. Although there are some gas shale plays in Canada (Utica, Muskwa, Montney, Duvernay, Horton Bluff and Frederick Brook) currently being produced economically, many basic scientific parameters pertaining to their mechanical properties (strength properties and elastic properties), permeability and porosity maps as well as a flow mechanisms remain unanswered.
Figure 2.14 Total number of wells drilled yearly for unconventional hydrocarbon resources in shales and tight sands per year in Canada and annual production of shale gas for British Colombia (Rivard et al. 2014).

2.7 Commercial models to predict Hydraulic fracture geometry

There are few commercial codes (MFRAC, StimPlan, GOHFER, Frac3D, simFrac and Mangrove) available as possible options for this project. The different codes had a variety of features and capabilities as well as a running time and cost. Based on the expected result, six of them are selected and described here: Mangrove, StimPlan, MFRAC, GOHFER, Frac3D and simFrac. After reviewing the programs listed, Mangrove from Schlumberger Company was selected to run this project. Mangrove is a “Petrel” plug-in module designed to perform integrated completion and stimulation design, production forecasting, and post-fracturing evaluation for horizontal and vertical wells in conventional or unconventional reservoirs. Since the formation geomechanical properties and stress behavior in the reservoir
had been investigated simultaneously in this research, Mangrove/Visage and Petrel package were applied to build a geological/geomechanical model using log data from the beginning.

In the Petrel package, Mangrove is referred to as Hydraulic fracture design and Hydraulic fracture production. Mangrove takes geological, petrophysical, geomechanical, microseismic, geophysical, and production data input to build a comprehensive zone/3D model. Multistage completion design and hydraulic fracture treatment designs are built based on this model. It includes the variety of fracture models which can be selected based on the available data as well as formation type. Therefore, the workflow order displayed in the order of the processes is not rigid and can perform the tasks in a different order. The operators are able to go back to the geological and geomechanical model to modify the fracture network behavior map. It can also simulate the simultaneous growth of multiple fractures at different intervals. It is able to simulate the acid fractures and pumping schedules. It includes a database of properties for fracturing fluids and proppants and offers data handling and analysis capabilities. Mangrove is a sophisticated and robust fracture simulator package. Using this code fractures can be modeled as either discrete or implicit fractures or a combination of both. Moreover, a reservoir geomechanics module can link the perturbed stress field directly to the active natural fractures and faults, under applied tectonic stresses. It also has the possibility to extract geometrical characteristics of potential natural fractures developed inside the perturbed stress field. This software has the possibility to go back to reservoir geomechanics setting using Visage finite-element geomechanics simulator. Visage or “Petrel Geomechanics module” is the industry’s leading environment for 3D preproduction geomechanics modeling of operating fields.
StimPlan (STIMPLAN) is another hydraulic fracture simulator as a complete design tool kit produced by NSI Technologies Inc. of Tulsa Oklahoma. This software offers the pseudo-3D and fully 3D fracture models as well as a quick 2D simulations. The simultaneous growth of multiple fractures can be simulated at different intervals. Implicit finite difference equations are used to solve mass balance, height growth and fluid flow. For this purpose, the fracture width is simulated through finite element method and fluid flow and proppant transport in the fracture is calculated using 2D numeric multi-phase flow solutions. StimPlan also is able to simulate the acid fractures and pumping schedules. It includes a database of properties for fracturing fluids and proppants and offers data handling and analysis capabilities (Castle et al. 2005).

MFRAC is another 3D fracture simulator that is the core of a suite of software packages produced by Meyer and Associates, Inc. of Natrona Heights, PA. It includes the fully coupled proppant transport, integrated acid fracturing, pumping schedule design, multilayer fracturing, options for 2D solutions, simulation of horizontal fractures, and a database of proppant, fluid and rock properties (Meyer & Associates Inc. 2011). This software is able to estimate the fracture length, height, width and geometry parameters as a function of time.

Grid Oriented Hydraulic Fracture Extension Replicator (GOHFER) is a planar 3D fracture simulator with a fully coupled fluid/solid transport simulator. It is produced by Dr. Bob Barree of Barree & Associates in association with Stim-Lab, a division of Core Laboratories. Like most of the reservoir simulator, it is used to describe the entire reservoir. The regular grid structure is used to calculate elastic rock displacement and fluid flow solutions. The grid
is used for both elastic rock displacement calculations as well as a planar finite difference grid for the fluid flow solutions. Fluid composition, proppant concentration, shear, leak-off, width, pressure, viscosity and other state variables are defined at each grid block.

An integration of the pressure distribution over each node has been determined by the fracture face displacement at the node. GOHFER is able to model the multiple fracture initiation spots simultaneously and display diversion between perforations. The pore pressure is used to calculate the in-situ stress, poroelasticity, elastic moduli and geologically consistent boundary conditions. Fracture propagate smoothly by closing tip model and eliminates the fictitious singularity at the tip as well as the stress intensity factor (Grid Oriented Hydraulic Fracture Extension Replicato (GOHFER)).

Frac3D is a 3D finite element based fracture analysis program designed to model structural engineering problems. The software is produced by Lehigh University of Bethlehem, PA. This software is capable of regular 3D stress analysis, 3D fracture analysis, non-linear analysis of solid structures (Ayhan and Nied 2010). However, this software is able to calculate a variety of 3D fracture geometries, there is lack of ability to calculate multi-phase fluid flow, proppant transport, postfracture fluid flow, acid fracturing, and fractures in complex geologic stratigraphy like shale formation.

Simfrac is a hydraulic fracturing code developed by TAURUS Reservoir Solutions Ltd. of Calgary, Alberta. The software features a conventional 3D hydraulic fracture simulation, is fully documented and runs under Windows (Nassir, Settari, and Wan 2013), but does not
have a graphical user interface. It also has a long running time compared to other fracture simulator codes (Foley 2006).

There are more codes available to model the hydraulic fracturing based on formation type, and existing data (Savitski et al. 2013; Suppachoknirun 2016; Riahi and Damjanac 2013; Zhang and Jeffrey 2013; Mahabadi et al. 2012). Haung (2015) presented a model to explore a dynamic fracturing approach that uses a dilation-recompaction model in a reservoir simulator to model hydraulic fracturing. In his model the geometry and length scale of the fracture is not prescribed a priori and the model can be relatively easily constructed and matched to field data (Huang 2015). In another model, described by Maulianda (2016), characteristics of the fracture network or stimulated rock volume (SRV) caused by hydraulic fracturing was investigated by using finite element method. In this model the dimensions of SRV, permeability, pore pressure, and in-situ stresses are examined during hydraulic fracturing and production (Maulianda 2016). Nassir M. has developed the 3D coupled geomechanical and flow model for analysis and optimization of tight and shale gas stimulation treatments. His formulation includes the dynamic propagation of tensile and shear fractures when the failure criteria are met. This model has the flexibility to select either tensile or shear fracturing mechanism or combination of both allows various scenarios to be examined (Nassir 2012).

There are also other methods to interpret hydraulic fracture growth as well as the geometry of an induced hydraulic fracture network, in unconventional reservoirs. One of them is Rate-
Transient Analysis (RTA) which can be used to provide information about effective hydraulic fracture length and conductivity as well as contacted or effective matrix surface area. This method can also determine a given rate-allocation data for multi-stage fracturing scenarios or individual stage fracture effectiveness, estimation of minimum and maximum reservoir permeability and minimum reserve volume (Clarkson and Beierle 2011). Although some hydraulic fracture information can be obtained, as well as drainage volumes, there is no way to assess fracture or Simulated Reservoir Volume (SRV) geometry by RTA method. MicroSeismic Monitoring and Analysis (MSMA) is another recent method to provide critical information about fracture geometry (height, length and azimuth) and complexity, and can be used to provide SRV limits. MSMA can identify the reservoir fabrics, like natural fractures and faults, which providing further information for well performance analysis (Baan, Eaton, and Dusseault 2013). Integration of RTA and MSMA is another method which is increasingly being used in hydraulic fracturing technology. RTA, constrained by microseismic interpretations, is used to obtain initial approximation of hydraulic fracture and reservoir properties, which are then compared with hydraulic-fracture modeling and help the starting point for reservoir simulation (Clarkson 2011).

Based on the software review, Mangrove, GOHFER, and Simfrac would be the top three choices of software based on the 3D modeling capabilities, design functions, treatment of fracture geometry and materials database. Mangrove software provides a specific workflow intended for predictive model building and evaluation of hydraulic fracture treatment in unconventional reservoir, such as Montney Formation. Therefore, in this study, Mangrove by Schlumberger was selected on the basis of available features and cost.
2.8 Fracture model input parameters

One of the main objectives in conducting hydraulic fracturing operations is to enhance the well production without negatively affecting the integrity of the formation or reservoir. There are few parameters that can be controlled by the operator in the fracturing growth process. Table 2.1 shows the parameters controlled by operators and the parameters controlled by nature.

Table 2.1 The main input parameters in the common hydraulic fracturing modeling

<table>
<thead>
<tr>
<th>Parameters controlled by operator</th>
<th>Parameters controlled by nature</th>
</tr>
</thead>
<tbody>
<tr>
<td>• fracture fluid and proppants type</td>
<td>• formation permeability and porosity</td>
</tr>
<tr>
<td>• fracture fluid temperature and density</td>
<td>• initial reservoir pressure</td>
</tr>
<tr>
<td>• optimum volume of material</td>
<td>• in situ stresses</td>
</tr>
<tr>
<td>• injection rate</td>
<td>• formation temperature</td>
</tr>
<tr>
<td>• injection location and schedule</td>
<td>• thermal conductivities of formations penetrated</td>
</tr>
<tr>
<td>• fluid thermal conductivity</td>
<td>• fracture closure pressure</td>
</tr>
<tr>
<td>• proppant size distribution</td>
<td>• net pressure</td>
</tr>
<tr>
<td>• proppant density</td>
<td>• formation elastic properties: modulus and fracture toughness</td>
</tr>
<tr>
<td>• proppant fracture conductivity as a function of fracture closure stress</td>
<td>• leak-off coefficient</td>
</tr>
<tr>
<td>• number of stages</td>
<td>• proppant concentration in the fracture and embedment in the formation</td>
</tr>
<tr>
<td>• perforation intervals</td>
<td></td>
</tr>
</tbody>
</table>

In general, more than 30 variables including detailed stratigraphy and mechanical properties are needed as the fracture simulator input. The input variables had been changed along the
reservoir depth and time of operation. An example of a Mangrove input data deck can be found in Appendix II of this thesis.

2.9 What is missing in the literature?

Multistage hydraulic fracturing has been performed in unconventional reservoirs, but the optimization of this stimulation method is still under discussion and remain unresolved. The mutual effect of hydraulic fractures and complex heterogeneity of unconventional reservoir can cause lots of uncertainties in hydraulic fracturing treatment. Hydraulic fracturing not only will change the stress condition but also will change the geological structures by changing their open/close state or create secondary fractures from them. Nevertheless, an understanding of how geological heterogeneity, as well as stress distribution, affect the multistage hydraulic fracturing network is vital for the optimization of hydraulic fracturing design. Also, the comprehensive realistic industrial applicable workflow which produce from log data is really missing in the literatures. The research in this thesis focuses on modelling of hydraulic fractures through an examination of the reservoir rock - both geologically and geomechanically – to understand how rock properties and heterogeneity, initial state-of-stress affect fracture formation. The research focused on in this thesis centres around the Montney Formation in Alberta, Canada.

CHAPTER THREE: SUMMARY OF PUBLICATIONS
The research documented in this thesis has resulted in four papers: one accepted in peer-reviewed journal, and in print and three submitted papers. A brief summary of these papers is given as follows.

**Paper 1. Modeling Geomechanical Properties in the Montney Formation, Alberta, Canada**

Recently, unconventional reservoirs have received attention particularly in North America. These reservoirs require hydraulic fracturing to be commercially productive. At this point, it remains unclear as to the influence of geomechanical properties on fracture stimulation and its effective permeability, nature of the fractured zone (whether single extensive fracture or network), and extent of fractured zone. An understanding of the geomechanical properties and their spatial heterogeneity can be used to guide well placement and fracturing job design. In most simulation models, geomechanical properties are assumed to be homogeneous throughout the reservoir. In this study, heterogeneity of geomechanical properties is demonstrated by using geomodeling. A three-dimensional (3D) earth model was built by integrating both petrophysical and geological log data. The model includes dynamic elastic properties and rock strength property distributions in both vertical and horizontal directions within the reservoir and provides an ideal basis to understand hydraulic fracturing and wellbore stability. To determine elastic rock properties, changes in compressional and shear velocity through all the layers of the reservoir rock were taken into consideration. A workflow was developed to constrain well properties to derive realistic rock property values and distributions even in areas where only limited well log information exist. The 3D
geomechanical earth model demonstrates that (1) the distribution of rock properties depends on formation lithology and (2) high lateral and vertical resolution can be achieved even in the areas with sparse wellbore information.

**Paper 2. New Insights on the State of Stress in the Montney Formation, Alberta, Canada**

With the reduction of conventional hydrocarbon production from Canadian resources, unconventional shale-gas reservoir development has accelerated due to the ability to hydraulically fracture these reservoirs in a quick and economic way. The productivity of many shale gas resources depends on accurate prediction of in situ reservoir stresses, that is, the change of pore pressure, vertical and horizontal stresses with depth, is important. These state-of-stress variations also play a significant role on well placement, both depth and orientation, within the reservoir as well as the locations chosen for the hydraulic fracture stages along the well. Generally, existing methods used to evaluate horizontal stresses, for example, leak off tests, diagnostic fracture injection test (DFIT), and breakout, only provide estimates of the state-of-stress at one depth of the reservoir and cannot determine the stress distribution within the reservoir. The research described here presents a practical method to determine horizontal stress magnitudes based on the geology and mechanical rock properties using numerical methods, namely, the finite element method, with application to the Montney Formation in Alberta, Canada. In this study, the state-of-stress prior to hydraulic fracturing is estimated by using geological log data to create a geomechanical model from near surface to below the Montney Formation. The state-of-stress of the Montney Formation
obtained from the finite element analysis are consistent with results from an analytic method as well as results from log analysis and DFIT analysis. The results of the analysis shows that the strike-slip regime is the dominant regime in the Montney Formation. The case study reveals that i) the state-of stress depends on formation properties, and ii) consistent stress orientation and magnitude can be obtained over the entire depth of reservoir. The outcomes of this study provide a method to guide well placement and the position of hydraulic fracture stages along the well.


Low permeability resource development has accelerated due to the ability to hydraulically fracture and subsequently produce these reservoirs in a rapid and economic manner. These resources, with natural fractures and faults have complex multi-connected pathways for fluid flow that can change as reservoir geomechanical conditions evolve as fluids are injected into the reservoir. The more detailed the characterization (position, connectivity, permeability, and interaction with natural fractures) of the induced fracture network, the easier it is to optimize recovery process design and future well and stage placement to maximize recovery. Stress magnitude and direction as well as elastic and plastic rock properties dictate the mode, orientation, and size of the hydraulic fracture network. Here, the effect of rock mechanical properties, initial reservoir pressure, and minimum horizontal stress on hydraulic fracture growth is investigated by using the Unconventional Fracture Model. The results show the strong impact of Young’s modulus on fracture geometry (width, height and length) as well
as fracture conductivity distribution. The results also reveal how that the fracture’s conductivity increased when the minimum horizontal stress was reduced.

**Paper 4. On Multistage Hydraulic Fracturing in Tight Gas Reservoirs: Montney Formation, Alberta, Canada**

The combination of horizontal drilling and multistage hydraulic fracturing technology has unlocked production of petroleum from tight/shale rock. Prediction of single or multistage hydraulic fracturing treatments along horizontal wells in tight formations remains a challenge and thus optimization of these stimulation treatments is difficult. Currently, there are few effective approaches to characterize multistages hydraulic fracturing in tight rock reservoirs. In this paper, we use a three-dimensional tight rock simulator based on the Unconventional Fracture Model (UFM) to understand multistage hydraulic fracturing in the Montney Formation in Alberta, Canada. We use geological and geomechanical properties, stress magnitude and orientation, completion and production data to history match and characterize fracture volume and conductivity in the Montney Formation. Predictions of fractures from the history-matched reservoir model reveal the strong connection between the fracture conductivity and reservoir permeability, elastic rock properties as well as stresses distributions. The field example demonstrates how stress maps and rock properties calculated from density and gamma logs are integrated to yield predictive hydraulic fracturing capability. This study shows that the critical role of reservoir permeability on fracture extent and conductivity. This workflow can be used to develop strategies for (1)
refracturing of existing wells, (2) design and number of perforations, and (3) prediction of fracture propagation in later stages.
CHAPTER FOUR: MODELING GEOMECHANICAL PROPERTIES IN THE MONTNEY FORMATION, ALBERTA, CANADA


4.1 INTRODUCTION

As production from North American conventional hydrocarbon accumulations decline, unconventional low permeability resource development has accelerated due to the ability to hydraulically fracture such reservoirs in a rapid and economic manner. The key challenge faced by these operations is optimal well placement especially in the context of the heterogeneity of the geomechanical properties (e.g. Young’s modulus and Poisson’s ratio), of the reservoir. At this point, in most fields, there is limited data on geomechanical properties and their spatial distribution.

Passey et al. (Passey et al. 2010) found that typical parasequences (an upward shoaling package of genetically related succession of beds and bedsets) in a shale gas reservoir
resulted in significant variation of petrophysical properties and formation lithology (Passey et al. 2010) In addition, organized distribution of platy clay minerals (Sondergeld et al. 2010) and compliant organic materials (Ernik and Ilovac 2011) can lead to complexity of their mechanical anisotropy. Ahmadov, 2011 claimed that the maturity of shale and the amount of clay affects mechanical anisotropy. Understanding rock anisotropy and its causes is crucial because it strongly influences the hydraulic fracturing process, well stability, and production (Ahmadov 2011).

Here, we report on the mechanical properties of tight siltstone reservoir rocks collected from several wells in the Montney Formation located in Western Alberta, Canada. We present a data set describing the mechanical behavior of Montney rocks, including dynamic elastic properties and their anisotropy within the reservoir. We also discuss these data in the context of three-dimensional (3D) earth models to better understand the spatial distribution of rock geomechanical properties.

4.1.1 Overview of the Montney Shale Gas Reservoir

There are several ways to obtain mechanical properties of underground reservoir rock. One method is from laboratory measurements of core samples. An alternative is to determine mechanical properties indirectly by using sonic well log data, based on the propagation of shear and compressional waves. In general, sound waves propagate through a solid medium in a variety of modes, such as compressional or shear waves or along interfaces as Rayleigh and Stoneley waves. Acoustic wave velocity (the velocity of the sound wave measured
across the receiver array is the speed of sound through the formation directly opposite the receivers) can be used to characterize materials. For instance, a compressional sound wave travels through steel at 57 μs/ft (187 μs/m), through zero porosity sandstone at 55.5 μs/ft (182 μs/m) and through zero porosity limestone at 47.3 μs/ft (155 μs/m) (Alford et al. 2006). The change in acoustic wave velocity is related to the properties or volume of fluid in the rock pore space which depends on the porosity (Alford et al. 2006) as well as grain and pore network geometries and wave frequency.

In 1821, the first commercial gas well was drilled in the shales by William Hart who is considering the “father of natural gas” in the USA (Zhiltsov and Semenov 2017). In the early 1980s several operators started production of gas from the Barnett shale in Texas and by the end of 1990s, production started to ramp up through the use of horizontal drilling combined with multi-stage hydraulic fracturing. In 1997, by using water with chemical additives as a fracturing fluid, productivity was further raised while decreasing well cost (Euzen 2011). Now, production from new shale gas resources is growing around the world.

Shale is a term applied to different rocks which are composed of fine-grained particles (clay, quartz, feldspar, heavy minerals, etc.), typically less than 4 microns in diameter, but which may contain variable amounts of silt-size particles (up to 62.5 microns). In comparison with shale, sandstones are composed of grains (e.g., quartz, feldspar, clays, etc.) that are generally between 62.5 and 2,000 microns in diameter (Passey et al. 2010). Among the shale gas fields, the Triassic Montney Formation is one of the largest economically feasible resource plays and is classified as a tight gas reservoir that requires special completion techniques to
produce at economic rates. It is located on the border between the provinces of British Columbia and Alberta in Western Canada and consists of shallow-water sands in the east to offshore muds in the west. Over the past few decades, exploration and development was mainly in conventional Montney reservoirs with production of petroleum from sandstone. More recently, exploration and development interest has shifted to the unconventional Montney area with production from shale formation.

The Montney Formation is a continuous vast hydrocarbon resource within an area of approximately 130,000 km$^2$, and a thickness ranging from less than 1 m in the east to over 350 m in the west. The thickness of the Montney Formation has motivated some operators to stack horizontal wells, where horizontal legs are drilled at two elevations from the same well. The depth of the Montney Formation also increases to the west; from approximately 500 m in the east to over 4,000 m in the west (Rivard et al. 2014). The variation in depth from the east to the west generates different types of stored hydrocarbon including oil, condensate (natural gas liquids), and dry gas zones (Rivard et al. 2014).

Estimates of the amount of natural gas in the Montney Formation are variable, from 2.3 to $20 \times 10^{12}$ m$^3$ of gas (expressed at surface conditions) in place. From the tight unconventional reservoir rock, ~20% of that volume is likely to be recovered (National Energy Board (NEB) 2009) whereas, from conventional reservoir rock, as much as 95% of the natural gas can be recovered (National Energy Board (NEB) 2009). The gas recovery factor for the tight shales is lower due to the low permeability of the rock despite high-density horizontal drilling and extensive hydraulic fracturing.
The Montney Formation can be divided into two units. The Lower Montney consists of sandy and silty shales (offshore transition and marine parts of the basin) and the Upper Montney below the shoreface, where silts have buried the tight sands at the foot of the ramp. These lithostratigraphic units are separated by a basin-wide unconformity that resulted from tectonic uplift of the basin margin (Chalmers and Bustin 2012). The Upper Montney becomes thicker gradually (up to about 159 m) from the east in Alberta to the west in British Columbia (Chalmers and Bustin 2012). Natural gas has been produced from conventional shallow-water shoreface sandstones at the eastern edge of the Montney Formation and from deep-water tight sands at the foot of the ramp (see Figure 4.1).
In both conventional and unconventional reservoirs, the pore system is controlled primarily by mineralogy-cementation, grain shape, texture, natural fractures and diagensis (Davey 2012). The pores control fluid storage (water, oil and gas) and network and connectivity of the pore structure control fluid flow and transport through the formation. In gas shales, mineralogy is an even more significant factor because the mechanical properties of the rocks and the rock response to hydraulic fracturing are strongly impacted by its composition.
Understanding the variations in mineralogy is necessary to build reliable petrophysical and geomechanical models and to optimize the placement of fracturing stages.

Previous studies have shown that the Montney Formation mainly consists of sandstone, shaley sandstone and shale (Chalmers and Bustin 2012). The sandstones tend to have low clay content and high amounts of quartz cement. Shaley sandstones include variable amounts of clay and detrital clay. The cement volume fraction is inversely proportional to clay content in sandstone and shaley sandstone. The porosity decreases with increasing cement volume.

