GEOMECHANICAL MODELING

AS A RESERVOIR CHARACTERIZATION TOOL

AT RULISON FIELD, PICEANCE BASIN, COLORADO

by

Shannon M. Higgins
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Golden, Colorado
Date 4/25/06

Signed: Shannon M. Higgins

Approved: Dr. Thomas L. Davis
Thesis Advisor

Golden, Colorado
Date April 27, 2006

Dr. Terence K. Young
Department Head
Department of Geophysics

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ABSTRACT

Geomechanics is a powerful reservoir characterization tool. Geomechanical modeling is used here to understand how the in-situ earth stresses relate to the geologic, production and completion practices of Rulison Field, Piceance Basin, Colorado. A one-dimensional geomechanical model is built for four wells, combining rock strength, static elastic moduli, stress magnitudes, pore pressure and stress direction. Empirical correlations are developed to derive rock strength and static elastic parameters from well logs in tight gas plays. Mini-fracture tests are used to determine pore pressure and minimum horizontal stress. Stress direction is identified from sonic logs and image logs. Through wellbore simulation, input parameters are validated and unknown inputs are calculated. The results of the modeling provide continuous strength and stress profiles for Rulison Field. These profiles provide insight into the relationship between natural and hydraulic fractures, optimal well placement, completion strategies and hydraulic fracture design.

Specifically, for the wells modeled at Rulison, most natural fractures are aligned in the same direction as the direction of present day maximum horizontal stress. This allows for hydraulic fracture growth without complex fracturing. There is a consistent direction of average maximum horizontal stress so optimal target well locations can be selected. High horizontal stress anisotropy will limit fracture re-orientation completions. Also, from mini-fracture tests and image logs, stress magnitudes were verified to be
lithology dependent. This contrast helps hydraulic fractures remain in sandstone intervals and terminate at bed boundaries. Thus, geomechanical modeling is used to better understand and optimize production at Rulison Field.
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CHAPTER 1

INTRODUCTION

1.1 Introduction

The Reservoir Characterization Project, RCP, is an industry sponsored consortium which is currently conducting research on reservoir characterization of Rulison Field, Piceance Basin, Colorado. The main goal of the group is to integrate unconventional technologies to better develop a tight gas play. My research utilizes geomechanical modeling to understand how in-situ earth stresses can be ascertained and then utilized to enhance production.

1.2 Motivation

The Energy Information Agency (EIA) predicts that from the year 2002 to 2025 natural gas consumption worldwide will increase by almost 70% (EIA, 2005). In the United States natural gas consumption will reach almost 31 TCF by 2025 (EIA, 2005). As the demand for energy increases and conventional resources decline, there is a growing need to develop and understand unconventional resources, such as tight gas sandstones. The EIA also states that 51% of the proven tight gas reserves in the lower 48 states are in the Rocky Mountains (McCallister, 2000). Therefore it is essential to
optimize the tight gas plays of the Rocky Mountains. In particular, I am using
geomechanics as a tool for both reservoir characterization and to improve performance of
Rulison Field, a tight gas play in western Colorado.

Rulison Field, located near Rifle, Colorado, is a tight gas play with interbedded
sandstones, shales, coals and siltstones. The reservoir has permeabilities in the
microdarcy range and there is little well-to-well communication, even at 10-acre spacing.
The challenge in this field is to understand how the geology of the reservoir and
engineering practices can be combined to optimize production. One aspect is to
understand how the in-situ earth stresses affect the reservoir.

To successfully determine how the in-situ stresses in the earth relate to geologic,
production and completion practices, I have developed a one-dimensional geomechanical
model for four wells in Rulison Field. The modeling inputs and details are presented in
Chapters 2-4. The goals of the modeling were to develop strength and stress profiles at
Rulison Field. These profiles provide insight into the relationship between natural and
hydraulic fractures, optimal well placement and hydraulic fracture design. Additionally,
the geomechanical model was used to compare reservoir properties at Rulison to a nearby
tight gas field, the Multi-Well Experiment Site, to understand the importance of reservoir
characterization.
1.3 Field Location and Geologic Overview

Rulison Field is located in western Colorado in the Piceance Basin, shown in Figure 1.1. The field is a basin-centered gas accumulation with no water leg. Gas production occurs in 1700 to 2400 feet of stacked discontinuous sandstones (Cumella and Ostby, 2003). The sandstone layers average 20 to 60 feet in thickness and are interbedded in layers of siltstones, shales and coals (Jansen, 2005). The sandstones are discontinuous with little lateral extent.

The top seal for the reservoir is thought to be shale, but it could be some other type of capillary seal (Cumella, 2006). The productive reservoir sandstones have porosities ranging from 6% to 12% and irreducible water saturations ranging from 40% to 65% (Cumella and Ostby, 2003). Permeability is in the microdarcy range and therefore enhanced production relies on the presence of natural fractures. The primary source of gas is from the lowermost coal intervals (Scheevel and Cumella, 2005).
Gas production at Rulison is from the Williams Fork and Iles Formations. The depth of primary production is labeled on a stratigraphic cross section shown in Figure 1.2. The upper seal for the reservoir is near the UMV shale. The Cameo coal represents the transition between discontinuous fluvial sandstones above, to marine and deltaic sandstones interbedded in coals below. The geological information provided is primarily from Cumella and Ostby, 2003. Within the Iles Formation, there are three regressive marine sandstones: Corcoran, Cozzette and Rollins, which are separated by layers of marine Mancos Shale. The Mancos Shale was deposited in the Cretaceous seaway. The marine sandstones were deposited along the western edge of the seaway during a series of regressions. The Cameo coals overlie the Rollins and were deposited in the lower coastal
plain. Above the coals are interbedded sandstones and shales in the Williams Fork formation, which were deposited from meandering streams in a fluvial and floodplain environment (Cumella and Ostby, 2003).

