INVESTIGATION OF STAGE ORDERING IMPACT ON FRACTURE GROWTH IN MULTI-STAGE HYDRAULIC FRACTURING OF HORIZONTAL WELLS IN STACKED PLAYS

by

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ABSTRACT

Resource extraction and utilization from unconventional reservoirs have become the main focus of the oil and gas industry in the past few decades. Advances in technological capabilities made the unconventional reservoirs congested with horizontal wells with multi-stage hydraulic fracture completions as the main method for recovery. This research aims to investigate the optimum hydraulic fracture treatment schedule on a multi-well pad in stacked pays in the Niobrara and Codell formations of the DJ basin. A 3D numerical hydraulic fracture model was constructed to assess the impact of fracture sequencing and scheduling on resource accessibility and fracture deliverability. The base model consisted of nine wells with a total of 501 hydraulic fracture stages completed in the Niobrara chalk intervals and Codell sandstone. Diagnostic fracture injection tests (DFITs) and well logs were used to calibrate the model.

In this study, twenty-five scenarios were created from the base model as a sensitivity analysis to investigate the effect of fracture sequencing and treatment stage scheduling and location in original reservoir pressure condition and in pressure depleted reservoir condition. The fracture sequencing examined different methodologies followed in the industry of consecutive fracturing, alternating two-step fracturing and zipper fracturing. The sensitivity of treatment stage scheduling and location investigated the impact of different treatment orders to complete the nine wells in the multi-well pad on fracture growth and propagation.

In the original reservoir pressure condition, where all of the wells in the multi-well pad are completed before the start of production, the optimum treatment stage ranking methodology aimed to ensure that the resulting hydraulic fractures dimensions from the treatments reached their designed potential. The stage ranking method prioritized wells located near stress barriers or in high stress zones, starting with the middle well or wells if a group of wells are located in these areas.
This method followed zipper fracturing sequence between the stacked wells. Simultaneous completion for all wells, i.e. completing all nine wells together in a zipper fracturing fashion, had the highest average values of fracture dimensions. Combining the ranking prioritization approach with the zipper fracturing sequence produced the optimum results for fracture dimensions and asymmetry.

In the depleted reservoir condition, two wells out of the nine were put on production before the commencement of the other wells’ hydraulic fracturing treatments, dividing the group into two parent wells and seven child wells. The objective of the optimized stage order schedule was to reduce hydraulic fractures propagation into the pressure depleted zones and generate more contact with unstimulated rock. The stage ranking prioritization aimed to alter the induced stress field created by the stress shadowing effect in order to increase the total stress in the depleted areas and divert the proceeding fracture treatments away from the pressure depleted zones. This was accomplished in the simulation by placing the nearest well to the parent wells and located in-between the parent wells and the child wells at the top of the treatment schedule. Consecutive fracturing for the first child well in this methodology was followed in order to create a stress field around the depleted zones that acts as a stress barrier to the subsequent fracture treatments. The following wells in the optimized stage scheduling system followed zipper fracturing and were ranked based on their proximity to depleted zones. The simulation results also indicated that reducing the treatment volumes of the nearest well to the parent wells or to the depleted zones would minimize the propagation of the hydraulic fractures in these areas and still generate the required stress field around them to divert fracture propagation from other treatments.

This study focuses on the effect of hydraulic fracture stage ordering and sequencing by holding all other aspects of the hydraulic fracture treatments constant, in order to isolate the
treatment scheduling as the only changing parameter. The results showed that optimizing treatment schedules in original pressure state conditions leads to an optimum outcome from the stimulation. In pressure depleted conditions, optimizing treatment scheduling alone does not provide a complete solution to the parent/child well problem. However, this research showed that treatment order and scheduling is an essential part that should be integrated with other solutions such as protection fracs and wellbore re-pressurization.
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NOMENCLATURE

a: Constant, dimensionless

b: Exponent, dimensionless

$C_D$: Coefficient of discharge, dimensionless

$d_p$: Diameter of perfs, in, [L]

$DTC$: Compressional wave travel time, µsec/ft, [T][L$^{-1}$]

$DTS$: Shear wave travel time, µsec/ft, [T][L$^{-1}$]

$E$: Young’s modulus, MMpsi, [M][L$^{-1}$][T$^{-2}$]

$E_d$: Dynamic Young’s modulus, MMpsi, [M][L$^{-1}$][T$^{-2}$]

$E_s$: Static Young’s modulus, MMpsi, [M][L$^{-1}$][T$^{-2}$]

g: Gravitational acceleration constant, in/s$^2$, [L][T$^{-2}$]

$g_0$: Dimensionless time at shut-in, dimensionless

$g(t_D)$: G-function dimensionless time for high leakoff and low efficiency conditions, dimensionless

$G(\Delta t_D)$: Normalized G-function dimensionless time to pumping time, dimensionless

$GR$: Gamma ray, API

$GR_{sh}$: Gamma ray value of shale baseline, API

$GR_{sand}$: Gamma ray value of clean sand line, API

$I_{sh}$: Shale index, fraction, dimensionless

$K$: System permeability, md, [L$^2$]

$K_{exp}$: Permeability exponent, dimensionless

$K_{mult}$: Permeability multiplier, dimensionless

$k_{per}$: Perforation proportionality constant lb/(gal*in$^4$), [M][L$^{-1}$]
$k_{tor}$: Tortuosity proportionality constant lb/(gal*in$^4$), [M] [L$^{-1}$]

$N_p$ : Number of perfs open, dimensionless

$P$: Applied point load, [M] [L] [T$^{-2}$]

$P_{hydrostatic}$: Hydrostatic pressure in the, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_c$: Closure pressure, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_{net}$: Net pressure that equates the difference between closure pressure and pressure inside the fracture, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_o$: Applied pressure, [M] [L$^{-1}$] [T$^{-2}$]

$P_p$: Pore pressure, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_{perforation}$: Pressure drop due to perforation friction, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_{pipe friction}$: Pressure drop due to pipe friction, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_{surface}$: Pressure measured at surface, psi, [M] [L$^{-1}$] [T$^{-2}$]

$P_{tortuosity}$: Pressure loss due to the tortuosity, psi, [M] [L$^{-1}$] [T$^{-2}$]

$\Delta P_{near wellbore}$: Pressure drop near wellbore, psi, [M] [L$^{-1}$] [T$^{-2}$]

$\Delta P_{near wellbore}$: Pressure drop near the wellbore area, psi, [M] [L$^{-1}$] [T$^{-2}$]

$\Delta P_{perf}$: Pressure drop due friction across the perforation, psi, [M] [L$^{-1}$] [T$^{-2}$]

$\Delta P_{tort}$: Pressure drop due to tortuosity, psi, [M] [L$^{-1}$] [T$^{-2}$]

$Q$: Pumping flowrate, bpm, [L$^3$] [T$^{-1}$]

$R$: Radius of pressurized circle, in. [L]

$R$: The square of shear-to-compressional travel times ratio, dimensionless

$r$: Lateral distance from point load pressure, [L]

$t$: Elapsed time, minutes, [T]

t: Transverse stress exponent, dimensionless
$t_p$: Total pumping time, minutes, [T]

$\Delta t_p$: Dimensionless pumping time, dimensionless

$u$: Displacement of crack or fracture width, in, [L]

$V_{pore}$: Pore volume, in$^3$, [L$^3$]

$V_{shale}$: Volume fraction of shale, fraction, dimensionless

$V_{total}$: Total volume, in$^3$, [L$^3$]

$w$: Fracture width, [L]

$y$: Coordinate in the plane, in, [L]

$z$: Depth, in, [L]

$Z$: Distance away from the fracture’s face, [L]

$z$: Vertical distance from point load pressure, [L]

$\alpha$: Biot’s coefficient, dimensionless

$\varepsilon_h$: Horizontal micro-strain, psi$\times 10^{-6}$, [M][L$^{-1}$][T$^{-2}$]

$\varepsilon_x$: Lateral strain, dimensionless

$\varepsilon_z$: Longitudinal strain, dimensionless

$\rho$: Rock density, lbm/in$^3$, [M][L$^{-3}$]

$\rho_b$: Bulk density, g/cm$^3$, [M][L$^{-3}$]

$\rho_f$: Density of the fluid, ppg, [M][L$^{-3}$]

$\theta$: Angle from the perpendicular line from the point load on the horizontal plane, degrees

$\nu$: Poisson’s ratio, dimensionless

$\sigma$: Stress, [M][L$^{-1}$][T$^{-2}$]

$\sigma_t$: Regional tectonic stress, psi, [M][L$^{-1}$][T$^{-2}$]

$\sigma_v$: Vertical stress, psi, [M][L$^{-1}$][T$^{-2}$]
$\sigma_{vi}$: Initial vertical stress, psi, [M] [L$^{-1}$] [T$^{-2}$]

$\phi$: Porosity, fraction, dimensionless

$\phi_{avg}$: Average porosity, fraction, dimensionless

$\phi_{eff}$: Effective porosity, fraction, dimensionless

$\phi_{density}$: Density porosity, fraction, dimensionless

$\phi_{Neutron}$: Neutron porosity, fraction, dimensionless
ABBREVIATIONS

ACA: After closure analysis
CFOP: Critical fracture opening pressure
DFIT: Diagnostic fracture injection test
DJ: Denver-Julesburg
GOHFER: Grid oriented hydraulic fracture extension replicator
GWA: Greater Wattenberg Area
HVFR: High viscosity friction reducer
ISIP: Initial shut in pressure
PPA: Pound of proppant added per gallon
PZS: Process zone stress
SRT: Step rate test
SRV: Stimulated reservoir volume
YMES: Young’s modulus estimated
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xxx
CHAPTER 1 INTRODUCTION

The purpose of this research is to investigate the optimum hydraulic fracture treatment schedule on a multi-well pad in stacked pays for unconventional reservoirs. As horizontal wells with multi-stage hydraulic fracture completions provide the means to access resources in unconventional reservoirs, optimizing their designs is vital for resource utilization and recovery. Unconventional completions have brought many challenges to the industry that have in turn stimulated research and development. Vast amounts of knowledge have been gained and numerous processes were restructured for more efficiency. However, the learning process is continuous and more knowledge is still being acquired through technical research and innovation. This study focuses on hydraulic fracture sequencing in multi-well stimulation jobs. The research aims to see if hydraulic fracture stimulation jobs schedules should be based only on operations cost optimization or if there are other factors to be considered?

In this study, various hydraulic fracturing sequences and patterns between adjacent wellbores are examined to identify the effects of treatment schedule on fracture orientation, propagation, and production performance. Based on the results, an optimized treatment sequencing methodology and other considerations are recommended for a multi-well pad in unconventional reservoir systems. A 3D numerical model was constructed to assess the multiple horizontal wells stimulation. This study aids in the improvement of hydraulic fracture treatment design with an emphasis of resource accessibility and fracture deliverability.

1.1 Motivation

In the past two decades, unconventional plays contributed significantly to the United States oil and gas industry and market share worldwide. In 2008, crude oil production in the US was estimated to be 5 Million barrels per day (MMBOPD). By 2017, crude oil production in the US
reached levels of approximately 9.37 MMBOPD (EIA 2018a). According to the U.S. Energy Information Administration (EIA 2018c), production from unconventional plays accounted for 50% of the US total crude oil production by 2017. Approximately 4.67 MMBOPD is produced from unconventionals. Advancements in technology and knowledge by accumulated literature and experimentation availed the hydrocarbons resources in ultra-tight formations. The multi-stage hydraulic fracturing technology and extended horizontal wellbores are the main contributors in enabling the exploitation and commercial production of these resources.

However, to date there are multiple challenges and complications associated with hydraulic fracturing including but not limited to: individual fracture contribution along the horizontal wellbore and their uniformity, fracture spacing to mitigate stress shadowing effects along the wellbore, well-to-well fracture interference, in-situ stress alteration effect on fracture geometry and dimensions, and fracture sequencing for multi-well treatment designs. As these issues are often combined when faced with multi-stage multi-well hydraulic fracturing for stacked plays, research and additional studies are required to access these challenges.

Extensive research can be found in literature on the challenges associated with hydraulic fracturing. Many scholars have conducted lab experiments and generated numerical simulations in order to gain more insight on the situation in the field. Yet, from the challenges mentioned above, little is found in literature that discusses fracture sequencing and its effects on stimulation success.

1.2 Introduction to the Project Study Area

The study area is the Wattenberg field in the Denver-Julesburg (DJ) Basin. The field is located north of Denver, Colorado, and commonly referred to as the Greater Wattenberg Area (GWA) (Mortiz and Barron 2012). The targeted formations of interest are the Niobrara and Codell
sands. Both reservoirs fall under the unconventional category. The Niobrara is a tight carbonate play that consists of four chalk layers alternating with marls. The Codell is a tight sandstone with high clay content situated below the Niobrara formation. More information of the geology of the study is provided in Chapter 2.

1.3 Research Objectives

The main goal of this study is to provide a quantitative understanding on the effect of stimulation treatment stage ordering on hydraulic fracture geometry and dimensions in multi-stage transverse hydraulic fractures in horizontal wellbores in unconventional stacked plays. The study reaches this goal using the following objectives:

1. Using a calibrated hydraulic fracture model that simulates multi-stage fractures in multiple horizontal producers in a stacked pay overlay, validate the model and the accompanying reservoir simulation using treatment pressures and diagnostic tests from the field;

2. Construct a sensitivity analysis to identify the optimum fracturing pattern in the subject stacked pay. The sensitivity analysis will approach this goal by analyzing different parameters and their impact on fracture geometry and productivity:
   o Investigate the impact of various fracture sequencing methodologies;
   o Investigate the impact of different stage order schedules and locations in a multi-well pad;
   o Investigate the impact of applying a rock property based fracture pattern with varying treatment volumes and fluids;
   o Examine the outcome of initiating the fracture pattern from high stress contrast regions in the stacked pay and vise versa; and,
3. Investigate the application of different approaches to mitigate unfavorable hydraulic fracture growth and propagation in depleted areas. This goal will be reached by analyzing the effects of:
   - Treatment schedules and location between stages;
   - Manipulating the induced stress field from stress shadowing by changing treatment sequencing;
   - Varying treatment volumes for the wells located nearest to the depleted zones; and,
4. Perform a production forecast of the fracture models generated from the sensitivity analysis to compare results of different fracture stage orders.

1.4 Data Availability

The results of the study are based on a constructed 3D hydraulic fracture model created using the commercially available software package GOHFER™, short for Grid Oriented Hydraulic Fracture Extension Replicator. The model incorporates data provided for multiple wells in a stacked play from an unconventional reservoir. Geologic input parameters define bounding/pay layers, stress contrast, and in-situ stresses. Well logs are used to interpret rock mechanical properties and their heterogeneity along the wellbore.

The geologic model built in GOHFER™ is calibrated using log data and field diagnostic tests. The geologic properties were geostatistically developed using vertical log profiles from the subject field. PVT and relative permeability data were acquired from Ning (2017). A sensitivity analysis is then performed using the generated hydraulic fracture base model on the parameters mentioned in the objectives section.

The sensitivity analysis that is conducted in this study is an extension of the work performed by Taylor Levon in his study titled “Workflow Development and Sensitivity
Investigation of Offset Well-To-Well Interference Through 3D Fracture Modeling and Reservoir Simulation in The Denver-Julesburg Basin” (Levon 2018). The model incorporates geologic, reservoir, and hydraulic fracture models to simulate poroelastic and mechanical effects on hydraulic fracturing propagation and interference.

1.5 Workflow

Figure 1.2 illustrates the work flow and process used in this study to reach its objectives. The aim is to implement sensitivities on two conditions:

1. Initial reservoir conditions, where the multi-well pad is fully completed and all of the assigned wells are drilled and put on production at the same time; and,

2. Depleted conditions, where original producing wells exist in the area creating depleted conditions for new added wells.

Figure 1.1: Workflow of the study to investigate the impact of fracturing pattern on a multi-well pad.
CHAPTER 2 GEOLOGY OF THE NIOBRARA AND CODELL FORMATIONS IN THE DJ BASIN

The subject multi-well pad is located in the Wattenberg field area (GWA) northeast of Denver, Colorado. For over a half a century, the GWA has been considered one of the most important oil and gas producers in Colorado (Sonnenberg 2013). The GWA is one of the hydrocarbon accumulations in the Denver-Julesburg (DJ) basin. The DJ basin covers northeast Colorado, southeast Wyoming, and southwest Nebraska. Figure 2.1 shows the areal extent of the DJ basin and the location of the GWA.

Figure 2.1: Denver-Julesburg (DJ) Basin and the Greater Wattenberg field area (GWA) location, highlighted in the dashed line box (after Sonnenberg 2013).
The discovery of the GWA was by Amoco Production Company in 1970 with primary production from the J Sandstones (Sonnenberg 2013). Initial production was largely from unconventional vertical tight gas and only during the last decade have the unconventional Niobrara and Codell formations have become major producers due to technological advancements in drilling and completion. As of 2017, the Niobrara play in the Denver Basin is estimated to have 2.32 billion barrels of proved reserves and produced 11 MMbbls during that year according to U.S. EIA (2018b).

2.1 Niobrara Geologic Setting

The DJ basin was formed during the Late Cretaceous to Early Tertiary Laramide orogeny (Sonnenberg 2013). It’s a large synclinal asymmetrical basin located on the east side of the Rockies’ Front Range. The cretaceous Niobrara formation was deposited in the Western Interior Cretaceous Seaway. The development of the geologic structure was parallel to the Rocky Mountains belt, and its deposition was in the form of a foreland basin (Sonnenberg 2016). The asymmetric syncline has a steep west flank near the Front Range of Colorado and a gentle east flank (Sonnenberg 2013), see Figure 2.2. The deepest part of the basin is further west to Rocky Mountains side and is overlain by the GWA.