4.2 Geomechanical rock properties and well logs in the Montney study area

Geomechanical rock properties can be determined by lab measurement, from well log data (Jizba 1991), from mineralogy (Mullen, Roundtree, and Turk 2007) and also from seismic data (Gray, Schmidt, and Delbecq 2010; Paddock et al. 2009). Here, well log data from eighteen horizontal and vertical wells, presented in Figure 4.2, were used to evaluate elastic and rock strength.
Figure 4.2 Wells used in this study (Accumap, 2014). The wells highlighted in orange by the radial spokes had GR and RHOB log data. Wells with sonic log data are also highlighted.

Log data is not available for five of those wells but they were still used to build the formation tops in the 3D model. The area, 15 km by 15 km, was chosen to obtain a sufficient number of wells to construct the earth model. The depth interval over which data was retrieved was from 500 m to 3,500 m. Figure 4.3 presents a listing of tops for the formations represented in the model. The topmost formation is the Bearpaw Formation whose top is located at 687 m depth. Since the primary pay zone for this study is the Montney Formation, details for this zone are discussed. The Montney Formation, used in this study, is on average about 150 m thick ranging from 58 m in the east to 254 m in the west. The top of the Montney Formation is between 2,854 m depth in the east to 3,180 m depth in the west.
Two elastic properties related to shale brittleness are the Young’s Modulus and Poisson’s ratio. Young’s Modulus is the ratio of normal stress to strain whereas Poisson’s ratio characterizes the transfer of strain from the direction of the stress load to the other direction. A rock with lower Poisson’s ratio is more brittle. Rocks with higher Poisson’s ratio are more difficult to fracture and prop open than those with a lower value (Ghanizadeh et al. 2015a). Rocks with higher Young Modulus require more normal stress to achieve a given amount of
strain. Formations with lower Young’s modulus tend to be harder to fracture. Based on the spatial distribution of Young’s modulus or Poisson’s ratio or both, the fracture orientation during fluid injection can vary.

Mechanical properties can be estimated indirectly by using the acoustic wave velocity. Measurement of mechanical properties from core samples is time consuming and costly (Jizba 1991; Han, Nur, and Morgani 1986). The determination of these properties is essential to optimize hydraulic fracturing operations.

4.2.1 Dependence on Clay (Shale) Volume

Clay (shale) content has a strong impact on rock properties. Shale volume variations cause changes in the pore network structure which in turn impact both the rock’s porosity and permeability. As described above, shale also affects the brittleness of the rock. Rocks with greater shale content are more ductile and tend to deform instead of breaking under stress (Euzen 2011).

Two sound wave modes propagate through a solid medium: compression (P) and shear (S) waves. S-waves transmit where the direction of movement is perpendicular to the direction of wave propagation. P-waves are such that the particles in the solid have vibrations along or parallel to the travel direction of the wave energy (Milsom 2003).
Here, we use two methods to determine elastic rock properties of the Montney Formation. In the first method, in-situ geomechanical properties are computed by using compressional and shear velocities, expressed as their reciprocal value (their travel time) in combination with the bulk density. For the case of isotropic rock, compression, shear, and bulk density from well log measurements can be used to estimate two mechanical properties: a) the compressional modulus, $M$, determined from the compressional travel time ($\Delta t_c$) and bulk density ($\rho_b$), and b) the shear modulus, $G$, is calculated from shear travel time and bulk density.

$$M = \frac{a \rho_b}{(\Delta t_c)^2} \quad (4.1)$$

$$G = \frac{a \rho_b}{(\Delta t_s)^2} \quad (4.2)$$

The “$a$” in both equations is a unit conversion constant. In turn, these two moduli are used to compute the bulk modulus, $K$, Young’s modulus, $E$, and Poisson’s ratio, $\nu$ (Alford et al. 2006):

$$K = M - \frac{4G}{3} \quad (4.3)$$

$$E = \frac{9KG}{3K+G} \quad (4.4)$$

$$\nu = \frac{3K-2G}{6K+2G} \quad (4.5)$$

The bulk modulus is the ratio of average normal stress to volumetric strain and is the extent to which a material can withstand isotropic compressive loading before failure.

In the second method, Young’s modulus and Poisson’s ratio were derived from the gamma ray ($GR$) and density logs (Jizba 1991). For gas reservoirs, Marion and Jizba (1990)
presented the following equation to calculate compression velocity (P-velocity) and shear velocity (S-velocity) from the GR and density logs (Marion and Jizba 1990):

\[ V_p = 4.82 - 5.04\phi - 0.597V_{sh} \]  
(4.6)

\[ V_s = 3.26 - 3.03\phi - 0.892V_{sh} \]  
(4.7)

where \( \phi \) is rock porosity which can be calculated from the bulk density log, RHOB:

\[ \phi = \frac{\rho_{matrix} - \rho_{OB}}{\rho_{matrix} - \rho_{liq}} \]  
(4.8)

and \( V_{sh} \) is the shale volume fraction which can be determined from the GR log and a correction:

\[ V_{sh,\text{linear}} = \frac{\text{GR}_{\text{GR,sh}}}{\text{GR}_{\text{shale}} - \text{GR}_{\text{sand}}} \]  
(4.9)

Three often used corrections for the fractional shale volume are listed as follows (Larionov 1969; Stieber 1970; Clavier, Hoyle, and Meunier 1971):

\[ V_{sh,Larionov} = 0.08 \left( 2^{3.7V_{sh,\text{linear}}} - 1 \right) \]  
(4.10)

\[ V_{sh,Stieber} = \frac{V_{sh,linear}}{3-2V_{sh,linear}} \]  
(4.11)

\[ V_{sh,Clavier} = 1.7 - \left[ 3.38 - (V_{sh,linear} - 0.7) \right]^{1/2} \]  
(4.12)

and

\[ v = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)} \]  
(4.13)

\[ E = 2\rho V_s^2(1 + v) \]  
(4.14)

The sonic velocity logs can also be used to estimate the unconfined compressive rock strength. There are many correlations between rock strength and sonic travel time or a combination of different logs (Zoback et al. 2012; Onyia 1988; Fjar et al. 2008; Vernik, Bruno, and Bovberg 1993; Bradford et al. 1998; Moos et al. 1999; Horsrud 2001; Hareland 2003).
and Nygaard 2007). Onyia (1988) applied laboratory tri-axial compressive tests from different lithologies to develop a continuous log-based rock strength based on compressional sonic travel time to determine the following correlation for the unconfined compressive strength, $UCS$:

$$UCS = \left[\frac{1.00}{k_1(\Delta t_c-k_2)}\right] + k_4$$

(4.15)

where $\Delta t_c$ is travel time in $\mu$s/ft, $UCS$ (MPa) is sonic-based unconfined compressive strength, and $k_1$, $k_2$, $k_3$ and $k_4$ are lithology dependent constants (Nygaard 2010) (listed in Table 4.1).

### Table 4.1 Lithological constants for Onyia’s correlation, Equation 4.15, for $UCS$

(Nygaard 2010).

<table>
<thead>
<tr>
<th></th>
<th>Sandstone</th>
<th>Shale</th>
<th>Combination</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k_1$</td>
<td>2.48x10^{-6}</td>
<td>1.83x10^{-5}</td>
<td>1.34x10^{-5}</td>
</tr>
<tr>
<td>$k_2$</td>
<td>23.87</td>
<td>23.87</td>
<td>23.87</td>
</tr>
<tr>
<td>$k_3$</td>
<td>2.35</td>
<td>1.8</td>
<td>1.92</td>
</tr>
<tr>
<td>$k_4$</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

In 2007, Hareland and Nygaard used Equation 4.15 but derived different constants for shale formations (listed in Table 2), sandstones, and combined shale and sandstone. In their study, the $GR$ log was used to distinguish between sandstone and shale: $GR<$40°API units were taken to be sandstone correlation whereas readings $>$110°API were taken to be shale and for all readings in between 40 and 110°API, a combined correlation was used (Hareland and Nygaard 2007). Haug et al. (2008) presented a correlation between $UCS$ and static Young’s modulus, $E_S$ given by:
\[ E_s = 111 \text{ UCS}^{1.2} \]  

where \( E \) is in GPa and \( \text{UCS} \) is in MPa (Haug, Nygaard, and Keith 2007).

### Table 4.2 Lithological constants for Onyia’s correlation, Equation 4.15, for UCS as derived by Hareland and Nygaard (Hareland and Nygaard 2007).

<table>
<thead>
<tr>
<th></th>
<th>Sandstone</th>
<th>Shale</th>
<th>Combination</th>
</tr>
</thead>
<tbody>
<tr>
<td>( k_1 )</td>
<td>0.0011</td>
<td>0.0013</td>
<td>0.0012</td>
</tr>
<tr>
<td>( k_2 )</td>
<td>50</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>( k_3 )</td>
<td>3.42</td>
<td>-2.66</td>
<td>0.22</td>
</tr>
<tr>
<td>( k_4 )</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

The \( V_{sh} \) log (pink line) presented in Figure 4.4 is based on the Clavier equation using Equation 4.12. Young’s modulus and Poisson’s ratio were calculated from Equations 4.13 and 4.14, respectively. Equations 4.8 and 4.9 utilize \( RHOB \) and \( GR \) from the logs data. Equations 4.1 to 4.5 use both density and transit time data from the sonic log and Equations 4.6 and 4.7 use porosity (derived from \( RHOB \)) and \( V_{sh} \). Equation 4.15 uses travel time to estimate \( UCS \) and Equation 4.16 estimates \( E_s \) from the \( UCS \). The results plotted in Figure 4.4 reveals the range of variability of shale volume fraction, porosity, Young’s modulus and Poisson’s ratio. The minimum \( GR \) is 10 and the maximum is 284 API units. \( E_s \) varies between 10 and 50 GPa over the depth range from surface to 3500 m depth. The core data is not available for all wells in the study area, therefore Well 2-28 is chosen based on available core data to show and compare results. Sound waves travel slower in high shale content rock compared to that in stiffer rock (Song 2012). Higher shale content results in higher compressional and shear transit times which are the main parameters required for the
Poisson’s ratio calculation (Song 2012). As shown in Figure 4.4, the Young’s modulus is lower in the shale-rich rock compared to that in the shale-poor rock.
Figure 4.4 Calculated rock properties for Well 2-28 from GR and RHOB logs using the Clavier equation.
Figure 4.5 compares UCS for Well 2-28 from core and log (sonic, RHOB, and GR) data (Equation 4.15). The UCS from core data were estimated by using a correlation developed by Ghanizadeh et al. (2014) (Ghanizadeh et al. 2014). Using this correlation, it is possible to estimate UCS values from mechanical hardness data measured by an Equotip Piccolo apparatus (Ghanizadeh et al. 2014). The results demonstrate a fair agreement between the sonic log-derived UCS values and the UCS values estimated from the Equotip Piccolo hardness tests.

Based on core analysis, the Montney Formation (3035 to 3160 m) is comprised of shaley-sandstone. In this study, four common methods have been selected to calculate $V_{sh}$: linear, Clavier, Larionov and Steiber equations.

Figure 4.6 reveals that at 3100 m depth, in the Montney Formation, the Young’s modulus varies between 40 and 82 GPa using the different methods. The highest value of the Young’s modulus is found from Equations 4.1-4.5 by using the sonic logs. The lowest value of the Young’s modulus is obtained from GR calculated from the Stieber equation (Stieber 1970). The value of Young’s Modulus reported from a laboratory test is 47 GPa from a core sample taken from the 3045.14 to 3046.66 m interval of the Montney Formation.
Figure 4.5 Comparison of UCS values from core analysis with log data (Red line is UCS determined from sonic log). The core data are derived from the UCS values (triangular symbols) estimated using a correlation developed by Ghanizadeh et al. (2014). Using this correlation, it is possible to roughly estimate UCS values from the mechanical hardness data measured by Equotip Piccolo apparatus (Ghanizadeh et al. 2014).
Figure 4.6 Comparison of different methods used to calculate Young’s modulus.
Figure 4.7 shows profiles of the rock mechanical properties versus depth for the 3D model. The values in this figure show the average magnitude of gamma ray, density, porosity, shale volume, Poisson’s ratio, and Young’s Modulus at each depth of the study area.

Figure 4.7 Profiles of rock mechanical properties versus depth
The results illustrate that the shaly formations (between 2,800 and 3,080 m) has a higher Poisson’s ratio compared to the less shaly formation (greater than about 3,080 m depth). However, Young’s modulus is lower in the shaly formations (or less brittle formations) such as Doig Formations and higher for less shaly formations above the Doig Formation.

4.3 3D GEOMECHANICAL MODEL CONSTRUCTION – MECHANICAL HETEROGENEITY

The workflow for geomechanic reservoir models is not as well established as for purely geological static models. There are difficulties in identifying rock properties with current logging tools (Yarus and Carruthers 2014). In unconventional tight rock resources, unlike conventional reservoirs, far more emphasis must be given to mechanical rock properties such as elasticity and strength properties. Mechanical and petrophysical properties are used to identify the maximum direction of stress to design the fracture job.

The three-dimensional (3D) geomechanical model developed in this study was constructed based on dynamic elastic properties of the Montney Formation obtained from the 18 wells displayed in Figure 4.2. The domain was tessellated into about 590,000 grid cells with horizontal dimensions of 15km by 15km, and 49 layers of varying thicknesses ranging from 5 to 100 m with true vertical depth between 800 and 3500 m. The population of Young’s modulus, Poisson’s ratio, porosity and UCS within the entire 3D domain was accomplished by using Sequential Gaussian simulation (Deutsch and Journel 1998). Different population algorithms were tested with the available log data. The final results were checked by
removing one well’s data and then populating the values at that well’s location. The results demonstrated that estimation with Sequential Gaussian simulation showed the closest result to the real data for the missing well. The available well data to build the mechanical earth model are listed in Table 4.3.

<table>
<thead>
<tr>
<th>NO</th>
<th>Well Status</th>
<th>UWI</th>
<th>DTC/DTS LOGS</th>
<th>GR LOG</th>
<th>RHOB LOG</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Horizontal</td>
<td>09-22-063-03W6</td>
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<td>06-24-063-05W6</td>
<td></td>
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</tr>
</tbody>
</table>

Table 4.3. Summary of available well data for constructing the mechanical earth model (dark color indicates data exists).
Figure 4.8 displays the porosity distribution. The porosity changes from 0.225 at 800 m depth to 0.025 at 3500 m. For the Montney Formation (2,600 to 3,100 m), the porosity ranges from 0.075 to 0.025. The distribution reveals that porosity varies both horizontally and vertically but in general the porosity decreases with depth. For example, at shallow depth in the Bearpaw or Belly River Formations, the porosity is equal to about 0.2 on average whereas in the Montney and Doig Formations, it is equal to 0.05 on average. Figure 4.9 shows that the density varies significantly throughout the study area. This implies that the mechanical properties will vary significantly within the domain, based on the Equation 4.1 to 4.5.

Figure 4.8 Distribution of porosity in the study area.
To determine $V_{sh}$, four correlations were evaluated to estimate the shale volume: linear (Equation 4.9), Larionov (Equation 4.10), Steiber (Equation 4.11), and Clavier (Equation 4.12), were used. DTS and DTC well log data were available for four wells: 9-22, 9-23, 9-30, and 1-06. By comparing the Young’s modulus determined from the DTS/ DTC logs with those derived from the $GR/RHOB$ logs, among the four methods, it is concluded that the Clavier, Larionov and Steiber Equations (Clavier, Hoyle, and Meunier 1971) gave almost the same values of Young’s Modulus which are most consistent with the core results in comparing with sonic log derived results.

Figure 4.9 Distribution of density (g/cm3) in the study area.
Figure 4.10 shows that the distribution of the Poisson’s ratio is strongly non-homogenous. This parameter varies between 0.05 and 0.28 for the study area but most of the values are in the range from 0.14 to 0.16. The distribution of Poisson’s ratio for the Montney Formation is displayed in Figure 4.11. Here, the Poisson’s ratio varies between 0.09 and 0.20.

The spatial distribution described in Figure 4.11 can be used to design multistage fracturing jobs and the drilling plan. Clays are a major constituent of mud rocks; the most common being illite, kaolinite, chlorite, expandable clays and also siliceous minerals such as quartz, calcite, pyrite, and feldspars. A higher amount of siliceous minerals cause higher values of
Young’s Modulus and consequently a relatively brittle rock unit (Ross and Bustin 2009; Sondhi 2011) whereas more clay is believed to reduce the brittleness of the rock (Ross and Bustin 2009).

Figure 4.11 Distribution of Poisson’s ratio in the Montney Formation.

Figure 4.12 shows the distributions of Young’s modulus throughout the 3D model and Figure 4.13 displays its distribution within the Montney Formation with most values between 55 and 70 GPa.

Most of the values of Young’s modulus are in the range from 40 to 70 GPa but any changes in the initial mineralogical condition of the reservoir can affect elastic properties. For example, the higher amount of calcite which introduces by hydraulic fracture fluids into the formation causes precipitation of minerals from the fluid, and as a result, a larger reduction
of the Young’s modulus with exposure to fracturing fluid will happen (Akrad, Miskimins, and Prasad 2011).

Figure 4.12 Distribution of Young’s modulus (GPa) in the study area.

Strength can be obtained from different methods using the compression and shear sonic log data (Hareland and Nygaard 2007), porosity (Horsrud 2001), and Young’s modulus (Horsrud 2001) for a given formation. Since the Hareland and Nygard (2007) equations are appropriate to our study area, their method was chosen (Hareland and Nygaard 2007). Barree et al. (2009) assumed that in both conventional and unconventional reservoir, the acoustic wave velocities are related to rock elastic properties and other factors will result in variability of the acoustic log; fractures and laminations, external stress, borehole conditions (i.e.
breakouts, mud weight, borehole size), pore pressure, and pore fluid saturation (Barree 2009). Therefore, knowing the acoustic wave velocities map helps to estimate the strength properties as well as the elastic properties distribution in the reservoir.

Figure 4.13 Distribution of Young’s modulus (GPa) in the Montney Formation.

Figure 4.14 shows the spatial distribution of the UCS. The value of the UCS for shallow depth, where the GR is ~70°API (shaley sand area) is in the range from 60 to 80 MPa. The greater the depth, the higher is the UCS. The most frequent value for UCS is between 180 and 210 MPa. Figure 4.15 shows the distribution of UCS throughout the Montney Formation.
Figure 4.14 Distribution of unconfined compressive strength (MPa) in the study area.

Figure 4.15 Distribution of unconfined compressive strength (MPa) in the Montney Formation.
A successful development of an unconventional shale reservoir depends strongly on the quality of reservoir, including its geomechanical properties, and the quality of the hydraulic fracturing stimulation treatment. For most of the time, without a stimulation map that provides spatial distributions of the rock geomechanical properties, shales are not economically targetable and for that reason characterization of reservoir quality and heterogeneity is critical. In the research documented here, we have presented an integrated approach to reservoir characterization and heterogeneity particularized for shale rock formations where hydraulic fracturing can be used, with a focus on the Montney Formation. Different empirical correlations are summarized that relate elastic and rock strength properties to well log data for the Montney shale gas reservoir. The elastic properties of the shale and their spatial distribution are dependent on rock composition. Geomechanical properties change with position and combined with the complex geology of the reservoir and the overburden, this variability can affect completion stability and cause casing collapse and sanding across the field.

4.4 Conclusions

A geomechanical model of the Montney Formation and overlying formations was constructed from petrophysical and geological log data. The 3D model includes distributions of dynamic elastic and rock strength properties. The work demonstrates that geomechanical stratigraphy provides a framework to compare formations and it can be estimated by standard log-based measurements such as the rock density, sonic velocity, and gamma ray logs. Montney Formation In the calculation of the Young’s modulus from sonic logs, different
methods to determine the correction to the fractional shale volume versus depth were compared and it is concluded that the Clavier, Larionov and Steiber equations gave almost the same value of Young’s Modulus which were most consistent with core sample results. The Young’s Modulus calculated from DTC and DTS logs shows a greater value than that derived from core analysis. The distributions of the elastic and rock strength properties of the Montney Formation were generated over a 15 km by 15 km area. The reservoir model of the Montney Formation reveals that the formation is laminated. This can cause hydraulic fracture reorientation during the fracturing job based on the spatial distributions of the Young’s modulus and Poisson’s ratio properties. This, in turn, could lead to complex fracture networks.
5.1 Introduction

Many papers have been published about the development of unconventional tight gas reservoir and in particular, the Montney Formation located in northwest Alberta (Egbobawaye 2013; Reynolds et al. 2015; Kuppe, Nevokshonoff, and Haysom 2012; McLelllan, Mostifavi, and Anderson 2013). Key challenges faced by operators of tight rock resources are optimal well placement, well stability, hydraulic fracturing placement, injectant volume, and number of hydraulic fracture stages. To design and control the fracturing operation, we have to know the magnitude and orientation of in-situ stresses and reservoir rock properties. Three principal stresses exist underground: vertical stress (Sv) and two orthogonal horizontal stresses (the minimum horizontal stress, Shmin, and the maximum horizontal stress, SHmax). The minimum horizontal stress is usually referred to as the closure pressure. Therefore, the fracture is open when the pressure in the fracture is greater than the fracture-closure pressure. These three principal stresses exist in static equilibrium prior to hydraulic fracture stimulation of a reservoir. The vertical stress is considered as a principal stress when the earth surface is completely flat and there is no shear stress acting at the surface. But in areas close to large mountains, the stress field is affected and SHmax (as well as Shmin) can be larger than the vertical stress. Isostatic rebound from deglaciation also alters the stress field, because the stress field will be inclined toward the significant topographic feature (Fox et al. 2013).
In situ stress states are usually divided into three categories based on the relative magnitudes of the three principal stresses (Anderson 1979). If the initial vertical stress $S_v$ is larger than the minimum and maximum horizontal stresses, $S_{hmin}$ and $S_{Hmax}$, in a tectonically relaxed area, the regime is normal faulting. In tectonically active areas, one of the horizontal stresses may exceed the vertical stress. If the intermediate stress is the vertical stress, then the regime is strike-slip faulting. If the least stress is the vertical stress, then the regime is reverse faulting (Zoback 2007). It is expected that all three principal earth stresses are compressive and grow in magnitude with depth (Fox et al. 2013). If the stress contrasts are not large, other mechanisms such as slip on bedding planes (Warpinski and Teufel 1987) and fracture toughness contrast (M. J. Thiercelin et al. 1987) play a role. If the in-situ stresses, that compose one vertical and two horizontal stresses, are comparable or lie within a narrow range, the tensile strength becomes one of the most important parameters in hydraulic fracturing simulation. The distribution of stresses depends mostly on rock elastic properties, lithostatic pressure (vertical stress), tectonic stress, and pore pressure (Keneti and Wong 2010).

The original method to calculate stresses used the bilateral constraint (or uniaxial strain condition/assumption) and had no tectonic component, means it assumed horizontal stresses were due to the overburden, which is an invalid assumption in many parts of the world (Settari 2012). Many attempts have been made to add tectonic forces and other factors into the analysis, but as yet there are no reliable methods to quantify stress other than to examine what happens in a well in response to injection as well as wellbore breakout analysis. Several
techniques to estimate in-situ stresses for shale gas reservoirs have been developed to estimate them from preserved core material, log, or seismic data (Zoback and Byerlee 1975; Bernabe 1987; Kwon, Kronenberg, and Gangi 2001; Warplnskl and Teufel 1992).