![Stratigraphic Column](image)

**Figure 1.2:** Simplified stratigraphic column of primary production interval for Rulison Field. Figure is modified from Hinze (1998).

### 1.4 Location of RCP Survey Site and MWX Site

The RCP consortium acquired time-lapse multicomponent seismic surveys shot in 2003 and 2004. I have constructed a geomechanical model of four wells in Rulison, which are located within the RCP seismic survey site. The location of the survey site is outlined in red in Figure 1.3. The approximate location of the modeled wells within this survey area that have image logs and dipole sonic logs are also labeled. The location of the Multi-Well Experiment, MWX, site is shown in green.
Figure 1.3: Location of RCP survey site and MWX site.

The RCP survey site and MWX site are shown in more detail in Figures 1.4 and 1.5. The four geomechanical model well locations are labeled in Figure 1.4. I have modeled these particular wells because of their spatial variability and available well logs. RMV 60-17, RWF 523-20 and RWF 540-20 all contain image logs. Dipole sonic logs were acquired in wells RWF 332-21 and RMV 60-17.
Figure 1.4: Wells selected for geomechanical modeling. Red circles represent wells that are already drilled or planned to be drilled. Blue lines show wellbore deviation.

The MWX site is the location of the core data I used to develop empirical correlations. The Multi-Well Experiment was a $40 million dollar project funded by the United States Department of Energy (Cumella and Ostby, 2003). The program was designed to better understand production in tight gas plays. Over the eight year project, three wells were drilled and studied in detail. The three wells studied are within 200 feet of each other and are shown in Figure 1.5 (Lorenz, et al., 1989). I have used data from
core tests at the MWX well #1 to develop empirical correlations for rock strength and static elastic moduli.

Figure 1.5: Location of the MWX wells. Figure is modified from Lorenz, et al. (1989).

1.5 Stress History of Rulison

Because the focus of this study is geomechanics, it is essential to understand the depositional history and causes of stress at Rulison. Numerous authors have previously described the burial and stress history of the Piceance Basin (Jansen, 2005; Johnson and Nuccio, 1986; Lorenz, 1985; Lorenz and Finley, 1991; Warpinski, 1989). The following
is a summary of their reports, though the majority of details presented are from Lorenz and Finely, 1991. Figure 1.6 shows a representation of the burial history of the MWX site.

![Graph showing burial history of rock units at the MWX site.](image)

**Figure 1.6:** Burial history of the rock units at the MWX site. Figure is from Lorenz and Finely, 1991. Full details used to construct this diagram are given in Lorenz (1985).

Deposition of the Mesaverde began ~75 million years ago and maximum burial occurred 37 million years ago. Stress magnitudes and orientations that are present at the RCP survey site and the MWX site are primarily a result of the Sevier and Laramide orogeny events (Lorenz and Finley, 1991). During the Sevier orogeny the North American plate was overriding the Pacific plate, which caused the formation of the
overthrust belt in Utah. This thrusting caused a maximum horizontal compressive stress in the west-northwest to east-southeast orientation (Lorenz and Finley, 1991).

Once the Sevier orogeny ended the Laramide orogeny began. During the Laramide orogeny the mountains to the east of Rulison began to be uplifted. During this uplift the maximum horizontal stress remained compressive in a west-northwest to east-southeast direction. At approximately 36 to 40 million years ago, Rulison was at its greatest burial depth and the reservoir became significantly overpressured due to gas generation (Warpinski, 1989). Also during this time period, most of the natural extension fractures formed due to high pore pressure, high temperatures, high overburden stress and the compressive west-northwest trending stress from the thrust belt (Lorenz and Finley, 1991).

After the Laramide orogeny, the next significant event in the stress history of Rulison was the uplift of the White River plateau to the west of Rulison. This caused a further increase in the compressive stresses, which are in the same direction as the Sevier orogeny compression (Lorenz and Finley, 1991). Since that time, there has been significant uplift of the Mesaverde rocks. In particular, the Colorado Plateau has been regionally uplifted, causing local areas of compression and extension. Rulison Field sits in a transition zone of extension, as shown in Figure 1.7. The State of Colorado is outlined in red. This figure was compiled from earthquake focal mechanisms, borehole breakouts and fault offset patterns (Zoback and Zoback, 1989).
Figure 1.7: Stress map of western Colorado. Outward pointing arrows are in extensional deformation while inward pointing arrows are in compression. State of Colorado is outlined in red. Figure is from Zoback and Zoback (1989).

Knowing the direction of compressional and extensional stress is extremely important in optimizing production of Rulison. When fractures, natural or hydraulic, form, they align in the direction of maximum horizontal stress. Therefore the stress history of Rulison suggests that during the last 75 million years the direction of maximum horizontal stress has primarily been west-northwest to east-southeast. This is the
dominant direction of natural fractures found at Rulison and the MWX site (Cumella and Ostby, 2003).