2.2 Stratigraphy of the Formations

The stratigraphic column of the Niobrara formation and Codell member in the GWA is shown in Figure 2.3. Two members make the Niobrara formation, the Smokey Hills and the Fort Hays members. The tight Codell sandstone is part of the Carlile formation. The Niobrara formation in the DJ Basin is overlain by the Pierre shale formation and underlain by the Carlile shale formation. The thickness of the Niobrara formation ranges between 300 to 400 ft across the GWA field (Sonnenberg 2016).
The main contributor of the Niobrara unconventional production is the Smokey Hills member. This member consists of alternating organic rich chalk layers with marl layers. The chalk units are the main targets for completions and hydraulic fracturing and are commonly referred to as the A, B, and C in a descending order (Sonnenberg 2016). The marl layers are considered source beds for the Niobrara and the chalk intervals as reservoirs. The lower Fort Hays member is primarily composed of chalk. The depth of the Niobrara formation ranges from 3,500 ft in the east side of the basin to 7,000 – 8,000 ft on the west side (Hart Energy 2014).

The Codell sandstone is situated at the top of the Carlile shale formation and is overlain by the Niobrara and underlain by the Greenhorn carbonate. This layer has been defined by Sonnenberg (2015) as fine-grained bioturbated sandstone. The Codell is highly heterogeneous and consists of clays, shale, sandstone, siltstone, and limestone layers (Hart Energy 2014). The Codell ranges in thickness from 22 to 35 ft (Hart Energy 2014).
Figure 2.3: Stratigraphic column showing the Niobrara formation and Codell member (after Sonnenberg 2016).

2.3 Wattenberg Field

As mentioned above, the greater Wattenberg field area (GWA) is located northeast of Denver, Colorado. In 2013, the GWA field was ranked fourth of top oil fields and ninth of gas
fields in the U.S. (EIA 2015). Even though this is an old field, technological advancement in drilling and completion aimed for the extraction of hydrocarbons from unconventional plays, enabled the GWA field to attain its rank as one of the top producers in the United States.

Initial production from horizontal wells with multi-stage hydraulic fracture completions is in the range of 100 to 700 BOPD with estimated ultimate recovery per well of more than 300,000 BOE (Sonnenberg 2013). One of the key elements of high production in GWA is high temperature (Sonnenberg 2016). High temperature gradients of 28 to 29 °F/1,000 ft are reported in the area of the deepest axis of the DJ Basin and reduce to 16 to 18 °F/1,000 ft around the edges (Sonnenberg 2016). The higher temperatures are one of the factors that created the conditions of overpressure in the producing Niobrara and Codell. In addition, it increases the oil gravities and gas oil ratios (GOR) in the producing zones (Sonnenberg 2016).

2.4 Petroleum System

Due to the structure of the Niobrara of brittle chalks interbedded with organic rich marl layers, the formation has a self-sourcing nature with chalk layers as reservoirs and marls as source/seal beds. This feature promotes the exploitation of this formation and makes it an attractive unconventional resource for development.

The primary target in the Niobrara formation is the chalk layers in the Smoky Hill Member shown in Figure 2.3 (A, B, and C layers colored in blue). The chalk layers’ range in thickness across the GWA from 20 ft to more than 50 ft. These layers are predominantly made of CaCO₃, where its content is generally between 70 – 80 wt. % (Sonnenberg 2016). The TOC values ranges from 1-2 wt. % (Sonnenberg 2016). The API gravity of the produced oil from the basin ranges from 32° to condensate (Hart Energy 2014). The gas oil ratio (GOR) ranges from 500 to 1,000 cf/bbl (Hart Energy 2014). Porosity values for the producing chalk layers are reported to be in the
range of 11% from density logs and 8% from core analysis (Sonnenberg 2016). Permeability is less than 0.1 md (Sonnenberg 2013).

The interbedded marl layers have higher organic content with TOC values ranges between 4 – 6 wt. % (Sonnenberg 2016). CaCO$_3$ content is lower compared to the chalks, 50 – 70 wt. %. The thickness of these layers has a wide range, in some areas it could be less than 20 ft to over 150 ft (Sonnenberg 2016).

The Niobrara is observed to be over-pressured within the GWA with pressure gradients ranging from 0.41 - 0.67 psi/ft (Luneau et al. 2011). The organic matter is classified as type-II kerogen for the Niobrara, oil prone, except for high subsurface temperature areas around the GWA where its production is generally wet gas (Hart Energy 2014) (see Figure 2.4).

The Codell tight sandstone ranges in thickness from 5 – 20 ft across the GWA with pressure gradients of 0.45-0.66 psi/ft (Sonnenberg 2015). Average API gravity is 45°, as reported by Higley and Cox (2007) with porosity and permeability of 14 % and 0.1 md, respectively.

2.5 Drilling and Completion within the Wattenberg Field

Recently, high activity has been seen in the GWA. Increased drilling and completion operations are attributed to the potential of the Niobrara and Codell plays. For new horizontal wells, the general spacing is 640 acres and laterals are drilled in a north-to-south orientation (Sonnenberg 2013). The selected orientation enables for more laterals per section and usually they alternate between Codell and Niobrara zones (Sonnenberg 2013). Figure 2.5 illustrates the orientation of horizontal wells in 36 sections of the GWA.

The Niobrara and Codell are completed with horizontal and vertical wells in the GWA. The vertical wells are older completions and the newer horizontal wells are usually completed with multi-stage hydraulic fracture stimulations (Sonnenberg 2015). Limited entry stimulation
techniques are common for hydraulic fracture completions (Paterniti and Losacano 2013). This technique allows operators to effectively stimulate individual sections of the laterals. Sliding sleeves and plug and perf are the main completion types that are used to achieve limited entry. Operators in the industry are utilizing both techniques. Preference in completion selection is driven by personal experience and cost effectiveness, as technological advancements in completions are still progressing and more data needs to be acquired in order to evaluate the most effective completion type.

Figure 2.4: Rock evaluation pyrolysis data of different sample depths of Niobrara in the DJ Basin (modified after Sonnenberg and Weimer 1993).
Within the hydraulic fracturing domain, sequencing or ordering of the fracturing stages operations has a wide application in the field. Various methods have been employed, with sequential and zipper fracturing being the most common. For the Niobrara and Codell system that consists of multiple stacked pay zones, the number of potential arrangements for fracturing treatment sequences are immensely high for multi-well pads with 30+ stages per well. One of the objectives of this study is to determine the effects of this fracturing order on stimulation effectiveness, in terms of productivity and reservoir contact.
Figure 2.5: Map showing horizontal wells of Niobrara and Codell in GWA (Purple: actual wells, Green: planned wells) (after COGCC GIS Online).
CHAPTER 3 LITERATURE REVIEW

With more wells being completed with hydraulic fracturing in unconventional plays, studying the effect of treatment scheduling and timing has become an important subject. The sequence of operations in completing a multi-well pad will affect the created hydraulic fractures conductivity and productivity. This chapter focuses on the related aspects that governs changes in hydraulic fracture properties due to changes in completion sequence or treatment scheduling between adjacent wellbores in a stacked play. The chapter also includes previous studies that analyzed the effects of treatment scheduling in stacked plays.

3.1 In-Situ Stresses

The in-situ stress field at reservoir depth controls the hydraulic fracture stimulation outcome. Parameters of fracture orientation and dimensions are highly affected by the stresses in the subject rock. The distribution of the stress field in the reservoir dictates the fracture growth orientation. The success of the stimulation operations in horizontal wells is measured by whether the hydraulic fractures are created in a desirable orientation that supports the well layout to increase production.

The ambient stress state in the formation is generated by the overburden, tectonic forces, geomechanical properties of the rock, and rock fabric. This stress state can be altered by the opening and reactivation of existing fractures or the growth and propagation of hydraulic fractures (King 2010). Overburden stress, horizontal maximum stress, and horizontal minimum stress are the main principle stresses that form the stress state surrounding a rock buried at certain depth. These principle stresses are perpendicular to one another and their magnitude varies depending on the geologic setting or environment of the surrounding rocks (King and Willis 1957). In the early publication by King and Willis (1957), they stated that rupture or induced fractures in the rock
would generate in the perpendicular direction to the least principle stress. The authors also stated that fracture orientation is dependent on the existing stress field within a formation and cannot be altered by changing injection pressure during hydraulic fracturing treatment or fracturing fluid selection. Furthermore, the stress state or magnitude of the stresses determines the required injection pressure to initiate the hydraulic fracture (King and Willis 1957). Figure 3.1 shows a graphic representation of the principle stresses acting on a buried rock.

![Stress state elements and fracture orientation place](modified after King and Willis 1957).

3.1.1 Overburden Stress

Overburden pressure is the resultant pressure on a rock layer at a certain depth by the weight of the material above it. The overburden stress is also called vertical stress, $\sigma_v$, or lithostatic pressure. The vertical stress is usually estimated by integrating rock density with respect to depth from rock density logs (Contreras et al. 2011) as presented in Equation 1.1.

$$\sigma_v = \sigma_{vi} + \int_0^z \rho g \, dz$$  \hspace{1cm} (1.1)
Where,

\( \sigma_v \): Vertical stress, psi, \([M][L^{-1}][T^{-2}]\)

\( \sigma_{v_i} \): Initial vertical stress, psi, \([M][L^{-1}][T^{-2}]\)

\( \rho \): Rock density, lbm/in\(^3\), \([M][L^{-3}]\)

\( g \): Gravitational acceleration constant, in/s\(^2\), \([L][T^{-2}]\)

\( z \): Depth, in, \([L]\)

### 3.1.2 Horizontal Stresses

Perpendicular to the overburden pressure are the horizontal stresses acting on the buried rock in the x-y plane. These stresses are defined by their magnitude, the higher stress is the maximum horizontal stress and the lower is minimum horizontal stress, and often referred to as the least principle stress. As shown in Figure 3.1, the induced hydraulic fracture opens against the least principle stress, therefore the minimum horizontal stress is also considered as the closure pressure for hydraulic fracturing calculations.

Depending on the geologic settings of the area, the difference of the principle stresses magnitude determines the stress state the rock will be subject to for fracturing purposes. Figure 3.2 shows the in-situ stress states for various downhole conditions.

![Figure 3.2: In situ stress states depending on principle stresses (after Tutuncu 2018).](image)
Based on the stress regime for a given area, wellbore horizontal laterals should be orientated in the direction that supports the hydraulic fracture stimulation objectives. Depending on the selected wellbores’ orientation and the present stress state, the resultant fractures will be transverse or longitudinal based on the least principle stress direction.

3.1.3 Pore Pressure

Pore pressure in this context is referred to the pressure of the fluid confined in the porous medium of the rock and often described as formation pressure or reservoir pressure. Fluids entrapped in rock’s pore space become pressurized as they support the rock to counter the load acting on it from burial or tectonic movements depending on the geologic settings of the subject formation. According to Terzaghi’s law (1925), the effective stress acting on rock is the difference of the overburden stress and pore pressure. Equation 1.2 shows a form of Terzaghi’s law with Biot’s coefficient or poroelastic constant (Biot 1941), which describes the efficiency in which the pore pressure offsets the overburden pressure (Miskimins 2018).

\[
\sigma_{eff} = \sigma_v - \alpha P_p
\]  

(1.2)

Where,

\( \sigma_v \): Vertical or overburden stress, psi, [M][L^{-1}][T^{-2}]

\( P_p \): Pore pressure, psi, [M][L^{-1}][T^{-2}]

\( \alpha \): Biot’s coefficient, dimensionless

Pore pressure also has a large role in hydraulic fracturing as it affects the closure pressure in the formation, which is addressed in later sections.

3.2 Stress Shadowing or Fracture Stress Interference

The opening of a hydraulic fracture will induce a tensile failure in the subject rock and increase the compressive forces around the fracture width. The resultant net stress from the
difference between the fracturing pressure and the minimum in-situ stress dictates the induced
stress alteration in magnitude and orientation surrounding the hydraulic fracture “stress shadowing
effect” (Morrill and Miskimins 2012). The shadow effect is at maximum at the fracture opening
point and along the fracture plane (Fisher et al. 2004). The effect also radiates into the nearby
formation and dissipates with distance away from the hydraulic fracture. This also indicates that
for multistage fracturing treatments, the stress shadowing effect is cumulative and dependent on
fracturing sequences and spacing (Roussel and Sharma 2011).

3.2.1 Impact of Stress Shadowing on a Single Wellbore

In transverse multistage fracturing treatments, the intra-well hydraulic fracture dimensions
are affected by their created stress alteration in the region. The primary fractures at the toe and
heel of the lateral are less affected since the stress alteration or stress shadowing effect is less in
their near vicinity (Fisher et al. 2004; Daneshy 2017). The increase in net stress due to stress
shadowing affects the fracture propagation reducing the overall productivity and success of the
hydraulic fracture treatment (Fisher et al. 2004). Figure 3.3 illustrates the effect of stress
shadowing between fracture stages on the local stress orientation and the center hydraulic fracture
dimensions.

Figure 3.3: Stress shadow effect in a horizontal wellbore with multiple horizontal
fractures (from Fisher et al. 2004).
As the magnitude of this effect is cumulative in multiple fractures, many authors have examined the effect of fracture sequencing in treatment design. Roussel and Sharma (2011) showed that alternate fracturing methods had lower impact on stress reorientation than consecutive fracturing. Nagel and Sanchez-Nagel (2011) argued that simultaneous fracturing will produce a more complex fracture system rather than sequential fracturing. These authors showed in their models that in a sequential fracturing pattern, the introduced new fracture stage will face new conditions due to the added compressive stresses from the previous hydraulic fracture that will affect its geometry and conductivity.

3.2.2 Impact of Stress Shadowing on Adjacent Wellbores

Roussel and Sharma (2011) have introduced from their models the “stress reversal” region around a fracture, where the in-situ stress state is completely reversed as shown in Figure 3.4. The authors have proposed this phenomenon in multi-stage transverse hydraulic fracture treatments to better understand how longitudinal fractures are created when everything is aligned for transverse hydraulic fractures. In addition to stress reversal, stress shadowing is one of the key elements for well spacing with multistage fractures (Patel et al. 2016). Figure 3.5 shows the stress shadow regions of fractures in adjacent wells. Roussel and Sharma (2011) also showed that sequencing fractures in alternate and zipper-frac patterns allowed for closer spacing as, the extent of the stress shadowing effect is less than the consecutive fracturing case.
3.3 Mechanisms of Stress Alteration and Effects on Hydraulic Fracturing

Stress reorientation and alteration can be induced by mechanical or poroelastic mechanisms. Mechanical being the introduction of a hydraulic fracture and poroelastic by formation depletion. Both mechanisms can be as severe as to completely reverse the stress state in the system (Singh et al. 2008). The main difference is that the mechanical induced alteration is
local and doesn’t extend as far into the formation as the poroelastic mechanism especially in uniform depletion cases.

Levon (2018) investigated the effect of depletion on child wells’ fracturing treatment in the DJ basin. Results of his study found that the new fractures’ orientation and geometries were driven by the depletion from the parent wells. This interference also affected production from the new wells. Agrawal and Sharma (2018) have also reached the same conclusions in their model that depletion will cause a significant stress reorientation that will alter hydraulic fracture dimensions.

In Levon’s (2018) study, hydraulic fractures from the child wells’ stimulations had asymmetric growth and the orientation was preferential towards the parent wells’ depleted region, as shown in Figure 3.6. Proppant distribution was not efficient in this case as the majority of the proppant was concentrated near the depleted areas, creating little conductivity in the unstimulated rock on the opposite sides.

Figure 3.6: Proppant concentration for Well 4N (black cross) in Niobrara C bench, in respect to the Niobrara B (red) and Codell (blue) parent wells (after Levon 2018).
3.4 Hydraulic Fracturing Techniques for Multiple Horizontal Wells

Various hydraulic fracturing techniques have been developed and exploited in tight or unconventional reservoirs to enhance production and recovery. The major objective of these methods is to increase the effective stimulated reservoir volume (SRV). The design of these methods has been driven by the aim of reducing stress shadowing between multistage fracturing treatments and stress interference between hydraulically fractured horizontal wellbores (Rafiee et al. 2012).

3.4.1 Consecutive Fracturing

Consecutive is one of the early fracturing techniques. In this method, the hydraulic fractures are placed in a sequential order from toe to heel in a horizontal wellbore (Roussel and Sharma 2011). This method was and continues to be popular due to its simplicity during operations.

3.4.2 Alternating Two-Step Pattern Fracturing Technique

This technique aims to initiate two fractures along the wellbore with a spacing that insures that the created fractures are outside of the stress shadow region, then place a middle fracture between them. The middle fracture could potentially activate stress-relieved fractures in order to create a more complex network fracture system that is connected to initial two fractures (East et al. 2010). Figure 3.7 demonstrates the effect of following the consecutive fracturing pattern verses the alternating two-step pattern of fractures propagation and growth.
3.4.3 Adjacent Simultaneous Fracturing or Zipper Fracturing Pattern

Fracturing two horizontal wells simultaneously from toe to heel is a technique widely used on multiple horizontal well pads. When fracturing stage one is completed in well A, in an adjacent offset well B fracturing stage one is then completed. This process is repeated, alternating between wellbores until the treatments are completed. The main objectives of this design are operational efficiency and the ability to achieve larger stimulated reservoir volume (Patel et al. 2016).

3.4.4 Modified Zipper Fracs

The technique proposed by Rafiee et al. (2012) combines the advantages of the zipper fracturing pattern and the alternating two-step pattern. In adjacent horizontal wells, two fracture stages are completed, then in the adjacent wellbore a fracture is placed in between the two fractures in the initially stimulated wellbore. Figure 3.8 shows the difference of zipper fracs and modified zipper fracs.
3.5 Fracture Sequencing in Mutli-Well Stacked Plays Case Studies

Several sensitivity studies have been conducted to see the effect of changing key parameters in operations and completions in overall production and recovery in unconventional resource plays. This section outlines two of the sensitivity studies conducted on stacked plays that included fracture sequencing and treatment scheduling in its criteria. The first study, stage order sensitivities in the DJ basin (Levon 2018) and the second sensitivity studied the Utica shale in the Appalachian basin (Yuyi et al. 2016).

3.5.1 The Denver Julesburg Basin Niobrara and Codell Formations Sensitivity Study

This study was conducted on the Niobrara three benches and the Codell sandstone in the DJ basin. Levon (2018) considered two scenarios in his sensitivities: complete the wells from top to bottom and complete the wells in an upward direction from the Codell to Niobrara benches. Both completion schedules showed different hydraulic fracture geometries as the induced stress shadowing differed between the two scenarios. Figures 3.9 and 3.10 show the resultant hydraulic fracture dimensions from both scenarios.
Figure 3.9: Proppant concentration of one stage for well 3N. Three fractures were created by three perforation clusters to show simulated fracture geometries in a downward completion pattern of the multi-well pad in the DJ basin (after Levon 2018).