Although testing physical samples is the most comprehensive and accurate method to establish geomechanical information on the strength and deformation of a material, use of core to estimate the stress at the sample’s depth is less reliable than other methods (Fox et al. 2013). Furthermore, core samples are typically obtained for the formation of interest only. Also, core tests only represent a single point in a formation without considering heterogeneity of geomechanical parameters. Therefore, with a lack of laboratory measurements for geomechanical parameters, properties must be obtained from indirect measurements such as well logs (Blanton and Olson 1999; Nygaard 2010). The most popular methods to evaluate in situ stresses are based on hydraulic fracturing of formations (e.g. DFIT, microfrac, minifrac) (Hubbert and Willis 1957; Haimson and Fairhurst 1967; Cornet and Valette 1984) and those based on wellbore stability problems (breakouts, drilling induced fractures) (Gough 1982; Zoback et al. 1985; Haimson and Herrick 1986). Recently, some have used sonic methods to examine stresses (Sinha and Kostek 1996; Plonal et al. 1997; Sinha et al. 2006).

Stresses depend on depth, lithology, pore pressure, structure and tectonic setting (Economides and and Nolte 1989). It is assumed that the three principal stresses at a given depth are the vertical stress or overburden stress, \(S_v\); and two orthogonal horizontal principal stresses, \(S_{H\text{max}}\) and \(S_{H\text{min}}\) – this is a simplification of the stress tensor with its six
independent components (Fox et al. 2013). The vertical stress at a depth $z$ from the surface is caused by the weight of the overburden (Jaeger and Cook 1976):

$$S_v(z) = \int_{z=0}^{z} \rho_b(z) g dz \approx \bar{\rho} g z$$

(5.1)

where $\rho_b$ is the bulk density of the overburden (obtained from well logs), $g$ is gravitational acceleration, and $\bar{\rho}$ is the mean overburden density.

Several methods have been used to estimate the minimum horizontal stress. The simplest one, which is called microfrac, uses the instantaneous shut in pressure as an approximation of the minimum stress (Economides and and Nolte 1989), although it is slightly greater than the minimum principal stress (Warren and Smith 1985). Instantaneous shut-in pressure is the pressure at which the pump is shut-in and fluid is allowed to flow back. The least principal stress also can be estimated from minifrac and extended leak-off tests Minifrac is another small-scale fracture test conducted at the start of a hydraulic fracturing operation. Another method, which is called extended leak-off test, is a full pressurization of an open interval of a well until the reservoir fractures from which the least principal stress can be estimated. For this purpose, leak of tests are conducted after casing has been cemented in place and the casing shoe is drilled out a short distance (usually 5 m) (Zoback 2007).

A minimum horizontal stress profile is important for hydraulic fracturing a reservoir especially for tight gas reservoirs such as the Montney Formation in Western Canada. The thickness of this formation ranges from <1 m in the east to >350 m in the west. Knowledge
of the minimum horizontal stress versus depth informs perforation design and zone containment for hydraulic fracturing. Given the thickness of the Montney Formation, some operators stack horizontal wells in a vertical multilateral arrangement (Rivard et al. 2014). The depth of the Montney Formation also enlarges from about 500 m in the east to greater than 4,000 m in the west (Rivard et al. 2014). The variation in depth from the east to the west generates different types of stored hydrocarbon including oil, condensate (natural gas liquids), and dry gas zones. A continuous minimum horizontal stress profile is important to ensure that the drilling operation remains in the safe mud weight window because of the relatively high formation pressure in this area (Boyer et al. 2006). The Shmin orientation can be determined from borehole breakouts or from tensile fractures. Breakouts are spalled cavities in a well where caving has occurred on opposite sides of the wellbore. breakout caving propagates along the minimum horizontal direction while tensile fractures opening parallel to maximum horizontal direction (Bell 2003).

Although the minimum horizontal stress can be determined from downhole tests, the maximum horizontal stress, SHmax, is difficult to estimate in situ. Zoback et al. (Zoback 2007) presented a method to estimate the range for SHmax at a given depth. If there is no tectonic stress and overburden pressure, and the Poisson’s ratio and pore pressure, p, are known, Shmin can be estimated from (Eaton 1969):

\[
S_{hmin} = S_v \frac{\nu}{1-\nu} + \alpha p \frac{1-2\nu}{1-\nu} = \frac{\nu}{1-\nu} (S_v - \alpha p) + \alpha p
\]  

(5.2)

where \(\alpha\) is Biot’s constant,
\[ \alpha = 1 - \frac{C_s}{C_b} = 1 - \frac{K_b}{K_s} \]  

(5.3)

and \( C_s = \frac{1}{K_s} \) is the compressibility of the rock mineral grains, and \( C_b = \frac{1}{K_b} \) is the bulk compressibility, and \( K_b, K_s \) are the corresponding moduli. In 1999, Blanton and Olson introduced tectonic stresses and derived the following equations (Blanton and Olson 1999):

\[
S_{H_{\text{max}}} = \alpha p + \frac{\nu}{1-\nu} (S_v - \alpha p) + S_{H_0}
\]  

(5.4)

\[
S_{h_{\text{min}}} = \alpha p + \frac{\nu}{1-\nu} (S_v - \alpha p) + S_{h_0}
\]  

(5.5)

where \( S_{H_0} \) tectonic stress parallel to the maximum horizontal stress and \( S_{h_0} \) is the tectonic stress parallel to the minimum horizontal stress. The main advantage of this method is that it considers stress features taken at various depths into one analysis. Equations 5.4 and 5.5 can be solved analytically given the pore pressure, Poisson’s ratio and vertical stress with assumptions on the \( S_{h_{\text{min}}} \) gradient and \( S_{H_{\text{max}}}/S_{h_{\text{min}}} \) ratio.

In 2014, Bois et al. presented a new method to calculate \( S_{H_{\text{max}}} \) at various depths of the formation. They assumed relations between the horizontal stress magnitudes and depth based on geology and derived fits for the constants in the relations by using statistical analysis. Their method can be applied to determine the stress state from features observed in more than one well and results only depend on a priori assumptions and not on a posteriori expert decisions (Bois and Vu 2014).
Many researchers have investigated the deformation of rock under stress using numerical methods (Asgian 1988; Bagheri and Settari 2006; Ki-Bok et al. 2004; Meng 1998; Chen and Teufel 1997). Numerical methods used for this analysis generally fall into either continuum methods, discrete element method, or the displacement discontinuity method. Among these methods, the Finite Element Method (FEM) is often the method of choice for stress calculations (Tao 2010). In the research reported here, the FEM, encoded in the VISAGE finite element software package (Schlumberger, 2017), is used to create a geomechanical earth model of the Montney Formation and overburden to understand the state of stress within the Montney Formation.

5.2 Geology of the Study Area

The Triassic Montney Formation is a large economically feasible tight gas reservoir that requires hydraulic fracturing to produce at economic rates. It is located on the border between the provinces of British Columbia and Alberta in Western Canada and consists of shallow-water sands in the east to offshore muds in the west. Over the past few decades, exploration and development was mainly in the conventional Montney reservoir with production of petroleum from sandstone. More recently, exploration and development interest has shifted to the unconventional Montney area with production from shale plays. The Montney Formation can be divided into two parts. The Lower Montney hosts sandy and silty shales whereas the Upper Montney, below the shoreface, contain silts which have buried the tight sands at the foot of the ramp. The Lower and Upper Montney lithostratigraphic units are separated by a basin-wide unconformity originating from tectonic
uplift of the basin margin (Chalmers and Bustin 2012). The Upper Montney is up to ~159 m in thick from the east in Alberta to the west in British Columbia (Chalmers and Bustin 2012).

Shale is a term that can be applied to different type of rocks which are composed of fine-grained particles (clay, quartz, feldspar, heavy minerals, etc.), typically less than 4 microns in diameter, but may contain variable amount of silt-size particles (up to 62.5 microns) (Chalmers and Bustin 2012). Passey et al. found that typical parasequences in a shale gas reservoir resulted in significant variation of petrophysical properties and formation lithology (Passey et al. 2010). In addition, organized distribution of platy clay minerals (Sondergeld et al. 2010) and compliant organic materials (Vernik and Milovac 2011) can lead to complexity of their mechanical anisotropy. In 2011, Ahmadov et. al. claimed that the maturity of shale and amount of clay affects mechanical anisotropy. Understanding rock anisotropy and its causes is crucial because it strongly influences the hydraulic fracturing process, well stability, and production (Ahmadov 2011).

5.3 Geomechanical Characterization

To properly interpret the rock behavior under fracturing, it is necessary to build a geomechanical model of reservoir that includes the mechanical rock properties along with state of three principal stresses. In general, geomechanical rock properties have both static and dynamic values. Deformation tests provide static moduli whereas dynamic moduli are determined from well log data. The two values, both of which can be measured in the lab, may be different for some core samples. Fluid saturation is often the main reason for the
difference between static and dynamic moduli. However, the deformation characteristic of tight shale is dominated by the skeleton stiffness which is close to the solid stiffness which is much higher than that of the fluids. Hence, static and dynamic conditions are similar in very low permeable shale and thus, dynamic and static rock properties are assumed to be the same. As a result, using log data is a practical method to evaluate geomechanical properties for the Montney Formation.

In this study, a three-dimensional (3D) earth model was built by integrating both petrophysical and geological log data as described in Chapter four. The model includes dynamic elastic properties and rock strength property distributions in both vertical and horizontal directions within the reservoir derived from log data from 18 wells and then populated through the model by using geostatistics. Figure 5.1 displays the lithological layers used in the 3D earth model which are located between 550 and 3,500 m below surface.
The distribution of shale content ($V_{sh}$), predicted by Clavier relations, is shown in Figure 5.2 (modified from Vishkai et al., 2017) illustrating the heterogeneity of the $V_{sh}$. Considerable data was gathered to define the geomechanical properties for the Montney area from the 18 well logs. To compute principal stresses, the Young’s modulus, $E$, and Poisson’s ratio are required, not only for the reservoir interval but for the entire overburden (reservoir top side), underburden (reservoir bottom side), and sideburden (reservoir west, east, north and south sides) (Figure 5.2).
Figure 5.2 3D Earth model showing the Goemechanical model with sideburden, overburden, underburden and stiff plate. The domain has been vertically exaggerated by five times.

A simplified set of mechanical properties have been used in our geomechanical model listed in Table 1. The friction angle was calculated from the Plumb equation (Plumb 1994):

\[ \varphi = 26.5 - 37.4(1 - \text{porosity} - V_{\text{shale}}) + 62.1(1 - \text{porosity} - V_{\text{shale}})^2 \]  \hspace{1cm} (5.6)

where porosity and \( V_{\text{shale}} \) were calculated from the gamma ray and density logs.
Table 5.1 Properties used in the geomechanical model.

<table>
<thead>
<tr>
<th>Property</th>
<th>Overburden Properties</th>
<th>Underburden Properties</th>
<th>Sideburden Properties</th>
<th>Stiff plates’ properties</th>
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<td>40</td>
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<tr>
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</table>
5.3.1 Determination of Stress and Pressure Conditions

To reduce the computational cost, the area of study was reduced by using a submodel extracted from the geological-geomechanical model which includes three production wells and one observation well, as shown in Figure 5.3. Sonic and gamma ray logs are available for all three production wells. The 5 km by 5 km domain was tessellated into tetrahedral finite element cells with 42 vertical layers with different thicknesses ranging from 5 to 100 m with depth between 800 and 5,000 m true vertical depth.

Figure 5.3 Production wells and observation well which used in this study (Accumap, 2016). The wells highlighted by the radial spokes had GR and RHOB log data.
To obtain greater resolution of the variation of rock properties in the Montney Formation, the 270 m thickness of the Montney Formation was divided into 27 different layers in the geomechanical finite element model. The cell size is 1m×1m. The total number of finite elements is equal to 42×42×73, 128,772. A visualization of the grid is shown in Figure 5.4.
Figure 5.4 A visualization of the elements is shown in this figure: top image is plane view whereas bottom image shows top view from an angle. The domain has been vertically exaggerated by five times.
Figure 5.5 shows the spatial distribution of Poisson’s ratio and Young’s Modulus in the 3D earth model. Since the density log of some wells began at 550 m MD, a density of 2.35 g/cm$^3$ was assumed for the first 550 m.

The in situ state-of-stress depends on geological features at all scales, from plate boundaries to grain boundaries as well as heterogeneity, both thickness and geological, within formations. The World Stress Map for Western Alberta, displayed in Figure 5.6, enables an examination of stress regimes (Fox et al. 2013). In this map, the orientation of maximum horizontal stress is displayed. The length of the stress symbols indicates the quality of the data, with A being the best quality. Quality A data are assumed to record the orientation of the maximum horizontal compressive stress to within 10°-15° accuracy whereas Quality B
data to within 15-20° and Quality C data are within 25° (not shown in Figure 5.6: Quality D data are considered to give questionable tectonic stress orientations).

Figure 5.6 Stress map of the study area which gives the orientation of the maximum horizontal compressive stress. A, B and C quality data are shown.

Based on this map the direction of SHmax in the study area is approximately 45° and the direction of Shmin is approximately 135° in a southeast-northwest direction. This means that
fractures will form and propagate in a vertical plane in a southwest-northeast direction (~45°).

5.4 Simulation Modeling

The workflow to create the initial in-situ stresses profile in the study area is as follows: 1. generate 3D geological model, 2. construct geomechanical grid, 3. input material properties, 4. populate properties in 3D domain, 5. define boundary conditions, 6. run geomechanical model, and 7. analyze results. The 3D geological model created in the PETREL geological modelling software package is described in Chapter four. This geological model was then input into the VISAGE geomechanical software package and each geological cell was converted into a finite element. The VISAGE package solves the state of stress equations assuming linear elasticity using the finite element method.

The stress tensor is a second order symmetric tensor then it can be shown in Voight notation (Settari 2012):

\[
\{\sigma\} = \begin{pmatrix}
\sigma_{xx} \\
\sigma_{yy} \\
\sigma_{zz} \\
\tau_{xy} \\
\tau_{yz} \\
\tau_{zx}
\end{pmatrix}
\] (5.8)
where $\sigma_{xx}$, $\sigma_{yy}$ and $\sigma_{zz}$ are normal stresses and $\tau_{xy}$, $\tau_{yz}$ and $\tau_{zx}$ are the shear stresses. For solving the stress equations three sets of equations are involved. The first is the constitutive law of linear elasticity stress-strain relationship which is given by Hooke’s law:

$$
\begin{bmatrix}
\sigma_{xx} \\
\sigma_{yy} \\
\sigma_{zz} \\
\tau_{xy} \\
\tau_{yz} \\
\tau_{zx}
\end{bmatrix} =
\begin{bmatrix}
C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\
C_{21} & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\
C_{31} & C_{32} & C_{33} & C_{34} & C_{35} & C_{36} \\
C_{41} & C_{42} & C_{43} & C_{44} & C_{45} & C_{46} \\
C_{51} & C_{52} & C_{53} & C_{54} & C_{55} & C_{56} \\
C_{61} & C_{62} & C_{63} & C_{64} & C_{65} & C_{66}
\end{bmatrix}
\begin{bmatrix}
\varepsilon_{xx} \\
\varepsilon_{yy} \\
\varepsilon_{zz} \\
\gamma_{xy} \\
\gamma_{yz} \\
\gamma_{zx}
\end{bmatrix}
$$

The second set of equations consists of the compatibility equations of the strain/displacement relationships:

$$
\begin{align*}
\mathbf{u} &= \begin{bmatrix} u(x, y, z) \\ v(x, y, z) \\ \omega(x, y, z) \end{bmatrix} \\
\mathbf{v} &= \begin{bmatrix} \varepsilon_{xx} \\ \varepsilon_{yy} \\ \varepsilon_{zz} \\ \gamma_{xy} \\ \gamma_{yz} \\ \gamma_{zx} \end{bmatrix}
\end{align*}
$$

The strain/displacement relationships are defined by:

$$
\begin{align*}
\varepsilon_x &= \frac{\partial u}{\partial x}, \quad \varepsilon_y = \frac{\partial v}{\partial y}, \quad \varepsilon_z = \frac{\partial \omega}{\partial z} \\
\gamma_{xy} &= \left(\frac{\partial v}{\partial x} + \frac{\partial u}{\partial y}\right), \quad \gamma_{yz} = \left(\frac{\partial \omega}{\partial y} + \frac{\partial v}{\partial z}\right), \quad \gamma_{zx} = \left(\frac{\partial \omega}{\partial z} + \frac{\partial u}{\partial x}\right)
\end{align*}
$$

The third set of equations are the static equilibrium conditions which are:

$$
\begin{align*}
\frac{\partial \sigma_{xx}}{\partial x} + \frac{\partial \tau_{xy}}{\partial y} + \frac{\partial \tau_{zx}}{\partial z} + \rho X &= 0 \\
\frac{\partial \tau_{xy}}{\partial x} + \frac{\partial \sigma_{yy}}{\partial y} + \frac{\partial \tau_{yz}}{\partial z} + \rho Y &= 0 \\
\frac{\partial \tau_{zx}}{\partial x} + \frac{\partial \tau_{yz}}{\partial y} + \frac{\partial \sigma_{zz}}{\partial z} + \rho Z &= 0
\end{align*}
$$

where $X$, $Y$, and $Z$ are forces due to gravity (zero in horizontal directions). Solving the above equations (the equilibrium, constitutive and compatibility) provides the stress, strain and displacement fields (15 equations in 15 unknowns for 3D problems). The finite element
method (FEM) is used to discretize the equations over the domain. After discretization, the solution for the displacements of the nodes (at the corners of each element) are found from the following set of linear equations (Settari 2012):

\[ K\Delta d = \Delta P \]  

(5.16)

where \( K \) is the stiffness matrix, \( \Delta d \) is the vector of displacements, and \( \Delta P \) is a load vector resulting from the imposed boundary conditions, induced pressure and temperature changes.

Overburden, underburden and sideburden mesh cells were added to the existing geomechanical grid to avoid boundary effects on the solution. In this study, it is assumed that the rocks are bound tightly by sideburden and underburden zones. Therefore, the tectonic strain is zero in their natural state. To perform a geomechanics simulation, properties are needed that describe the characteristics of the material in each finite element. These properties vary according to the type of geomechanical material present in that finite element.

The initial guess for the stress is determined by using information from the global tectonic stress from the World Stress Map [for Shmin (the minimum horizontal stress gradient due to tectonic loading), \( SH_{\text{max}} \)] which are applied at the boundaries of the model in addition to vertical stress determined based on material density and gravity. Also needed for the boundary conditions are values for \( SH_{\text{max}}/Sh_{\text{min}} \) (the ratio of the maximum horizontal stress gradient and the minimum horizontal stress gradient) and the \( Sh_{\text{min}} \) direction (the horizontal stress azimuth is the angle that the minimum principal stress projected onto the horizontal plane makes with the north bearing).
For finite element solution, user tolerances that are specified are as follows. Mesh pinchout
tolerance (specify the minimum distance between two adjoining nodes) is equal to 0.1 m.
The iterative matrix solver convergence tolerance is set equal to $1.0 \times 10^{-7}$.

5.5 Results and Discussion

The results of the finite element solution have been compared to the industrial standard
conventional method of calculating stresses from logs. In addition, the results were
compared to Diagnostic Fracture Injection Test (DFIT) results. Values of the minimum stress
from DFIT analysis from several wells were obtained from an operator in the Montney
Formation and varied from 38 to 50 MPa. At each depth, the least principal stress should
always exceed the pore pressure and the difference between the minimum and maximum
principal stresses cannot exceed the strength of the rock which in turn depends on depth and
pore pressure (Zoback 2007).

As shown in Figure 5.7, target horizons in the Montney are characterised by Young’s
modulus between 43 and 57 GPa, Poisson’s ratio between 0.22 and 0.35, and tensile strength
between 18 to 24 MPa (results from Chapter four). In general, the rock mechanical properties
vary because of the variation of rock composition in the formation. Shale-rich rock has
higher Poisson’s ratio compared to less shaly rock. Sound waves travel slower in high shale
content rock compared to that in stiffer rock (Song 2012). Higher shale content results in
higher compressional and shear transit times which are the main parameters affecting for the Poisson’s ratio calculation (Song 2012). The results from the finite element calculation are displayed in Figure 5.7 along the trajectory of the observation well. The minimum stress is highest in the Montney Formation and that it correlates to the profile of the Poisson’s ratio. There is a sharp increase of the tensile strength near the top of the Montney Formation because of tectonic effect as well as poroelastic effect at the pay zone. The maximum value of the Young’s Modulus (57 GPa) in the pay zone (at 2860 m depth) is affected by high rock compressibility at this area. Greater rock compressibility makes the pay zone more ductile and easier to crack.

Figure 5.7 Elastic properties and pore pressure, Shmin, Sv, and SHmax stress profiles in the 3D geomechanical model at the location of the observation well. The green box indicates the Montney Formation.
Figure 5.8 displays the 3D distributions of the stresses and pore pressure from the FEM calculations for the base case. The values of the horizontal and vertical stress magnitudes as well as pore pressure all increase with depth but heterogeneity of the profiles are evident arising from the underlying heterogeneity of the geomechanical properties. The minimum horizontal stress is lower than the vertical stress whereas the maximum horizontal stress is larger than the vertical stress. This defines a strike-slip faulting regime. This distribution of stress demonstrates high strain situation caused by poroelastic effect and low Young’s Modulus units correlating with low differential stress and high differential stress associated with high Young’s Modulus units (Zoback 2007).
Figure 5.8 Base case stress distributions. The pink marker indicates the surface location of the observation well. The vertical dimension has been exaggerated five times.

Three cases were considered to calibrate the stress value based on the minimum horizontal stress gradient and maximum and minimum horizontal stress ratio as follows:

Case 1: Minimum horizontal stress gradient is assumed to be 21 kPa/m and maximum horizontal stresses/minimum horizontal stress ratio is equal to 1.2.

Case 2: Minimum horizontal stress gradient is assumed as 18 kPa/m and maximum horizontal stresses/minimum horizontal stress ratio is equal to 1.4.

Case 3: Minimum horizontal stress gradient is assumed as 19 kPa/m and maximum horizontal stresses/minimum horizontal stress ratio is equal to 1.2.
Figure 5.9 displays the results for Case 1. In this case, the stress regime ranges from strike-slip faulting (from about 2200-2700 m) and reverse faulting regimes.

The minimum stress varies from 59 to 73 MPa which is higher than that obtained from DFIT analysis (38-50 MPa reported by 7Generation Ltd.). Knowledge of the minimum horizontal stress gradient allows better mud weight window planning and hence reduces the chance of
wellbore break-out or unintentional fracturing injecting at or above the interpreted fracture pressure of 25.52 kPa/m in Case 1. The breakdown pressure is 73 MPa with $SH_{\text{max}}=1.5$ Sv and $Sh_{\text{min}}=0.917$ Sv. The maximum horizontal stress line lies well above the vertical stress but the minimum horizontal stress is nearly equal to vertical stress up to 2,000 m depth.

Figure 5.10 presents the results for Case 2. The results reveal that strike-slip is the structure-controlling regime in this case. The minimum horizontal stress values vary from 36 to 56 MPa which is in DFIT analysis range of 38-50 MPa (from 7Generation Ltd.). The $SH_{\text{max}}=1.6$ Sv and $Sh_{\text{min}}=0.68$ Sv. The maximum horizontal stress profile lies well above the vertical stress, and the minimum horizontal stress profile is below the vertical stress but is still greater than the pore pressure profile.
Figure 5.10 Case 2: Stress profiles resulting from minimum horizontal stress gradient equal 18 kPa/m and the horizontal stress ratio of 1.4.