Despite this dominant trend, there are records of multiple fracture directions in this area (Clark, 1983; Lorenz and Finley, 1991). These areas of multiple fracture directions usually occur in localized areas of structure such as along the Hogback monocline and the Divide Creek anticline (Verbeek and Grout, 1997). Multiple fracture directions that are not on anticlines are likely caused by stress relief during regional uplifting (Lorenz and Finley, 1991). The specific details of my work pertaining to the fracture and stress directions at the RCP survey area are discussed in Chapters 3 and 5. To use geomechanical modeling to improve production at Rulison, it is important to understand the role of tectonics and depositional history in local and regional stress trends.

1.6 Geomechanics for Improved Reservoir Characterization

One way the oil and gas industry is utilizing geomechanics is to reduce unwanted operational surprises and costs. Reservoir geomechanics is an integrated study combining field geology, tectonics, rock properties and practical engineering. Using knowledge of rock mechanics in drilling for oil and gas is not new. However, the practice of designing geomechanical models was not extensively developed until the late 1990’s (Chardac, et al., 2005). A geomechanical model is a numerical representation of the state of stress and rock mechanical properties for a field. These models are primarily
driven from static elastic properties, rock strength, pore pressure, in-situ stress magnitudes and stress direction (Plumb et al., 2000).

Geomechanics relates to almost all technical aspects of reservoir production. Some examples of areas where geomechanics is used in the oil and gas industry include pore pressure prediction, sand production, wellbore instability issues, casing design, safe mud weight window prediction, subsidence, compaction and fully coupled simulation (Chardac, et al., 2005). The most critical geomechanical issues are in weak rock systems, deep water reservoirs and tight fractured formations (Spath, 2006).

Rulison Field contains tight fractured formations, and I am therefore using geomechanics as a reservoir characterization tool. In this study, geomechanics is used primarily to understand how stress magnitudes and orientations affect natural fractures, hydraulic fractures and faults, and how all three variables interact.

1.7 Methodology and Workflow

I have utilized a precise methodology to apply geomechanics as a reservoir characterization tool at Rulison Field. A ten-step workflow was used to construct a geomechanical model for four wells in Rulison. I then interpreted the model to understand nine specific topics related to production at Rulison.

1.7.1 Methodology for Geomechanical Modeling

(1) Data Audit: This step involved well selection and data gathering. The specific data I gathered to construct the model included logging data, core testing results,
well tops, drilling surveys, drilling and completion reports, image logs, dipole sonic logs, mini-fracture summaries and micro-seismic data.

(2) Lithology determination: Lithology classifications were determined from the gamma ray log and a neutron density crossplot.

(3) Empirical correlations for elastic moduli and rock strength: I used log and core data from the MWX well #1 to develop empirical correlations for unconfined compressive strength, friction angle, tensile strength, Young’s modulus and Poisson’s ratio.

(4) Overburden stress: This was calculated by integrating the bulk density logs.

(5) Pore pressure: I fit gradients to mini-fracture interpretation results.


(7) Stress direction: Stress direction was found by analyzing image logs, dipole sonic logs and micro-seismic data.

(8) Maximum horizontal stress: This variable cannot be measured in-situ and was therefore back calculated from a wellbore stability simulation.

(9) Wellbore stability simulation: A one-dimensional wellbore stability simulation was used to validate the input parameters and solve for maximum horizontal stress. The simulation of wellbore stability was checked with caliper and image logs.
(10) Sensitivity and Error Analysis: I used a sensitivity analysis to understand the sensitivity of each input variable to wellbore stability. I also conducted an error analysis to recognize and understand uncertainties and errors in the model.

1.7.2 Objectives for Interpretation of Modeling

My specific interpretation objectives were to:

(1) Design empirical correlations to determine rock strength and static elastic parameters from logs;

(2) Use stress magnitude to classify faults at Rulison;

(3) Understand how hydraulic fractures interact with natural fractures;

(4) Use stress directions to design optimal target well locations;

(5) Understand zone completion strategies based on stress magnitude variations with lithology;

(6) Determine a value of stress anisotropy for possible stress re-orientation completions;

(7) Analyze spatial variability within the reservoir;

(8) Determine whether hydraulic fracture design needs to be zone specific; and

(9) Compare the model results from the RCP survey site to reported stress results at the MWX site.
CHAPTER 2

PETROPHYSICS AND EMPIRICAL CORRELATIONS

2.1 Introduction

To correctly build a geomechanical model of four wells in Rulison Field, it is important to use accurate values of static elastic parameters and in-situ rock strength. Of specific interest are unconfined (or uniaxial) compressive strength (UCS), friction angle (FA), tensile strength, static Young’s modulus (E) and static Poisson’s ratio (PR).

Static properties measured from cores are more accurate for modeling than dynamic properties calculated from log data. However, the RCP survey area does not contain wells with core data and is therefore limited to log data. Thus, empirical correlations were developed between log and core properties using data at the MWX well #1. Then these empirical correlations were used for the four wells in Rulison to derive rock strength and static elastic parameter inputs needed for geomechanical modeling. The methodology for constructing the empirical correlations is shown in Figure 2.1.