Figure 3.10: Proppant concentration of one stage for well 3N. Three fractures were created by three perforation clusters to show simulated fracture geometries in an upward completion pattern of the multi-well pad in the DJ basin (after Levon 2018).
Completing the wells from top to bottom order for this stacked play resulted in a larger fracture height growth in the downward direction for well 3N, as shown in Fig. 3.10 when compared to the opposite order results shown in Figure 3.11. This demonstrates that changing the fracture pattern or completion order for a multi-well pad in a stacked play will affect the overall contacted or stimulated rock volume. Therefore, cumulative production or recovery from the stimulated resource will differ to a certain extent by optimizing fracture pattern and scheduling.

3.5.2 The Utica shale of the Appalachian Basin

Yuyi et al. (2016) performed a study on a new multi-well pad in Noble County, Ohio, to see how stage sequencing influenced fracture growth and communication to older producing wells in nearby pads. The new pad, referred to in the study as the Noble County Wet 2 (NCW-2), consisted of five wells completed in the Point Pleasant target in the north-west direction. Figure 3.11 shows a schematic of the NCW-2 wells with the older wells of the NCW-1 pad.

![Figure 3.11: Wells location in Noble County pads 1 and 2, the green tubes represents the perforated sections of the wells (after Yuyi et al. 2016).](image-url)
The wells were completed with 34 to 39 stages with the same treatment design of stage spacing and pump schedule. Wells were spaced 500 ft apart. The wells were stimulated in six different phases, allowing some wells to be fully completed ahead of the group or portions of the lateral to be ahead. Figure 3.12 shows the treatment sequencing implemented.

Figure 3.12: Fracture stimulation sequencing order. In phases were there were more than one well, the stimulation followed a zippering fracturing scheme between the wells (after Yuyi et al. 2016).

Chemical tracers were injected in NCW-2C to investigate any communication with offsetting wells after stimulation. Evidently, communication was found with wells 2B and 2D due to their near proximity. However, in parts where the 2C treatment stages were scheduled ahead of 2A and 2B, communication was observed between NCW-2C and the older wells NCW-1A and NCW-1B (Yuyi et al. 2016). This observation confirms the effect of treatment sequencing on fracture propagation and orientation.

The concept of influencing hydraulic fracture geometries and direction has been proven in literature. Studies using physical evidence of chemical tracers and seismic recordings along with modeling have showed that hydraulic fracture growth can be manipulated both in direction and magnitude. To date, the established work in this area focuses on the effects of fracture sequencing
on well to well interference or well bashing during stimulation. Minimal work has been done on the optimization of fracture sequencing to increases the efficiency of the stimulation and enhance productivity in stacked plays.
CHAPTER 4 HYDRAULIC FRACTURE MODELING

As one of the main objectives of this research is to perform a sensitivity analysis on the effect of fracture sequencing, a calibrated hydraulic fracture model is needed and was developed. The model used in this study is based on the model created by Levon (2018). The software that was used to generate the model was the multi-well version of GOHFER™. The model incorporates a multi-well pad with nine wells completed in different layers or formations.

This chapter reviews the input parameters used to develop the model. The chapter also discusses the procedure used to ensure that the generated fracture geometries mimic field data.

4.1 Introduction to Hydraulic Fracture Simulation

Hydraulic fracturing is a stimulation method that aims to increase wellbore productivity by either bypassing near wellbore damage or enhancing near wellbore productivity. The treatment process is done by injecting non-damaging fluids into the formation at high pressures and rates that exceed the leakoff rate of the formation and would not accept without rupturing (Barree 2018a). The rupture or hydraulic fracture is then filled with a propping agent that creates an additional surface area of the formation that is open to flow and connected to the wellbore. Generally, hydraulic fracture initiation is created by injecting a clean fluid “pad” into the formation followed by a proppant-laden slurry, to keep the flow path open and connected to the wellbore. Figure 4.1 shows a diagram of what a hydraulic fracture created underground may generally look like.
Figure 4.1: Hydraulic fracture schematic (modified after Miskimins 2018). The diagram depicts wellbore perforated section colored black at the center of the picture, that serves as open ports for the pad and proppant-slurry to exit the wellbore and create the fracture surface in the target zone (yellow layer). The fracture is contained from the bottom and top by barrier zones (brown layers).

In engineering application, computer models are developed with the goal to predict the outcome of a process or evaluate its’ results for design optimization. For hydraulic fracturing, modeling and simulation aim to predict fracture geometry and conductivity (Barree 2018a). Another objective of the simulations is to optimize the design of the treatment for future operations. This requires adequate information of reservoir characterization and production history analysis (Barree 2018a).

Hydraulic fracture models and simulators available in the industry are based on many scholars’ research throughout the history that has aimed to mathematically represent how a crack is initiated and propagated through a solid medium. Models are based on three basic principle equations: fluid flow, conversation of mass, and fracture compliance that relates the generated
width with applied pressure inside the fracture (Ayoub et al. 1992). Most of the older two-dimensional (2D) models used a form of Sneddon’s equation (Barree 1984). Sneddon’s derived equation express the relation of fracture width and applied pressure over a circular area from the center of the crack, shown in Equation 4.1 (Sneddon 1946). The expression presents the fracture width as a function of Poisson’s ratio, Young’s modulus, and applied pressure.

\[ u = \left[ \frac{2(1-v^2)P_o}{E} \right] \sqrt{R^2 - y^2} \]  

(4.1)

Where,

\( u \): Displacement of crack or fracture width, in, [L]

\( v \): Poisson’s ratio, dimensionless

\( P_o \): Applied pressure, [M] [L^{-1}] [T^{-2}]

\( E \): Young’s modulus, MMpsi, [M] [L^{-1}] [T^{-2}]

\( R \): Radius of pressurized circle, in, [L]

\( y \): Coordinate in the plane, in, [L]

Some of the most common 2D classical models are the Khristianovich-Geertsma-De Klerk (KGD) model (Geertsma and De Klerk 1969) and the Perkins-Kern-Nordgren (PKN) model (Nordgren 1972). Both models were the first to include more complexity in simulating fractures geometry and dimension and incorporated volume balance and solid mechanics (Economides and Nolte 2000). The assumed fracture geometry is an ellipse, and the main difference in PKN and KGD models is the orientation of the ellipse (Geertsma and De Klerk 1969, Nordgren 1972). Fracture height is contained by the intended stimulated formation, thus the only computed variables are fracture length and width (Geertsma and De Klerk 1969, Nordgren 1972). Figure 4.2 shows fracture geometries for the PKN and KGD models.
Figure 4.2: PKN and KGD fracture geometries (modified after Economides and Nolte 2000).

In the KGD model, the assumed ellipse is in the horizontal plane and the fracture width changes along the vertical face of the fracture are much less than width changes along the horizontal face. This condition requires fracture height to be far greater than length, which implies the use of this model for fractures with short lengths and greater heights (Economides and Nolte 2000). The PKN model assumes the opposite orientation of fracture geometry. The ellipse is assumed to be in the vertical plane and fracture width changes along the vertical fracture face. In contrast with the KGD model, the PKN model is usually used to simulate fractures with longer lengths compared to height (Barree 2018a).

Hydraulic fracture simulation has progressed to avoid some of the assumptions regarding fracture geometry and growth from these older models. The newer generation models are capable of simulating three-dimensional (3D) fracture growth in height, length, and width. As mentioned in Section 1.4, the 3D hydraulic fracture simulator GOHER™ is used for this study. The numerical simulator developed by Barree (1984) is able to predict 3D fracture geometries with
variations of rock strength, pore pressure, confining stress, and rock elastic properties. The simulator uses a shear decoupled system to represent fracture height containment. In case of bedding planes or laminations, the fracing fluid loses its energy to shear along the bedding planes resulting in diminished height growth. The fracing fluid must then re-initiate the fracture above the shear plane when conditions are permissible (Barree 2018a). Barree (1983) presented simulated fracture geometries that are in agreement with laboratory experiments under various confining stress conditions. The results showed that this application is capable of handling various downhole environments with different in-situ or confining stresses and rock properties (Barree 1984).

4.2 Well Log Calibration

Log analysis is one of the initial steps in developing a coherent hydraulic fracture model. As providing a comprehensive reservoir characterization is a requirement for efficient fracture modeling, one of the objectives of well log interpretation is to determine rock mechanical properties, the stress profile, and a geomechanical model for the simulation. For accurate modeling, reservoir lateral heterogeneity should be considered and a complete earth model should be constructed. The available geophysical data for this study comes from a single vertical well located near the stimulated wells in the multi-well pad. The acquired data was either directly attained from the logs or computed by using correlations if specific logs were not available. Figure 4.3 shows the location of the logged reference well.
4.2.1 Effective Porosity

Porosity is the volume fraction of pore space to the total volume of the rock. Porosity is usually estimated by the ratio expression in Equation 4.2.

\[ \phi = \frac{V_{\text{pore}}}{V_{\text{total}}} \]  \hspace{1cm} (4.2)

Where,

\( \phi \): Porosity, fraction, dimensionless

\( V_{\text{pore}} \): Pore volume, in\(^3\), [L\(^3\)]

\( V_{\text{total}} \): Total volume, in\(^3\), [L\(^3\)]

The above expression computes total porosity of the system, which is the total pore volume in the rock and is represented in volume fraction or percentage (Economides and Nolte 2000).
Effective porosity is the interconnected pore volume that allows passage of fluids. In GOHFER™ the effective porosity is estimated from the average porosity values and volume fraction of shale (Barree 2018b). Average porosity is obtained from the arithmetic average of neutron and density porosities. The calculations for effective porosity is shown below in Equations 4.3 and 4.4:

\[
\phi_{avg} = \frac{\phi_{Neutron} + \phi_{Density}}{2}
\]

\[
\phi_{eff} = \frac{\phi_{avg}}{1 - V_{shale}}
\]

Where,

- \( \phi_{Neutron} \): Neutron porosity, fraction, dimensionless
- \( \phi_{Density} \): Density porosity, fraction, dimensionless
- \( \phi_{avg} \): Average porosity, fraction, dimensionless
- \( V_{shale} \): Volume fraction of shale, fraction, dimensionless
- \( \phi_{eff} \): Effective porosity, fraction, dimensionless

The volume fraction of shale is estimated from the gamma ray log in determining shale index and the Stieber (1970) correlation. Equations 4.5 and 4.6 shows the calculation method (Barree 2018b).

\[
I_{sh} = \frac{GR - GR_{sand}}{GR_{sh} - GR_{sand}}
\]

\[
V_{shale} = \frac{0.5I_{sh}}{1.5 - I_{sh}}
\]

Where,

- \( I_{sh} \): Shale index, fraction, dimensionless
- \( GR \): Gamma ray, API
- \( GR_{sand} \): Gamma ray value of clean sand line, API
- \( GR_{sh} \): Gamma ray value of shale baseline, API
4.2.2 Effective Permeability

Effective permeability in GOHFER refers to system permeability, including matrix and natural fracture permeability (Barree 2018b). The system permeability contributes in production calculations and matrix leakoff. The values are estimated as a function of effective porosity. The power law function is shown in Equation 4.7 (Barree 2018b).

\[ K = K_{mult} \times \phi_{eff}^{K_{exp}} \]  \hspace{1cm} (4.7)

Where,

- \( K \): System permeability, mD, \( [L^2] \)
- \( K_{mult} \): Permeability multiplier, dimensionless
- \( K_{exp} \): Permeability exponent, dimensionless

The permeability exponent is recommended to have an input value of three (3) with a multiplier of two (2) in the model based on correlations for tight shale formations (Barree 2018b). Figure 4.4 shows the log tracks for effective porosity and permeability from the reference well used in this study.

4.2.3 Pore Pressure

The default setting in the GOHFER simulator for the reservoir pressure gradient is water of 0.44 psi/ft. However, the Niobrara is observed to be over pressured within the GWA with pressure gradients ranging from 0.41 - 0.67 psi/ft (Luneau et al. 2011) as mentioned in Section 2.4. A pressure offset of 220 psi was set to account for the overpressure condition of the formation, see Figure 4.5. The final pore pressure gradient used in the study is 0.51 psi/ft.
Figure 4.4: System permeability (md) shown on the right track and effective porosity on the left track. The Niobrara top is 7333 ft; the Codell top is 7770 ft.
Figure 4.5: Adjusted pore pressure curve for the overpressured formation. The Niobrara top is 7333 ft; the Codell top is 7770 ft.
4.2.4 Geomechanical Properties

The geomechanical rock parameters that are of most importance in hydraulic fracture models are Poisson’s ratio, Young’s modulus, and Biot’s coefficient. These properties define the deformation behavior of the rock, closure stress of the rock, and the applied effective stress on the rock (Miskimins 2018). The integrity of the model relies on the accuracy of defining these parameters in the model to describe the stress and strain relationship of the rock. Strain is defined as the change in length of a rock sample when subjected to stress.

Stress and strain have a proportional relationship, where the higher applied stress, the larger amount of strain generated. The relation is often used to describe the deformation behavior of a material under loading or unloading conditions. A linear elastic property material generates a straight line relationship for stress versus strain, and the generated amount of strain will always be the same whether for loading or unloading. This condition also implies that there is no permanent deformation after stress is removed (Barree 2018a). This condition doesn’t apply to rock mechanics. The relation between stress and strain in rocks exhibits a nonlinear plastic behavior. The rock sample if loaded and then unloaded it will retain some deformation and will not revert to its original form.

4.2.4.1 Poisson’s Ratio

Poisson’s ratio expresses the ratio of lateral strain to longitudinal strain of a rock sample when subjected to a stress under axial loading conditions (Barree 2018a). This parameter describes the deformation characteristics of the formation rock, and its theoric values ranges from 0 – 0.5. A Poisson’s ratio of 0 suggests that there is no lateral strain when the subject sample is loaded and a value of 0.5 suggests that the sample will have a lateral strain equal to the longitudinal strain when compacted (Barree 2018a). Equation 4.8 gives a general description of Poisson’s ratio.
\[ v = \frac{\varepsilon_x}{\varepsilon_z} \]  \hspace{1cm} (4.8)

Where,

\( v \): Poisson’s ratio, dimensionless

\( \varepsilon_x \): Lateral strain, dimensionless

\( \varepsilon_z \): Longitudinal strain, dimensionless

For hydraulic fracturing models, Poisson’s ratio is derived from log data to present values of this parameter along depth intervals of the intended formation for stimulation. Usually, the ratio of shear to compressional travel times from sonic data is used to compute Poisson’s ratio, as seen in Equations 4.9 and 4.10 (Barree 2018b). However, if sonic data is not available, the ratio can be derived by using correlations from gamma ray, average porosity, and resistivity (Barree et al. 2009a).

\[ R = \frac{DTS^2}{DTC^2} \]  \hspace{1cm} (4.9)

\[ v = \frac{R-2}{2R-2} \]  \hspace{1cm} (4.10)

Where,

\( DTS \): Shear wave travel time, \( \mu \)sec/ft, \([T][L^{-1}]\)

\( DTC \): Compressional wave travel time, \( \mu \)sec/ft, \([T][L^{-1}]\)

\( R \): The square of shear-to-compressional travel times ratio, dimensionless

\( v \): Poisson’s ratio, dimensionless

4.2.4.2 Young’s Modulus

Young’s modulus or moduli of elasticity is the slope of the line from the stress-strain relationship. It measures the amount of required stress to generate deformation in the material. The stress-strain nonlinear plastic relationship in rocks is illustrated in Figure 4.6. If the sample is
subjected to a loading stress, the sample will retain some residual deformation when stress is unloaded.

Figure 4.6: Illustration of nonlinear plastic relation of stress and strain in rocks (after Miskimins 2018). The stress and strain in a rock graph starts from the point of origin and increases in a linear form; until stress is relieved from the rock and some strain remains, showing large hysteresis in strain during load cycling.

Young’s modulus values are frequently computed from logs and the results are expressed as dynamic Young’s modulus. Laboratory measurements of the moduli are expressed as static Young’s modulus. Extracted values from logs often yield much higher values of the moduli and requires correction to convert to static values. In GOHFER, a modified form of the Eissa and Kazi (1988) model correlation is used for to convert dynamic Young’s modulus to static values (Barree 2018b). Equation 4.11 (Barree 2009a) is used to calculate the dynamic values of Young’s modulus and Equation 4.12 (Barree et al. 2009a) is then used to convert to static values. Figure 4.7 shows the log tracks for Poisson’s ratio and static Young’s modulus.
\[ E_d = 13447 \rho_b \frac{{3R-4 \over DTC^2 R(R-1)}} \]  \hspace{1cm} (4.11)

\[ \log E_s = \log(\rho_b E_d) - 0.55 \]  \hspace{1cm} (4.12)

Where,

\[ \rho_b: \text{Bulk density, g/cm}^3, [M][L^{-3}] \]

\[ DTC: \text{Compressional wave travel time, \text{\mu}sec/ft, [T][L^{-1}]} \]

\[ R: \text{The square of shear-to-compressional travel times ratio, dimensionless} \]

\[ E_d: \text{Dynamic Young’s modulus, MMpsi, [M][L^{-1}][T^{-2}]} \]

\[ E_s: \text{Static Young’s modulus, MMpsi, [M][L^{-1}][T^{-2}]} \]

4.2.4.3 Biot’s Coefficient

Biot’s coefficient or poroelastic constant (Biot’s 1941) as presented in Section 3.1.3, is used as a correction factor for pore pressure support of external loads acting on the rock. The coefficient gives a more accurate representation of pore pressure support by accounting for cementation and irregularities in grains shape and distribution (Barree 2018a). The coefficient is estimated in GOHFER™ as a function of effective porosity. The correlation for Biot’s poroelastic constant is shown in Equation 4.13.

\[ \alpha = a \phi_{eff}^b \]  \hspace{1cm} (4.13)

Where,

\[ \alpha: \text{Biot’s coefficient, dimensionless} \]

\[ \phi_{eff}: \text{Effective porosity, dimensionless} \]

\[ a: \text{Constant, dimensionless} \]

\[ b: \text{Exponent, dimensionless} \]
The recommended values for the $a$ and $b$ constants of 1 and 0.1, respectively, were used in the model. The recommendation comes from correlated data of effective porosities and Biot’s coefficients (Barree 2018b). Figure 4.8 shows the log track for Biot’s poroelastic constant.