Figure 5.11 indicates the results for Case 3. The results reveal that the strike-slip regime is structure-controlling in this case. The minimum horizontal stress values vary between 43 and 58 MPa which is consistent with the DFIT analysis range of 38-50 MPa (from 7Generation Ltd.). The results show that SHmax=1.39 Sv and Shmin= 0.813 Sv. The
maximum horizontal stress profile lies well above the vertical stress and the minimum horizontal stress profile is below the vertical stress but is still higher than the pore pressure profile.

Figure 5.11 Case 3: Stress profiles resulting from minimum horizontal stress gradient equal 19 kPa/m and the horizontal stress ratio of 1.2.

Figure 5.12 displays a comparison of stresses calculated from the industry standard conventional method which uses Equations (5.4) and (5.5) based on log data (solid lines)
versus values from the FEM method (dashed lines), for Case 3. Young’s Modulus and Poisson’s Ratio are also shown in the depth range between 2,500 and 3,000 m. Figure 5.12 reveals both methods are reasonably well matched although in general, the values from Equations 5.4 and 5.5 are higher than that determined from the FEM method. Both the FEM results and conventional method show that the strike-slip faulting regime exists throughout the whole depth of reservoir. The maximum horizontal difference from the FEM method arises from the heterogeneity of the rock properties in 3D space which is ignored in the conventional method.
Figure 5.12 Rock properties and stresses profile based on logs versus depth (in m). Dashed lines are from the FEM model (Case 3) whereas solid lines are from Equations (5.4) and (5.5).
5.5.1 Effect of Mountain on Stress Profile at Observation Well

The Rocky Mountains sit on the western side of Alberta, Canada and consequently affect the stress profiles in the Western Canada Sedimentary Basin. Here, we examine the impact of the presence of mountains on the west side of the model. To simplify the addition of the mountains, we added a vertically loaded region to the west side of the model (as illustrated in Figure 5.13) to approximate the mountains as a large vertically directed load on the west side of the model.

![Figure 5.13](image.png)

**Figure 5.13** The simulated mountain (yellow region) on the west side of the study area. The domain has been vertically exaggerated by five times.
The changes of the stress profiles are shown in Figure 5.14. The results show that the maximum stress, minimum stress and vertical stress all increase with depth but follow the same basic profiles as the base case. The presence of the ‘mountain’ load causes more compressional stress on the system. This implies that more energy is required to drill the well or fracture the rocks. In the shallow zones (<1,000 m) the difference between those two cases is small but around the production zone in the Montney Formation the difference between those cases is approximately 8 MPa.

Figure 5.14 reveals that compared to the base case, the faulting regime has changed to reverse faulting between 1,500 and 2,200 m depth. In other words, the minimum horizontal stress is more than vertical stress at this depth range and the reverse faulting took place at this depth in the presence of mountain.
Figure 5.14 Comparison of stress magnitudes in the absence and presence of mountain around the observation well.
5.5.2 Hydraulic Fracturing Operations

Accurate placement of horizontal well plays a critical role in the successful economical production from unconventional shale gas reservoir. However, there are several uncertainties due to many uncertain parameters such as reservoir permeability, porosity, fracture spacing, fracture half-length, fracture conductivity, and well spacing. The fracture grows parallel to that of the maximum horizontal direction in its longest horizontal dimension and grows perpendicular to the minimum horizontal stress in its shorter horizontal dimension.

Usually it is difficult to quantify and verify stress contrasts in the reservoir and thus, stress behavior map have significant role in fracturing studies in addition to the rock properties map. One of the critical rock properties which needs attention is stiffness. The stiffness parameter is indicated by the Young’s Modulus; the higher the Young’s Modulus, the stiffer the rock. The 3D geomechanical model represents the spatial variability of the rock mechanical properties within the reservoir and surrounding formations. Figure 5.7 reveals that the Montney Formation has higher Young’s modulus and tensile strength than overlying formations. Higher values of the Young’s modulus indicate brittle (versus ductile) behaviour. The more ductile the rock, the greater is the tendency for plastic deformation before fracturing. The elevated value of the Young’s modulus in the Montney Formation than that in the surrounding formations suggests that the hydraulic fracture extend to this formations. The stress and Young’s modulus contrasts between the formations also play a role in fracture containment within the Montney since it is undesirable to propagate the fracture into non-hydrocarbon formation. Also, the stress can impact fracture aperture
growth since it is controlled by the minimum horizontal stress magnitude and as a result more fracture conductivity will be expected in areas with less minimum horizontal stress.

5.6 Conclusions

A comprehensive study has been performed to get a better understanding of the state-of-stress in the Montney Formation in Alberta, Canada prior to hydraulic fracturing. A geomechanical earth model has been used to evaluate the initial state of stress in the Montney Formation using the finite element method. The results on the state-of-stress of the Montney Formation are consistent with results from log analysis and DFIT analysis. The analysis of the state-of-stress reveal that the strike-slip regime is the dominant regime in the Montney Formation although depending on the gradient of the minimum horizontal stress, the reverse faulting regime may also be present. The distributions of the stresses provide information to guide hydraulic fracturing. Montney Formation. The differences of the Young’s modulus and stresses between the Montney Formation and the surrounding formations may provide some degree of containment of the hydraulic fractures within the Montney Formation. The base case results suggest that the faulting regime is in the strike-slip regime. The results also show that the stress distributions are heterogeneous reflecting the heterogeneity of the density and geomechanical properties in the domain. In the case where a stress load is added to represent the mountains, the faulting regime changes to reverse faulting over an interval between 1,500 and 2,200 m depth. Although this interval is not in the Montney Formation, this implies that in the presence of extra load, fracture propagation could be complex since the tectonic stress is changed due to the presence of the mountains and the maximum and
minimum horizontal stress values is altered as well as the failure model. Since it is practically impossible to evaluate the impact of mountains in the laboratory, the method used here provides a unique data source to understand the stress profile in the Montney Formation with mountains.
CHAPTER SIX: GEOMECHANICAL EFFECTS ON HYDRAULIC FRACTURE CONDUCTIVITY: MONTNEY FORMATION, ALBERTA, CANADA

6.1 Introduction

In tight shale, hydraulic fracturing of the rock is necessary to create sufficient permeability for commercial production of petroleum (Bello and Wattenbarger 2010). Hydraulic fracturing was introduced to the industry in 1947 in the Hugoton gas field, in the Kelpper Well, located in Grant County, western Kansas, U.S.A, to maximize the output of the well. The response of the reservoir rock to fluid injection depends on the rock geomechanical properties, amount of fluid injected, presence and characteristics of natural fractures, and properties of the confining underlying and overlying formations (Skomorowski 2016). Thus, there is a need to build predictive models that take these features into account to understand and determine the extent of fracturing that occurs when fluid is injected into the reservoir and to optimize these processes to make them more cost effective with improved performance.

Hydraulic fracturing occurs when fluid exceeding the fracture pressure of the reservoir is pumped into the reservoir from a wellbore. The reservoir rock breaks either under tension resulting in tensile fractures or compression, resulting in shear fractures. As illustrated in Figure 6.1, there are three main modes of failure when fracturing rock (Settari 2012). Mode I fractures (open mode) occur when a fracture opens against the least principal stress. This means that the tensile stress in the fracture must exceed the least principle stress. Mode II
(sliding mode) and III (tearing mode) fractures are both consequences of shear but with different directions of fracture propagation relative to the applied stress. Dissolution of rock material under very high compressive stress can be caused by Mode IV (closing mode) fractures. Mode V fractures (deformation bands) are created from displacement of material during shear (Fox et al. 2013).

Figure 6.1 Different modes of fracture displacement (Modified from: www.makel.org).

Hydraulic fracturing design is usually done by computer modelling, often using two-dimensional (2D) simplified models, or by experience (rules-of-thumb). The outcome from these designs are specifications for the fracture volume, fluid injection rate, and proppant rate to realize goals of fracture geometry (height, fracture width (aperture) and fracture length) or extent of the stimulated reservoir volume (fracture network). When a fracture (or
fracture network) starts to propagate into the reservoir, the fracture width, length and height grow (Fox et al. 2013).

Describing the process of initiation, propagation, short-term, and long-term evolution of hydraulic fractures requires a combination of fluid flow in reservoir and fracture (fluid-solid interactions), proppant fluidization in the fracture, rock failure, fracture geometry and geomechanics of the reservoir rock. There is a large body of literature on fracture mechanics and models that deals with impermeable rocks, for example see (Dong and De Pater 2001). In modeling these processes, there are serious challenges: a variety of complex physical processes, limited geomechanics information, heterogeneous and discontinuous matrix, changing temperature, changing pressure, single or multiphase fracture fluids, Newtonian or non-Newtonian fluid behaviour, laminar or turbulent flow regimes, different stress profile caused by formation heterogeneity, proppant fluidization, and so on. Because of these difficulties, it is necessary to make simplifications to balance efficiency, spatial resolution, and inclusion of physical processes. The classical conceptual model of hydraulic fracturing is that of a single opening-mode fracture that propagates away from the wellbore into a homogeneous, non-porous, linearly elastic reservoir rock (Perkins and Kern 1961). These basic models, including the Perkins-Kern- Nordgren (PKN) (Perkins and Kern 1961) and Khristianovitch-Geertsma-de Klerk (KGD) (Geertsma and De Klerk 1969) 2D models, are still used in hydraulic fracturing design and modeling (Nassir, Settari, and Wan 2013). However, in settings with complex fracture networks, classical models are not useful with having a large degree of uncertainty.
Three-dimensional (3D) models have been developed to estimate height growth. The Pseudo 3D model (P3D) is a natural extension of the 2D PK (Perkins and Kern 1961) model. It can provide quite realistic height growth calculations while being computationally fairly efficient (Settari and Cleary 1984). For a contained fracture (i.e., height growth smaller than length growth), it is assumed that the fracture height growth is represented by a KGD-type (Geertsma and De Klerk 1969) model and the fracture length growth is governed by PKN-type (Perkins and Kern 1961; Nordgren 1972) model, resulting in a “lateral lumped model” (Settari 2012). These methods are still used in some commercial software packages, although they tend to overestimate the fracture height as reported in (Lee and Ghassemi 2011). Most 3D models assume that the fracture propagates in a plane (called planar models). In this case, the solution of the fracture problem is simplified to a half-space and the fracture opening under the load given by the fluid in the crack, and the 2D flow through the crack and leak-off, subject to the overall mass balance, are solved simultaneously (Settari 1980; Ji, Settari, and Sullivan 2009; Dontsov and Peirce 2015; Suppachoknirun 2016; Ma 2016; Cipolla et al. 2010; Passey et al. 2010; Britt and Smith 2009). Planar 3D models have been used to study the details of the mechanics of fracture containment and can be coupled with proppant transport models (Settari 2012; Weng 2015). Pseudo-3D (P3D) models also provide realistic height growth predictions compared to planer model. Non-planar, truly fully 3D models, are the most complex fracture simulation models available (Weng et al. 2014). In these models, the fracture propagates in any direction but the computational expense is significant.

In grid-based models, the fracture is propagated through a fixed grid. This idea was used in early 2D hydraulic fracture simulators (Settari 1980) where when the stress normal to the
fracture plane exceeded the tensile strength, the fracture extended into a new grid cell. Therefore, grid-based models were suitable for coupling with reservoir simulators and geomechanics codes (Ji, Settari, and Sullivan 2009). 3D grid-based models were extended to deal with multiple fractures, for example, the MultiFrac Placement Pseudo 3D (MLF-P3D) model (Dontsov and Peirce 2015). These models are very complex being capable of simulating multiple hydraulic fractures simultaneously propagating from multiple perforation intervals where each perforation location can have specific rock properties and stress profile. Therefore, the flow rate distribution at the perforation intervals can be variable.

Conventional planar fracture models are adequate to represent the physics of non-fractured formations with high stress anisotropy but are inadequate to simulate complex fracture geometry in shale formations (Suppachoknirun 2016). Wiremesh models represent the fracture network as the combination of two orthogonal sets of fractures, with the major fracture set parallel to the maximum horizontal stress and the minor fracture set parallel to the minimum horizontal stress (Ma 2016). The wiremesh network model provides a reasonable representation of induced fracture networks if the shale formation contains two perpendicular sets of vertical planar fractures. Since all natural fractures are not active, the induced fractures may not follow exactly the same spacing as the natural fractures (Weng 2015).

For a formation that contains weak planes such as natural fractures or faults which are oriented at arbitrary angles to the stress direction, the induced fracture network can be very complex. These types of formations require models that account for fluid flow,
geomechanics and crack formation and evolution, and account for interactions between the induced hydraulic fractures and natural fractures (Kresse, Weng, and Cohen 2014; Qiu et al. 2015). The Unconventional Fracture Model (UFM), developed by Cipolla et al. (2010), considers the effect of natural fractures, stress distribution, and influence of the mechanical properties of fracture morphology (Cipolla et al. 2010). The UFM model can simulate the propagation of asymmetric fracture networks accounting for fluid flow in the fracture network and elastic deformation of the fractures. The initial assumptions and governing equations (fluid flow in the fracture network, mass conservation and fracture deformation) are similar to the conventional P3D model (Weng 2015).

Passey et al. (2010) claimed that there is a large variability in lithology between shale plays and even within a single shale formation (Passey et al. 2010). Britt and Smith (2009) emphasized the importance of geomechanics and the state of stress of a shale play for a successful hydraulic fracturing stimulation (Britt and Smith 2009). In addition, Rickman et al. (2008) stressed that the mechanical rock properties, such as brittleness and mineralogy, are fundamental in completion designs. While ductile shale tend to restore any fracture formed, brittle shale often have natural fractures which react to hydraulic fracturing (Rickman et al. 2008). In general, the Young’s Modulus of the shale measured parallel to the bedding plane is greater than that measured perpendicular to the bedding plane. Sone and Zoback (2013) explained the role of anisotropy on the elastic behavior of shale and analysed static and dynamic elastic properties of several samples from Barnett, Eagle Ford, Haynesville, and Fort St. John shale plays in both perpendicular and parallel orientations to the bedding plane. They claimed that the elastic properties of these rocks had high variability.
between the shale formations and within the play itself and the parallel orientation samples had higher values when compared to the perpendicular orientation (Sone and Zoback 2013). Based on Sone and Zoback (2013), shale is comprised two types of layers: one “soft” and the other “stiff”. Clay and kerogen contents compose the “soft” layer while quartz, feldspars, and carbonates compose the “stiff” layer. These minerals impact the mechanical properties resulting in layers with variable properties.

Despite the diversity of hydraulic fracturing modeling described in the literature, few studies have been done to model hydraulic fracturing in laminated and heterogeneous reservoirs such as the Montney Formation in Alberta, Canada. Here, a 3D Unconventional Fracture Model accounting for flow and geomechanics together with geological, petrophysical, and geomechanical heterogeneity is used. Uncertain parameters such as the in-situ horizontal stresses and Young’s modulus are constrained so that the model matches production data.

6.2 Hydraulic fracturing modelling

In hydraulic fracturing, fluid is pumped into the pay zone at high enough rates and pressure to crack the reservoir rock. The fluid pressure, being above the breakdown pressure, causes one or more tensile fractures to be created that extend from the wellbore perforation (Gidley 1989). Continued injection of fluid extends the fractures at the fracture tips which extends the fracture network into the reservoir creating a storage space for the injected fluid. After fluid injection is stopped, the pressure levels off as some fraction of the injected fluid invades
the tight matrix of the reservoir rock. Proppants, fluidized in the injected fluid, preserve newly created fractures within the reservoir rock (Weng et al. 2014).

Hydraulic fracture models have evolved over the past 70 years with increased accuracy and complexity (Gidley 1989). These models are used to specify the pump rate, volume of fluid and proppant injected, and potential ramping of the proppant concentration during injection to achieve a target fracture network extent in field operations (Weng et al. 2014).

In the research documented here, the Mangrove hydraulic fracturing simulator is used (Schlumberger, 2017). For the fracture geometry model, in this simulator, the Unconventional Fracture Model (UFM) is used. In this method, the effect of geomechanical properties on the fracture network growth and propagation as well as fluid flow and proppant transport is considered. It is a cell-based model which solves the fully coupled problem of fluid flow in the fracture network and the elastic deformation of the fractures. In this model, stresses increase with depth but are assumed to be constant at each depth (no variability in a horizontal plane). The UFM fracture models contain four essential components to represent the behaviour of the process: i) fracture creation and aperture dependence on fluid pressure, ii) fluid flow within the fracture, iii) boundary conditions (well and reservoir) and extent of fracture propagation, and iv) proppant transport in the injected fluid (Weng et al. 2014). These are described in the following.

i) Fracture creation and aperture dependence on fluid pressure: In typical hydraulic fracturing practice, the fluid pressure exceeds the minimum in-situ stress to initiate the fracture. Thereafter, the fracture propagates normal to the minimum in-situ stress.
Theoretically, the higher the net pressure (the fluid pressure minus the minimum stress), the wider is the fracture aperture. However, the fracture aperture depends on several additional factors including the rock strength properties and formation elastic properties. When the formation consists of weak planes such as faults and natural fractures, the interaction of hydraulic and natural fractures creates multiple intersecting fracture planes and a complex fracture network. For a planar fracture in an elastic medium, the 3D fracture problem can be reduced to a 2D integral equation over the fracture plane (Adachi, Detournay, and Peirce 2010):

\[
p(x, y) - \sigma_h(x, y) = \int_A C(x, y, x', y')W(x', y')dx'y'
\]  

(6.1)

where \(p(x, y)\) is fluid pressure, \(\sigma_h(x, y)\) is a minimum in-situ stress, \(W(x', y')\) is a fracture opening width, \(A\) is a surface area of the fracture, and \(C(x, y, x', y')\) is a complex stiffness function (the induced stress at location \((x,y)\) generated by a unit opening width at location \((x', y')\) on the fracture plane). To solve this equation, the net pressure must be known. However, the fluid pressure itself depends on the fracture opening width. Consequently, the fracture opening width equation and fluid flow equation are coupled and must be solved simultaneously to obtain fluid pressure and width.

ii) Fluid flow within the fracture: Fluid flow within the fracture must satisfy mass conservation: the net fluid flow into the fracture is equal to the enlargement of fracture volume minus the fluid loss beyond the fracture. Therefore, the mass balance equation for an incompressible fracturing fluid in the planer fracture is:

\[
\frac{\partial w}{\partial t} + \frac{\partial q_x}{\partial x} + \frac{\partial q_y}{\partial y} + q_l = 0
\]  

(6.2)
where \( q_x \) and \( q_y \) are components of flow rate per unit length in the fracture and \( q_l \) is the leak off fluid into the formation through the both face of the fracture which can be estimated from the Carter equation (Mack and Warpinski 2000):

\[
q_l = \frac{2c_t}{\sqrt{t - \tau(x,y)}}
\]

(6.3)

where \( c_t \) is fluid leakoff coefficient and \( \tau(x, y) \) is the time when the fluid arrives at location \((x, y)\) on the fracture surface. Fluid flow must also satisfy the momentum balance which relates flow rate to pressure gradient in the fracture (Gidley 1989):

\[
\frac{\partial p}{\partial s} = \frac{2k}{w^{2n+1}} \left[ \frac{4n+2}{n} \right]^n q_s [q]^{n-1}
\]

(6.4)

where \( n \) and \( k \) are power-law and consistency indices of the fracturing fluid. In general, the slurry that enters the formation obeys a power-law rheological behavior and \( s \) applies to \( x \) and \( y \) directions.

iii) Boundary conditions and extent of fracture propagation: The boundary conditions at the fracture tip govern fracture propagation. After the fracture is initiated, the fluid pressure causes the rock ahead of the fracture tip to become stressed under tension and consequently, the rock close to the tip undergoes plastic deformation. The stress intensity factor \((K_I)\) characterizes the magnitude of stress singularity at the fracture tip. The material’s resistance to fracture propagation is quantified by the critical stress intensity factor, also referred to as fracture toughness \((K_{IC})\). The fracture front propagates when the stress intensity factor at the tip induced by the fracture fluid pressure becomes equal to the fracture toughness. Thus, at the fracture tip, the boundary conditions are: \( W = 0 \) and \( q = 0 \). For any time step, the mass balance will dictate the amount of fracture tip extension. Therefore, the resulting pressure as well as the fracture width must satisfy the elasticity-flow equations (Equations 6.1-6.4) and
above boundary conditions. At each time step, the fracture volume is equal to the amount of injected fluid minus the leaked fluid to the formation. The fracture tip position solved for iteratively.

iv) Proppant transport in the injected fluid: Proppant transport is governed by the ability of the fluid to carry the particles within the fracture. After the fluid pressure distribution in the fracture is obtained from the coupled elasticity-flow equations, the flow velocity field can be found which can be used to solve for proppant transport:

$$\frac{\partial (cw)}{\partial t} + \nabla \cdot (cwv_p) = 0$$  \hspace{1cm} (6.5)$$

where $c$ is the volume concentration of the proppant and $v_p$ is the velocity of proppant which is obtained from the coupled elasticity-flow equations. This model assumes that the proppant particles do not affect the fluid velocity and that transport is solely by convection.

In the UFM model, vertical flow is neglected, the stress intensity factors at fracture top ($K_{tu}$) and bottom tip ($K_{tl}$) as well as fracture width ($W$) can be directly computed analytically for a layered medium with piecewise constant stress (but not layered moduli), as given in the following equations (Mack and Warpinski 2000):

$$K_{tu} = \sqrt{\frac{\pi h_f}{2}} \left[ P_{cp} - \sigma_m + \rho_f g \left( h_{cp} - \frac{3}{4} h_f \right) \right]$$

$$+ \frac{2}{\pi h_f} \sum_{i=1}^{m-1} (\sigma_{i+1} - \sigma_i) \left[ \frac{h_f}{2} \cos^{-1} \left( \frac{h_f - 2h_i}{h_f} \right) - \sqrt{h_i(h_f - h_i)} \right]$$  \hspace{1cm} (6.6)$$

and

$$K_{tl} = \sqrt{\frac{\pi h_f}{2}} \left[ P_{cp} - \sigma_m + \rho_f g \left( h_{cp} - \frac{1}{4} h_f \right) \right]$$
\[ W(y) = \frac{4}{E'} \left[ P_{cp} + \rho_f g (h_{cp} - y) - \sigma_m \right] \sqrt{y(h_f - y)} \]

\[ + \frac{4}{\pi E'} \sum_{i=1}^{m-1} (\sigma_{i+1} - \sigma_i) \left[ (h_i - y) \cosh^{-1} \left( \frac{y}{|y-h_i|} \frac{h_f-2h_i}{h_f} + \frac{h_i}{|y-h_i|} \right) + \sqrt{y(h_f - y) \cos^{-1}(\frac{h_f-2h_i}{h_f})} \right] \]

where \( h_i \) is the distance from top of the \( i^{th} \) layer to the fracture bottom tip; \( P_{cp} \) is the fluid pressure at a reference depth; \( h_{cp} \) is the height at the center of the perforations; \( \rho_f \) is fluid density, \( E' \) is the plane strain modulus, \( E' = E/(1 - \nu^2) \); \( h_f \) is the total height of the fracture, \( m \) is the total number of layers and \( y \) is the elevation measured from the bottom tip of the fracture. The fracture height can be determined at each position of the fracture by matching Equations 6.6 and 6.7. The UFM fracture growth shows in Figure 6.2.
Equations 6.2 and 6.4 together with Equation 6.8 form a set of equations with unknown variables $p$, $w$, and $q$ at each cell which are solved numerically subject to the boundary condition at the tip and at the wellbore perforations by using the finite element method. Since the flow equation is highly nonlinear, Newton’s method is used to find the solution.