MWX-1 (Cores) → Rock Strength → Static Moduli → Dynamic Moduli

Figure 2.1: Methodology for designing empirical correlations between core and log data at the MWX well#1, and its application at Rulison.
2.2 Static versus Dynamic Properties

Typically, static rock properties are measured from recovered cores. Deformation is measured on core samples as pressure is applied. Dynamic properties are calculated using sonic wave velocities and density values from well logs. Because rock properties are both frequency and amplitude dependent, values measured at higher amplitudes in the laboratory can differ significantly from low amplitude log measurements. Dynamic moduli are usually 2 to 10 times larger than static moduli (Plona and Cook, 1995). The exact reason for this difference is not clear. Dvorak, in 1970, suggested possible reasons such as cracks and void space, time effects, stress magnitude, temperature effects and fluid saturation (Dvorak, 1970). Other possible reasons are the differences in magnitudes of stress and strain as well as differences in frequencies used to measure the static and dynamic properties (TerraTek, 1998).

It should be noted that core data are often not representative of in-situ conditions because the rock changes when it is removed from the reservoir. However, for most reservoir calculations and modeling, static properties are desired because they predict the behavior of the formation at larger stresses where failure may occur, while dynamic moduli give behavior at smaller stresses. Although static values are desired, log data is more continuous, easier to acquire and less expensive than the laboratory testing of recovered core. Therefore, the standard industry procedure is to use empirical correlations to derive static properties from dynamic properties. Beginning with Ide in 1936, numerous people have developed and published empirical correlations relating
static and dynamic moduli (Ide, 1936). However, the values determined from these correlations range considerably due to varying reservoir conditions. Therefore, I have developed empirical correlations from the MWX well #1 to be used at Rulison, because the two sites are nearby and the correlations are representative of tight gas sandstone reservoirs in the Williams Fork.

The empirical correlations I developed are unique, but it should be noted that at the MWX site, extensive work was conducted to understand and relate static and dynamic moduli (Lorenz, et al., 1989; Sattler, 1991; Warpinski, et al., 1985; Warpinski and Teufel, 1989; Warpinski, et al., 1998).

2.3 Rock Strength

The rock strength inputs for the geomechanical model are friction angle (FA) and unconfined compressive strength (UCS). These were calculated from the Mohr-Coulomb failure criteria using triaxial test results of core samples from the MWX well #1.

2.3.1 Core Sample Information

The data I used to determine rock strength are from triaxial testing results from the MWX well #1 core samples. Sandia National Laboratories used ReSpec Inc. to conduct the triaxial testing. All of the samples are plugged vertically and range from one and a half to two inches in diameter and from one to four inches in length (Finley, 1985). Almag oil was used as a coolant and flushing fluid (Senseny, 1983). In the report issued by Sandia in 1985, 62 depth intervals were analyzed. I selected 17 samples for the
empirical correlation analysis. The criteria for selecting 17 of the 62 samples is that first, the plugs had data recorded for at least three different confining pressures and second, the depth of the plug matched a depth where log data were recorded.

2.3.2 Mohr-Coulomb Failure Criteria

The Mohr-Coulomb failure criterion was used to calculate UCS and FA. Mohr proposed in 1900, that shear failure across a plane is related to normal and shear stress by a linear function shown in equation 2.1 (Cook and Jaeger, 1976).

\[ |\tau| = S + \mu \sigma \]  

(2.1)

where \( \tau \) is the shear stress, \( \mu \) is coefficient of internal friction, \( \sigma \) is normal stress, and \( S \) is the cohesion or inherent shear strength. Cohesion is the strength required to hold one sand grain to the rock surface. The coefficient of internal friction is the resistance to movement along a shear plane due to frictional forces (Rahim, et al., 2003).

The Mohr-Coulomb failure criteria is designed such that if a rock sample has three unequal principal stresses, a failure line can be determined, and if the values of \( \sigma \) and \( \tau \) fall below the line, failure does not occur (Cook and Jaeger, 1976). This is demonstrated in Figure 2.2.
Figure 2.2: Mohr-Coulomb failure criteria and Mohr's circle representing the stress state. Figure is modified from Fjaer et al. (1992).

Shear and normal stress are determined from equations 2.2 and 2.3.

\[ |\tau| = \frac{1}{2}(\sigma_1 - \sigma_3)\sin 2\beta \quad (2.2) \]

\[ \sigma = \frac{1}{2}(\sigma_1 + \sigma_3) + \frac{1}{2}(\sigma_1 - \sigma_3)\cos(2\beta) \quad (2.3) \]

where, from the triaxial test results, \( \sigma_1 \) is the applied load in psi and \( \sigma_3 \) is the confining pressure in psi. \( 2\beta \) is the angle between the point of coincidence on Mohr's circle and the failure line (Fjaer, et al., 1992). The two variables of interest for geomechanical modeling are FA (\( \Phi \)) and UCS, defined in equations 2.4 and 2.5. Friction angle is the angle from horizontal of the plane, along which shear failure occurs in a core test (Rahim, et al., 2003). UCS is the load per unit area where the rock will fail in compression.
\[ \tan \phi = \mu \]  

\[ UCS = 2S \frac{\cos \phi}{1 - \sin \phi} \]  

2.3.3 Rock Strength at MWX Well #1

The Mohr-Coulomb failure criterion was applied to 17 samples from the MWX well #1. Figure 2.3 shows the Mohr-Coulomb failure criteria for a sandstone sample at 6452 feet. Each Mohr’s circle represents a different confining pressure and compressive strength measurement performed on the same core sample. The black line is the failure line. It should be noted that in reality the failure line is curved. For simplification, I am using a straight failure line that is validated by core measurements.