Figure 4.7: Static Young’s modulus track on the right (YMES) and Poisson's ratio on the left (PR). The Niobrara top is 7333 ft; the Codell top is 7770 ft.
4.3 Prefrac Diagnostics

A diagnostic fracture injection test (DFIT) and a step-down rate test (SRT) are usually coupled in performing pre-job hydraulic fracture diagnostics. A DFIT provides vital information of input data for fracture models in addition to output data to test its validity. The test captures information on closure pressure, fracture pressure, pore pressure, process zone stress, formation flow capacity, and leakoff mechanisms. When combined with SRT data, the acquired data will
give additional information on near wellbore pressure losses that is essential for modeling. Performing SRT’s will determine perforation, pipe, and near wellbore tortuosity pressure losses (Cleary et al. 1993)

The DFIT process aims to create a small extended fracture in contact with the reservoir. After the fracture is established, pumping ceases to terminate fracture extension and observe pressure behavior for analysis. When a SRT is included, before shutting down the pumps to terminate fracture extension, the pumping rate would be stepped down for a couple of points while recording the corresponding pressure values at each rate. For this study, data from two DFITs are available for analysis and use in the model. The first one was in the Niobrara B bench and the second in the Codell sandstone.

4.3.1 Niobrara Prefrac Diagnostics

Prior to the stimulation treatments in the Niobrara formation in the parent well 1N, a DFIT and SRT was conducted at the toe of the well. Freshwater was pumped as the fracturing fluid during the test at three different rates 10, 6, and 2.5 barrels per minute (BPM), respectively, to establish fracture propagation and record rates for the SRT. Figure 4.9 shows the test events of the fracture extension and pressure falloff periods. The total pumping or fracture extension period recorded was 6.6 minutes and the shut-in or falloff period was 192.35 hours or ≈ 8 days. The initial shut-in pressure (ISIP) was obtained by extrapolating the best fit straight line through the recorded pressure values during the falloff period. By using this method in estimating the ISIP, any irregularities in pressure behavior due to fluids stability in the wellbore was discounted (Barree et al. 2014). The extrapolated value for ISIP is 2710 psi at surface and 5966 psi bottomhole. Figure 4.10 shows the extrapolated line on the pressure curve during the falloff interval for determining ISIP.
Figure 4.9: Test events of the conducted DFIT in the Niobrara B bench of well 1N. The figure is zoomed in to the fracture extension period, highlighted by the green bar on the top of the graph. The interval on the right, highlighted with blue bar, is the falloff period. The interval on the left topped with the orange bar is the pretest interval. The pump rate in BPM is shown in red, the measured wellhead pressure is shown in blue.
Figure 4.10: Illustration of the rates picked for SRT analysis and ISIP determination during the falloff event from the extrapolated best fit straight line for the 1N well.

While pumping pressure, fluid hydrostatic pressure, and ISIP are known, the remaining pressure node in the system, pressure drop near wellbore, can be calculated. The pressure drop near wellbore is the sum of pressure drop across the perforations and pressure drop across the tortuous path around the wellbore that fracturing fluids travel through before propagating the
hydraulic fracture (Cleary et al. 1993). The summation of the near wellbore pressure drop can be seen in Equation 4.14 (Economides and Nolte 2000).

$$\Delta P_{\text{near wellbore}} = \Delta P_{\text{perf}} + \Delta P_{\text{tort}}$$  \hspace{1cm} (4.14)

Where,

$$\Delta P_{\text{perf}}$$: Pressure drop due friction across the perforation, psi, [M] [L$^{-1}$] [T$^{-2}$]

$$\Delta P_{\text{tort}}$$: Pressure drop due to tortuosity, psi, [M] [L$^{-1}$] [T$^{-2}$]

$$\Delta P_{\text{near wellbore}}$$: Pressure drop near the wellbore area, psi, [M] [L$^{-1}$] [T$^{-2}$]

Generally, the pressure drop due to friction across perforation is related with the square of flowrate and tortuosity pressure drop with the square root of flowrate, seen in Equation 4.15 (Economides and Nolte 2000).

$$\Delta P_{\text{near wellbore}} = k_{\text{perf}} Q^2 + k_{\text{tort}} Q^{1/2}$$  \hspace{1cm} (4.15)

Where,

$$k_{\text{perf}}$$: Perforation proportionality constant lb/(gal*in$^4$)

$$k_{\text{tort}}$$: Tortuosity proportionality constant lb/(gal*in$^4$)

$$Q$$: Pumping flowrate, bpm, [L$^3$] [T$^{-1}$]

$$\Delta P_{\text{near wellbore}}$$: Pressure drop near wellbore, psi, [M] [L$^{-1}$] [T$^{-2}$]

By using the stepdown rates recoded from Figure 4.10 and substituting the data into Equation 4.15, the constants $$k_{\text{perf}}$$ and $$k_{\text{tort}}$$ can be solved for. Then $$\Delta P_{\text{tort}}$$ and $$\Delta P_{\text{perf}}$$ can be estimated by using Equation 4.15. The pressure drops due to tortuosity and perforation friction are important components in matching treatment pressures and input data into the design model. Additional information can be obtained regarding the number of perforations opened for stimulation by Equation 4.16 (McClain 1963).

$$\Delta P_{\text{perf}} = k_{\text{perf}} Q^2 = \frac{0.2369 q^2 \rho_f}{c_f^2 N_f^2 d_p^2}$$  \hspace{1cm} (4.16)
Where,

- \( q \): Flowrate, bpm, \([M \, [T^{-1}]}\)
- \( \rho_f \): density of the fluid, ppg, \([M \, [L^{-3}}]\)
- \( C_D \): coefficient of discharge, dimensionless
- \( N_P \): Number of perfs open, dimensionless
- \( d_P \): diameter of perfs, in, \([L}\)

The DFIT closure analysis provides information of closure pressure, time to closure, and fluid loss characteristics to the formation (Barree et al. 2009b). The main method of analysis to identify fracture closure is analyzing the pressure decay during the falloff period in relation to the dimensionless G-function time. Results are also compared with graphs of pressure decay with square root of time and log-log plot of pressure and time to ensure the accuracy of the obtained closure pressure value and time to closure (Barree et al. 2009b). The G-function is a dimensionless time function that relates shut-in time to the total pumping time (Nolte 1979). The G-function value for a given time during the test can be calculated by Equations 4.17 through 4.19 (Barree 1998).

\[
\Delta t_D = \frac{(t-t_p)}{t_p} \tag{4.17}
\]

\[
g(t_D) = \frac{4}{3} (1 + \Delta t_D)^{1.5} - \Delta t_D^{1.5} \tag{4.18}
\]

\[
G(\Delta t_D) = \frac{4}{\pi} (g(t_D) - g_0) \tag{4.19}
\]

Where,

- \( \Delta t_D \): Dimensionless pumping time, dimensionless
- \( t \): Elapsed time, minutes, \([T]\)
- \( t_p \): Total pumping time, minutes, \([T]\)
\( g(t_D) \): G-function dimensionless time for high leakoff and low efficiency conditions, dimensionless

\( g_0 \): Dimensionless time at shut-in, dimensionless

\( G(\Delta t_D) \): Normalized G-function dimensionless time to pumping time, dimensionless

For G-function analysis, the semi-log derivative (G dp/dG) is plotted against \( G(\Delta t_D) \) along with pressure versus \( G(\Delta t_D) \). Closure time is identified from the behavior of the semilog derivative curve. A straight line that passes through the origin is imposed on the G dp/dG curve and when the curve deviates from the straight line; closure time is identified and closure pressure is obtained from the pressure curve at the corresponding time (Barree 2009b). Figure 4.11 shows the G-function plot and closure of the Niobrara.

![G-Function Analysis](image)

Figure 4.11: G-function plot representing closure time pick and closure pressure for the conducted DFIT in Niobrara B bench well 1N.
The closure pressure obtained from DFIT is used as a reference point to calibrate the closure pressure calculated from the well logs. Equation 4.20 shows calculation of minimum horizontal stress or closure pressure from derived data from the well logs (Barree et al. 2009b):

\[ P_c = \frac{v}{1-v} [\sigma_v - \alpha_v P_p] + \alpha_h P_p + \varepsilon_h E + \sigma_t \] (4.20)

Where,

- \( P_c \): Closure pressure, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( v \): Poisson’s ratio, dimensionless
- \( \sigma_v \): Vertical stress, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( P_p \): Pore pressure, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( \alpha_v \): Vertical Biot’s coefficient, dimensionless
- \( \alpha_h \): Horizontal Biot’s coefficient, dimensionless
- \( E \): Young’s modulus, MMpsi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( \varepsilon_h \): Horizontal micro-strain, psi\(*10^6\), [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( \sigma_t \): Regional tectonic stress, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]

The characteristics of the semi-log derivative line depict the leakoff mechanism of the formation. The semi-log derivative line exhibits a “hump-like” shape before it merges with the origin straight line. This behavior indicates a pressure dependent leakoff mechanism (PDL) (Barree et al. 2009a). The analysis of the pressure and square root of time (sqr(t)) plot and the log-log plot of change in pressure with time were performed to confirm the findings of the G-function analysis. Figures 4.12 and 4.13 show the confirmation of the identified fracture closure from the G-function analysis.
Figure 4.12: Pressure and square root of time plot used to confirm fracture closure in the Niobrara.
Figure 4.13: Log-log plot of change in pressure with time used to confirm fracture closure in the Niobrara.

Closure is picked from the pressure and sqr(t) plot following the same method in picking closure from the G-function plot. Once the semi-log derivative (sqr(Δt) dp/sqr(Δt)) deviates from the extrapolated line from the origin, closure is indicated. For the log-log plot analysis in Figure 4.16, the semi-log derivative (Δt dΔP/dΔt) follows a straight line with ½ slope and when it deviates from that slope, closure is picked. All three methods correspond to a closure pressure of 5197 psi for the conducted DFIT in the Niobrara B bench.

Additional information can be acquired from observing the pressure decay after closure. After fracture propagation is ceased, any change in pressure is a result of the fracturing fluid leakoff (Barree et al. 2009a). After closure analysis (ACA) can estimate reservoir pore pressure and reservoir permeability. The analysis requires the determination of reservoir flow regimes.
during the test. Linear or pseudo-radial flow regimes are identified from the log-log plot of pressure difference of falloff pressure minus initial reservoir pressure and semi-log derivative of pressure change and the square of linear flow time (Barree et al. 2009a) as shown in Figure 4.14. Depending on the slope of the semi-log derivative, the flow regime can be identified. Slope values of 1 and $\frac{1}{2}$ corresponds to pseudo-radial flow and linear flow regimes, respectively (Barree et al. 2009a). From Figure 4.14, only linear flow was identified from the data set and analysis to obtain reservoir transmissibility couldn’t be performed. Therefore, only an estimation of pore pressure was conducted, shown in Figure 4.15. The estimated reservoir pore pressure of the Niobrara was approximately 4500 psi, which corresponds to values found in literature of pressure gradients ranging from 0.41 - 0.67 psi/ft (Luneau et al. 2011).

Figure 4.14: Log-log plot of change in pressure against square of linear flow time for the Niobrara. Linear flow time is identified by the interval of log derivative curve with slope of $1/2$, the start of linear flow period is pick by vertical line BL and ends with line EL.
4.3.2 Codell Sandstone Prefrac Diagnostics

The same process of Niobrara prefrac diagnostics was followed for the Codell sandstone. A combination of DFIT and SRT were conducted on the Codell sandstone in well 2C. For the DFIT, 2990 gallons of water was pumped at a rate of 10.5 barrels per minute. Figure 4.16 shows the test events of fracture extension and pressure falloff periods. The total fracture extension period recorded was 10.5 minutes and the shut-in or falloff period was 192.8 hours or $\approx 8$ days. The extrapolated value for ISIP is 2911 psi at surface and 6285 psi at bottomhole, shown in Figure 4.17.
Figure 4.16: Test events of the conducted DFIT in Codell sandstone well 2C. The figure is zoomed in the fracture extension period, highlighted by the green bar on the top of the graph. The interval on the right, highlighted with blue bar, is the falloff period. The interval on the left topped with the orange bar is the pretest interval. The pump rate in BPM is shown in red, the measured wellhead pressure is shown in blue.
Figure 4.17: Illustration of ISIP determination during the falloff event from the extrapolated best fit straight line in the Codell sandstone.

The rate data for the SRT gathered from Figure 4.16 doesn’t represent good data for use. The step down rates are not captured and the analysis couldn’t be accurately performed for pressure drop estimation from friction across perforations and tortuosity. Fracture closure information was obtained by following the same process of closure analysis done for the Niobrara. G-function analysis was performed and findings were confirmed by the pressure and square root of time (sqr(t)) plot and log-log plot of change in pressure with time seen in Figures 4.18 to 4.20.
Figure 4.18: G-function plot representing closure time pick and closure pressure for the conducted DFIT in Codell sandstone well 2C.

Figure 4.19: Pressure and square root of time plot used to confirm fracture closure in the Codell sandstone.
Figure 4.20: Log-log plot of change in pressure with time used to confirm fracture closure in the Codell sandstone.

From the behavior of the semi-log derivative of pressure in Figure 4.18, the dominant leak-off mechanism is the transverse storage mechanism. The mechanism is identified by the distinguished behavior of the semi-log derivative curve of having a belly shape curve during the storage effect before merging with the straight line that passes through the origin point (Barree et al. 2009a).
After closure analysis is similar to the Niobrara, as radial flow couldn’t be identified on the log-log plot of pressure and square of time, shown in Figure 4.21. Therefore, only pore pressure was estimated using the Cartesian plot of pressure and linear flow time, see Figure 4.22.

Figure 4.21: Log-log plot of change in pressure against square of linear flow time for the Codell sandstone. Linear flow time is identified by the interval of log derivative curve with slope of 1/2, the start of linear flow period is pick by vertical line BL and ends with line EL.
Figure 4.22: ACA linear flow analysis for pore pressure estimation for the Codell sandstone.

Comparing the calibrated logs with DFIT data for calculated stress to be used in the model, shows that the calibration methods used are sufficient in representing field conditions. Figure 4.23 shows the calculated total stress log track with data retrieved from DFITs for both the Niobrara and Codell. Table 4.1 summarizes the findings of both DFIT and SRT conducted in the Niobrara and Codell formations.
Table 4-1: DFIT and SRT results for the Niobrara and Codell.

<table>
<thead>
<tr>
<th>Well</th>
<th>1N</th>
<th>2C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Formation</td>
<td>Niobrara</td>
</tr>
<tr>
<td></td>
<td>Depth (ft)</td>
<td>7542</td>
</tr>
<tr>
<td></td>
<td>Closure Stress (spi)</td>
<td>5320</td>
</tr>
<tr>
<td></td>
<td>Leakoff Type</td>
<td>Pressure dependent leakoff</td>
</tr>
<tr>
<td></td>
<td>Fracture Gradient (psi/ft)</td>
<td>0.79</td>
</tr>
<tr>
<td></td>
<td>CFOP (psi)</td>
<td>233</td>
</tr>
<tr>
<td></td>
<td>PZS (psi)</td>
<td>762</td>
</tr>
<tr>
<td></td>
<td>Number of Open Perforations</td>
<td>7.6</td>
</tr>
<tr>
<td></td>
<td>Pressure Drop Due to Tortuosity (psi/sqrt(BPM))</td>
<td>58.5</td>
</tr>
</tbody>
</table>
Figure 4.23: Calculated stress profile from log calibration (yellow log track) in psi compared to the DFIT-analyzed stress data (blue dots) in psi for the Niobrara and Codell.
4.4 Grid Setup

After the geomechanical rock properties were generated from logs of the Reference well, the properties were extrapolated into different property grids in order to model the propagation of a hydraulic fracture in GOHER™. The grid height contains the Niobrara producing chalk intervals, Niobrara marls, and Codell sandstone layer. As there is no complete geologic model that captures lateral heterogeneity in the studied area, geologic properties were distributed equally in the lateral direction for each layer. The 3D grid was adjusted to accommodate for lithology changes across the multi-well pad area. The geologic structure of the model was correlated with all of the nine wells’ gamma ray logs in order to produce an accurate representation of the geologic model. Figures 4.24 and 4.25 shows gamma ray (API units) and total stress (psi) across the model.

![Figure 4.24](image)

**Figure 4.24:** A side view of gamma ray property grid. The white line shows well 1N completed in the Niobrara B bench. The colored legend on the right indicates the values of the gridded property and the black lines highlight formation tops and bottoms.
Figure 4.25: A side view of the total stress property grid. The white line shows well 1N completed in the Niobrara B bench. The colored legend on the right indicates the values of the gridded property and black lines highlight formation tops and bottoms.

As this study investigates hydraulic fractures geometries in depleted and non-depleted conditions, two sets of property grids were developed. The main difference between the two is the pore pressure grid and the resultant total stress grid. The pressure depletion profile was created by Levon (2018) from a reservoir model and imported into GOHFER™. Figures 4.26 and 4.27 show the pore pressure grids for non-depleted and depleted conditions, respectively.
Figure 4.26: A cross-sectional view of the mid-perf point for the pore pressure grid for the non-depleted condition showing the location of the nine wells in the multi-well pad for this study. The colored column on the right represents a scale for pore pressure values, next to it in the white boxes is the true vertical depth (ft).
Figure 4.27: A cross-sectional view of the mid-perf point for the depleted pore pressure property grid with well locations. The graph depicts the pressure depletion profile generated by wells 1N and 2C, as they were the older parent wells in the pad. The colored column on the right represents a scale for pore pressure values, next to it in the white boxes is the true vertical depth (ft).