In the model, a given fracture pumping schedule is divided into small time increments. The fracture tip is extended by a small increment at each time step until the total mass balance is satisfied. This procedure is repeated for all the time steps to the end of the pumping.
For rock failure, the Mohr-Coulomb failure criterion is used to predict failure load as well as the angle of fracture. The stresses, $\sigma$ and $\tau$, oriented at direction $\theta$ is given by (Fjar et al. 2008):

\[
\sigma = \frac{1}{2}(\sigma_1 + \sigma_2) + \frac{1}{2}(\sigma_1 - \sigma_2) \cos 2\theta
\]

\[
\tau = -\frac{1}{2}(\sigma_1 - \sigma_2) \sin 2\theta
\]

(6.9) \hspace{1cm} (6.10)

where $\sigma_1$ a maximum is horizontal stress, $\sigma_2$ is a minimum horizontal stress, $\tau$ is a shear stress, and the angle $\theta$ is the angle at which the normal to the plane of interest is inclined to $\sigma_1$. The radius of circle is $\frac{1}{2}(\sigma_1 - \sigma_2)$ and the center is at the point $\frac{1}{2}(\sigma_1 + \sigma_2)$ on the x-axis.

Therefore, the largest absolute value for the shear stress is $\frac{1}{2}(\sigma_1 - \sigma_2)$ which occurs at $\theta = \frac{\pi}{4}$ and $\theta = \frac{3\pi}{4}$. Mohr-Coulomb failure is based on the assumption that when a component of the dynamic stress field $\delta T(t)$ is added to the local stress field $T$, the extra stress can push a critically-stressed fracture or fault beyond the Coulomb failure threshold. The extra stress can be caused by a seismic event or hydraulic fracturing (Davey 2012):

\[
T(t) = T + \delta T(t)
\]

(6.11)

The Coulomb failure threshold is defined by Byerlee’s Law for rock friction (Byerlee 1978):

\[
\tau(t) = \pm [C + \mu \sigma_m(t)]
\]

(6.12)

where $C$ is a cohesive strength, $\mu$ coefficient of static friction, $\tau(t)$ is shear stress and $\sigma_m(t)$ is an effective normal stress components acting on the fault under the stress field $T(t)$. Failure occurs when the Mohr circle touches the Coulomb failure envelope with the tangent point $(R_c, \theta_c)$ (Fjar et. al. 2008).
In the model used here, the Mohr-Coulomb criterion is applied in 3D with the following equations. The stress state for any gauss points defined as (Fjar et. al. 2008):

\[
\{\sigma\} = [\sigma_x, \sigma_y, \sigma_z, \sigma_{xy}, \sigma_{yz}, \sigma_{zx}]^T
\]  

This parameter can be rewritten independent of the coordinate system as follow:

\[
I_1 = (\sigma_1, \sigma_2, \sigma_3)
\]

where \(\sigma_1, \sigma_2, \sigma_3\) are principal stresses and

\[
J_2 = \frac{1}{2} s
\]

is the second principal invariant of the deviatoric stress tensor, where \(s = \sigma - \frac{1}{3} I\)

and \(s\) is a deviatoric stress tensor and \(I\) is the identity matrix and

\[
J_3 = s_1 s_2 s_3
\]

is the third principal invariant of the deviatoric stress tensor. Then, \(p, q, \) and \(\theta\) are given by:

\[
p = \frac{1}{3} I_1, \quad q = \sqrt{3J_2}, \quad \theta = \tan^{-1}\left[\frac{1}{\sqrt{3}} \left(2 \left(\frac{\sigma_2 - \sigma_3}{\sigma_1 - \sigma_3}\right) - 1\right)\right]
\]  

where \(-30^\circ \leq \theta \leq 30^\circ\). The yield function is then given by:

\[
F = p \sin \varphi + J \left(\cos \theta - \frac{\sin \theta \sin \varphi}{\sqrt{3}}\right) - c \cos \varphi
\]

where \(J = \sqrt{J_2}\), \(\varphi\) is the friction angle and \(c\) is the cohesive strength.

At any time step, \(F < 0\) means there is no viscoplastic flow and then the net pressure can be increased to the next step. Once \(F \geq 0\), the yield criterion at any integration point has occurred and shear failure occurs in the rock.
To initiate a hydraulic fracture, the pressure necessary to breakdown the formation is the pressure required to overcome hoop stress around a perforation (at wellbore) and rock tensile strength, $T$, of the formation. In our case study the horizontal well was drilled perpendicular to the minimum horizontal stress. So the breakdown pressure can be obtained from Haimson and Fairhurst equation (B. Haimson and Fairhurst 1967):

$$P_b = T + 3S_{hmin} - S_{Hmax} - P_{pore}$$

(6.16)

where $P_b$ is a fracture breakdown pressure, $T$ is a tensile strength of a rock, $S_{hmin}$ is a minimum horizontal stress, $S_{Hmax}$ is a maximum horizontal stress and $P_{pore}$ is a pore pressure within the rock. This relationship assumes elastic behavior, an isotropic response from the fracture rock (Jaeger and Cook 1976), as well as no fluid penetration by wellbore wall.

For fracture propagation, the classical criterion, based on the original idea of Griffith (1921), determines the ability to propagate a fracture based on the comparison of stress intensity factor, $K_{lc}$, between the fracture and the rock containing the fracture. The subscript I refers to the opening mode of crack deformation. Typically, a hydraulic fracture propagates perpendicular to the least principal stress and in low pressure zone.

$$K_I \geq K_{IC}$$

(6.17)

$$K_I = (P_f - \sigma_{min})\sqrt{\pi L_f}$$

(6.18)

Where $P_f$ is pressure inside the fracture, and $L_f$ is the initial fracture half-length, $\sigma_{min}$ is initial minimum stress ahead of fracture tip and $K_{IC}$ is fracture toughness. Fracture toughness
is one of the rock properties and is a measure of the resistance of the rock to crack propagation (Thiercelin and Roegiers 2003).

Therefore, the minimum pressures required to propagate the fracture can be written as:

\[ P_f = \sigma_{\text{min}} + \frac{K_{IC}}{\sqrt{\pi L_f}} \]  

(6.19)

### 6.3 Geological-geomechanical reservoir model

The geological-geomechanical model was constructed from well data from the Montney Formation in Alberta, Canada. A description of the lithological layers in the model is presented in Figure 6.3.

![Lithological layers used in the earth model (from 550 to 3,500 m below surface).](image)

Figure 6.3. Lithological layers used in the earth model (from 550 to 3,500 m below surface).
The properties of the 3D geomechanical model was populated geostatistically by using the Petrel (Schlumberger 2016) geological modelling package as described in Vishkai et. al. (Vishkai et al. 2016). The distributions of the Young’s modulus, Poisson’s ratio, porosity, and tensile strength are displayed in Figure 6.4. More details on the source data used to create the geological and geomechanical properties of the three-dimensional (3D) model and input data (18 wells) are provided in Chapter four and Chapter five and will not be repeated here.
Figure 6.4 Porosity and elastic properties around Well 9-22. The black box indicates Montney Formation.
Table 6.1. Properties used in the geomechanical model.

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Rock Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Young’s Modulus</td>
<td>38-50</td>
<td>GPa</td>
</tr>
<tr>
<td>Poisson Ratio</td>
<td>0.2-0.4</td>
<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>2.3-2.8</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.01-0.30</td>
<td>m³/m³</td>
</tr>
<tr>
<td>Biot Elastic Constant</td>
<td>0.95</td>
<td></td>
</tr>
<tr>
<td>Fracture toughness</td>
<td>1099</td>
<td>kPa·m⁰.⁵</td>
</tr>
<tr>
<td>Tensile Strength</td>
<td>6-27</td>
<td>MPa</td>
</tr>
<tr>
<td>Friction Coefficient</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>Rock Compressibility</td>
<td>2E-06</td>
<td>KPa⁻¹</td>
</tr>
<tr>
<td><strong>Overburden Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Young’s Modulus</td>
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<td>GPa</td>
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<tr>
<td>Poisson Ratio</td>
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<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>2.35</td>
<td>g/cm³</td>
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<tr>
<td>Porosity</td>
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<td>m³/m³</td>
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<tr>
<td>Unconfined Compressive Strength</td>
<td>4</td>
<td>MPa</td>
</tr>
<tr>
<td><strong>Underburden Properties</strong></td>
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<td></td>
</tr>
<tr>
<td>Young’s Modulus</td>
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<td>GPa</td>
</tr>
<tr>
<td>Poisson Ratio</td>
<td>0.30</td>
<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>2.30</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Property</td>
<td>Value</td>
<td>Unit</td>
</tr>
<tr>
<td>--------------------------</td>
<td>--------</td>
<td>---------------</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.30</td>
<td>m³/m³</td>
</tr>
</tbody>
</table>

**Sideburden Properties**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young’s Modulus</td>
<td>40</td>
<td>GPa</td>
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<tr>
<td>Poisson Ratio</td>
<td>0.25</td>
<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>2.30</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.30</td>
<td>m³/m³</td>
</tr>
</tbody>
</table>

**Stiff plates’ properties**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young’s Modulus</td>
<td>500</td>
<td>GPa</td>
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<td>Poisson Ratio</td>
<td>0.25</td>
<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>2.30</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.30</td>
<td>m³/m³</td>
</tr>
</tbody>
</table>

**Fluid property**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$n$</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>$k$</td>
<td>$6 \times 10^{-4}$</td>
<td>Pa.s$^{n}$</td>
</tr>
</tbody>
</table>

Briefly, the model ranges from 550 to 3500 m below surface – the Montney Formation is located between ~2850 and ~3100 m depth. To reduce the computational cost, the area of study was reduced by using a submodel, described in Vishkai et al. (2017b), which was extracted from the original model and includes three production wells.
The Mangrove hydraulic fracturing model requires geomechanical and geological properties of the reservoir rock, initial reservoir rock (and surrounding formation) stress magnitude and orientation, and well completion and production data. The unstructured production grid for one stage hydraulic fracturing consists of 137550 finite elements in total with grid cells \((n\times n\times n_{\text{Grid Layer}})\) equal to \(4585\times 1\times 30\). The geomechanical input data is listed in Table 6.1 and the summary of the input data set in the model is shown in Table 6.2. The input data required to model hydraulic fracturing around the Well 9-22 is as follows: fracture fluid and proppant properties, completion design, and pump rates. The stress and pore pressure profiles in the vertical direction at Well 9-22 is shown in Figure 6.5.

<table>
<thead>
<tr>
<th>Production grid type</th>
<th>Unstructured</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir target depth</td>
<td>2860 m TVD</td>
</tr>
<tr>
<td>Initial reservoir temperature</td>
<td>76.85 °C</td>
</tr>
<tr>
<td>Minimum reservoir pressure</td>
<td>7 MPa</td>
</tr>
<tr>
<td>Maximum reservoir pressure</td>
<td>35 MPa</td>
</tr>
<tr>
<td>Pore pressure gradient</td>
<td>11.8 KPa/m</td>
</tr>
<tr>
<td>Matrix permeability</td>
<td>0.0001 mD</td>
</tr>
<tr>
<td>Gas gravity</td>
<td>0.66</td>
</tr>
<tr>
<td>Oil API gravity</td>
<td>45</td>
</tr>
<tr>
<td>Bubble point pressure</td>
<td>30 MPa</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>0.3985 cP</td>
</tr>
<tr>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>Solution gas/oil ratio (undersaturated oil)</td>
<td>270.0862 sm³/sm³</td>
</tr>
<tr>
<td>Water Formation Volume Factor</td>
<td>1.013 rm³/sm³</td>
</tr>
<tr>
<td>Sgr</td>
<td>0.1</td>
</tr>
<tr>
<td>Corey Coefficient Gas</td>
<td>6</td>
</tr>
<tr>
<td>kgr@Swmin</td>
<td>0.8</td>
</tr>
<tr>
<td>krg@Sorg</td>
<td>0.7</td>
</tr>
<tr>
<td>Sorw</td>
<td>0.25</td>
</tr>
<tr>
<td>Sorg</td>
<td>0.25</td>
</tr>
<tr>
<td>Corey Coefficient O/W</td>
<td>3</td>
</tr>
<tr>
<td>Corey Coefficient O/G</td>
<td>3</td>
</tr>
<tr>
<td>kro@Somax</td>
<td>0.8</td>
</tr>
<tr>
<td>Swmin</td>
<td>0.3</td>
</tr>
<tr>
<td>Swcr</td>
<td>0.35</td>
</tr>
<tr>
<td>Corey Coefficient Water</td>
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</tr>
<tr>
<td>krw@Sorw</td>
<td>0.7</td>
</tr>
<tr>
<td>krw@S=1</td>
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</tr>
<tr>
<td>Perforation per stage</td>
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</tr>
<tr>
<td>Distance between adjacent stages</td>
<td>70-85 m</td>
</tr>
<tr>
<td>Perforation spacing</td>
<td>13 m</td>
</tr>
<tr>
<td>Perforation diameter</td>
<td>10.67 mm</td>
</tr>
</tbody>
</table>
Figure 6.5 (a) Pore pressure and stress profiles (b) and maximum horizontal stress and minimum horizontal stress ratio.

Figure 6.6 shows the Well 9-22 trajectory with its 19 fracture stages as well as formation tops. The domain is separated into zones based on the formation layers for the Mangrove simulation. The Montney Formation depth is in the range of 2840 to 3110 m. The total measured depth (depth as measured along the trajectory of the well) is 4636 m and temperature gradient was taken to be $3^\circ C/100$ m vertical depth. Here, the first stage of hydraulic fracturing is modelled. The first stage measured depth is equal to 3706 m with true vertical depth equal to 2868 m. The fracturing fluid for the first stage was pumped at 7.8 m$^3$/min (through the casing). The fracture fluid is slickwater with 100 mesh Sand B361-100 proppant. In the model, the fracturing fluid is taken to be Newtonian ($n = 1$).
Figure 6.6 Well 9-22 is located in the upper Montney Formation (horizontal section landed at 2860m) with the 19 stages perforation intervals.
Figure 6.7 displays the 3D distribution of the Young’s modulus in the Montney Formation close to Well 9-22.

6.3.1 Initial stress and pressure conditions

The state of stress is affected by geological features at all scales, from grain boundaries to natural fractures to faults to plate boundaries, and heterogeneity of the formation. Based on the World Stress Map for Western Alberta, the direction of the maximum horizontal stress, $S_{Hmax}$, in the study area is oriented approximately 45° and the direction of the minimum horizontal stress, $S_{hmin}$, is approximately 135° in the southeast-northwest direction (Heidbach 2016). This implies that fractures will form and propagate in vertical plane oriented in the southwest-northeast direction (~45°). The initial state of stress was obtained by using the VISAGE finite element stress simulator, described in Chapter five. The stress
profiles reveals that the least principal stress is below the vertical stress. In this case, a more compressional stress state is indicated and maximum horizontal stress exceeds the vertical stress which would define a strike-slip faulting regime. The minimum horizontal stress gradient is around 18 kPa/m and maximum horizontal stress/minimum horizontal stress ratio is equal to about 1.5.

6.4 Reservoir Model

Dual-continuum concepts, dual porosity and dual permeability, can be used to model the fluid flow in the reservoir. Mangrove uses a dual-porosity model where gas can only flow from matrix to the fracture and between fractures and gas allows to flow between the matrix blocks by using a dual-permeability model. The shale has a relatively high storage capacity and thus provides gas to the fracture. Two parameters are used to represent the connectivity between the matrix and fracture zone: 1. the interporosity flow parameter (transmissibility or transfer coefficient), $\lambda$, measures the flow between matrix blocks and fracture system and 2. the fluid capacitance coefficient (storativity ratio), $\omega$, which is the ratio of fracture storage capacity to the total storage capacity. The concept of black oil model is used within a production grid. Two pseudo components defined at the surface condition are referred as the oil and gas at stock-tank conditions. In reservoir, volume of the oil phase contains of oil component and soluble gas component. The gas phase which referred as dry gas, holds only gas component, can be existed when the in situ pressure is lower than the bubble point pressure, $P_b$. The amount of dissolved gas in oil phase is determined from the solution gas-oil ratio, $R_s$, which decreases with decreasing pressure below the $P_b$. Solution gas-oil ratio
remains constant when the oil is undersaturated at the pressure greater than Pb. The volume of oil and gas at these two different conditions are related by formation volume factor, Bo, and, Bg respectively.

By considering the water as the wetting phase of rock matrix, the relative permeability functions used for three-phase fluid flow calculations in the scope of this study have been derived based on Corey’s correlations (Fekete Associates Inc. 2012). Based on these correlations, each system has been assumed to consist of only 2 mobile fluids, that is, either oil-water system or gas-oil system with irreducible water (krw depends only on Sw while Krog depends only on Sg).

In this study, the properties, including the relative permeability, capillary pressure, formation volume factors, and overall proppant permeability versus closure pressure as well as the properties of fluids, specified in Table 6.2. However, several properties including formation volume factor, compressibility, and viscosity of each phase have been determined from the correlations at a particular condition during the production simulation.

The grid system in the production numerical model should be exclusively constructed to facilitate the fluid flow simulation in this study. So to the characteristics of the grid used in this thesis, Cipolla et al. (2010) explained that the grid system has very fine grid next to the fractures and a logarithmically increasing grid size away from the fracture to efficiently simulate the fluid flow (Cipolla et al. 2010) which is called unstructured grid, Figure 6.8.
Figure 6.8 Unstructured grid

6.5 Results and discussion

Figure 6.9 shows the fracture treatment results for the first stage for the base case parameters. The data shows that the average Young’s modulus in the pay zone is equal to 50 GPa. Figure 6.9c shows the maximum fracture width is 3 mm which happens at a time of 13 min at which the breakdown pressure occurs. As pumping continues, the fracture width decreases to 2.7 mm at 20 min. The hydraulic conductivity is defined as the product of the fracture permeability and fracture width (Economides and Nolte 1989). Figure 6.9b displays the fracture conductivity map through the hydraulic fracturing treatment with the average value
equal to 150 mD.m. Figure 6.9d demonstrates that the maximum fracture length for Perforations 1 and 2 are both 550 m. The fracture height grows mostly downwards into the Montney Formation. The fracture height is reported as the total height of the fracture with the center located at the specified target depth. The average fracture height for Perforation 1 is 210 m whereas for Perforation 2 it is 200 m. The total leak off volume in this case is 713 m$^3$ with total fracture volume equal to 1561 m$^3$ and the reported fracture fill efficiency, defined as the ratio of fracture volume and pumped volume, is 68.7%. This implies that a large fraction of the injected fluid is lost to the matrix. The higher conductive region is shown in the yellow color (around 500 mD.m) and the lower conductive region is displayed in the pink color (around 2 mD.m). The distribution of conductivity is variable through the fracture planes based on the rock properties and stresses variations through the formation.

The minimum horizontal stress for the pay zone lies between 51 and 56 MPa and the maximum horizontal stress ranges from 80 to 85 MPa. There is a region around the well bore where the conductivity is lowest (2 mD.m), but it increases away from the perforation and is around 500 mD.m in the Lower Montney Formation, as seen in Figure 6.8b. Figure 6.8c shows the net pressure profile for Fractures 1 and 2 at Perforations 1 and 2. The net pressure is defined as the excess pressure beyond the closure pressure that causes the fracture to grow. After fracture initiation, the zone is pressurized and reaches the fracture propagation pressure, which is greater than the fracture closure pressure. The net pressure represents the sum of the frictional pressure drop and the fracture-tip resistance to propagation (Nolenhoeksema 2013) and it depends on the fracture geometry. The net pressure declines versus time in radial geometry, therefore the highest net pressure would occur initially. If the
geometry is a confined height fracture that extends in length, then the net pressure tends to increase with time, and the highest net pressure would be at the end of pumping (Castle et al. 2007). In this study the net pressure is gradually increased to 1.9 MPa at 13 min when rock breakdown occurs. The fracture starts to propagate after breakdown. As pumping continues the net pressure slowly decreased to 1.3 MPa at 20 mins.
Figure 6.9 Base case results: (a) Young’s modulus profile around Well 9-22, (b) 3D results showing distribution of conductivity (single stage), (c) fracture width and net pressure graphs, and (d) fracture height (blue and purple), fracture length (green and pink) and efficiency (orange) magnitudes.
6.5.1 Effect of Young’s modulus on fracture conductivity

To investigate how the Young’s modulus affects fracture conductivity, two simulations were conducted with all other parameter constant except for the Young’s modulus. The average Young’s modulus for Montney Formation was dropped to 43 GPa (Figure 6.10a). For Perforation 1, Fracture 1, there is no connected pathway around the well bore, from well into the formation, at the end of fracturing job, although there is expected to see more conductive pathway for softer rock with lower Young’s modulus. Figure 6.109b shows the fracture conductivity; compared to the base case value in Figure 6.9b, the fracture conductivity decreased with lower Young’s Modulus. Relative to the base case, Figure 6.10c displays that the net pressure increased to 1.9 MPa (from 1.4 MPa for the base case) and fracture width increased to 3.2 mm (from 2.7 mm for the base case) at time 20 min with lower Young’s modulus. Based on the KGD model, the width is related to modulus by $w \sim (1/E)^{1/4}$ which shows that the fracture width is relatively insensitive to Young’s modulus. However, the results from the 3D numerical model show a small growth of fracture width with decreasing modulus which does not explain the enhancement of the conductivity. The stiffer rock with higher Young’s modulus is expected to need more pressure to crack. Based on the KGD model the net pressure is related to the Young’s modulus by $P_{net} \sim (E)^{3/4}$ (Mack and Warpinski 2000; Gidley 1989).
Figure 6.10 Sensitivity with respect to Young’s modulus: (a) Base case Young’s modulus (orange dots) and reduced Young’s modulus (blue dots), (b) 3D results showing distribution of conductivity (single stage), (c) fracture width and net pressure graphs, and (d) fracture height, fracture length and efficiency magnitudes.
The height of the fracture is mostly affected by the offset from the well to the upper or lower barrier layers and their initial state of stress and geomechanical properties relative to that of the target formation. The heights of Fractures 1 and 2 are equal to 190 and 210 m, respectively. The length of the fracture into the target formation is strongly dependent on the target formation’s Young’s modulus. For the reduced Young’s modulus, the total fracture volume is equal to 1590 m$^3$ with total leak off volume 682 m$^3$ with efficiency (ratio of fracture volume and pumped volume) equal to 70.0%. There are numerous attempts at correlating fracture conductivity versus rock characteristics from experimental results (Jansen et al. 2015; Britt and Smith 2009; Egbobawaye et al. 2013). The results from experiments suggest that the fracture conductivity rises with larger Young’s modulus but the results remain unclear since other parameters also affect fracture growth simultaneously, such as proppant type, fracture roughness, and formation geology (initial porosity, permeability, and mineralogy).