![Mohr-Coulomb failure criteria applied to a sandstone sample at 6452 feet.](image)

The cohesion (S) is determined from the interception of the y-axis with the failure line. Friction angle is determined from the angle the failure line makes with the x-axis.
For this sample the cohesion is 3767 psi, the friction angle is 32.7 degrees and the UCS is 13,800 psi. The values of FA and UCS for all 17 samples are shown in Figure 2.4 and the averages are listed in Table 2.1. For all of the data used in this analysis see Appendix A. Lithology classifications for the core data were initially described by Sandia National Laboratories (Finley, 1985). I further streamlined those classifications.

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Average FA (degrees)</th>
<th>Average UCS (PSI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>34.3</td>
<td>16,641</td>
</tr>
<tr>
<td>Siltstone</td>
<td>31.6</td>
<td>26,406</td>
</tr>
<tr>
<td>Mudstone</td>
<td>15.1</td>
<td>10,466</td>
</tr>
</tbody>
</table>

Table 2.1: Average FA and UCS values for 17 samples at MWX well #1.

![UCS vs Friction Angle](image)

Figure 2.4: UCS vs. Friction Angle for 17 samples at MWX well #1 based on lithology.

From the relationship shown in Figure 2.4, I developed empirical correlations between UCS and FA. These are shown in equations 2.6 through 2.8. To account for
possible lab errors, the empirical correlations were developed with an uncertainty regression. Uncertainty is based on the correlation coefficient of axial stress to confining pressure for the MWX well #1 triaxial test results. Samples with high uncertainty contributed less to the regression than samples with low uncertainty.

Sandstones: \[ UCS = -0.367 \times (FA) + 29.151, \quad R^2 = 0.47 \] (2.6)

Siltstones: \[ UCS = -0.583 \times (FA) + 44.924, \quad R^2 = 0.91 \] (2.7)

Mudstones: \[ UCS = -0.618 \times (FA) + 19.397, \quad R^2 = 0.95 \] (2.8)

where the units of UCS are MPa and the units of FA are degrees. Additionally, with my empirical correlations it was necessary to constrain the correlations to account for unrealistic values. For friction angle, cutoff values were chosen at 12.5 and 55 degrees (Bratton, 2006). For UCS, cutoff values were from 0 to 43,524 psi (Chang, 2004).

2.3.4 Tensile Strength

In addition to UCS and FA, it is important to have an estimate of tensile strength. Tensile strength is often estimated as a percentage of unconfined compressive strength. Although published values vary, tensile strength is usually estimated to be one-eighth to one-twelfth of unconfined compressive strength (Chardac, et al., 2005). From the MWX core results, tensile strength was measured from Brazilian tests. With a Brazilian test, tensile strength is measured indirectly. Tensile failure is produced by the compression of a disc across the plugs diameter (Brown, 1981). Of the 17 samples, five had tensile strength measurements. These values were compared to the UCS previously calculated.
From this analysis an empirical correlation between UCS and tensile strength was developed and is shown in equation 2.9.

\[ Tensile \text{ Strength} = UCS \times 0.057 \]  

(2.9)

2.4 Rock Strength and Static Moduli Correlations

To determine rock strength parameters from logs, it is first necessary to understand the relationship between rock strength and static elastic parameters. Numerous published correlations suggest a relationship between UCS and Young’s modulus (GMI, 2005). However, for this correlation to be valid, the static and dynamic moduli must be compared at equal stress levels (Fjaer, et al., 1992). Therefore, the static Young’s modulus value I am using in the correlations came from a confining pressure, which is equal to the in situ effective stress, represented in equation 2.10 (Fjaer, et al., 1992). The concept of effective stress was developed by Terzaghi in 1943 for soil mechanics and suggests that “the effective stress, rather than total stress, is determining in whether the rock fails or not due to the external load.” (Fjaer, et al., 1992).

\[ \sigma' = \sigma - Pp \]  

(2.10)

where \( \sigma' \) is the effective stress, \( \sigma \) is the total stress and \( Pp \) is the pore pressure. Biot in 1956 introduced a constant, \( \alpha \), to modify Terzaghi’s equation to make it more applicable to rocks (Biot, 1956). Thus equation 2.10 is modified to equation 2.11.

\[ \sigma' = \sigma - \alpha Pp \]  

(2.11)
For my empirical correlations, stress and pore pressure were approximated from mini-fracture tests discussed in chapter 3.5. \( \dot{\alpha} \) was determined from equations 2.12 and 2.13 (Bratton, 1994).

\[
\alpha = \left(1 - \frac{K_{\text{skeleton}}}{K_{\text{solid}}} \right)
\] (2.12)

\[
K_{\text{skeleton}} = K_{\text{bulk}} - K_{\text{pore}}
\] (2.13)

where \( K \) is the bulk modulus. \( K_{\text{pore}} \) is assumed to be zero because the fluid is primarily gas and \( K_{\text{bulk}} \) is determined from log data and is discussed in section 2.5.3. \( K_{\text{solid}} \) is assumed to be quartz and has a value of 38 GPA (Wildens, et al., 1984).

The results of correlating UCS to static Young’s modulus for the 17 samples at the MWX well #1 are shown in Figure 2.5. The empirical correlation equations are shown in equations 2.14 through 2.16. These were determined with an uncertainty regression based on the R-squared value of axial stress to confining pressure for the MWX well #1 triaxial test results. For other published correlations between \( E \) and UCS see Appendix B.
Figure 2.5: UCS vs. Static E for 17 samples from the MWX well #1 based on lithology.