4.5 Pad’s Hydraulic Fracture Completions and Treatment Designs

The subject pad consists of nine wells. Six are completed in the Niobrara chalk benches and referenced with the letter N and three in the Codell sandstone with the reference letter C. The completion type used for the hydraulic fracture treatments was the plug-and-perf method. The pad was completed in three stages or phases. The first phase, the parent wells, included one well in the Niobrara B bench (1N) and another well in the Codell sandstone (2C). After the completion of the first phase, the wells were put on production which generated the pressure depletion as seen in
Figure 4.27. The parent wells from phase one were completed in a zippering style, starting with the 1N well. The second and the third phases saw the completion of the rest of the wells, which are referred to as child wells, as opposed to the reference of the older wells in the pad as parent wells. Wells 1C, 3N, and 2N were completed, in this order, in phase two following a zippering method. In phase three, wells 6N, 3C, 5N, and 4N were completed in this order following a zippering method. Information regarding the hydraulic fracture stimulation completions can be seen in Tables 4.2 through 4.4.

Table 4-2: General completion information of the wells in the pad.

<table>
<thead>
<tr>
<th>Well#</th>
<th>Formation</th>
<th>Number of stages</th>
<th>Number of clusters per stage</th>
<th>Cluster spacing (ft)</th>
<th>Cluster length (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6N</td>
<td>Niobrara A</td>
<td>57</td>
<td>3</td>
<td>40</td>
<td>2</td>
</tr>
<tr>
<td>5N</td>
<td>Niobrara B</td>
<td>62</td>
<td>3</td>
<td>50</td>
<td>2</td>
</tr>
<tr>
<td>2N</td>
<td>Niobrara B</td>
<td>61</td>
<td>3</td>
<td>50</td>
<td>2</td>
</tr>
<tr>
<td>1N</td>
<td>Niobrara B</td>
<td>61</td>
<td>4 clusters for 15 stages, 3 clusters for 46 stages</td>
<td>50</td>
<td>2</td>
</tr>
<tr>
<td>3N</td>
<td>Niobrara C</td>
<td>60</td>
<td>3</td>
<td>40</td>
<td>2</td>
</tr>
<tr>
<td>4N</td>
<td>Niobrara C</td>
<td>62</td>
<td>3</td>
<td>50</td>
<td>2</td>
</tr>
<tr>
<td>3C</td>
<td>Codell SS</td>
<td>47</td>
<td>4</td>
<td>40</td>
<td>2</td>
</tr>
<tr>
<td>2C</td>
<td>Codell SS</td>
<td>45</td>
<td>4</td>
<td>50</td>
<td>2</td>
</tr>
<tr>
<td>1C</td>
<td>Codell SS</td>
<td>46</td>
<td>4</td>
<td>50</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 4-3: Total treatment fluid volumes.

<table>
<thead>
<tr>
<th>Well#</th>
<th>28# pHaserFrac (gal)</th>
<th>FR Water (gal)</th>
<th>25# Linear Gel (gal)</th>
<th>Treated Water (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1N</td>
<td>5,538,861</td>
<td>3,323,089</td>
<td>162,585</td>
<td>828,446</td>
</tr>
<tr>
<td>2C</td>
<td>3,531,990</td>
<td>96,180</td>
<td>2,402,610</td>
<td>458,934</td>
</tr>
<tr>
<td>2N</td>
<td>-</td>
<td>3,446,058</td>
<td>4,557,672</td>
<td>767,634</td>
</tr>
<tr>
<td>3N</td>
<td>-</td>
<td>3,498,222</td>
<td>4,631,970</td>
<td>776,160</td>
</tr>
<tr>
<td>4N</td>
<td>-</td>
<td>2,230,091</td>
<td>7,975,907</td>
<td>938,994</td>
</tr>
<tr>
<td>5N</td>
<td>-</td>
<td>3,639,995</td>
<td>6,101,539</td>
<td>879,018</td>
</tr>
<tr>
<td>6N</td>
<td>-</td>
<td>1,533,926</td>
<td>7,998,289</td>
<td>819,118</td>
</tr>
<tr>
<td>1C</td>
<td>-</td>
<td>2,501,581</td>
<td>3,398,911</td>
<td>626,102</td>
</tr>
<tr>
<td>3C</td>
<td>-</td>
<td>2,423,195</td>
<td>3,546,267</td>
<td>656,116</td>
</tr>
<tr>
<td>Total</td>
<td>9,070,851</td>
<td>22,692,337</td>
<td>40,775,750</td>
<td>6,750,522</td>
</tr>
</tbody>
</table>
Table 4-4: Total treatment proppant mass.

<table>
<thead>
<tr>
<th>Well#</th>
<th>Premium White 40/70 (lbs)</th>
<th>Premium White 20/40 (lbs)</th>
<th>CRC 20/40 (lbs)</th>
<th>100 Mesh (lbs)</th>
<th>Premium White 30/50 (lbs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1N</td>
<td>75,140</td>
<td>3,583,760</td>
<td>310,220</td>
<td>544,240</td>
<td>3,376,970</td>
</tr>
<tr>
<td>2C</td>
<td>436,988</td>
<td>7,763,155</td>
<td>477,652</td>
<td>5,351</td>
<td></td>
</tr>
<tr>
<td>2N</td>
<td>-</td>
<td>10,667,128</td>
<td>608,288</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>3N</td>
<td>-</td>
<td>10,701,690</td>
<td>638,888</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>4N</td>
<td>-</td>
<td>13,043,763</td>
<td>794,349</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>5N</td>
<td>-</td>
<td>13,047,559</td>
<td>754,801</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>6N</td>
<td>-</td>
<td>10,994,871</td>
<td>899,515</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>1C</td>
<td>-</td>
<td>8,728,406</td>
<td>473,564</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>3C</td>
<td>-</td>
<td>8,944,980</td>
<td>486,529</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>512,128</td>
<td>87,475,312</td>
<td>787,872</td>
<td>5,205,525</td>
<td>3,376,970</td>
</tr>
</tbody>
</table>

4.6 Wells Treatment Pressure Matching of Subject Wells

During a stimulation treatment, the pressure trend in the wellbore goes through various behaviors depending on the pumping treatment design and downhole conditions. The applied downhole pressure is the controlling element that affects the induced hydraulic fracture dimensions. During operations, pressure can only be monitored at surface due to the configuration of the well’s completion. At that pressure node, several components affect the values measured. Equation 4.21 (Miskimins 2018) shows the different variables that goes into the surface pressure value.

\[ P_{surface} = P_{pipe\ friction} + P_{perforation} + P_{tortuosity} - P_{hydrostatic} + P_c + P_{net} \]  

(4.21)

Where,

- \( P_{surface} \): Pressure measured at surface, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( P_{pipe\ friction} \): Pressure drop due to pipe friction, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( P_{perforation} \): Pressure drop due to perforation friction, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( P_{tortuosity} \): Pressure loss due to the tortuosity, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
- \( P_{hydrostatic} \): Hydrostatic pressure of the fluid column in the wellbore, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]
\( P_c \): Closure pressure, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]

\( P_{net} \): Net pressure that equates the difference between closure pressure and pressure inside the fracture, psi, [M] [L\(^{-1}\)] [T\(^{-2}\)]

Matching the simulation surface pressure to the actual treatment pressure is done by adjusting the components shown in the above equation. Some of the variables illustrated in the equation are adjusted on a per stage basis as they are dependent on surface treating conditions and local downhole variations (pipe friction, perforation friction, and pressure loss due to the tortuosity). The hydrostatic pressure is computed from the selected fracturing fluid and proppant properties. The closure pressure is calculated based on rock poroelastic and mechanical properties derived from log data and confirmed by DFIT. Pipe friction component is also estimated from the SRT performed with DFIT.

The last term in Equation 4.21, \( P_{net} \), estimates the difference between closure pressure and pressure in the fracture. The resultant pressure in the fracture is affected by additional parameters other than the applied pressure from the fracturing fluid. Some of the factors are the amount of leakoff of fracturing fluid into the matrix, friction along the fracture planes, and stress shadowing effects. The simulator gives the user the option to adjust these parameters in case of post treatment analysis, where actual post job data is available to match with simulation output data.

DFIT analysis and log calibration are the most essential parts in calibrating the model in order to produce representative field data. After the log and DFIT calibration, the initial step in matching the simulated surface pressure to the actual treatment pressure is to ensure the treatment stages and design are mimicked in the simulator with the correct volumes and types of fluids and proppants. Then run the simulator and the variables adjusted accordingly.
Treatment pressure matching was done in two phases in the base model. Phase one was matching the parent wells in the non-depleted condition, using the original pore pressure profile. The second phase was matching the child wells after depletion using the depleted pore pressure profile shown in Figure 4.27. Figures 4.28 and 4.29 illustrate the matching for a parent well stage and a child well, respectively.

Figure 4.28: Stage 32 of well 2N treatment matched data. The dashed purple line represents the actual treatment pressure and the solid purple line represents the simulated treatment pressure data.
Figure 4.29: Stage 26 of well 3C treatment matched data. The dashed purple line represents the actual treatment pressure and the solid purple line represents the simulated treatment pressure data.
CHAPTER 5 FRACTURE SEQUENCING AND SENSITIVITY MODELS

This chapter presents different modeled fracture sequencing orders with their resultant fracture geometries. The sensitivities of stage ordering of hydraulic fracture treatments were implemented on the subject pad’s nine-well calibrated model. Other sensitivities were carried out as well on treatment volumes, fluids, and pumping rates. The analysis is divided into two main sections: sensitivities under non-depleted conditions and sensitivities under depleted conditions. The base model for all sensitivities is the calibrated and matched model provided in Chapter 4.

5.1 Modeling Stress Shadowing

Induced fracture stress interference or stress shadowing effect is one of the major components that drives hydraulic fracture geometry and dimensions. In a multi-well system with multi-stage hydraulic fracture completion settings, stress shadowing must be considered in treatment design for optimum outcome. As hydraulic fractures tend to propagate in the direction of the least amount of stress, areas of increased stress in the vicinity of other hydraulic fractures from previous treatments will act as local stress barriers for future treatments.

Roussel and Sharma’s (2011) 3D model mentioned in Section 3.2.2 showed that stress interference will deviate subsequent fractures from previous fractured zones. Dohmen et al. (2014) and Castonguay et al. (2013) also showed that stress accumulation from hydraulic fracture stimulation in the target zone forced subsequent fractures to propagate out of zone. As the out of zone region accumulates stress from fracturing, subsequent fractures are then contained in the target zone.

In GOHFERTM, stress shadowing is modeled based on the concept of linear-elastic deformation in an infinite half space (Barree 2015). The equation for the induced stresses was first
solved by Boussinesq (1885), as shown in Equation 5.1. Boussinesq’s solution computes how stress from a point load radiates through a horizontal surface that is perpendicular to it.

\[
\sigma = \frac{3P \cos^2 \theta}{2\pi (r^2 + z^2)}
\]  

(5.1)

Where:

\( \sigma \): Stress, [M] [L\(^{-1}\)] [T\(^{-2}\)]

\( P \): Applied point load, [M] [L] [T\(^{-2}\)]

\( r \): Lateral distance from point load pressure, [L]

\( z \): Vertical distance from point load pressure, [L]

\( \theta \): Angle from the perpendicular line from the point load on the horizontal plane, degrees

However, Boussinesq’s solution only considers an isotropic homogeneous medium and doesn’t consider any poroelastic effects or bedding and shear effects of non-uniform deformation in rocks. In addition, the solution implies that induced stress only applies if the applied force is active and there is no residual stress due to deformation (Barree 2015). The approach used in the current software to simulate stress shadowing in a heterogeneous porous medium with shear boundary conditions computes the induced stress as a function of the created propped fracture width and Young’s modulus (Barree 2015). Equation 5.2 is used to calculate the induced stress at a distance from a hydraulic fracture (Barree 2015).

\[
\sigma = \frac{wE}{12Z^2}
\]  

(5.2)

Where:

\( \sigma \): Stress, [M] [L\(^{-1}\)] [T\(^{-2}\)]

\( w \): Fracture width, [L]

\( E \): Young’s modulus, [M] [L\(^{-1}\)] [T\(^{-2}\)]

\( Z \): Distance away from the fracture’s face, [L]
t: Transverse stress exponent, dimensionless

The transverse stress exponent is one of the variables that are enabled for the user to adjust in order to match treatment pressures in their area. The default value in the simulator of 1.2 is based on diagnostic field measurements of multiple fracture stimulations (Barree 2015).

5.2 Stage Order Sensitivity in Non-Depleted Conditions

The original model in Chapter 4 consisted of 501 stages between the nine wells in the multi-well pad. Each stage had three or four perforation clusters. The pumped fluid and proppant types and volumes are the same as used in the actual treatment of the pad, provided in Section 4.5. Each stage’s treatment pumping schedule was matched with the actual treatment in the field to mimic the changes in pumping rate and the duration of the treatment.

Eleven (11) scenarios or treatment schedules were modeled in GOHFER™ using the original model with non-depleted conditions as the base model for the sensitivities. The non-depleted condition refers to the scenario where all wells in the pad were completed and put on production at the same time, draining the reservoir simultaneously.

The schedules that were chosen for the sensitivity analysis were based on field practices and additional factors that would configure the resultant stress shadowing to the benefit of the stimulation outcome. For analyzing the results of the modeling, several parameters were selected as the base criteria for comparison. Definitions of these values are provided later during the comparison. The parameters are:

- Proppant cutoff length (ft),
- Fracture height (ft),
- Fracture width (in),
- Estimated flowing length (ft),
- Average proppant concentration (lb/ft\(^2\)), and
- Total flow area (ft\(^2\)).

The averages of these parameters generated from each well were compared between the eleven sensitivities. The optimum treatment configuration was identified as the treatment schedule that yields the highest values for fracture dimensions, thus more reservoir contact. Table 5.1 summarizes the stage ordering of the eleven scenarios created for this sensitivity analysis. Figures 5.1 through 5.11 show illustrations of the stimulation sequencing and location on the multi-well pad setting.

<table>
<thead>
<tr>
<th>Scenario #</th>
<th>Wells’ stage order and treatments’ schedule description</th>
</tr>
</thead>
</table>
| Scenario 1 | Mimic the actual order used to complete the wells in the field:  
- Phase 1: 1N and 2C. Zipper fracturing starting with 1N  
- Phase 2: 1C, 2N, and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 2 | Consecutive fracturing (complete each well individually) from right to left:  
1. 1N  
2. 2N  
3. 1C  
4. 3N  
5. 4N  
6. 2C  
7. 5N  
8. 3C  
9. 6N |
| Scenario 3 | Zipper fracturing alternating between benches in a triangle form (wine rack sequence):  
- Phase 1: 3N, 2N, and 1N. Zipper fracturing starting with 3N  
- Phase 2: 2C, 4N, and 3C. Zipper fracturing starting with 2C  
- Phase 3: 1C, 5N, and 6N. Zipper fracturing starting with 1C |
| Scenario 4 | Fracture the inner wells then the outer wells in the pad:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 3N and 2C. Zipper fracturing starting with 3N  
- Phase 3: 1N and 5N. Zipper fracturing starting with 1N  
- Phase 4: 1C and 3C. Zipper fracturing starting with 1C  
- Phase 5: 6N. Consecutive fracturing |
<table>
<thead>
<tr>
<th>Scenario #</th>
<th>Wells’ stage order and treatments schedule description</th>
</tr>
</thead>
</table>
| Scenario 5 | Zippering each bench alone, this also orders the treatment to start from highest pore pressure and Young’s modulus layers to the lowest:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 1N, 3N, and 5N. Zipper fracturing starting with 1N  
- Phase 3: 3C, 2C, 1C, and 6N. Zipper fracturing starting with 3C |
| Scenario 6 | Consecutive fracturing (complete each well individually) starting with the inner wells then the outer wells in the pad:  
1. 2N  
2. 2C  
3. 4N  
4. 3N  
5. 1N  
6. 1C  
7. 5N  
8. 3C  
9. 6N |
| Scenario 7 | Zipper all wells together starting with the inner wells then the outer wells in the following order:  
2N – 4N – 2C – 3N – 1N – 3C – 5N – 1C – 6N |
| Scenario 8 | Complete the wells from bottom to top in a zippering fashion by formation:  
- Phase 1: 2C, 3C, and 1C. Zipper fracturing starting with 2C  
- Phase 2: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 3: 3N, 5N, and 1N. Zipper fracturing starting with 3N  
- Phase 4: 6N. Consecutive fracturing |
| Scenario 9 | Complete the wells from top to bottom in a zippering fashion by formation:  
- Phase 1: 3N, 5N, 1N, and 6N. Zipper fracturing starting with 3N  
- Phase 2: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 3: 2C, 3C, and 1C. Zipper fracturing starting with 2C |
| Scenario 10 | Zipper all wells together starting from wells with or located nearby higher stress zones and avoiding creating a stress cage on the inner wells:  
2C – 6N – 3C – 1C – 2N – 4N – 3N – 1N – 5N |
| Scenario 11 | Zipper all wells together starting from bottom to top:  
2C – 3C – 1C – 2N – 4N – 3N – 1N – 5N – 6N |
Figure 5.1: Sensitivity Scenario 1. The diagram shows the location of the wells with their respective target zones as part of the stacked horizontal well completions in a multi-well pad. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order. The box below gives a cross-sectional view of the well locations and which completion phase they fall under.
Figure 5.2: Sensitivity Scenario 2. The wells in the pad are completed in a consecutive order. Each well was stimulated completely before commencing to the next well. The column to the right shows the descending completion order; as well as the box below that shows well locations with the associated completion order.
Figure 5.3: Sensitivity Scenario 3. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order.
Figure 5.4: Sensitivity Scenario 4. The wells in the pad are completed in five phases. The first four phases, zippering completion style was followed, starting with the wells highlighted in lighter colors. The fifth phase, consecutive fracture completion was followed for the last well in the pad. The column to the right shows the five phases and the associated descending completion order.
Figure 5.5: Sensitivity Scenario 5. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order.
Figure 5.6: Sensitivity Scenario 6. The wells in the pad are completed in a consecutive order, starting with the interior wells and moving out. Each well was stimulated completely before commencing to the next well. The column to the right shows the descending completion order; as well as the box below that shows well locations with the associated completion order.
Figure 5.7: Sensitivity Scenario 7. All wells in the pad are completed in a zippering fashion in one phase. The column to the right shows the descending completion order; as well as the box below that shows well locations with the associated completion order.
Figure 5.8: Sensitivity Scenario 8. The wells in the pad are completed in four phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the four phases and the associated descending completion order.
Figure 5.9: Sensitivity Scenario 9. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order.
Figure 5.10: Sensitivity Scenario 10. All wells in the pad are completed in a zippering fashion in one phase. The column to the right shows the descending completion order; as well as the box below that shows wells locations with the associated completion order.
Figure 5.11: Sensitivity Scenario 11. All wells in the pad are completed in a zippering fashion in one phase. The column to the right shows the descending completion order; as well as the box below that shows wells locations with the associated completion order.
All data for each component of the comparison criteria mentioned earlier was collected for every transverse fracture created in the models. Longitudinal fracture data was not considered as part of the comparison, as longitudinal fractures between perforation clusters did not increase the contacted reservoir volume and only accelerated production rather than enhanced recovery. Tables 5.2 through 5.8 contain the averaged values for the generated parameters.