### 6.5.2 Effect of initial reservoir pressure changes on fracture conductivity

To study the effect of initial reservoir pressure on fracture growth, the reservoir pressure was raised (by 5 MPa) with all other parameters kept constant. The results are displayed in Figure 6.11. Figure 6.11c shows that this pressure has grown to 2 MPa after 12 minutes of injection at the elevated reservoir pressure. The results show that the fracture width is not affected by changing the reservoir pressure. Figure 6.11b displays fracture propagation downward into the Montney Formation. The fracture conductivity map shows the connected pathway from the well bore to the fracture network conductivity between 100 and 150 mD.m. The fracture
network is not symmetric as shown in Figure 6.1b. This is due to the laminated layers in the Montney and heterogeneity of rock properties and stress magnitudes.

Fracture height is not intensely influenced by pressure changes whereas the fracture length changes significantly. The net pressure is affected by the fracture tip pressure drop caused by viscous fluid flow and vice versa. Therefore, at constant formation porosity and permeability, a longer fracture is expected with higher net pressure. In the raised reservoir pressure case, the fracture length has grown to 750 m with total leak off volume reduced to 628 m$^3$, total fracture volume increased to 1644 m$^3$, and efficiency (ratio of fracture volume and pumped volume) raised to 72.4%.
Figure 6.81 Sensitivity with respect to initial reservoir pressure: (a) Base case initial reservoir pressure (orange dots) and enlarged initial reservoir pressure (blue dots), (b) 3D results showing distribution of conductivity (single stage), (c) fracture width and net pressure graphs, and (d) fracture height, fracture length and efficiency magnitudes.
6.5.3 Effect of minimum horizontal stress on fracture conductivity

3D distribution of the minimum horizontal stress in the Montney Formation close to Well 9-22 has been shown in Figure 6.12. Here, we explore how the minimum horizontal stress in the target reservoir affects the fracture network. Therefore, the initial minimum horizontal stress has been lowered in the reservoir as displayed in Figure 6.13a. Gidley et al. (1989) claimed that the fracture can propagate upward into hard, high strength and high modulus materials, but they would not propagate downward through the thin, high stressed layers (Gidley 1989). If the stress profile is uniform then the fracture growth is radial and we have a theoretical decrease in net pressure with pump time.

Figure 6.92 3D distribution of the minimum horizontal stress in the Montney Formation close to Well 9-22. The domain has been vertically exaggerated by ten times.
If there is a stress contrast or stress barrier then we have confined fracture height growth and there is a theoretical increase in net pressure with time. If net pressure is high in comparison with the closure stress contrast, the fracture will grow into the neighbouring zones (Warpinski 2011).

Figure 6.13 shows the minimum horizontal stress through the Montney between 51 and 57 MPa. The stress magnitude increases with depth but does not vary horizontally.

Hubbert and Willis (1957) showed that whenever the stress field is anisotropic, there is a preferred fracture azimuth perpendicular to the minimum compressive principal in situ stress. In the other words, the fracture prefers to take the path with the minimum resistance and therefore opens against the smallest stress (Hubbert and Willis 1957). Therefore, by decreasing the minimum horizontal stress it is expected that the fracture width will enlarge; this result is observed in Figure 6.13c. The results show that the net pressure is not affected by changing the minimum horizontal stress. Figure 6.13b shows the fracture propagation downward through the Montney Formation with raised conductivity to 500 mD.m directly around the well bore. There is a good connected pathway from the well bore to the fracture network. It is shown that the fracture conductivity mostly varies between 50 and 300 mD.m. As shown in Figure 6.13b, the fracture network is not symmetric around the well bore.
Figure 6.103 Sensitivity with respect to minimum horizontal stress: (a) Base case minimum horizontal stress (orange dots) and reduced minimum horizontal stress (blue dots), (b) 3D results showing distribution of conductivity (single stage), (c) fracture width and net pressure graphs, and (d) fracture height, fracture length and efficiency magnitudes.
Fracture height and length are not intensely influenced by the change of the minimum horizontal stress. The total leak off volume in this case drops to 674 m$^3$ and total fracture volume rises to 1599 m$^3$ with efficiency (ratio of fracture volume and pumped volume) at 70.4%. If the minimum horizontal stress is raised further until it exceeds the overburden stress, the stress regime has been changed to the reverse stress regime. Therefore, the smaller the difference between minimum horizontal stress and overburden, the higher the chance to shift to a reverse stress regime. A shift to a reverse stress regime leads to the so-called “pancake frac” behavior (Blanton and Olson 1999) where there is relatively little height growth with relatively large lateral growth of the fracture network.

6.6 Conclusions

Successful production from the Montney Formation is related to the quality of the reservoir (rock and fluid) as well as the quality of the hydraulic fracturing stimulation design. Therefore, accurate characterization of reservoir and heterogeneity is critical. Here a UFM model has been used with properties sourced from a detailed geological and geomechanical reservoir model. The hydraulic fracture and reservoir production model was run to obtain the best match with field production data. The results from this study demonstrate the influence of Young’s modulus, reservoir pressure, and minimum horizontal stress on fracture geometry and characteristics for the Montney Formation. In the case of the Montney reservoir with its laminated layers, hydraulic fractures are easily initiated and grow in zones of homogeneity but after they reach the interface with an upper zone, the hydraulic energy is dissipated in the upper zone. Given the anisotropy of reservoir geological and
geomechanical properties, hydraulic fractures propagate as a complex network. The results of this study indicate typical characteristics for the baseline case. The simulations demonstrate how hydraulic fracturing conductivity distributes in the formation and what factors influence fracture characteristics. Elastic rock properties such as the Young’s modulus have a significant impact on the resulting fracture network and geometry. The results reveal that lowering the Young’s modulus of the pay zone raises the fracture width, and reduces the fracture conductivity. Differences of the Young’s modulus between the reservoir rock and overburden and understrata rocks affects the height growth of the fracture. An increase of the initial reservoir pressure results in a larger fracture length as well as higher conductivity. The decrease of the minimum horizontal stress increases the fracture width and fracture conductivity. The fracture height and length were not significantly affected by the change of the minimum horizontal stress.
CHAPTER SEVEN: ON MULTISTAGE HYDRAULIC FRACTURING IN TIGHT GAS RESERVOIRS: MONTNEY FORMATION, ALBERTA, CANADA

7.1 Introduction

Hydraulic fracturing is the process of pumping fluid through the wellbore into rock to crack it yielding enhanced permeability for production of petroleum from the rock (Yu and Sepehrnoori 2013). The fluid carries proppant into the fracture network which keeps the fractures open, since the high-pressure environment of the rock formation naturally causes fractures to close. The productivity of tight rock resources, whether for gas or liquids, is linked to the extent and permeability of the fracture network that is created around the well. However, at this point, there is limited ability to model and predict the growth of fractures or fracture networks around wells especially considering multistage operations.

The purpose of fracturing is to enhance well production by increasing the volume of relatively high permeability rock that can connect with the wellbore. Therefore, the number of fracture stages per well must be optimized in long horizontal wells. If the number of fracture stages are too low per well, production is not be maximized and if the stages are too tightly spaced, the risk of ‘screen out’ or longitudinal fractures is increased, which can also harm productivity (Roussel and Sharma 2011).

Horizontal wells with multistage hydraulic fracturing is a relatively new technology which replaced vertical well with a single hydraulic fracturing treatment. Since drilling multiple horizontal wells with single stage fracturing are uneconomical, multistage hydraulic
fracturing has become the standard operation. Although many operators have attempted to put as many stages into a well as possible to access the maximum amount of resource, evidence has revealed adding stages does not always raise the production rate proportionately (Dohmen et al. 2014). Instead, research in the literature has claimed that more stages may actually lead to less production in the long term (Nagel, Zhang, and Lee 2013; Dohmen et al. 2014). On hydraulic fracturing behavior, the transient pressure and production rate are strongly influenced by several factors, such as reservoir permeability and fracture conductivity. Therefore, some operators have focused on these parameters to evaluate fracture behavior (Yao 2013).

Since the mid-1960s, many attempts have been made to predict MultiStage Hydraulic Fracturing (MSHF) behavior by using analytical and numerical modeling (Yao 2013). In 1973, Gringarten and Ramey presented a method using Green’s functions to describe the pressure behavior of a continuous plane source. Their model provided information concerning permeability, fracture lengths, and distance to a symmetrical drainage limit (Gringarten and Ramey 1973). In 1984, Giger et al. suggested another analytical solution for evaluation of horizontal wells intersecting fractures; however, their method could not manage fluid flow in the fracture and reservoir properly (Giger, Reiss, and Jourdan 1984). Roberts et al. (1991) presented a semi analytical solution to evaluate multistage hydraulic fracture productivity (Roberts, Engen, and Kruysdijk 1991). In 1994, Herge presented relatively accurate method to determine the productivity of multifractured horizontal wells. He used a wide ranges of examples to illustrate the effectiveness of multifractured horizontal wells with well response compared to non-fractured vertical and horizontal wells and to
fractured vertical wells (Herge and Laif 1994). In 1996, Kuppe and Settari investigated the productivity of different configurations of fractured horizontal wells by means of numerical simulation (Kuppe and Settari 2012). In the 2000s, several models were developed to describe multistage fracture behavior in horizontal wells (Guo and Yu 2008; Wei et al. 2016). Recently, Liu et al. (2017) showed that the number of fractures, fracture half length, fracture conductivity, and fracture volume are the main factors that control well productivity (Liu et al. 2017). Proposed models include several flows (reservoir radial and linear flow, fracture linear and radial flow) but none of them take interference effects between adjacent fractures into account. Other models have been developed to model this behavior on the hydraulic fracturing treatments (Zangeneh, Eberhardt, and Bustin 2015; Gil et al. 2011; Suppachoknirun 2016).

Based on the literature, it is widely known that formation properties and rock elastic properties have a strong impact on the hydraulic fracture conductivity. Therefore, knowledge of formation properties as well as completion procedure are necessarily to design the hydraulic fracture treatment. However, predictive modelling of hydraulic fracturing treatments are not yet available. Here, we develop a field-calibrated hydraulic fracture model to understand and optimize fracturing treatments in the field.
7.2 Background on the Montney Operation

Two completion methods are typically used in the Montney Formation to generate multiple fractures along horizontal wellbores: the first is the cement liner plug and perforate (CLPP), and the second is the open hole multistage system (OHMS).

In the CLPP method, the production casing is cemented in the horizontal wellbore and then perforated by using guns to create access to the formation at the selected locations from which the fracturing jobs are done. Fracturing is initiated from the wellbore and after each stage is completed, a bridge plug is pumped down to seal off that zone. The same procedure is done for each other stage after which the bridge plugs are drilled out. In the OHMS method (also referred to as the ball drop method), the production zone is isolated by packers and a tool is used to mechanically create access points for fracturing between packers (Seale 2007). The packers are automated and do not have to be drilled out afterward. In OHMS, the time that fracture fluid is in contact with the rock is reduced and the risk of formation damage is less than CLPP.

In the Montney Formation, the most economical treatment type are slickwater treatments (King, 2010). In this treatment type, a large volume of water with low sand concentration and trace amounts of friction reducing chemicals are used (Kazakov and Miskimins 2011). Although low sand concentration can cause rapid proppant settling (King 2010), as claimed by Wang and Miskimins (2010), slickwater is the best choice for brittle heterogeneous rock
with higher silica content and lower clay content (Wang and Miskimins 2010). In general, slickwater fractures generate a higher stimulated reservoir volume and better production at a lower cost than other methods (Romanson et al. 2010).

The production well studied in the research documented here is a 4636 m long horizontal well located in the Montney Formation (Well identifier 9-22-63-3W6, referred to here as Well 9-22) where production not only consists of gas but also liquids. This well was completed with nineteen hydraulic fracturing stages.

7.3 Geological characterization of the Montney Formation

The Montney Formation is considered a prime candidate for horizontal drilling and multistage hydraulic fracturing treatment. Despite many studies on the Montney Formation and units within it and separation into different stratigraphic levels, there are no universally accepted lithostratigraphic subdivisions. In some studies, the Montney is divided into two main intervals: Upper and Lower Montney (Gegolick et al. 2016) whereas in other studies, three intervals: Upper Montney, Middle Montney and Lower Montney (Kuppe, Nevokshonoff, and Haysom 2012), and in other studies four different intervals: Upper, Middle, Middle lower and Lower (ENB 2011). The Montney Formation covers about 57,000 square miles from west-central Alberta to northeastern British Columbia. More than 3,200 horizontal, multistage wells have been drilled and completed in the Montney since 2008.
The heterogeneity of the Montney arises from sedimentological and ichnological factors that result in highly variable reservoir characteristics (Clarkson et al. 2012; Wood 2013). Changes of rock properties in both vertical and horizontal directions result in compartmentalization of resource within zones of distinctly different porosity and permeability values (Gegolick et al. 2016). The Montney Formations is dominated by siltstone; an example of the variability rock type is listed in Table 7.1 for Well 9-22. From the data from this well, the Montney Formation is described as dark argillaceous siltstone and interbedded shale. At the top, a small percent of limestone also appears. The description listed in Table 1 shows that the Montney is laminated, and that the lithology changes at length scales between 5 and 10 m. Different laminations results from specific transport of materials or depositional events (Slatt and Abousleiman 2011). The degree of lamination has a strong influence on rock properties and can act as barriers to fracture propagation. The interfaces between two zones with differing properties creates a surface of stress concentration which gives rise to opportunities for rock slip (Seifert et al. 2015).

<table>
<thead>
<tr>
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<th>Shale</th>
<th>Siltstone</th>
<th>Limestone</th>
<th>Depth Interval</th>
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The Montney Formation has a complex maturation history which causes varying amounts of natural gas liquids and condensate yields per volume of produced gas. Available data of the Montney shows that deeper Montney reservoirs tend to be less rich in liquids whereas the shallower Montney are liquid rich and may have condensate yields in the 200 or even 300 barrels per MMcf gas (Kuppe, Nevokshonoff, and Haysom 2012).
Figure 7.1 Regional map of Montney showing the isotherm lines (Bachu and Burwash 1994). Well 9-22 is also shown.

This is caused by continuous thermal cracking of oil in deeper parts of the Montney where there is higher temperature. Well 9-22 lies within a lower than normal geothermal gradient as shown in Figure 7.1 which preferentially preserved oil, gas and condensate in some of the highest ratios within the unconventional Montney (Kuppe, Nevokshonoff, and Haysom 2012). Table 7.2 displays the expected phase or fluid type for each play area. Well 9-22 is between the 80 and 100°C isotherms which is predicted to have liquid-rich gas and condensate.
Table 7.2. Expected phase or fluid type within the Montney reservoir (Seifert et al. 2015)

<table>
<thead>
<tr>
<th>Temperature Class (°C)</th>
<th>Dominant Phase</th>
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<tbody>
<tr>
<td>&gt;100</td>
<td>Dry Gas</td>
</tr>
<tr>
<td>80-100</td>
<td>Liquid-Rich Gas and Condensate</td>
</tr>
<tr>
<td>60-80</td>
<td>Liquid-Rich Gas</td>
</tr>
<tr>
<td>&lt;60</td>
<td>Oil</td>
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</table>

Figure 7.2a shows the distribution of Young’s modulus in Montney layer as well as the overlying (Doig Formation) and underlying (Belloy Formation) layers for the model that is used here in this work based on Vishkai et al. A full description of the geological and geomechanical properties of the model are described in Vishkai et al. (Vishkai et al. 2016). Figure 7.2b shows the distribution of shale volume for Montney as well as that in the overlying and underlying layers. Figure 7.3 displays the initial state of stress of the Montey Formation, obtained from Vishkai et al. (Vishkai, Wang, and Gates 2017).
Figure 7.2 3D earth model showing a) distribution of Young’s modulus and b) distribution of shale volume.

The Montney Formation commonly has permeability in the nanoDarcy to microDarcy range. To create a stimulated region where sufficient oil and gas can flow within the Montney Formation to a well, multistage hydraulic fracturing is the stimulation process of choice. Because of the heterogeneity and laminated nature of the Montney, obtaining permeability measurements and mapping its spatial variability is one of the most challenging issues for this reservoir.
Figure 7.3 Pore pressure and stress profiles from 2500m to 3500m depth.
Figure 7.4 Core analysis results for porosity and permeability.
Figure 7.4a displays the porosity versus depth for cores in the neighborhood of Well 9-22. The porosity ranges from 0.02 to 0.07 in the pay zone (between about 2850 and 3150 m). Figure 7.4b shows the permeability versus depth for cores in the neighborhood of Well 9-22 in the Montney Formation.

The permeability varies from 0.008 to 0.05 mD with average value equal to 0.01 mD; however, these values are obtained from core that have been brought to surface and thus, they are not at in situ conditions. Other sources have different values: Kuppe et al. (2013) found an average permeability equal to 0.0015 mD (Kuppe, Nevokshonoff, and Haysom 2012) and Ghanizadeh et al. (2015) found the permeability ranges from $\text{1.1x10}^{-6}\text{mD}$ to $\text{6.7x10}^{-3}\text{mD}$ for the same formation. The variability of the results demonstrates the uncertainty associated with the permeability of the study area (Ghanizadeh et al. 2015a). For the history match done here, given its uncertainty, the permeability is taken to be a constant within the Montney Formation and is estimated from the history match.

### 7.4 Hydraulic Fracturing Modeling

Hydraulic fracturing involves geomechanics, rock failure, and fluid flow and thus, modelling of the fracturing process is complex. In this study, a three-dimensional (3D) earth model was built by integrating both petrophysical and geological log data as described in Vishkai et al. (Vishkai et al. 2016; Vishkai, Wang, and Gates 2017); the details will not be repeated here.
The model includes dynamic elastic properties and rock strength property distributions which vary in both vertical and horizontal directions derived from log data from eighteen wells and then populated through the model by using geostatistics. To reduce the computational cost, the area of study was reduced by using a submodel extracted from the geological-geomechanical model which includes three production wells. The 3D geomechanical model contains the variation of Young’s modulus and Poisson’s ratio at each point of reservoir (Vishkai et al. 2017). The 3D distribution of the state of stress was determined by using the Visage finite element package as described by Vishkai et al. (Vishkai, Wang, and Gates 2017).

Figure 7.5 shows Well 9-22’s trajectory which is located in the Upper Montney layer which has 230 m thickness around that well. The Montney Formations depth is in the range of 2840 to 3110 m depth. The total measured depth is 4636 m and temperature gradient is equal to about 3°C/100 m vertical depth. The first stage was conducted at measured depth of 3706.10 m (true vertical depth 2868.59 m). The treatment fluid pumped through the casing (pumping rate is 7.8 m³/min). The fracture fluid is slickwater with proppant type 100 mesh Sand B361-100. An OHMS completion method was used.

In the research documented here, the Mangrove hydraulic fracturing simulator is used (Schlumberger, 2017; Weng et al. 2014). For the fracture geometry model, the Unconventional Fracture Model (UFM) is used (Weng et al. 2014). In this method, the effect of geomechanical properties on the fracture network growth and propagation as well as fluid
flow and proppant transport is considered. More details of the UFM can be found in the Vishkai and Gates, 2017 (Vishkai and Gates 2017).

![Diagram](Figure 7.5 Horizontal Well 9-22 with 19 stages hydraulic fracturing locations illustrated in the Upper Montney layer.)

In the UFM, the fracture geometry and the width distribution in the fracture plane at any given time of the simulated treatment is generated as part of the solution. To achieve computational efficiency in the UFM, a 1D proppant transport model in the horizontal direction is used. A three-layer model has been assumed for simulating proppant transport in the fracture network for each element: a proppant bank at the bottom, a slurry layer in the middle, and clean fluid at the top. The vertical heights of those three layers (the settled proppant bank, the slurry, and the clean fluid) are computed and tracked in each fracture element at each time step by satisfying the transport equations for each component of the
fluids and proppant pumped. More details can be found on the fracture model is described in Chapter 6.

7.5 Results: History Match of the Montney Operation

In the field, Well 9-22 was oriented parallel to the minimum horizontal stress direction. For the history match, as described above, the initial permeability is the most uncertain parameter to obtain from the history match since other parameters such as the stress and rock properties have been compared from different sources and thus, their uncertainty is considered less than that of the permeability. For the match, a single stage fracture was modeled. Thereafter, the parameters obtained for the match of this single stage was then used for the other stages.

The zone for simulation was extended 70 m up and 250 m down from the horizontal well elevation. The field data used to calibrate the history match for Well 9-22 was production data between 01/01/2014 and 30/12/2015 (in total, two years of production). Figure 7.6a shows the gas production rate in those years of production. The red line is the field production rate from single stage. It shows that the minimum production rate occurred in July 2015. The green line is the gas production rate of five stages (Stages 1 to 5) and the blue line is the production rate for all nineteen stages of hydraulic fracturing treatment. For all nineteen stages, the maximum produced gas flow rate is 3,200 Sm$^3$/day and the maximum oil production rate is 5.2 Sm$^3$/day. The single stage chosen for the history match was Stage 10, shown in Figure 7.7, since it was mid-way along Well 9-22.
Figure 7.6 Production data for Well 9-22 for Stage 10, 5 stages (Stages 1 to 5), and 19 stages: a) gas production rate, b) oil production rate, and c) water production rate.
Figure 7.7 3D model shows a) one stage fracture volume with the conductivity map b) the distribution of the proppant concentration c) fracture width distribution d) fracture fluid pressure distribution map.
7.5.1 History Match of Stage 10

As part of the sensitivity study to obtain the history match, the permeability of the Montney Formation was first varied from 0.00005 to 0.01 mD in steps. At 0.01 mD, the fracture could not grow because of the large fracture fluid leak off into the formation. Therefore the permeability was lowered in steps to 0.001, 0.0001 and then 0.00005 mD. As the permeability was lowered, the fracture length increased but wellbore connectivity was lost when the permeability decreased to 0.00005 mD where the conductive channels closed when production occurred. Thereafter, the permeability values of 0.005, 0.0001 and 0.0015 mD were tested. The value that gave the closest match to the field data was 0.0001 mD. This is smaller than the core data displayed in Figure 7.4 but similar in magnitude to the average value of the results of Ghanizadeh et al. (2015). The results of the history match to the field data is presented in Figure 7.8. The plots show that a reasonable match between the field data and simulation results is obtained. The simulator yields more gas production rate compared to field data between August 2014 until December 2014 where the maximum difference between the simulation and field data is 33 Sm$^3$/day.
Figure 7.8 History match for gas production rate from Stage 10 between January 2014 and December 2015. Dotted line is field data and continuous line is the simulation result.