Sandstones: \( UCS = 6.032e^{2.46(\text{Static E})} \), \( R^2 = .61 \) \hspace{1cm} (2.14)

Siltstones: \( UCS = .190e^{.827(\text{Static E})} \), \( R^2 = .88 \) \hspace{1cm} (2.15)

Mudstones: \( UCS = 3.761e^{.415(\text{Static E})} \), \( R^2 = .97 \) \hspace{1cm} (2.16)

where the units of UCS and static E are MPSI.

2.5 Static and Dynamic Moduli Correlations

Correlations were also developed between static and dynamic values for Young’s modulus and Poisson’s ratio. With these correlations log data can be used to derive static values, which can be related to rock strength values through equations 2.14 through 2.16.
2.5.1 Log Data

The log data for MWX-1 was depth matched to account for errors associated with recordings from different logging runs. Additionally, a synthetic shear wave was created because only compressional velocity data was available. A synthetic shear wave was developed for MWX well #1 from an actual recorded shear wave log in well RWF 332-21 in Rulison. From this dipole sonic log, the shear wave velocity was determined as a function of volume of clay and compressional velocity, equation 2.17. The volume of clay was calculated from the neutron density crossplot discussed in section 2.5.2.

\[ \Delta t_{shear} = \Delta t_{compressional} \times ((.6477 \times V_{clay}) + 1.5933) \]  
(2.17)

where \( \Delta t_{shear} \) is the travel time of the shear wave in us/ft, \( \Delta t_{compressional} \) is the travel time of the compressional wave in us/ft and \( V_{clay} \) is the volume of clay (or shale) expressed as a percent.

2.5.2 Neutron-Density Crossplot

A neutron-density crossplot was used for both lithology determination and petrophysical calculations. The lithological categories in my geomechanical models are coal, sandstone, siltstone and shale (or mudstone).

I am basing the lithology description from a model shown by Rasmus and Stephens (1991). In this model lithologies are determined from their location in a neutron density crossplot, Figure 2.6.
Figure 2.6: Typical neutron-density crossplot. Figure is modified from Rasmus, et al. (1991).

Figure 2.7 shows the neutron-density crossplot for MWX well #1. The color variation represents the range of gamma ray values in API units. Because the gamma ray values correspond to the groupings of sand, silt and shale lithologies on the crossplot, I used the gamma ray log for a lithology indicator. For the MWX well #1, the gamma ray values of 0 through 15 API units are coals, 15 through 60 API units are sandstones, 60 through 75 API units are siltstones and all values above 75 API are shales.
Figure 2.7: Neutron density crossplot for lithology determination from MWX well #1.

Additionally, the neutron-density crossplot was used to determine petrophysical properties, both for the MWX well #1 and for the four wells modeled in Rulison. Porosity and volume of clay were determined from the neutron-density crossplot by measuring the distance of each point from the outside of the triangle, illustrated by the red arrows in Figure 2.6. The points on the triangle represent the dry clay, water and quartz values.

2.5.3 Dynamic Moduli

Dynamic moduli were calculated from the log data at MWX well #1 using equations 2.18 through 2.21 (Bratton, 1994). The assumptions associated with these equations are that the reservoir is assumed to be a single-component solid that is linearly elastic, isotropic and homogeneous.
\[ G = (13474.45) \frac{\rho_b}{(\Delta t_{\text{shear}})^2} \]  
(2.18)

\[ K_{\text{bulk}} = (13474.45)\rho_b \left[ \frac{1}{(\Delta t_{\text{compression}})^2} \right] - \frac{4}{3} G \]  
(2.19)

\[ v = \frac{3K_{\text{bulk}} - 2G}{6K_{\text{bulk}} + 2G} \]  
(2.20)

\[ E = \frac{9G \times K_{\text{bulk}}}{G + 3K_{\text{bulk}}} \]  
(2.21)

where \( K_{\text{bulk}} \) is the bulk modulus of the bulk formation in MPSI, \( \rho_b \) is the bulk density of the bulk formation in gm/cc, \( \Delta t_{\text{compression}} \) is the compressional slowness of the bulk formation in us/ft, \( \Delta t_{\text{shear}} \) is the shear slowness of the bulk formation in us/ft, \( G \) is the shear modulus of the bulk formation in MPSI, \( v \) is Poisson’s ratio (unitless) and \( E \) is Young’s modulus in MSPI. Given the assumptions controlling this model, with any two known elastic moduli, all four dynamic elastic moduli can be determined.

**2.5.4 Static to Dynamic Correlations for the MWX Well #1**

For the MWX well #1, empirical correlations were developed between static and dynamic moduli, specifically Young’s modulus and Poisson’s ratio. To accurately compare the static values to dynamic values, the static values I have used in the empirical correlations are taken at a confining pressure that is equal to the effective stress. Also, even though the sonic logging tool records a value every half foot, the recording is averaging the travel time values over its receiver array. Therefore, the dynamic Poisson’s
ratio and Young's modulus values that are being used in the empirical correlations were averaged over a five foot interval.

Static versus dynamic Young's modulus is shown in Figure 2.8. The empirical correlation equations are shown in equations 2.22 through 2.24. From this figure it is clear that the values cluster according to lithology. As expected, the dynamic Young's modulus for sandstones and shales is generally larger than the static Young's modulus. However, it is not typical for the siltstones to have higher static Young's modulus than dynamic Young's modulus. I think this is primarily a function of erroneous static measurements on the core data. The three siltstone values with high static Young's modulus have low correlation coefficients between axial stresses and confining pressures. The correlation coefficients are .78, .31 and .48 respectively. There may also be errors associated with creating the synthetic shear wave or collecting accurate data from the density or compressional wave logs. For other published correlations see Appendix B.