<table>
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<tr>
<th>Well#</th>
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<td>300</td>
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<td>322</td>
<td>321</td>
<td>284</td>
<td>322</td>
<td>321</td>
</tr>
</tbody>
</table>

The cutoff in the proppant length of Table 5.2 is a user defined input in the model. This cutoff length can be used to describe the effectively propped length of the fracture. This length is much shorter than the gross length of the fracture as the remaining length from the proppant cutoff length is assumed to not contribute to production as it’s not effectively propped (Barree 2018b). The cutoff is set to count the length generated by cells that have a minimum of 2 md-ft effective conductivity in the fracture plane. Figure 5.12 shows the selected proppant cutoff length of one of the stimulated stages in Scenario 5.
Figure 5.12: Fracture effective conductivity grids of Well 2N, Stage 21 of Scenario 5. Each grid represents a transverse fracture created by the three clusters in the stage. Proppant cutoff length for each fracture is defined by the width of the black box that encapsulates the cells with effective conductivity values of more than 2 (md-ft). The color scale on the right of each graph is the effective conductivity scale with light colors representing low values and the darker colors representing higher values of conductivity.
Each of the eleven Scenarios used in the treatment scheduling sensitivity generated a different value of average propped fracture length. The average values of the proppant cutoff length of each model shown in the last row of Table 5.2 suggests that zipper fracturing would be more beneficial as a completion method in the multi-well pad. Scenarios 7, 10, and 11 had the highest values of proppant cutoff length. The treatment sequence in these orders are configured to complete the whole pad in one phase of zipper fracturing, pumping the first stage in one well then moving to the first stage of the next well until all wells and all stages are stimulated. The three scenarios had almost the same value for the overall average in proppant cutoff length. The difference between them is the well order they followed. Ordering the wells is shown to have huge effect on the outcome of the stimulation. In considering Well 2C, the lowest value for proppant cutoff length was 134 ft in Scenario 9 and the highest was 310 ft in Scenario 1. Different rankings of Well 2C in the treatment schedule could affect the propped fracture length by 230%.

Comparing Scenarios 6 and 2, which were both consecutive fracturing, Scenario 6 yielded values 10% higher than Scenario 2. The Scenario 6 treatment order configuration was to start with the inner middle wells of the multi-well pad then move to the outer wells. The inner middle wells are 2N, 4N, 2C, and 3N. Scenario 2 configuration started from the wells located on the right then move to the wells on the left. The wells that had a significant difference in the propped length were the Codell wells. Scenario 6 even had higher values than Scenarios 4, 5, and 9, which were zipper fracturing. Scenarios 4, 5, and 9 followed a zippering fracturing completion order in multiple phases (perform zipper fracture stimulation on a group of wells then move to the next group of wells until the whole pad is completed) and not zippering the whole pad, as done in Scenarios 7, 10, and 11. Again, the significant difference in the average propped length values between Scenario 6 and Scenarios 4, 5, and 9 were in the Codell wells. Scenarios 4, 5, and 9 situated the Codell wells
in the later stages of the treatment schedule which allowed more stress to accumulate in their region from stress shadowing from earlier stages. Referring to the total stress grid shown in Figure 5.13, the completed wells in the Niobrara and Codell have two stress barrier zones identified on the grid at depths of roughly 7270 ft and 7760 ft. These are the Pierre formation on top of the Niobrara A bench, and the Carlile formation below the Codell sandstone. In the current multi-well pad setting, the Niobrara A bench has only one well, 6N, and it is situated 200 ft above the next row of wells in Niobrara B bench. The Codell wells however are directly located on top of the high stress barrier zone, with the next row of wells 130 ft above in the Niobrara C bench. Ordering the Codell wells in the later stages of the treatment schedule increases stress in their vicinity from stress shadowing effects of completing the shallower Niobrara wells before them. This creates a stress cage around the Codell wells that diminishes the outcome of the stimulation. Similar analysis can be drawn from the models that started with the inner wells then complete the outer wells versus the models that had the opposite treatment schedule configuration. If the outer wells preceded the inner wells in the completion schedule, stress accumulates around the inner wells and lowers their stimulation outcome. On the other hand, if the opposite was followed, the outer wells don’t have stress barriers on their sides, which allows the hydraulic transverse fractures to propagate to their designed potential. Maximum and minimum values of the average proppant cutoff length of the outer wells 6N and 5N in Table 5.2 had a difference of less than 5%. The inner well 3N however, the minimum and maximum values had a difference of 15%. This suggests that it is more beneficial to start with inner wells.
Figure 5.13: A cross sectional view of the mid-well point for total stress grid for the non-depleted condition showing the location of the nine wells in the multi-well pad. The colored column on the right represents a scale for total stress values, next to it in the white boxes is the true vertical depth (ft).
The average height parameter follows the same trend as the average proppant cutoff length.

Table 5.3 shows the average fracture heights generated in the sequencing sensitivity analysis.

<table>
<thead>
<tr>
<th>Scenario#</th>
<th>Well#</th>
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<th>2</th>
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<td>94.6</td>
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</table>

Height for each transverse fracture is reported by the simulator as the total nodes’ height contacted by the fracture face (Barree 2018b). Models that followed zipper fracturing for the whole pad’s wells together had the highest values of fracture height. In addition, treatment schedules that considered putting the inner wells and the wells that are located near high stress zones ahead had higher values for fracture height.

<table>
<thead>
<tr>
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<th>Well#</th>
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The average fracture width is calculated by averaging the generated fracture width in each grid in the simulation. Table 5.4, showed that fracture width along the fracture faces didn’t differ much between the models. The difference between the highest (Scenario 10) and lowest (Scenario 9) value is 9%. Scenarios 7, 10, and 11, zippering the whole pad orders, had the highest values following a similar trend as fracture height and proppant cutoff length. Its worth mentioning that near wellbore screenouts in the simulation might have skewed the results shown in the above table.

Table 5-5: Average proppant concentration (lb/ft²)

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The average proppant concentration, Shown in Table 5.5, is calculated in the simulator by averaging the proppant concentration within the defined proppant cutoff length and net pay (Barree 2018b). The averaged data of the proppant concentration followed an opposite trend of the previously mentioned parameters. Orders with the lowest values of proppant cutoff length and fracture height had the highest average proppant concentration. As the assigned pumped proppant mass for each stage of the nine wells is the same in all models, average proppant concentration will be higher in smaller fractures. However, the values didn’t vary much between the different treatment schedules. The difference between the highest (Order 6) and lowest (Order 11) value is about 9%.
The flowing fracture length by definition is the closest term to the effective fracture length. In the simulator it is defined as the length that is propped and can clean-up to contribute to production. When proppant concentration and fracture width are generated, the simulator estimates the multiphase flow effects through the proppant pack to estimate fracture conductivity. The estimated flowing fracture length is then computed as a function of proppant cutoff length, fracture conductivity, and reservoir permeability (Barree 2018b).

All Orders had similar values as shown in Table 5.6. As this parameter is mainly a function of fracture cleanup and not fracture propagation, stress shadowing will have a minor impact on the values of the estimated flowing fracture length. Fracturing fluid properties and reservoir deliverability are the major controls for this parameter. The reservoir properties and fracturing fluid types are identical for all models. Therefore, values of the estimated flowing length have minimal differences between the modeled treatment schedules.
Table 5-7: Average flow area per stage (ft²)

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Table 5-8: Total flow area per well (ft²)

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98
The flow area is the area generated by the product of fracture height and the estimated fracture flowing length. The data in Tables 5.7 and 5.8 followed the same trend as the fracture height data. Consecutive fracturing methods generated smaller flow areas as they generated shorter fracture heights. Orders 7, 10, and 11 had the highest values of average flow area per stage and total flow area for the whole pad.

As sequencing is shown to affect fracture dimensions, it also affects fracture geometry and direction by introducing stress shadowing effects and manipulating the stress profile of the system. Figures 5.14 – 5.19 illustrates the fracture propagation geometries of Wells 2N and 2C across the simulated eleven scenarios. Depending on the rank of the wells in the stimulation order; the resultant fracture shape changes. Figures 5.18 and 5.19 show that models that ranked the Codell wells at the end of the treatment schedule, hardly created any fractured surface for Well 2C. The same scenarios are shown in Figure 5.15 for the generated fractures for Well 2N that extended and concentrated in the area of Well 2C, creating stress interference and diminishing the stimulation potential in the Codell sandstone. Scenarios 7, 10, and 11, which had the highest fracture dimensions, created almost identical fracture geometries for the stimulated wells, with lower levels of fracture interference from fracturing the Niobrara bench C into the Codell sandstone. This indicates that zipper fracturing all of the wells in the pad simultaneously, while ranking the inner wells and wells that are located near the stress barrier zones first, is most beneficial for the stimulation outcome.
Figure 5.14: Proppant concentration grids of Well 2N Stage 5 toe transverse fracture for the eleven non-depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.15: Proppant concentration grids of Well 2N Stage 30 toe transverse fracture for the eleven non-depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.16: Proppant concentration grids of Well 2N Stage 45 toe transverse fracture for the eleven non-depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 – 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values.
Figure 5.17: Proppant concentration grids of Well 2C Stage 5 toe transverse fracture for the eleven non-depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.18: Proppant concentration grids of Well 2C Stage 20 toe transverse fracture for the eleven non-depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.19: Proppant concentration grids of Well 2C Stage 35 toe transverse fracture for the eleven non-depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
5.3 Stage Order Sensitivity in Depleted Conditions

In this condition the parent wells in the pad (1N and 2C) were completed prior to the remaining seven wells and put on production. This exposed future treatments in the seven child wells to depleted zones, which altered the stress profile in the formation. The generated hydraulic fractures of the newly treated child wells, especially the wells that are in the near vicinity of a parent well and ranked on the top of the treatment order schedule, propagated towards and were drawn to the parent wells. The performance of the treatments in the child wells are the main subject of interest in this section. The sensitivities of treatment schedule orders were only performed on the child wells. The parent wells treatment simulations were performed on the non-depleted pressure model. The child wells’ simulations were then performed on the depleted pressure model that had the depleted pressure profile shown in Figure 4.30 and the resultant total stress profile shown in Figure 5.20.

Seven scenarios with different treatment schedules were created in GOHFER™. The end goal was to observe which treatment order generated the most contact of previously unstimulated reservoir section. Fracture dimensions were compared with the same criteria as the previous section but only for the child wells. Table 5.9 summarizes the stage ordering of the seven scenarios created for this sensitivity analysis. The parent wells are not included in the scheduling as they are completed prior to the child wells stimulation. Figures 5.21 through 5.28 show illustrations of the stimulation sequencing and locations in the multi-well pad setting.
Figure 5.20: A cross sectional view of the mid-well point for the total stress (psi) grid for the depleted condition showing the location of the nine wells in the multi-well pad for this study. The colored column on the right represents a scale for total stress values, next to it in the white boxes is the true vertical depth.
Table 5-9: Pressure depleted sensitivity models’ stage ordering information

<table>
<thead>
<tr>
<th>Scenario #</th>
<th>Wells’ stage order and treatments’ schedule description</th>
</tr>
</thead>
</table>
| Scenario 12 | Mimic the order used to complete the wells in the field:  
- Phase 1: 1C, 2N, and 3N. Zipper fracturing starting with 1C  
- Phase 2: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 13 | Complete one well located in between the parent wells, in order to create enough stress shadow effect to drive the other treatments in the child wells away from the depleted region:  
- Phase 1: 2N. Consecutive fracturing  
- Phase 2: 1C and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 14 | Complete the middle row or bench in the multi-well stack as the parent wells are located in the top and bottom of the stack:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 1C, 3C, and 3N. Zipper fracturing starting with 1C  
- Phase 3: 5N, 6N. Zipper fracturing starting with 5N |
| Scenario 15 | Complete each bench alone. From bottom layers to the upper layers:  
- Phase 1: 1C, and 3C. Zipper fracturing starting with 1C  
- Phase 2: 4N and 2N. Zipper fracturing starting with 4N  
- Phase 3: 3N, 5N, and 6N. Zipper fracturing starting with 3N |
| Scenario 16 | Perform alternating fracturing method on the wells located in between the parent wells (Stage 1, stage 3, stage 2, stage 4, stage 6……….etc):  
- Phase 1: 1C. Alternate fracturing  
- Phase 2: 2N. Alternate fracturing  
- Phase 3: 3C. Alternate fracturing  
- Phase 4: 4N and 3N. Zipper fracturing starting with 4N  
- Phase 5: 6N and 5N. Zipper fracturing starting with 6N |
| Scenario 17 | Perform alternating fracturing method on one well located in between the parent wells:  
- Phase 1: 2N. Alternate fracturing  
- Phase 2: 1C and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 18 | Zipper all wells together, starting with the wells located in between the pressure depleted zones then stimulate the wells that are nearer to the high stress zones:  
2N – 4N – 1C – 3C – 3N – 6N – 5N |
| Scenario 19 | Completed the wells located in between the parent wells in a zippering fashion starting with the middle well then complete the rest of the group in an upward fashion:  
- Phase 1: 2N, 1C, and 3N. Zipper fracturing starting with 2N  
- Phase 2: 3C, 4N, 5N, and 6N. Zipper fracturing starting with 3C |
Figure 5.21: Sensitivity Scenario 12. The wells in the pad are completed in two phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the two phases and the associated descending completion order. The black colored wells represent the parent wells in the pad that have been already treated. This is the scenario that was actually pumped in the field.
Figure 5.22: Sensitivity Scenario 13. The wells in the pad are completed in three phases. The first phase followed a consecutive fracturing method in Well 2N only. For phases two and three, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order. The black colored wells represent the parent wells in the pad.
Figure 5.23: Sensitivity Scenario 14. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order. The black colored wells represent the parent wells in the pad.
Figure 5.24: Sensitivity Scenario 15. The wells in the pad are completed in three phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order. The black colored wells represent the parent wells in the pad.
Figure 5.25: Sensitivity Scenario 16. The wells in the pad are completed in five phases. The first three phases, an alternating stage fracturing method was followed. Phases four and five, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the five phases and the associated descending completion order. The black colored wells represent the parent wells in the pad.
Figure 5.26: Sensitivity Scenario 17. The wells in the pad are completed in three phases. The first phase followed an alternating stage fracturing method. For phases two and three, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the three phases and the associated descending completion order. The black colored wells represent the parent wells in the pad.
Figure 5.27: Sensitivity Scenario 18. All child wells in the pad are completed in a zippering fashion in one phase. The column to the right shows the descending completion order; as well as the box below that shows wells locations with the associated completion order. The black colored wells represent the parent wells in the pad.
Figure 5.28: Sensitivity Scenario 19. The wells in the pad are completed in two phases. In each phase, zippering completion style was followed, starting with the wells highlighted in lighter colors. The column to the right shows the two phases and the associated descending completion order. The black colored wells represent the parent wells in the pad that have been already treated.
As with the non-depleted condition, the simulated fracture geometries were collected for all transverse fractures in the scenarios for comparison. Longitudinal fractures are discarded, similar to the comparison in the previous sensitivity. What differs in this condition compared to the non-depleted conditions is that fracture direction propagation (asymmetry) is crucial for the success of the treatment. Fracture growth is drawn to the less stressed zones. In this case, it’s the parent wells. Even though, some treatment orders might produce larger fractures, fracture direction must be considered. Tables 5.10 through 5.16 show the averaged values of the collected comparison parameters.

Table 5-10: Average proppant cutoff length (ft) for depletion condition sensitivity.

<table>
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<th>Well#</th>
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<th>14</th>
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The values of proppant cutoff length generated in the depleted condition in Scenarios 12 through 19 had higher values than the simulated models under the non-depleted conditions. This is due the overall decrease in total stress in the system by pore pressure reduction. This also emphasizes that the propagation direction of the simulated fractures must be examined. Placing the fracture into the depleted zones of the parent wells will not add access new hydrocarbons. Most likely fracturing into the parent well will diminish its performance by adding the burden of clean up and the requirement to flow back treatment fluids from adjacent stimulations.
Wells 5N and 6N were seen to have the least amount of fluctuation in their simulated values of propped length. These wells are located the furthest from the parent wells and are placed in most of the sensitivity scenarios at the end of the treatment schedules. If they were to be advanced in the schedule, their fractures would propagate towards the depleted zones interfering with the middle wells. In addition, the effectiveness of their stimulation would be lowered, as contacting unstimulated reservoir sections would not have been achieved.

The well layout in the pad shown in Figure 5.21 situates the child wells laterals of 1C, 2N, and 3N in between the parent wells, 1N and 2C. The three child well locations puts them in a vulnerable position as their treatments are highly affected by the depleted zones created by the parent wells. Figures 5.29 to 5.42 show the created fracture planes of the three child wells 1C, 2N, and 3N for each scenario. In addition to the magnitude of the fracture dimensions of the comparison criteria, fracture propagation direction is also observed in this sensitivity analysis. Figures 5.43 through 5.48 show the fracture planes of Wells 2N and 3C.