Table 7.3 lists all of the input parameters determined from the history match to model Stage 10’s hydraulic fracturing operation. The average fracture conductivity determined from the results based on Stage 10’s hydraulic fracturing operation is 150 mD.m. Figure 7a shows the fracture conductivity map for Stage 10. Figure 7.7b shows the distribution of the area-based proppant concentration which varies between 2 and 16 kg/m². Figure 7.78c displays the fracture width map for Stage 10 of hydraulic fracturing design with the average value of 2.5 mm.
Table 7.3. Parameters of history matched model.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
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<tbody>
<tr>
<td>Rock type</td>
<td>Siltstone</td>
<td>-</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>33.8</td>
<td>MPa</td>
</tr>
<tr>
<td>Max Bottom hole pressure (BHP)</td>
<td>68.9</td>
<td>MPa</td>
</tr>
<tr>
<td>Reservoir permeability</td>
<td>0.0001</td>
<td>mD</td>
</tr>
<tr>
<td>Reservoir porosity</td>
<td>0.02-0.07</td>
<td>%</td>
</tr>
<tr>
<td>Poisson Ratio</td>
<td>0.2-0.3</td>
<td>-</td>
</tr>
<tr>
<td>Young’s Modulus</td>
<td>45-55</td>
<td>GPa</td>
</tr>
<tr>
<td>Tensile strength</td>
<td>18-24</td>
<td>kPa</td>
</tr>
<tr>
<td>Maximum stress angle</td>
<td>221.16</td>
<td>deg</td>
</tr>
<tr>
<td>Minimum horizontal stress</td>
<td>54-58</td>
<td>MPa</td>
</tr>
<tr>
<td>Maximum horizontal stress</td>
<td>81-86</td>
<td>MPa</td>
</tr>
<tr>
<td>Fracture gradient</td>
<td>18.93</td>
<td>kPa/m</td>
</tr>
<tr>
<td>Overburden stress gradient</td>
<td>22.85</td>
<td>kPa/m</td>
</tr>
</tbody>
</table>

7.5.2 Prediction of the Other Stages

In this simulation, all nineteen stages are modelled by using the parameters obtained for matching Stage 10. The hydraulic fracture operation started from Stage 1 and proceeded through to Stage 19. It was assumed that all stages contributed equally to well productivity. As Figure 7.9 shows the volume growth of the nineteen hydraulic fracture stages in 3D model.
Figure 7.9 Fracture conductivity results of 3D model showing volume growth of the nineteen hydraulic fracture stages.

To evaluate how well the model matches the field data, the results for the five stages (Stages 1 to 5) were also compared to their corresponding field data. The data in Figure 7.10 reveal that the model provides an excellent prediction of the field data. The model demonstrates that history-matching a single stage provides a good prediction of the operation for a subset of five stages and all nineteen stages. The results show the excellent history match for the nineteen stages based on the same input data. However, since the reservoir is heterogeneous, the fracture conductivity and geometry are different for each stage. Figure 7.10 also shows the simulator gas production rate for the nineteen stages compared to field data. The dark blue line shows the simulation result which is close to the field data through two years of
production. It is obvious that the heterogeneities of rocks properties, such as the porosity, Young’s modulus and Poisson’s ratio, have an impact on hydraulic fracturing geometry and conductivity. The contrast between rock properties also influences hydraulic fracturing in the laminated Montney Formation.

Figure 7.10 History match for gas production rate for Stage 10 and prediction of volumes for five stages (Stages 1 to 5) and nineteen stages between January 2014 and December 2015. Dotted line is field data and continuous line is the simulation result.

A comparison of the conductivity of the hydraulic fractures for all stages is shown in Figure 7.11. The maximum value is found in Stage 5 at 174 mD.m whereas the minimum value is found in Stage 9 at 64.5 mD.m. The conductivity varies due to the heterogeneity of the porosity, Young’s modulus, and Poisson’s ratio as well as the initial state of stress (recall, the permeability is constant).
Variation of the average fracture width can be significant due to the position of the perforations in the horizontal well and adjacent properties of the formation. Figure 7.12 shows the distribution of fracture width for each stage predicted by the model. The maximum average fracture width is 1.84 mm which occurs in Stage 5. Since hydraulic fractures may mutually affect each other, the state of stress has changed due to the hydraulic fracturing stages. This phenomena is known as “stress shadow effect” and it happens when a previous stage (or stages) significantly alters the stress conditions and formation deformation behaviour in the surrounding rock around the propagating fracture (Li et al. 2015). Therefore, the final fracture may adopt a different orientation and propagation direction compared to the original fracture. Depending on the spacing of the stages, stress conditions
can be changed to prevent or enhance fracture growth at neighbouring fractures (Skomorowski 2016).

![Average Propped Fracture Width (mm)](image)

**Figure 7.32 Comparison of average fracture width for all hydraulic fracture stages.**

The elastic properties of each rock face bounding the fracture can influence the propagation of vertical growth by affecting the vertical distribution of the minimum horizontal stress. This is because the increase in minimum horizontal in-situ stress in the bounding layers of rock together with weak shear strength of these layers could constrain vertical growth of hydraulic fractures (Teufel and Clark 1984). In tight rock reservoirs, the variability of the Young's modulus and fluid volume within the fracture as well as conductivity and productivity of adjacent rock layers to the fracture can influence the width of the hydraulic fracture when it propagates across bedding interfaces (Fung, Vilayakumar, and Cormack...
The fracture width is strongly influenced by the fracture fluid volume and its leak off into the surrounding formation. Since the conductivity of the adjacent rock layers has serious impact on the leak off rate, the adjacent layer properties will be as important as the production zone properties.

The fracture height distribution for the nineteen hydraulic fracture stages is displayed in Figure 7.13. The fracture height growth is controlled by the properties of the adjacent rock layer to the fracture as well as the thickness of the pay zone. The results in Figure 7.13 show that the fracture height does not vary significantly amongst the stages.

![Average Hydraulic Fracture Height (m)](image)

**Figure 7.43** Comparison of average fracture height for all hydraulic fracture stages.
The total hydraulic fracture volumes are displayed in Figure 7.14. The first stage has the largest fracture volume. Fracture height is strongly influenced by rock properties such as the Young’s modulus whereas the fracture length is largely depends on the net fluid pressure (Chapter 6). The net pressure results from the pressure drop from the injection point to the extent of the fracture. Therefore, by keeping the formation permeability constant, a longer fracture is expected with higher net pressure.

![Total Hydraulic Fracture Volume (m³)](image)

**Figure 7.54** Comparison of total fracture volume for all hydraulic fracture stages.

### 7.6 Implications and Discussion

The heterogeneous nature of unconventional tight rock reservoirs with several layers provides special challenges for hydraulic fracturing. It is difficult to constrain newly created
fractures to the reservoir pay zone during the process. Consequently, fractures intersect variable lithology which exhibit different petrophysical and mechanical properties (Ajaya et al. 2013). Also, geologic heterogeneity along wellbores directly affect where fracture stages will encounter producible reservoir rock. As a result, the geometric placement of stages often results in poor well performance, leading completion engineers to use manual, time consuming methods to pick stage and perforation location based on subtle well log characteristics.

The Montney Formation in Western Canada is a thick active liquid-rich shale gas play (Bachman et al. 2011). To produce gas from this low permeability reservoir, the operator must stimulate production intervals through multistage hydraulic fracturing treatment. Since shales possess vertical layering caused by the horizontal alignment of finely laminated sediments and platy clay minerals, the rock properties, such as permeability, porosity, elastic and plastic moduli vary more from layer to layer than within the layer. Consequently, the data used to design early stages could apply for later stages with a reasonable outcome similar to the results of the early stages. Since stages should target rocks with similar petrophysical and geomechanical properties to yield uniform fracturing along the well, focused staging is important (Ajaya et al. 2013). This means that geomechanical-geological maps must be examined carefully for placement of stages and to set stage volumes.
7.7 Conclusions

In this study, the Unconventional Fracture Model (UFM) for multistage hydraulic fracturing stimulation was calibrated to a single stage along a horizontal well contained in the Montney Formation by history matching field production data. Geological and geomechanical properties of the model were obtained from core (eighteen wells) and log (eighteen wells) data. Although there are several uncertain parameters in this process, an excellent match on gas production history was achieved by altering the initial permeability of the formation. Thereafter, the matched parameters were used to successfully predict all nineteen fracture stages in the well. The results show that rock mechanical properties, stress conditions, and permeability are important for design of multistage completions and that variability of these properties in the reservoir lead to varying fracture height, width, and length. The primary variable that affects the history match is the initial permeability of the intact reservoir rock. The permeability controls fracture growth, final volume, width, and height and thus, the fracture conductivity. Permeability values from core samples were too large creating short fracture length with large volume of leak off fluid which could not support the field production data. This is likely because the core samples were not tested at the conditions of the reservoir.
CHAPTER EIGHT: CONCLUSIONS AND RECOMMENDATIONS

The special geological setting of the Montney reservoir together with the 7 Generation Ltd. data sets available for comparison and analysis, provided a unique opportunity to evaluate three-dimensional hydraulic fracture evolution and its application in highly laminated Montney reservoirs. One key objective of the study was to present the ‘best practical’ methodology to develop an accurate three-dimensional (3D) hydraulic fracture model of a geologically complex reservoir. This study can help to identify the critical parameters as well as the primary controlling factors which are necessary for operators to develop relevant hydraulic fracture models. The use of log-derived rock mechanical properties, stresses analysis has been accomplished. The effects of key simulator inputs have been assessed, and their effects on hydraulic fracture parameters quantified. Individual chapters document conclusions from the outcomes of the research.

8.1 Conclusions

- Geomechanical stratigraphy was estimated by using standard log-based measurements such as the rock density, sonic velocity, and gamma ray logs.
- A geomechanical model of the Montney Formation and overlying formations was constructed from petrophysical and geological log data over a 15 km by 15 km area. The 3D model included distributions of dynamic elastic and rock strength properties.
- The wells examined in this study illustrated that the Montney Formation was comprised of sand, shale and shale-sand combinations.
• A comprehensive study had been performed to get a better understanding of the state-of-stress in the Montney Formation in Alberta, Canada prior to hydraulic fracturing. A geomechanical earth model has been used to evaluate the initial state of stress in the Montney Formation using the finite element method.

• The analysis of the state-of-stress reveal that the strike-slip regime was the dominant regime in the Montney Formation although depending on the gradient of the minimum horizontal stress, the reverse faulting regime might also be present.

• The results showed the Montney Formation was a more brittle formation than surrounding formations. The differences of the Young’s modulus and stresses between the Montney Formation and the surrounding formations might provide some degree of containment of the hydraulic fractures within the Montney Formation.

• The results also showed that the stress distributions are heterogeneous reflecting the heterogeneity of the density and geomechanical properties in the domain.

• In the case where a stress load was added to represent the mountains, the faulting regime changed to reverse faulting over an interval between 1,500 and 2,200 m depth. Although this interval was not in the Montney Formation, this implied that in the presence of extra load, fracture propagation could be complex since the tectonic stress was changed due to the presence of the mountains and the maximum and minimum horizontal stress values was altered as well as the failure model. Since it was practically impossible to evaluate the impact of mountains in the laboratory, the method used here provided a unique data source to understand the stress profile in the Montney Formation with mountains.
• UFM model had been used with properties sourced from a detailed geological and geomechanical reservoir model. The hydraulic fracture and reservoir production model was run to obtain the best match with field production data.

• The results demonstrated the influence of Young’s modulus, reservoir pressure, and minimum horizontal stress on fracture geometry and characteristics for the Montney Formation.

• In the case of the Montney reservoir with its laminated layers, hydraulic fractures are easily initiated and grow in zones of homogeneity but after they reach the interface with an upper zone, the hydraulic energy is dissipated in the upper zone.

• The simulations demonstrated how hydraulic fracturing conductivity distributes in the formation and what factors influenced fracture characteristics. Elastic rock properties such as the Young’s modulus had a significant impact on the resulting fracture network and geometry. The results revealed that lowering the Young’s modulus of the pay zone raised the fracture width, and reduced the fracture conductivity. This parameter reduced the breakdown pressure and time. Differences of the Young’s modulus between the reservoir rock and overburden and understrata rocks affected the height growth of the fracture. The decrease in modulus made fracture propagation easier within the formation.

• An increase of the initial reservoir pressure resulted in a larger fracture length as well as higher conductivity.

• The decrease of the minimum horizontal stress increased the fracture width and fracture conductivity. The fracture height and length were not significantly affected by the change of the minimum horizontal stress.
• An excellent match on gas production history was achieved by altering the initial permeability of the formation. Thereafter, the matched parameters were used to successfully predict all nineteen fracture stages in the well.

• The results show that rock mechanical properties, stress conditions, and permeability are important for design of multistage completions and that variability of these properties in the reservoir lead to varying fracture height, width, and length.

• The primary variable that affects the history match was the initial permeability of the intact reservoir rock. The permeability controlled fracture growth, final volume, width, and height and thus, the fracture conductivity.

8.2 Recommendations

It is recommended that the microseismic analysis be used to map the natural fracture network before hydraulic fracturing treatment as well as a tool for comparing the hydraulic fracturing results after the treatment process. Natural fracture maps will help to predict more accurate model in pre-frac study. Especially when we cannot claim certainly if the geometry and stimulated volume estimated by the program represent what is truly happening within the subsurface. It is clear from the simulation that the stress profiles will be changed after the fracturing treatment, so it is recommended to evaluate the stress state after each stage in multistage hydraulic fracturing process. Besides, the stress shadowing will effect hydraulic fracture operations by increasing the breakdown pressure or by losing the intervals due to an inability to break the formation after it has been subjected to a stress change. Therefore, the stress states during and after multistage hydraulic fracturing treatment have significant effect
on production rate. Temperature effect on fracture conductivity is recommended to consider in the future work. The history matches have been done here, is based on the equal rates have been obtained from different stages regardless of rock properties and stress states. It is recommended to use an exact production rate for each stages to get more accurate result.
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APPENDIX I

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Influence of Stress Anisotropy on Hydraulic Fracturing

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ABSTRACT: Rocks with natural fractures, cracks, faults and vugs have complex multi-connected pathways for fluid flow. In these systems, fluid flow, especially to production wellbores, can change as reservoir conditions change as fluids are injected to the reservoir. In typical practice, the more detailed the characterization of the fracture network, the easier it is to optimize recovery process design and well placement to maximize the recovery factor of petroleum fluids. Furthermore, for tight rocks where hydraulic fracturing is required to enable sufficient fluid mobility for economic production, it is critical to understand the placement of the induced fractures, their connectivity, extent, and interaction with natural
fractures within the system. Stress anisotropy and interactions between new fractures and natural fractures in the formation can dictate the mode, orientation and size of the hydraulic fracture network. In this study, normal deformation is coupled with fluid flow to evaluate the effect of the stress anisotropy on fracture network propagation in rock. The results demonstrate that stress anisotropy and existing natural fractures networks are playing critical roles in creating fracture-network complexity and connectivity. The model developed here assumes that the flow is single-phase and isothermal, matrix permeability is zero, and that deformation arises from small normal displacement in an infinite, homogeneous, linearly elastic medium. Specifically, the model couples fluid flow and stresses induced by fracture deformation in a plane. For this purpose, a system of equations governing fracture deformation and fluid flow through a complex fracture network is solved. The results illustrate the importance of rock properties, stress magnitude, and stress orientation on fracture complexity in unconventional naturally fractured reservoirs.

1. INTRODUCTION

Many petroleum reservoirs are naturally fractured [1]. In general, hard rock masses are typically composed of intact rock and microfractures, which may have the capability to serve as pathways for fluid flow. It is required to understand fracture fluid flow characteristics, fracture network connectivity and the effect of stresses on the rock mass to maximize the economics of petroleum recovery from reservoirs. The presence of small scale natural fractures in a rock mass can make it more sensitive to stress than intact rock. Therefore, the direction and geometry of a hydraulically-created fracture is affected by existing natural
fractures, or planes of weakness within the rock. In addition, fluid injection at high pressure can rearrange the stress distribution which in turn, can result in the opening and reorientation of fractures. The stresses caused by fracture opening are not uniform, and effects on neighboring fractures are dependent on relative orientations and locations of the neighboring fractures. In the absence of strong interactions between fractures, during hydraulic fracturing, the aperture and extent of the fracture increases orthogonal to the direction of the minimum stress, as shown in Figure 1.

Figure 1. Individual fracture, of dimensions w by a by s, into which fluid flows.

Single opening mode fracturing is a simple classical hydraulic fracturing model that propagates away from the wellbore. In this model, one of the dimensions is fixed, usually fracture height, and then the width and length of the fracture are calculated. In 1964, Sneddon and Elliot presented the first hydraulic fracturing model by working on solutions for the stress field and pressure associated with static pressurized cracks [2]. Later, Khristianovich
and Zheltov (1955) made several simplifying assumptions concerning fluid flow and focused on fracture mechanics [3]. Carter (1957) neglected both fluid viscous effects and solid mechanics and concentrated on leak-off. His model also ignored the pressure losses within the fracture [4]. Howard and Fast (1957) assumed the fracture width was constant everywhere. This assumption enabled the calculation of the fracture area based upon fluid leak off behaviour [5]. Perkins and Kern (1961) assumed that fracture mechanics is relatively unimportant and focused on fluid flow [6]. In 1972, Nordgren enhanced Perkins and Kern model (PKN), by another two-dimensional (2D) model in which the fracture height remains constant as the fracture grows. Another 2D model was the Geertsma and Klerk (GDK) model [8]. They assumed a plane strain situation with smooth closure of the fracture tip. These approximate models are still used in hydraulic fracturing design today [9]. However, in more complex systems where preexisting fractures play an important role, the models described above may be overly simplified. Fracture size, orientation, and growth direction in heterogeneous naturally fractured reservoir is a complex phenomenon that is difficult to predict with low uncertainty. Over the years, various models have been used to predict approximate fracture size and orientation. In 1986, Murphy and Fehler addressed hydraulic fracturing in naturally fractured reservoirs. They focused on the primary behaviors of hydraulic fracturing in naturally fractured formations [10] and presented a series of 2D numerical experiments for fluid-driven opening mode fracture growth in naturally fractured reservoirs [11, 12, 13, 14].

Here, a new method is developed for modelling 3D hydraulic fracturing of a rock mass. It is assumed that the rock mass is filled with pre-existing microfractures which act as seeds
for fracture growth and propagation when the rock is hydraulically fractured. Here, the seed fractures are distributed throughout the rock mass by using a uniformly distributed set of fractures, modeled as rectangles, with initial aperture equal to 0.1 microns.

2. DISCRETE FRACTURE NETWORK MODELLING

In complex hydraulic fracturing in low permeability rock, Discrete Fracture Network (DFN) models present a useful means to track individual fractures and their growth and interactions within the rock mass. There are two requirements for flow within the fracture network. First, the fractures must be connected and second, the overall conductivity within the network must be large enough for flow over practical time scales. Thus, fluid flow between locations in a reservoir is dependent on fracture network characteristics. Discrete fracture models are capable of describing flow fractures providing they are connected.

Hossain et al. (2002) identified limitations of conventional hydraulic fracturing models and presented a 3D model to address hydraulic fracturing in naturally fractured reservoirs (NFRs) [15]. Some studies have been done to emphasize the role of the fracture network on the interaction between a hydraulic fracture and NFR [16]. Some authors noted the role of fluid viscosity and injection rate on hydraulic fracturing in NFRs from laboratory evaluations [17]. They found that high flow rate or high viscosity created new fractures whereas low rates tended to open pre-existing fractures. King (2010) reported a comprehensive study on hydraulic fracturing in shale gas reservoirs [18]. He inferred that no two shale formations are similar. Therefore, there is no optimum, one-size-fits-all completion or stimulation
design for shale gas wells. King further noted fracability of the shale formation is related to the brittleness index [18] and the in-situ stress ratio [19]. Lehman et al. (2010) believed that microseismic data provide a better tool than net pressure to evaluate shale gas fracture geometry [20].

The initial discrete fracture network used here surrounding a horizontal well is displayed in Figure 2. At the center of the domain is a horizontal well. The domain is 35 m in extent on each side of the horizontal well, 20 m in height, and 70 m long (in the direction of the horizontal well). The fractures are 1 m by 1 m in extent. When the system is hydraulically fractured, the fluid is injected from the well into the reservoir via the seed fractures. Only those seed fractures that are connected to the well receive fluid and fractures that are members of the cluster connected to the well can be hydraulically fractured.

Figure 2. Seed fracture network.
3. HYDRAULIC FRACTURE MODELLING

To design hydraulic fracturing treatment in a petroleum reservoir, it is first necessary to predict the growth of fracture geometry as a function of treatment parameters, time, and space. 2D models have been used to obtain solutions for solid/fluid mechanical interaction problems. In many of these models, the fracture plane of propagation needs to be specified in advance. In some three-dimensional (3D) models, the fracture height depends on fluid injection and vertical components of fluid flow [21]. Early attempts were devoted to optimize hydraulic fracture geometry by using simplified 2D models. Among the 2D methods used in the fracturing modeling, the PKN and GDK models are most popular [22]. Generally, the PKN model is preferred [23] because its vertical plane strain assumption is physically more acceptable for height-constrained fractures where the fracture length becomes considerably greater than the fracture height [24]. 3D hydraulic fracture models can be divided into two groups: 1. fully 3D models and 2. Pseudo-3D (P-3D) models. For both of these approaches, the fracture is subdivided into discrete fracture elements and the governing equations representing fluid dynamics, mass continuity, and solid mechanics (elasticity equation that relates the stress on the crack face to that at the crack opening) are solved simultaneously. Another requirement of these models is the tensile fracture criteria [25]. There are many studies in the literatures devoted to evaluate the fracture system connectivity in relate with fracture orientation, size and conductivity [26, 27, 23]. In Adachi et al., P-3D models were examined with the basic assumption that the created fracture is bi-planar and that the reservoir elastic properties are homogenous and can be averaged across all the layers containing the hydraulic fracture [27].
In this study, the basic mathematical formulation of PKN and P-3D fracture models is briefly presented. Because there are very strong stress barriers (overburden rock and understrata rock) bounding the reservoir rock, the fracture height growth is considered fixed at the value of the thickness of the reservoir rock.

If there are microfractures existing in the rock prior to hydraulic fracturing, then when the rock is hydraulically fractured, it will most likely do so through the pre-existing fractures. First, as the fluid is injected into the rock, the pre-existing fractures will be dilated and if the dilated pre-existing fractures are unable to contain more fluid, the fractures extend into the reservoir rock. When hydraulic fracturing starts, the injected fluid first enters pre-existing microfractures that intersect the wellbore, as illustrated in Figure 3.

For modelling the growth of individual fractures, here, the PKN model is used. For deep systems, the length of the fracture grows perpendicular to the minimum horizontal stress and the fracture width (aperture) expands parallel to the minimum horizontal stress. The assumptions of the PKN model for linear fracture propagation used here are as follows [25]:
Figure 3. Schematic of pre-existing natural fracture intersecting the well bore

- Fracture height is constant during the stimulation although each fracture can have its own height.
- The fracture fluid pressure does not change in the direction perpendicular to the fluid flow.
- The average width is used in all calculations.
- Leak-off of fluid from the fracture to the rock matrix is assumed to be equal to zero.