Static versus dynamic Poisson's ratio is shown in Figure 2.9. The empirical correlations are shown in equations 2.25 through 2.27. These values also cluster according to lithology. However, the figure does not show a typical response for correlations between static and dynamic Poisson's ratio. For a good correlation of Poisson's ratio, the curve is usually one-to-one or static values are higher than dynamic. I think this is probably due to erroneous measurements in lab data. It may also be associated with errors in creating the synthetic shear wave or collecting accurate data.
from the density or compressional wave logs. Examples of other published correlations are provided in Appendix B.

Figure 2.8: Dynamic vs. Static Young’s Modulus for 17 samples from the MWX well #1 based on lithology.

Figure 2.9: Dynamic vs. static Poisson’s ratio for 17 samples from the MWX well #1 based on lithology.
Sandstones: \( Dynamic \ E = 0.544 \ast (Static \ E) + 3.886, \quad R^2 = 0.55 \) \hspace{1cm} (2.22) 

Siltstones: \( Dynamic \ E = 2.83 \ast (Static \ E) - 11.084, \quad R^2 = 0.80 \) \hspace{1cm} (2.23) 

Mudstones: \( Dynamic \ E = 0.594 \ast (Static \ E) + 3.961, \quad R^2 = 0.31 \) \hspace{1cm} (2.24) 

Sandstones: \( Dynamic \ \nu = -0.121 \ast (Static \ \nu) + 0.226, \quad R^2 = 0.14 \) \hspace{1cm} (2.25) 

Siltstones: \( Dynamic \ \nu = -0.143 \ast (Static \ \nu) + 0.295, \quad R^2 = 0.29 \) \hspace{1cm} (2.26) 

Mudstones: \( Dynamic \ \nu = -0.171 \ast (Static \ \nu) + 0.303, \quad R^2 = 0.56 \) \hspace{1cm} (2.27) 

where the units of dynamic and static Young’s modulus are MPSI and Poisson’s ratio is unitless. To ensure reasonable values, I have used cutoffs for Poisson’s ratio, .08 to .5, and added a lower bound to Young’s Modulus at 350 psi (Bratton, 2006).

2.6 Modeling at MWX Well #1

Before using the derived empirical correlations at Rulison, I verified the functionality of the equations for the MWX well #1 by assuming only log data were available. Log moduli were correlated to static moduli through equations 2.22 through 2.27. Then static moduli were correlated to UCS through equations 2.14 through 2.16. UCS was correlated to FA by equations 2.6 through 2.8. Lastly, tensile strength was estimated as a function of UCS in equation 2.9. The results of estimating rock strength parameters and static moduli from logs are shown in Figure 2.10. Additionally the values measured for core properties are displayed as blue triangles for comparison. It is evident the log curves, dynamic values, closely align with the dark blue triangles, static values.
2.7 Modeling at Rulison

From the empirical correlations developed at the MWX well #1, log data at Rulison was used to determine the necessary geomechanical modeling inputs, including unconfined compressive strength, friction angle, tensile strength, static Young’s modulus and static Poisson’s ratio.
2.7.1 Lithology and Petrophysics

For the four wells in Rulison, a neutron-density crossplot was used to determine porosity, volume of clay and to help determine lithology. Porosity and volume of clay were found by measuring the distance of each point from the outside of the triangle shown in Figure 2.11. Initial lithology clusters were defined from the neutron-density crossplot model demonstrated in Figure 2.6. Similar to the MWX well #1, the lithology clusters correlated to the gamma ray log data, and therefore gamma ray log was used as the lithology indicator. An example of the neutron-density crossplot for RWF 542-20 is shown in Figure 2.11. Table 2.2 shows the lithology cutoffs based on gamma ray values for the four wells in Rulison.

Figure 2.11: Neutron density crossplot for RMV 60-17. This was used to determine lithology, porosity and volume of clay.
<table>
<thead>
<tr>
<th>WELL NUMBER</th>
<th>Coal MD&lt;6000 ft</th>
<th>Coal MD&gt;6000 ft</th>
<th>Sand MD&lt;6000 ft</th>
<th>Sand MD&gt;6000 ft</th>
<th>Siltstone All MD</th>
<th>Shale All MD</th>
</tr>
</thead>
<tbody>
<tr>
<td>332-21</td>
<td>GR&lt;15</td>
<td>GR&lt;30</td>
<td>15≤GR&lt;60</td>
<td>30≤GR&lt;60</td>
<td>60≤GR&lt;75</td>
<td>GR≥75</td>
</tr>
<tr>
<td>542-20</td>
<td>GR&lt;15</td>
<td>GR&lt;35</td>
<td>15≤GR&lt;60</td>
<td>35≤GR&lt;60</td>
<td>60≤GR&lt;75</td>
<td>GR≥75</td>
</tr>
<tr>
<td>523-20</td>
<td>GR&lt;15</td>
<td>GR&lt;35</td>
<td>15≤GR&lt;60</td>
<td>35≤GR&lt;60</td>
<td>60≤GR&lt;75</td>
<td>GR≥75</td>
</tr>
<tr>
<td>60-17</td>
<td>GR&lt;15</td>
<td>GR&lt;35</td>
<td>15≤GR&lt;60</td>
<td>35≤GR&lt;60</td>
<td>60≤GR&lt;75</td>
<td>GR≥75</td>
</tr>
</tbody>
</table>

Table 2.2: Gamma ray cutoffs used for lithology determination for Rulison wells.