Scenarios 15 and 18 generated the highest values of proppant cutoff length in the pressure depleted scenarios. The Scenario15 stage ordering sequence completed each bench alone in a zippering fashion. The order started from the bottom layers and moved to the upward layers. This sequence showed that the initiating wells in the zippering sequence of each bench had fractures with most of their proppant placement in the parent well zone. Thus the effectiveness of the three wells 1C, 4N, and 3N stimulation is in question. Scenario18 considered zippering the whole wells in the pad together and resulted with the highest values of proppant cutoff length. Following this ordering scheme allowed all of the wells’ fractures to propagate towards the depleted zones. Therefore, zippering the whole pad should not be considered for fracture treatment scheduling in depleted conditions.
Figure 5.29: Proppant concentration grids of Well 3N Stage 5 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.30: Proppant concentration grids of Well 3N Stage 20 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.31: Proppant concentration grids of Well 3N Stage 32 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.32: Proppant concentration grids of Well 3N Stage 41 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.33: Proppant concentration grids of Well 3N Stage 53 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.34: Proppant concentration grids of Well 1C Stage 5 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values.
Figure 5.35: Proppant concentration grids of Well 1C Stage 20 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.36: Proppant concentration grids of Well 1C Stage 32 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.37: Proppant concentration grids of Well 1C Stage 41 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values.
Figure 5.38: Proppant concentration grids of Well 2N Stage 5 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.39: Proppant concentration grids of Well 2N Stage 20 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.40: Proppant concentration grids of Well 2N Stage 32 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.41: Proppant concentration grids of Well 2N Stage 41 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values.
Figure 5.42: Proppant concentration grids of Well 2N Stage 53 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.43: Proppant concentration grids of Well 3C Stage 5 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.44: Proppant concentration grids of Well 3C Stage 20 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft2) with lighter colors for low values and darker color for high values.
Figure 5.45: Proppant concentration grids of Well 3C Stage 32 toe transverse fracture for the seven pressure depleted scenarios. The well has four perforation clusters per stage. The depicted fracture planes are of the fourth toe cluster, transverse 4. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values.
Figure 5.46: Proppant concentration grids of Well 4N Stage 5 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.47: Proppant concentration grids of Well 4N Stage 20 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.48: Proppant concentration grids of Well 4N Stage 32 toe transverse fracture for the seven pressure depleted scenarios. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft$^2$) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Consecutive fracturing was evaluated in Scenario 13 for Well 2N. Well 2N is located in the middle Niobrara B bench and in between the parent wells, 1N and 2C. Completely fracturing this well alone will place its fractures in the depleted areas. However, the generated stress shadow effect deterred proceeding treatments’ fractures propagation into the pressure depleted areas. This method preserves the potential of child well treatments to a certain degree.

Alternative fracturing methods were considered for the inner wells 1C, 2N, and 3N in Scenario 16. The initial thought was that as the middle stage is skipped during the treatment, the before and after stages would generate enough stress shadow in the pressure depleted zone and would force the middle stage to propagate in the opposite direction. The results however suggest that the void left by the initial stages is filled by the middle stage. The model results indicate that the created fractures of the middle stage will not only propagate towards the depleted zones but also generate irregularly shaped fracture planes diminishing their contribution to production.

From observing the fracture propagation directions in the pressure depleted conditions, fracturing into the parent well areas is inevitable. Depending on stage ordering alone will not generate the best outcome of the stimulation in treating pads with depleted pressure zones and parent/child well scenarios. However, this analysis isolates the stage sequencing factor to recommend the most optimum treatment schedule for the depleted scenarios. Scenario 13 had a mid-range value for the proppant cutoff length and showed that by completely fracturing one well located between the parent wells, the tendency of other wells’ fractures to propagate into the depleted zones is minimized; as stress has accumulated in the depleted areas by the completion of the first child well. Scenario 12 also had the same effect as all of the middle wells 1C, 2N, and 3N in between the parent wells were zippered starting with 1C. The initial well in the zippered group,
1C, saw the highest attraction towards the pressure depleted zones. Similar to Scenario 13, the rest of the wells’ fracture propagation towards the depleted zones was minimized.

Table 5-11: Average fracture height (ft) for depletion condition sensitivity

<table>
<thead>
<tr>
<th>Scenario#</th>
<th>Well#</th>
<th>12</th>
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Table 5-12: Average fracture width (in) for depletion condition sensitivity

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Table 5-13: Average proppant concentration (lb/ft²) for depletion condition sensitivity

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Table 5-14: Estimated flowing fracture length (ft) for depletion condition sensitivity

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Table 5-15: Average flow area per stage per well (ft$^2$) for depletion condition sensitivity

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Table 5-16: Total flow area per well (ft$^2$) for depletion condition sensitivity

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5.4 Fluids, Volumes, and Pumping Rate Sensitivities

In this section, fluid types, volumes, and pumping rates were investigated on the pressure depleted model and the original pressure profile non-depleted model. Results were analyzed to identify which are the optimum components for the treatments.
5.4.1 Original Pressure Profile Model Treatment Components Sensitivities

For the non-depleted scenario, Scenario 10 was chosen as the stage ordering sequence for fracturing fluid types, volumes and pumping rates sensitivities. Four treatment pumping schedules were considered in this analysis. Fluid types were varied to analyze fluids with different ranges of viscosity. The treatment pumping schedules were unified for all wells for this sensitivity analysis. Tables 5.17 through 5.20 show the different pumping schedule used for this analysis.

<table>
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<th>Pumping stage</th>
<th>Fluid</th>
<th>Volume (gal)</th>
<th>Proppant</th>
<th>Proppant mass (LB)</th>
<th>Rate (BPM)</th>
<th>Slurry concentration (PPA)</th>
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</thead>
<tbody>
<tr>
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<td>-</td>
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<td>-</td>
<td>-</td>
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Table 5-18: Scenario 21 pumping schedule, HVFR 8 gpt 20 BPM treatment.

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<th>Proppant mass (LB)</th>
<th>Rate (BPM)</th>
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<td>100 Mesh</td>
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<td>20</td>
<td>0.25-0.55</td>
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<tr>
<td>Proppant laden fluid</td>
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<td>Premium White 20/40</td>
<td>220,000</td>
<td>20</td>
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<td>-</td>
<td>-</td>
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Table 5-19: Scenario 22 pumping schedule, linear Guar-Borate 45# 70 BPM treatment.

<table>
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<th>Proppant</th>
<th>Proppant mass (LB)</th>
<th>Rate (BPM)</th>
<th>Slurry concentration (PPA)</th>
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<td>-</td>
<td>20.00</td>
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<td>Proppant laden fluid</td>
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<td>70</td>
<td>0.25-0.55</td>
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<td>Guar-Borate 45#</td>
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<td>Premium White 20/40</td>
<td>220,000</td>
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Table 5-20: Scenario 23 pumping schedule, HVFR 8 gpt 70 BPM treatment

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<th>Proppant mass (LB)</th>
<th>Rate (BPM)</th>
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<td>100 Mesh</td>
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<td>Premium White 20/40</td>
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<td>-</td>
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Fracture dimensions were compared using the same comparison criteria presented earlier. Results were compared with Scenario 10 that simulated the actual field treatment fluids and pumping rates (Guar-Borate 30# at 50 BPM). Tables 5.21 through 5.26 show the simulated results.

Table 5-21: Average proppant cutoff length (ft) for pumping schedule component sensitivities

<table>
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<th>Scenario#, Well#</th>
<th>Scenario 20</th>
<th>Scenario 21</th>
<th>Scenario 22</th>
<th>Scenario 23</th>
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Table 5-22: Average fracture height (ft) for pumping schedule component sensitivities

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<th>Scenario 21</th>
<th>Scenario 22</th>
<th>Scenario 23</th>
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Table 5-23: Average fracture width (in) for pumping schedule component sensitivities

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Table 5-24: Average proppant concentration (lb/ft²) for pumping schedule component sensitivities

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Table 5-25: Estimated flowing fracture length (ft) for pumping schedule component sensitivities

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Table 5-26: Average flow area per stage per well (ft²) for pumping schedule component sensitivities

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Table 5-27: Total flow area per well (ft²) for pumping schedule component sensitivities

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</table>
Scenario 23 with HVFR as the treating fluid pumped at 70 BPM gave the largest fracture dimensions simulated results. Scenario 20, slickwater as the fracturing fluid, resulted in the largest propped length and estimated producing flowing length, however the generated height was the least among the sensitivity results. The fracture height created by slickwater was contained in the chalk layers for the Niobrara wells and in the sandstone for the Codell wells with an average value of about 32 ft. For this analysis, fracturing height propagation into the above zones, the Niobrara marls, was encouraged and desired as they are considered as potential producing zones. In other conditions and settings where fracture height containment in a single zone is preferable, slickwater design might be the better option.

5.4.2 Depleted Pressure Profile Model Treatment Components Sensitivities

The comparison analysis in this scenario, adopted the selection of the fluid used in Scenario 23, as it gave the largest simulated fracture dimensions’ outcome. Scenario’s 19 stage sequencing order was used as the base stage completion order for the child wells. The sensitivities in this section aim to see that if by modifying the treatment components in the stimulation of the child wells, the invasion of the fractures to the depleted areas would be affected.

Two scenarios were created for this sensitivity. Scenario 24 has an identical pumping schedule to Scenario 23 with the HVFR as the main treatment proppant laden fluid pumped at 70 BPM. Scenario 25 has the same pumping schedule except for well 2N. Well 2N located in Niobrara B is situated in between the parent wells 1N and 2C. Stimulating Well 2N always results in the invasion of the treating fluids to the depleted zones of the parent wells. Scenario 25’s objective is to investigate whether reducing the treating stage volume of Well 2N by half would minimize the invasion to the depleted zones and still create enough of a stress shadow effect to divert the other
wells fractures from the depleted zones. Tables 5.28 to 5.33 show the results of the simulated transvers fracture dimensions for this sensitivities.

Table 5-28: Average proppant cutoff length (ft) for pumping schedule component sensitivities of pressure depleted model

<table>
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<th>19</th>
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<td>377.9</td>
<td>353.2</td>
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<tr>
<td>4N</td>
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Table 5-29: Average fracture height (ft) for pumping schedule component sensitivities of pressure depleted model

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</table>

Table 5-30: Average proppant concentration (lb/ft²) for pumping schedule component sensitivities of pressure depleted model

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Table 5-31: Average fracture width (in) for pumping schedule component sensitivities of pressure depleted model

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Table 5-32: Average flow area per stage per well (ft$^2$) for pumping schedule component sensitivities of pressure depleted model

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</tr>
<tr>
<td>3C</td>
<td></td>
<td>63033</td>
<td>72356</td>
<td>46124</td>
</tr>
<tr>
<td>1C</td>
<td></td>
<td>56466</td>
<td>56623</td>
<td>31578</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td>64009</td>
<td>63123</td>
<td>39382</td>
</tr>
</tbody>
</table>

Table 5-33: Total flow area per well (ft$^2$) for pumping schedule component sensitivities of pressure depleted model

<table>
<thead>
<tr>
<th>Scenario#</th>
<th>Well#</th>
<th>24</th>
<th>25</th>
<th>19</th>
</tr>
</thead>
<tbody>
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<td>6N</td>
<td></td>
<td>3121098</td>
<td>3077070</td>
<td>1435694</td>
</tr>
<tr>
<td>5N</td>
<td></td>
<td>3908028</td>
<td>3980988</td>
<td>2734536</td>
</tr>
<tr>
<td>4N</td>
<td></td>
<td>3732734</td>
<td>3887428</td>
<td>2254719</td>
</tr>
<tr>
<td>3N</td>
<td></td>
<td>4847940</td>
<td>4832758</td>
<td>3017707</td>
</tr>
<tr>
<td>2N</td>
<td></td>
<td>4265621</td>
<td>3165682</td>
<td>2570414</td>
</tr>
<tr>
<td>3C</td>
<td></td>
<td>3908028</td>
<td>3400709</td>
<td>2167842</td>
</tr>
<tr>
<td>1C</td>
<td></td>
<td>2597428</td>
<td>2604672</td>
<td>1452596</td>
</tr>
<tr>
<td><strong>Sum</strong></td>
<td></td>
<td>26380878</td>
<td>24949307</td>
<td>15633507</td>
</tr>
</tbody>
</table>
Scenarios 24 and 25 outperformed Scenario 19 in comparing the simulated fracture dimensions. Similar to the results of the previous sensitivity, the performance of the HVFR treating fluid is greater than the 45# guar-borate gels. However, for pressure depleted conditions, fracture propagation direction is essential to the success of the stimulation treatment as shown in Figures 5.49 to 5.51 for the wells located in the center between the depleted areas of 2N, 1C, and 3N. By reducing the treatment volume of well 2N, the level of the fracture growth into the depleted zones was reduced as the whole fracture areal extent is lower. For the other wells 1C and 3N, the occupied area of the fracture planes didn’t differ as much between Scenarios 24 and 25. This indicates that fracture propagation behavior and direction were similar in both models.

Figure 5.49: Proppant concentration grids of Well 2N Stages 5, 20, and 32 toe transverse fracture for the pressure depleted scenarios created under the treatment component sensitivities. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.50: Proppant concentration grids of Well 1C Stages 5, 20, and 32 toe transverse fracture for the pressure depleted scenarios created under the treatment component sensitivities. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
Figure 5.51: Proppant concentration grids of Well 3N Stages 5, 20, and 32 toe transverse fracture for the pressure depleted scenarios created under the treatment component sensitivities. The well has three perforation clusters per stage. The depicted fracture planes are of the third toe cluster, transverse 3. The color scale on the right of each graph represents proppant concentrations from 0 - 2 (lb/ft²) with lighter colors for low values and darker color for high values. The black dots show the location of the parent wells that resembles the pressure depleted areas created by them.
CHAPTER 6 PRODUCTION ANALYSIS

After analyzing the sensitivities from Chapter 5 and observing the effect of stage ordering on fracture dimensions and propagation, the next step is to see to what extent does stage ordering affect production. This chapter presents forecasted production results for some of the sensitivity scenarios from the previous chapter in order to evaluate the outcome of optimizing stage ordering on final production. In this study, the production analysis and historical matches were performed in the production module in GOHFERTM.

6.1 Production History Matching of Parent Wells

The available production data at the time of this study is from the two parent wells 1N and 2C. Results from analyzing the production of these two wells was utilized to generate the production forecasts in this chapter. Analysis of the historical production data provided information on reservoir deliverability and post-stimulation fracture performance.

The production analysis in GOHFERTM is based on type curve matching in combination with decline curves analysis from the work of Agarwal et al. (1988) (Barree et al. 2003). Through this analysis, the actual production data is treated as a production draw down test in order to estimate effective reservoir flow capacity, drainage area, and effective fracture half length (Barree et al. 2003). Figures 6.1 and 6.2 show the type curve match plots for Wells 1N and 2C, respectively. The data fit in the type curves of dimensionless wellbore pressure against dimensionless time was achieved by matching the drainage area of the fracture stage, aspect ratio, and flow capacity of the reservoir. Assumptions of flow conditions included a finite conductivity fracture and a rectangular drainage area.
Figure 6.1: Well 1N type curve plot showing fitted data of dimensionless pressure and dimensionless pressure derivative.

Figure 6.2: Well 2C type curve plot showing fitted data of dimensionless pressure and dimensionless pressure derivative.
Other curve fits were used as well to confirm the obtained data from the analysis. Figures 6.3 and 6.4 show fitted data on the pseudo plot pressure change – flow rate ratio against time on a Cartesian scale that confirmed the matched aspect ratio and drainage area. Figures 6.5 and 6.6 illustrate the fitted data on the semi-log plot of pressure change – flow rate ratio against time plot. Analysis of these figures provided information of reservoir transmissibility and effective fracture length.

Figure 6.3: Well 1N fitted pseudo plot of $\Delta p/Q$ against time.
Figure 6.4: Well 2C fitted pseudo plot of $\Delta p/Q$ against time.

Figure 6.5: Well 1N fitted semi-log plot of $\Delta p/Q$ against time.
Figure 6.6: Well 2C fitted semi-log plot of $\Delta p/Q$ against time.

Table 6.1 shows a summary of the results of the production analysis. This data was also used to match oil flow rates and cumulative oil production for the two wells as shown in Figures 6.7 and 6.8.

Table 6-1: Summarized data from production history match of the two parent wells 1N and 2C

<table>
<thead>
<tr>
<th>Parameter</th>
<th>1N</th>
<th>2C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stage drainage area (acre)</td>
<td>0.2</td>
<td>1.6</td>
</tr>
<tr>
<td>Aspect Ratio</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Effective permeability (md)</td>
<td>0.007</td>
<td>0.05</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.08</td>
<td>0.06</td>
</tr>
<tr>
<td>Effective fracture half length (ft)</td>
<td>15</td>
<td>35</td>
</tr>
<tr>
<td>Fracture conductivity, kfwf (md-ft)</td>
<td>20</td>
<td>20</td>
</tr>
</tbody>
</table>
Figure 6.7: Well 1N actual and matched production data.
Figure 6.8: Well 2C actual and matched production data.
6.2 Production Comparison of the Stage Ordering Sensitivity Scenarios

The production module in GOHFERTM was also used in this section to obtain a production forecast of the sensitivity-modeled scenarios. Production is forecasted for each well of the selected scenarios for this comparison. The derived data of drainage area, aspect ratio, and reservoir transmissibility from the history match in Section 6.1 is used as the basis for all of the modeled scenarios’ production forecasts. Scenarios 1, 6, 7, and 8 were selected for this comparison in order to show the effect of changing fracture dimensions as a result of different stage sequencing orders on cumulative oil production in the non-deleted pressure condition. The forecast duration is five years and the selected fracture stage for each well in the models to simulate the forecast had similar fracture dimension values to the total average of the well. Figure 6.9 and Table 6.2 show the results of the production forecast.

![Bar Chart](Figure 6.9: Five years production forecast of cumulative oil (Mbbl) for all wells in the selected non-depleted pressure models.)
Table 6-2: Detailed five years forecast data of cumulative oil production (Mbbl) for the selected non-depleted pressure models.