The continuity equation for one-dimensional transient flow in a fracture with no leak-off is given by:

\[
\frac{\partial Q}{\partial x} + \frac{\partial A}{\partial t} = \frac{\partial Q}{\partial x} + \frac{\pi h_f}{4} \frac{\partial w}{\partial t} = 0
\]

where \( Q \) is the total injection rate (volume per unit time) and \( A \) is the cross section area of the fracture. Under plane strain, England and Green derived an equation for the width of line crack between \(-\frac{1}{2} h_f\) and \(+\frac{1}{2} h_f\) opened by an equal and opposite normal pressure distribution on each side of the crack as exerted by a fluid [28]. The most simple case is a
uniformly distribution load, $\Delta p =$ constant, over the full fracture length. The result is then given by [25]:

$$w(x) = \frac{2(1-\nu)s\Delta p}{G} \sqrt{(1-x^2)}$$

(2)

where at $x = 0$

$$w(0, t) = \frac{2(1-\nu)s\Delta p(0, t)}{G}$$

(3)

Fluid flow through two parallel plates is based on the pressure diffusion equation:

$$q = -h_f \frac{w(0,t)^3 \partial p_f}{\mu} \frac{\partial p_f}{\partial x} \text{ or } -q \frac{\mu}{w(0,t)^3 h_f} = \frac{\partial p_f}{\partial x}$$

(4)

By incorporating Equation (2) and Equation (3) into Equation (1) the results are then

[25]:

$$L(t) = (0.6) \left[ \frac{Gq_0^3}{(1-\nu)\mu h_f^4} \right]^{1/5} [t]^{4/5}$$

(5)

$$p(0,t) - \sigma_H = \left( \frac{3}{h_f} \right) \left[ \frac{Gq_0^3 \mu L(t)}{(1-\nu)^3} \right]^{1/4}$$

(6)

$$w(0, t) = (2.64) \left[ \frac{(1-\nu)q_0^2 \mu}{G h_f} \right]^{1/5} [t]^{1/5}$$

(7)

where $L(t)$ is the fracture half length, $p(0, t)$ is the fracture pressure at the wellbore, $\sigma_H$ is the maximum horizontal stress, $w(0, t)$ is the fracture width at the wellbore, $G$ is the rock shear modulus, $\mu$ is the fluid viscosity, $\nu$ is the Poisson’s ratio for the rock mass, $h_f$ is the fracture height (= $a$ in Figure 1), $q_0$ is the fluid injection rate, and $t$ is time.

### 3.1. Mechanical and Hydraulic Properties of Intact Rock

For the model developed here, the rock properties and operational conditions during fluid injection are listed in Table 1.
Table 1. Input data for running the model [25].

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
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<tbody>
<tr>
<td>Rock Shear Modulus, kPa</td>
<td>1.0x10^7</td>
</tr>
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Figures 4 to 6 display the single fracture half-length, fluid centerline pressure, and centerline width (aperture) given the data in Table 1 obtained from the PKN model (given by Equations 5 to 7, respectively).

4. EFFECT OF STRESS ANISOTROPY ON HYDRAULIC FRACTURING

We tested hydraulic fracture stimulation by injection the fluid into the pre-existing natural fracture network that intersects the wellbore as shown in Figure 2. The model developed here assumes that the flow is single-phase and isothermal, matrix permeability is negligible,
and that the deformation arises from small normal displacement in an infinite, homogeneous, linearly elastic medium. As the injected fluid penetrates the natural fractures, the pressure can build up until it exceeds the level of the local confining normal stress. The contact will be lost at these points where sufficient fluid pressure is developed and the natural fracture is opened mechanically.

5.1 Fracture initiation and propagation criteria

A fracture initiates when the effective minimum stress becomes equal to the given critical effective stress. If the pressure $P$, and the compressive stresses are assumed positive, $\sigma_c$ critical effective stress, is negative and the fracture initiation criterion is:

$$\sigma_{\text{min}}' = (\sigma_y - \alpha P) \leq \sigma_c$$

Therefore the fracture will propagate if the minimum principal effective stress falls below the tensile strength of the rock material.

Figure 4. Fracture half-length given by PKN theory with data listed in Table 1.
Figure 5. Fracture fluid centerline pressure given by PKN theory with data listed in Table 1.

Figure 6. Fracture centerline width (aperture) given by PKN theory with data listed in Table 1.

The resulting components of the stress tensor are then given by [29]:

\[
\sigma_{xx} = \frac{K_I}{\sqrt{2\pi r}} \cos \frac{\theta}{2} \left(1 - \sin \frac{\theta}{2} \sin \frac{3\theta}{2}\right) - \frac{K_{II}}{\sqrt{2\pi r}} \sin \frac{\theta}{2} \left(1 - \cos \frac{\theta}{2} \cos \frac{3\theta}{2}\right)
\]  

(9)

\[
\sigma_{yy} = \frac{K_I}{\sqrt{2\pi r}} \cos \frac{\theta}{2} \left(1 - \sin \frac{\theta}{2} \sin \frac{3\theta}{2}\right) - \frac{K_{II}}{\sqrt{2\pi r}} \sin \frac{\theta}{2} \left(\cos \frac{\theta}{2} \cos \frac{3\theta}{2}\right)
\]  

(10)

\[
\sigma_{zz} = \nu (\sigma_{xx} + \sigma_{yy})
\]  

(11)
where $\sigma_{xx}$ is the normal stress along x direction near the crack tip, $\sigma_{yy}$ is the normal stress along y direction near the crack tip, $\sigma_{zz}$ is the normal stress along z direction near the crack tip, $K_I$ opening mode stress intensity factor, $K_{II}$ in-plane shearing mode stress intensity factor, and $\theta, r$ are polar coordinates relative to the crack tip. To close the system of equations, the material and momentum balances for the injected fluid must be maintained. Given the gap-to-planar extent aspect ratio of the fracture, shown in Figure 7, fluid flow in the open fracture can be approximated by lubrication theory.

![Figure 7. Schematic of individual natural fracture](image)

The resulting momentum balance for the fluid becomes:

$$
\frac{\partial a(w+w_0)}{\partial t} = \frac{\partial}{\partial s} \left( a(w+w_0)^3 \frac{\partial p_f}{\partial s} \right)
$$

(12)

where $a$ is the fracture height, $w$ is the fracture width, $w_0$ original natural fracture width, $p_f$ is the fracture fluid pressure, $\dot{\mu} = 12\mu$ where is $\mu$ the fluid viscosity and $s$ is the fracture length. The flow rate through the fracture is given by:

$$
q = -a \frac{(w+w_0)^3}{\dot{\mu}} \frac{\partial p_f}{\partial s}
$$

(13)

and the overall material balance is given by:

$$
Q_0 t = \sum \int_0^{l_f} (w + w_0) ds
$$

(14)
By using the lubrication approximation as defined by the above equations, the assumptions placed on fluid is that it is incompressible and Newtonian and that the flow is laminar with no leak-off from the fractures to the rock matrix. Fluid flow in the fracture is based on the pressure diffusion equation:

\[
\frac{\partial p_f}{\partial t} - \frac{1}{\chi_1 \mu} \frac{\partial}{\partial s} \left( a w_0^2 \frac{\partial p_f}{\partial s} \right) = 0
\]  

(15)

\[
q = -a \frac{w_0^3}{\mu} \frac{\partial p_f}{\partial s}
\]

(16)

where \( \chi_1 \) is the compressibility of the fracture, \( w \) is the mechanical opening along the fracture, \( w_0 \) is the hydraulic aperture at the centerline of the original fracture, and \( Q_0 \) is the injection rate, and \( l_f \) is the fluid filled length of each fracture. The hydraulic aperture \( w_0 \) versus time can be obtained by solving the evolution equation \( \frac{dw_0}{dp_f} = \chi w_0 \) at each time step, starting with an initially assigned hydraulic aperture \( w_0 \). The distribution of \( w_0 \) can be assigned according to information about the detailed microstructures in the fracture, if available. Here, \( w_0 \) is assumed to be constant at 0.1 microns.

5. COUPLED DFN, FLOW, AND PKN MODELS

The above governing equations for fluid flow, PKN, and mass continuity has been solved in a DFN code. Figures 8 and 9 show early results of two example results after 20 minutes of hydraulic fracturing. Figure 8 displays the results for the case where the reservoir is filled with seed fractures but the rock properties are uniform and the horizontal and vertical stresses are equal. Figure 9 shows the case where the vertical stress is 2.5 times that of the horizontal stresses (which are equal). The color indicates the extent of fracturing (reflecting the
aperture of the fractures in the network surrounding the well; red is equal to 0.04 m and white is no dilation of fracture). The results demonstrate that the fractured zone propagates further out in the anisotropic case.

Figure 8. Fracture propagation after 20 mins of hydraulic fracturing in the isotropic case.
Figure 9. Fracture propagation after 20 mins of hydraulic fracturing in the anisotropic case.

6. CONCLUSIONS

Early results from a new approach to modelling hydraulic fracturing demonstrates that stress anisotropy impacts hydraulic fracture propagation. Future work will extend the model to alter the state of stress of the rock mass as hydraulic fracturing evolves.
7. ACKNOWLEDGMENTS

This research work was supported financially by Seven Generation Energy Ltd., Talisman Energy Inc., Pason Systems Corp. and the Natural Science and Engineering Research Council of Canada (NSERC).

REFERENCES


APPENDIX II

Executive Summary
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09-22-063-03W6 - Proposed completion 2 - Stage 10 Zones, Perforation 20 (3743.09-3747.09 m)

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### 09-22-063-03W6 - Proposed completion 2 - Stage 10

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<th>Tunnel Length (mm)</th>
<th>Entrance Diameter (mm)</th>
<th>Phasing (deg)</th>
<th>Shot Density (1/m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perforation 20</td>
<td>3743.09</td>
<td>3747.09</td>
<td>203.20</td>
<td>10.67</td>
<td>60.00</td>
<td>10.00</td>
</tr>
<tr>
<td>Perforation 19</td>
<td>3756.09</td>
<td>3760.09</td>
<td>203.20</td>
<td>10.67</td>
<td>60.00</td>
<td>10.00</td>
</tr>
</tbody>
</table>
## Fluids

### Slickwater

<table>
<thead>
<tr>
<th>Fluid Description</th>
<th>Base Fluid - B315(0.25) + B244(0.25) + B317(0.1)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Additives</strong></td>
<td><strong>Code</strong></td>
</tr>
<tr>
<td>B315</td>
<td>0.25 L/m³</td>
</tr>
<tr>
<td>B244</td>
<td>0.25 L/m³</td>
</tr>
<tr>
<td>B317</td>
<td>0.10 L/m³</td>
</tr>
</tbody>
</table>

### Leakoff

<table>
<thead>
<tr>
<th>Leakoff Model</th>
<th>No-Wall building (Cnvc)</th>
</tr>
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</table>

### Friction @ 09-22-063-03W6 - Proposed completion 2 - Stage 10 - Pumping schedule 1

<table>
<thead>
<tr>
<th>Inner Diameter</th>
<th>Low Rate</th>
<th>Pivot Rate</th>
<th>High Rate</th>
<th>Low Pressure</th>
<th>Pivot Pressure</th>
<th>High Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>mm</td>
<td>m³/min</td>
<td>m³/min</td>
<td>m³/min</td>
<td>Pa/m</td>
<td>Pa/m</td>
<td>Pa/m</td>
</tr>
<tr>
<td>99.568</td>
<td>0.17</td>
<td>4.77</td>
<td>15.90</td>
<td>22.62</td>
<td>1583.44</td>
<td>7238.59</td>
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### Rheology @ 09-22-063-03W6 - Proposed completion 2 - Stage 10 - Pumping schedule 1 - Treatment design 1

<table>
<thead>
<tr>
<th>Input Mode</th>
<th>LabData</th>
</tr>
</thead>
<tbody>
<tr>
<td>n'</td>
<td>1.00</td>
</tr>
<tr>
<td>K'</td>
<td>4E-004 Pa.s^n</td>
</tr>
<tr>
<td>Viscosity @ 170.00 1/s</td>
<td>0.3743 cP</td>
</tr>
<tr>
<td>Exposure Temperature</td>
<td>113 degC</td>
</tr>
<tr>
<td>Exposure Time</td>
<td>0.00 h</td>
</tr>
</tbody>
</table>
## Proppants

### 100 mesh

<table>
<thead>
<tr>
<th>Proppant Type</th>
<th>Sand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proppant Name</td>
<td>100 mesh Sand B361-100</td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>2.65</td>
</tr>
<tr>
<td>Mean Diameter</td>
<td>0.16 mm</td>
</tr>
</tbody>
</table>

### Badger Sand 40/70

<table>
<thead>
<tr>
<th>Proppant Type</th>
<th>Sand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proppant Name</td>
<td>Badger Sand 40/70</td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>2.64</td>
</tr>
<tr>
<td>Mean Diameter</td>
<td>0.29 mm</td>
</tr>
<tr>
<td>Pack Porosity</td>
<td>35.00 %</td>
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</tbody>
</table>

### 40/80 CarboHydroProp

<table>
<thead>
<tr>
<th>Proppant Type</th>
<th>Ceramic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proppant Name</td>
<td>40/80 CarboHydroProp</td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>2.61</td>
</tr>
<tr>
<td>Mean Diameter</td>
<td>0.35 mm</td>
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</tbody>
</table>
# Stimulation Data

09-22-063-03W6 - Proposed completion 2 - Stage 10 - Pumping schedule 1

## Treatment Schedule

<table>
<thead>
<tr>
<th>Step Name</th>
<th>Pump Rate</th>
<th>Fluid Name</th>
<th>Fluid Volume</th>
<th>Proppant Name</th>
<th>Proppant Conc.</th>
<th>Proppant Mass</th>
<th>Slurry Volume</th>
<th>Pump Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Pad</td>
<td>7.80</td>
<td>Slickwater</td>
<td>100.00</td>
<td>0.00</td>
<td>0.00</td>
<td>100.00</td>
<td>12.82</td>
<td></td>
</tr>
<tr>
<td>2 20 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>100.00</td>
<td>100 mesh</td>
<td>20.00</td>
<td>2000.00</td>
<td>100.75</td>
<td>12.92</td>
</tr>
<tr>
<td>3 30 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>200.00</td>
<td>Badger Sand 40/70</td>
<td>30.00</td>
<td>6000.00</td>
<td>202.27</td>
<td>25.93</td>
</tr>
<tr>
<td>4 40 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>300.00</td>
<td>40/80 CarboHydroProp</td>
<td>40.00</td>
<td>12000.00</td>
<td>304.60</td>
<td>39.05</td>
</tr>
<tr>
<td>5 75 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>400.00</td>
<td>40/80 CarboHydroProp</td>
<td>75.00</td>
<td>30000.00</td>
<td>411.49</td>
<td>52.76</td>
</tr>
<tr>
<td>6 100 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>500.00</td>
<td>40/80 CarboHydroProp</td>
<td>100.00</td>
<td>50000.00</td>
<td>519.16</td>
<td>66.56</td>
</tr>
<tr>
<td>7 150 kgPA</td>
<td>7.80</td>
<td>Slickwater</td>
<td>600.00</td>
<td>40/80 CarboHydroProp</td>
<td>150.00</td>
<td>90000.00</td>
<td>634.48</td>
<td>81.34</td>
</tr>
<tr>
<td>8 Flush</td>
<td>7.80</td>
<td>Slickwater</td>
<td>29.14</td>
<td></td>
<td></td>
<td>29.14</td>
<td>3.74</td>
<td></td>
</tr>
</tbody>
</table>

## Fluid Totals

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slickwater</td>
<td>2229.15 m³</td>
</tr>
</tbody>
</table>

## Proppant Totals

<table>
<thead>
<tr>
<th>Proppant</th>
<th>Mass</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 mesh</td>
<td>2000.00 kg</td>
</tr>
<tr>
<td>Badger Sand 40/70</td>
<td>6000.00 kg</td>
</tr>
<tr>
<td>40/80 CarboHydroProp</td>
<td>182000.00 kg</td>
</tr>
</tbody>
</table>

## Stage Summary

<table>
<thead>
<tr>
<th>Summary</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Slurry Volume</td>
<td>2272.76 m³</td>
</tr>
<tr>
<td>Total Clean Volume</td>
<td>2200.00 m³</td>
</tr>
<tr>
<td>Total Proppant Mass</td>
<td>190000.00 kg</td>
</tr>
<tr>
<td>Percent Pad Clean</td>
<td>4.55 %</td>
</tr>
<tr>
<td>Percent Pad Dirty</td>
<td>4.40 %</td>
</tr>
<tr>
<td>Under Displacement Volume</td>
<td>0.00 m³</td>
</tr>
</tbody>
</table>
09-22-063-03W6 - Proposed completion 2 - Stage 10 - Pumping schedule 1 - Treatment design 1

**Frac Geometry Model**
UFM

**Use Old StimLAB Correlations**
False

**Max BH Pressure**
689476 kPa

**Reference Pressure**
33833 kPa

**Bridging Factor**
2.50

**Wall Roughness**
0.00 cm

**Complexity Factor**
1.00

**Include effect of fracture offset at laminations**
False

**Containment at the zone boundaries due to shear slip**
False

### Zone Ledges

**Include zone ledges**
False

### Fracture Settings

<table>
<thead>
<tr>
<th>Fracture Index</th>
<th>Is Active</th>
<th>Top TVD</th>
<th>Bottom TVD</th>
<th>Perforation Friction</th>
<th>Erosion rate coefficient</th>
<th>Number of Active Perforations</th>
<th>Discharge coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Perforation</td>
<td>True</td>
<td>2868.45</td>
<td>2868.43</td>
<td>True</td>
<td>0.50</td>
<td>40.00</td>
<td>0.56</td>
</tr>
<tr>
<td>2 Perforation</td>
<td>True</td>
<td>2868.39</td>
<td>2868.37</td>
<td>True</td>
<td>0.50</td>
<td>40.00</td>
<td>0.56</td>
</tr>
</tbody>
</table>

**Auto Height Calculation**
True

**Max Height Growth Up**
100.00 m

**Max Height Growth Down**
150.00 m

**2D Fracture Network**

**Stress Shadow On**

**Time Until Next Stage**

**Use Maximum Stress Angle**
False

### Fluid Leakoff Calibration Table

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Leakoff Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slickwater</td>
<td>1.00</td>
</tr>
</tbody>
</table>
Simulation Results

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOJ Total Fracture Volume</td>
<td>1436 m³</td>
</tr>
<tr>
<td>EOJ Total Leak-off Volume</td>
<td>837 m³</td>
</tr>
<tr>
<td>Total Area of Fracture Surface</td>
<td>215430.00 m²</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface</td>
<td>93745.60 m²</td>
</tr>
<tr>
<td>Total Area of Fracture Surface by Pay</td>
<td>0.00 m²</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface by Pay by Pay</td>
<td>0.00 m²</td>
</tr>
<tr>
<td>Maximum Surface Pressure</td>
<td>40229 kPa</td>
</tr>
<tr>
<td>Maximum BH Pressure</td>
<td>58082 kPa</td>
</tr>
<tr>
<td>Estimated closure time</td>
<td>5368.38 min</td>
</tr>
</tbody>
</table>

Simulation Results @ Fracture 1

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulic Final Extension of HFN in the Direction of Max</td>
<td>758.95 m</td>
</tr>
<tr>
<td>Hydraulic Final Extension of HFN in the Direction of Min</td>
<td>19.21 m</td>
</tr>
<tr>
<td>Max Hydraulic Fracture Height</td>
<td>259.91 m</td>
</tr>
<tr>
<td>Avg Hydraulic Fracture Height</td>
<td>174.83 m</td>
</tr>
<tr>
<td>EOJ Max Hydraulic Fracture Width</td>
<td>20.21 mm</td>
</tr>
<tr>
<td>EOJ Avg Hydraulic Fracture Width</td>
<td>5.20 mm</td>
</tr>
<tr>
<td>EOJ Total Hydraulic Fracture Volume</td>
<td>700 m³</td>
</tr>
<tr>
<td>EOJ Total Hydraulic Leak-off Volume</td>
<td>551 m³</td>
</tr>
<tr>
<td>Total Area of Hydraulic Fracture Surface</td>
<td>133481.00 m²</td>
</tr>
<tr>
<td>Total Area of Hydraulic Fracture Surface by Pay</td>
<td>0.00 m²</td>
</tr>
<tr>
<td>Propped Final Extension of HFN in the Direction of Max</td>
<td>384.77 m</td>
</tr>
<tr>
<td>Propped Final Extension of HFN in the Direction of Min</td>
<td>16.09 m</td>
</tr>
<tr>
<td>Avg Propped Fracture Height</td>
<td>129.04 m</td>
</tr>
<tr>
<td>Fracture Width at Wellbore</td>
<td>4.22 mm</td>
</tr>
<tr>
<td>Avg Propped Fracture Width</td>
<td>1.18 mm</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface</td>
<td>49936.70 m²</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface by Pay by Pay</td>
<td>0.00 m²</td>
</tr>
<tr>
<td>EOJ Net Pressure at Wellbore</td>
<td>3384 kPa</td>
</tr>
<tr>
<td>Average Fracture Conductivity</td>
<td>110.60 mD.m</td>
</tr>
</tbody>
</table>
Simulation Results @ Fracture 2

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulic Final Extension of HFN in the Direction of Max</td>
<td>365.45 m</td>
</tr>
<tr>
<td>Hydraulic Final Extension of HFN in the Direction of Min</td>
<td>8.52 m</td>
</tr>
<tr>
<td>Max Hydraulic Fracture Height</td>
<td>259.91 m</td>
</tr>
<tr>
<td>Avg Hydraulic Fracture Height</td>
<td>222.58 m</td>
</tr>
<tr>
<td>EOJ Max Hydraulic Fracture Width</td>
<td>4.29 mm</td>
</tr>
<tr>
<td>EOJ Avg Hydraulic Fracture Width</td>
<td>8.91 mm</td>
</tr>
<tr>
<td>EOJ Total Hydraulic Fracture Volume</td>
<td>737 m³</td>
</tr>
<tr>
<td>EOJ Total Hydraulic Leak-off Volume</td>
<td>286 m³</td>
</tr>
<tr>
<td>Total Area of Hydraulic Fracture Surface</td>
<td>81949.00 m²</td>
</tr>
<tr>
<td>Propped Final Extension of HFN in the Direction of Max</td>
<td>250.63 m</td>
</tr>
<tr>
<td>Propped Final Extension of HFN in the Direction of Min</td>
<td>8.52 m</td>
</tr>
<tr>
<td>Avg Propped Fracture Height</td>
<td>158.57 m</td>
</tr>
<tr>
<td>Fracture Width at Wellbore</td>
<td>1.58 mm</td>
</tr>
<tr>
<td>Avg Propped Fracture Width</td>
<td>1.17 mm</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface</td>
<td>39958.90 m²</td>
</tr>
<tr>
<td>Total Area of Propped Fracture Surface by Pay</td>
<td>0.00 m²</td>
</tr>
<tr>
<td>EOJ Net Pressure at Wellbore</td>
<td>2546 kPa</td>
</tr>
<tr>
<td>Average Fracture Conductivity</td>
<td>110.27 mD·m</td>
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</tbody>
</table>

Exposure Time Prediction by Step

<table>
<thead>
<tr>
<th>Step Name</th>
<th>Fluid Name</th>
<th>Pump Rate</th>
<th>Fluid Volume</th>
<th>Perforation Injection Temperature</th>
<th>Exposure at BHST of 113 degC</th>
<th>Exposure Above Observation Temperature of 110 degC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad</td>
<td>Slickwater</td>
<td>7.80</td>
<td>100.00</td>
<td>113</td>
<td>25.74</td>
<td>5637.62</td>
</tr>
<tr>
<td>20 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>100.00</td>
<td>113</td>
<td>52.16</td>
<td>5609.35</td>
</tr>
<tr>
<td>30 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>200.00</td>
<td>113</td>
<td>84.01</td>
<td>5584.07</td>
</tr>
<tr>
<td>40 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>300.00</td>
<td>113</td>
<td>138.05</td>
<td>5527.10</td>
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<tr>
<td>75 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>400.00</td>
<td>113</td>
<td>201.49</td>
<td>5465.57</td>
</tr>
<tr>
<td>100 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>500.00</td>
<td>113</td>
<td>278.88</td>
<td>5383.50</td>
</tr>
<tr>
<td>150 kgPA</td>
<td>Slickwater</td>
<td>7.80</td>
<td>600.00</td>
<td>113</td>
<td>1753.53</td>
<td>3951.95</td>
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