<table>
<thead>
<tr>
<th></th>
<th></th>
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<tr>
<td>380 HN</td>
<td>80.62</td>
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<td>138.67</td>
<td>379 HN</td>
<td>122.16</td>
<td>379 HN</td>
<td>113.10</td>
</tr>
<tr>
<td>378 HN</td>
<td>139.27</td>
<td>378 HN</td>
<td>153.22</td>
<td>378 HN</td>
<td>170.23</td>
<td>378 HN</td>
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<td>152.42</td>
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<td>376 HN</td>
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<td>374 HC</td>
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<td>Total</td>
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<td>1599.90</td>
<td>Total</td>
<td>1913.38</td>
<td>Total</td>
<td>1868.80</td>
</tr>
</tbody>
</table>

Results of this comparison followed the trend of the results from the sensitivities performed in Section 5.2. Scenarios with greater fracture dimensions (length and height) generated larger forecasted cumulative oil production. Cumulative oil values saw an incremental of 20% from the lowest value (Scenario 6) to the highest value (Scenario 7). In comparison of production values to the base case (Scenario 1), Scenario 6 cumulative oil production forecast has 8% less values than the base case, Scenario 7 forecast has 12% higher values than the base case, and Scenario 8 forecast has 10% higher values than the base case. This suggests that fracture stage sequencing and ordering has a significant impact on production for a multi-well pad. However, several assumptions were made in this study to generate the production forecasts that would limit the validity of the forecasted data if obtaining an accurate production values was the main objective. The main objective of the analysis in this section is to observe whether optimizing stage orders or treatment schedules will impact production. Data shown in Table 6.2 indicates that stage ordering will influence production as it affected fracture growth and propagation as shown in Chapter 5. These assumptions are:
• Reservoir permeability and porosity are equal for all of the wells in the subject pad and based on values from Wells 1N and 2C for the Niobrara wells and Codell wells, respectively.

• The production module in GOHFER™ assumes a constant bottom whole pressure and single phase flow in the reservoir.

• No pressure interference between the wells during production.

• Aspect ratio and drainage area for all wells are based on derived data from Wells 1N and 2C for the Niobrara wells and Codell wells, respectively.

Production forecasting for the depleted pressure models from Section 5.3 was not performed in this study. This is due to the complexity of the issue that simulated fractures for some of the wells are placed in the depleted zones created by the parent wells. Simulating the performance of the fractures combined with reservoir deliverability in this scenario requires numerical modeling to produce presentable results.
CHAPTER 7 CONCLUSIONS AND FUTURE WORK RECOMMENDATIONS

Hydraulic fracturing is a complex stimulation treatment method. Numerous variables come into play in designing a successful treatment. Analyzing and understanding the effect of each variable is crucial. Many studies have been conducted that examine the effect of these variables individually or collectively on the stimulation. This study focuses on hydraulic fracture stage ordering and sequencing and its contribution on the overall outcome of the treatment. All other variables were held constant and the only changing parameter was stage treatment sequence and schedule. The work in this study begins with the construction of the base hydraulic fracture model with two stress profiles. One represents the original pore pressure state of the completed reservoir section encountered by the nine wells in the pad. The second profile represents a depleted pore pressure state created by the production of two out the nine wells in the pad. The base model in this study is based on the model created by Levon (2018) for the same data set used in this study.

The study then moves into a sensitivity analysis of different treatment orders in both cases of original pore pressure and depleted pore pressure system, the stage fracture sequences summary is shown in Appendix A, Tables A-1 and A-2. Other sensitivities of treatment components were carried out as well in the study for both pressure cases. While results of this project were produced from conducted sensitivities on a multi-well pad in the DJ basin, conclusions of this work can be adapted to other areas. A summary of the main results of the sensitivities are included in this chapter along with future work recommendations.

7.1 Conclusions

Eleven hydraulic fracture scenarios were created as part of the first sensitivity in this project. The scenarios had different treatment sequencing of the five hundred and one total stages pumped in the nine wells. This sensitivity considered the original pore pressure state as the basis
for the stress profile in the eleven scenarios. The simulated fracture dimensions were compared for all scenarios and the following conclusions were drawn from optimizing stage ordering on the stimulation outcome:

- Stage ordering and sequencing impacted fracture growth and propagation. The extent of the impact varied between the wells, with the most severe case seeing a variation of 231% in propped fracture length and 240% in fracture height for the lowest and highest values generated for one well of the group.
- Propagation direction and asymmetry for the same fracture stage simulated in the scenarios differed between them as its ranking in the treatment schedule changed from scenario to scenario. This was observed in the proppant concentration results.
- Stage order scenarios that considered simultaneous completion for all wells, i.e. completing all nine wells together in a zipper fracturing fashion, had the highest average values of transverse fracture dimensions. This is attributed to the distribution of the generated stress shadow effect from the completed stages. Segmenting the treatment schedule by completing in a consecutive sequence or by dividing the wells into subgroups and completing them in a zippering sequence, generates high localized stress zones by the accumulation of stress shadowing effects that hinder the growth of the transverse fractures in proceeding treatments.
- Simulated fracture dimensions were highest among treatment orders that prioritized the stage order ranking based on three aspects:
  - The location of the well’s lateral, viewing the locations of the laterals in the pad from a cross-sectional view, the middle wells should be ranked at the top of the treatment schedule.
Wells located near stress barriers or in high stress zones should also be prioritized in the treatment schedule ranking.

The overall fracturing technique that produced the best stimulation outcome in terms of fracture dimensions was zipper fracturing. Scenarios that scheduled their treatments to complete all wells together in the pad simultaneously, zipper fracturing all wells, had the highest average values of fracture propped length and height. Scenarios that followed this technique also produced the most almost-symmetrical fracture planes in the simulation.

The second sensitivity in the study investigated the stage ordering effect in the pore pressure depleted case. For the data set provided for this project, two “parent” wells were put on production before the completion of the rest of the wells in the pad. This resulted in pore pressure depletion and the generation of a new stress profile around these two wells that the treatment of the new wells will be subject to. Eight scenarios were created for this part, examining different stage orders and sequences. The objective was to identify which treatment ranking methodology reduced hydraulic fracture propagation into the pressure depleted zones and generated more contact with unstimulated rock. From reviewing the results of three hundred and ninety-five stages from seven child wells, the following observations were drawn:

- Wells ranked first in the treatment schedule are the most affected by depletion. As most of their stimulated fractures propagated towards the pressure depleted areas.
- Creating a stress field around the pressure depleted zones in the early stages of the treatment, acts as an induced stress barrier and diverts the proceeding treatments from propagating into the pressure depleted zones. This was accomplished in the
simulation by completing the middle well, located, between the pressure depleted zones first, following consecutive fracturing sequence for that well.

- **Completing the child wells simultaneously in a zippering fashion is not beneficial or recommended in pressure depleted conditions.** Zippering all the wells in the pad together prevented the creation of a stress field around the pressure depleted zones. This resulted in all the treatments from the wells nearest to the pressure depleted areas to propagating towards the pressure depleted zones.

- **An alternating two-step fracturing technique produced irregular shaped fracture planes and did not promote fracture propagation away from the pressure depleted zones for the middle skipped stage in this particular sequencing.**

- **Scenarios that showed the least amount of invasion of transverse fractures from stimulating child wells into the parent wells followed the below aspects in their stage ordering methodology:**
  - Create a stress field around the parent wells’ depleted pressure zone by prioritizing the nearest wells to the depleted zones in the treatment scheduling. This will influence the propagation of fractures of the subsequent wells away from the pressure depleted zones.
  - From the group of the child wells nearest to the parent wells, the first well is recommended to be completed in a consecutive fracturing technique. This would accumulate stress in its vicinity and in the surrounding area of the parent well that will minimize the propagation of the proceeding treatments in its direction or the parent’s well direction. The selection of this well is based on its location following these considerations:
• Nearest to the parent well and located in-between the parent well and the child wells.

• If there are more than one parent well, the child well to be ranked first is the most centric well between the parent wells.

  o After completing the nearest child wells to the pressure depleted areas and ensuring that the generated stress field from stress shadowing would minimize the effect of depletion on the rest of the child wells, the remaining well completions should be ranked following the same methodology of the previous sensitivity, the non-depleted condition.

The third sensitivity examined various treatment pumping schedule components in the original pore pressure state of the section. Treatment fluid types, volumes, and pumping rates were varied in this sensitivity. Results of the simulated fractures from four scenarios with different treatment pumping schedule components lead to the following conclusions:

• Treatments with slickwater as the main fracturing fluid generated fractures that were contained in the completed interval. Fracture height was constrained in the thickness of the completed interval.

• Scenarios with higher pumping rates had higher average values of fractures dimensions, both in length and height.

• Performance of the fluid as a fracturing fluid drove the outcome of the simulated results. HVFR outperformed linear gels and slickwater in proppant distribution and in length and height propagation.

The final sensitivity carried out in this project examined varying treatment pumping schedule components in the depleted pore pressure state condition. Fluid types and treatment
volume were the main components in this sensitivity. Two models were created. The first scenario examined the use of HVFR fluids instead of linear gel systems for the child wells. The second scenario decreased the treatment volume of the first well to be completed in the stacked well, which is also the nearest well to the parent wells. The following observations were made from the simulated results:

- As the performance of HVFR is higher than linear gel systems as a fracturing fluid, simulations that utilized HVFR had a better outcome of larger fracture dimensions and greater proppant distribution. Proppant concentration grids showed that proppant deposition concentrated in the pressure depleted areas in the scenario that used linear gel systems. Proppant distribution was more efficient using the HVFR system.

- The stage ordering that was implemented for all models in this sensitivity started with the completion of the middle well between the parent wells in a consecutive fracturing pattern. The objective was to create a stress field around the parent wells that would divert the proceeding treatments away from the depleted zones. This part considered only varying the treatment volume of this well. Two main observations were derived:
  - Reducing the treatment volume resulted in smaller fractures. However, this is beneficial in completing wells nearby localized depleted zones as the invasion of the simulated fractures to these zones are reduced.
  - The magnitude of the resultant stress field around the parent wells was adequate to serve as an induced stress barrier to the following child wells treatments.

Finally, a production analysis and forecast were conducted in this study to compare the treatments performance of the fracture models generated from the fracture sequencing and scheduling sensitivities. The analysis was only performed on the non-depleted pressure models.
The outcome of the analysis indicates that optimizing fracture stage sequencing and scheduling to achieve larger fracture dimensions will translate into an increase in production.

7.2 Future Work Recommendations

This project’s main objective was to investigate the effect of stage ordering on the outcome of a hydraulic fracturing stimulation treatment on a multi-well pad in unconventional stacked plays. Several limitations were encountered during the construction of the base model and drafting the sensitivities from the provided data set for this study. This leads to the proposal of several recommendations that could expand this research work into further studies that will exploit the same objectives. These proposed recommendations include the following:

- This project studied only one geologic setting as the data set provided information of one multi-well pad. Performing stage ordering sensitivities following the same methodology of this work in other areas will solidify the current derived conclusions and expand them.

- Perforation cluster spacing was different from well to well. Perforation set back length also changed between the wells. This made the location of the stages different in the lateral direction and not vertically aligned from a vertical point of view. Other configurations where stage distribution is uniform among the wells in the pad should be investigated as the generated stress shadowing will be affected.

- The duration of the recorded pressures in the falloff test of the parent wells DFITs was short. Radial flow couldn’t be identified from the after closure analysis and reservoir transmissibility information was not derived. If longer tests were provided this would increase the accuracy of the input data of the model.
• DFITs were only conducted in the parent wells. If child wells DFITs were provided, the calibrated stress profile after depletion would be more accurate as the depleted pore pressure can be obtained from these tests. Leakoff characteristics and fissure opening pressures data quality would also be improved.

• The stage ordering sensitivity in the pressure depleted conditions considered optimizing treatment schedule in order to reduce the overall stimulated fractures growth towards the depleted zones for completing the whole pad. The approach did not consider any other remedial action of pressure maintenance for the parent wells. Combining the optimized stage ranking methodology with pressure maintenance solutions and recharging for the parent wells should be investigated.

• The hydraulic fracture simulator GOHFER™ reports fracture propped length based on a conductivity threshold value. This length represents a realistic value of the propped length of the fracture. Fracture height is reported by the total height of the grids; in other words, the reported value is gross height. It would be beneficial if propped height was reported for more accurate evaluation.

• Flow area and propped area reporting is done in the simulator by multiplying the fracture height by the propped length and flow length. The reported numbers conceive that the fracture is rectangular in shape and symmetric. The generated fracture shapes by the simulator can be observed in the output grids for each fracture. The generated shapes are almost always irregular, asymmetric, and constrained by in-situ stresses and proppant transportation and deposition. If the simulator reports the areal occupancy of the generated grid cells that meets the flow
area or propped fracture area definitions, this would elevate the efficiency of multiple designs comparison.

- The geologic model in this project is based on one reference logged vertical well. All rock properties in the model for each layer were assumed to be equal in the lateral direction. Constructing an earth model with multiple reference wells to capture lateral heterogeneity will improve the hydraulic fracture model.

- Only short term production data for the parent wells was available in the data set for this study. Acquiring production data of the child wells will aid in confirming the pressure depletion profile as well as the performance of the conducted fracturing treatments.

- Production analysis would be improved if the hydraulic fracture model was coupled with a reservoir numerical simulator in order to simulate pressure drawdown interference between adjacent wells in the model.
REFERENCES


<table>
<thead>
<tr>
<th>Scenario #</th>
<th>Wells’ stage order and treatments’ schedule description</th>
</tr>
</thead>
</table>
| Scenario 1 | Mimic the actual order used to complete the wells in the field:  
- Phase 1: 1N and 2C. Zipper fracturing starting with 1N  
- Phase 2: 1C, 2N, and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 2 | Consecutive fracturing (complete each well individually) from right to left:  
1. 1N  
2. 2N  
3. 1C  
4. 3N  
5. 4N  
6. 2C  
7. 5N  
8. 3C  
9. 6N |
| Scenario 3 | Zipper fracturing alternating between benches in a triangle form (wine rack sequence):  
- Phase 1: 3N, 2N, and 1N. Zipper fracturing starting with 3N  
- Phase 2: 2C, 4N, and 3C. Zipper fracturing starting with 2C  
- Phase 3: 1C, 5N, and 6N. Zipper fracturing starting with 1C |
| Scenario 4 | Fracture the inner wells then the outer wells in the pad:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 3N and 2C. Zipper fracturing starting with 3N  
- Phase 3: 1N and 5N. Zipper fracturing starting with 1N  
- Phase 4: 1C and 3C. Zipper fracturing starting with 1C  
- Phase 5: 6N. Consecutive fracturing |
| Scenario 5 | Zippering each bench alone, this also orders the treatment to start from highest pore pressure and Young’s modulus layers to the lowest:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 1N, 3N, and 5N. Zipper fracturing starting with 1N  
- Phase 3: 3C, 2C, 1C, and 6N. Zipper fracturing starting with 3C |
| Scenario 6 | Consecutive fracturing (complete each well individually) starting with the inner wells then the outer wells in the pad:  
1. 2N  
2. 2C  
3. 4N  
4. 3N  
5. 1N  
6. 1C  
7. 5N  
8. 3C  
9. 6N |
<table>
<thead>
<tr>
<th>Scenario #</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Scenario 7</td>
<td>Zipper all wells together starting with the inner wells then the outer wells in the following order: 2N – 4N – 2C – 3N – 1N – 3C – 5N – 1C – 6N</td>
</tr>
</tbody>
</table>
| Scenario 8 | Complete the wells from bottom to top in a zipper fashion by formation:  
- Phase 1: 2C, 3C, and 1C. Zipper fracturing starting with 2C  
- Phase 2: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 3: 3N, 5N, and 1N. Zipper fracturing starting with 3N  
- Phase 4: 6N. Consecutive fracturing |
| Scenario 9 | Complete the wells from top to bottom in a zipper fashion by formation:  
- Phase 1: 3N, 5N, 1N, and 6N. Zipper fracturing starting with 3N  
- Phase 2: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 3: 2C, 3C, and 1C. Zipper fracturing starting with 2C |
| Scenario 10 | Zipper all wells together starting from wells with or located nearby higher stress zones and avoiding creating a stress cage on the inner wells: 2C – 6N – 3C – 1C – 2N – 4N – 3N – 1N – 5N |
| Scenario 11 | Zipper all wells together starting from bottom to top: 2C – 3C – 1C – 2N – 4N – 3N – 1N – 5N – 6N |
### Table A-2: Pressure depleted sensitivity models’ stage ordering information

<table>
<thead>
<tr>
<th>Scenario #</th>
<th>Wells’ stage order and treatments’ schedule discerption</th>
</tr>
</thead>
</table>
| Scenario 12 | Mimic the order used to complete the wells in the field:  
- Phase 1: 1C, 2N, and 3N. Zipper fracturing starting with 1C  
- Phase 2: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 13 | Complete one well located in between the parent wells, in order to create enough stress shadow effect to drive the other treatments in the child wells away from the depleted region:  
- Phase 1: 2N. Consecutive fracturing  
- Phase 2: 1C and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 14 | Complete the middle row or bench in the multi-well stack as the parent wells are located in the top and bottom of the stack:  
- Phase 1: 2N and 4N. Zipper fracturing starting with 2N  
- Phase 2: 1C, 3C, and 3N. Zipper fracturing starting with 1C  
- Phase 3: 5N, 6N. Zipper fracturing starting with 5N |
| Scenario 15 | Complete each bench alone. From bottom layers to the upper layers:  
- Phase 1: 1C, and 3C. Zipper fracturing starting with 1C  
- Phase 2: 4N and 2N. Zipper fracturing starting with 4N  
- Phase 3: 3N, 5N, and 6N. Zipper fracturing starting with 3N |
| Scenario 16 | Perform alternating fracturing method on the wells located in between the parent wells (Stage 1, stage 3, stage 2, stage 4, stage 6, stage 5………etc):  
- Phase 1: 1C. Alternate fracturing  
- Phase 2: 2N. Alternate fracturing  
- Phase 3: 3C. Alternate fracturing  
- Phase 4: 4N and 3N. Zipper fracturing starting with 4N  
- Phase 5: 6N and 5N. Zipper fracturing starting with 6N |
| Scenario 17 | Perform alternating fracturing method on one well located in between the parent wells:  
- Phase 1: 2N. Alternate fracturing  
- Phase 2: 1C and 3N. Zipper fracturing starting with 1C  
- Phase 3: 6N, 3C, 5N, and 4N. Zipper fracturing starting with 6N |
| Scenario 18 | Zipper all wells together, starting with the wells located in between the pressure depleted zones then stimulate the wells that are nearer to the high stress zones:  
2N – 4N – 1C – 3C – 3N – 6N – 5N |
| Scenario 19 | Completed the wells located in between the parent wells in a zippering fashion starting with the middle well then complete the rest of the group in an upward fashion:  
- Phase 1: 2N, 1C, and 3N. Zipper fracturing starting with 2N  
- Phase 2: 3C, 4N, 5N, and 6N. Zipper fracturing starting with 3C |