### 2.7.2 Elastic Moduli and Rock Strength

The first steps in geomechanical modeling of Rulison involved determining elastic moduli and rock strength. The five necessary geomechanical modeling inputs are unconfined compressive strength, friction angle, tensile strength, static Young’s modulus and static Poisson’s ratio.

To determine static properties, dynamic values were first calculated. Dynamic elastic moduli were determined for the Rulison wells with equations 2.18 through 2.21. However, wells RMV 60-17 and RWF 523-20 did not have sonic log recordings. Therefore a synthetic compressional and shear wave log was created from well RWF 332-21, where actual compressional and shear waves were recorded. As suggested in numerous published papers, synthetic sonic logs are often created in relation to porosity (Medlin and Alhilail, 1992). Published empirical correlations are shown in Appendix B. To create synthetic logs for RMV 60-17 and RWF 523-20, the relationship between
porosity and both the compressional and shear waves at RWF 332-21 was used. This is shown in equations 2.28 and 2.29.

\[ \Delta t_{\text{compressional}} = 95.708 \times \phi + 64.395 \]  
(2.28)

\[ \Delta t_{\text{shear}} = 225.49 \times \phi + 107.04 \]  
(2.29)

Log moduli for the four wells were then correlated to static moduli through equations 2.22 through 2.27. Because core data are not measured in the coals, other existing empirical correlations were used for the coals in the geomechanical modeling. In the coals, for static to dynamic Young’s modulus, the Modified Morales correlation (proprietary) was used. Static moduli were then correlated to UCS through equations 2.14 through 2.16. For the coals, the Coates-Denno correlation shown in equation 2.30 was used. Next for the four wells, UCS was correlated to FA by equations 2.6 through 2.8. The Plumb-Clay volume and porosity function (proprietary) were used in the coals. Lastly, tensile strength was estimated as a function of UCS from equation 2.9.

\[ UCS = \left( \frac{0.025 \times 10^{-6}}{0.289} \right) \left( \frac{E_{\text{dyn}}}{25 \times 10^{-6}} \right) \left( 8000 \times 10^{-6} V_{sh} + 4500 \times 10^{-6} (1 - V_{sh}) \right) \]  
(2.30)

2.8 Conclusions

Empirical correlations have been developed between log data and core data for the MWX well #1. From these empirical correlations, log data at Rulison was used to derive the necessary geomechanical modeling inputs, including unconfined compressive strength, friction angle, tensile strength, static Young’s modulus and static Poisson’s ratio. Figure
2.10 demonstrates the validity of the derived empirical correlations which were used in the geomechanical modeling of Rulison.
CHAPTER 3

STRESS MODELING

3.1 Introduction

The objective of my geomechanical modeling is to determine the magnitude and direction of stress in the earth. Stresses in the earth can be defined in terms of a minimum horizontal stress ($\sigma_h$), a maximum horizontal stress ($\sigma_h$) and a vertical stress ($\sigma_v$). Vertical stress was determined by integrating the bulk density log. Horizontal stresses were estimated using a gradient model. Minimum horizontal stress was calibrated through mini-fracture tests and maximum horizontal stress was constrained with a wellbore stability geomechanical simulator. The maximum horizontal stress direction at Rulison was determined from interpretation of image logs and dipole sonic logs. With these techniques, I established a continuous stress profile of the stresses controlling production at Rulison.

3.2 Stresses for Geomechanical Modeling

Stress is defined as a force per unit area. Stress can be described in tensor form by picturing an infinitesimally small cube shown in Figure 3.1. The complete stress state of the infinitesimally small cube is defined by a stress tensor with three normal stresses
and six shear stresses shown in Figure 3.2. A rotation can be applied for each
infinitesimally small cube in the earth, to one coordinate system where all six shear stress
components are zero. This results in three remaining normal stresses which are called
principal stresses and the directions they act are called principal directions (Keaney,
2005). The rotated stress tensor is shown in Figure 3.3. I am assuming the principal
stresses are in the vertical and horizontal directions. There are circumstances where this
is not always true. Principal stresses may vary near local structures such as anticlines and
salt domes (GMI, 2005). However, because Rulison Field is relatively flat, I am making
this assumption for simplification purposes.

Figure 3.1: Cube demonstrating the components of the stress matrix.
\[
\begin{pmatrix}
\sigma_{xx} & \tau_{xy} & \tau_{xz} \\
\tau_{yx} & \sigma_{yy} & \tau_{yz} \\
\tau_{zx} & \tau_{zy} & \sigma_{zz}
\end{pmatrix}
\]

Figure 3.2: Complete stress tensor.

\[
\begin{pmatrix}
\sigma_{xx} & 0 & 0 \\
0 & \sigma_{yy} & 0 \\
0 & 0 & \sigma_{zz}
\end{pmatrix}
\]

Figure 3.3: Principal stress tensor.

Two sets of stresses in the earth are important when using wellbore data to understand geomechanics (Bratton, et al., 1999). The first set is far-field stresses that exist far away from the wellbore. The far-field stresses are the stresses that exist in the earth before a well is drilled and can be described by an infinitesimally small cube. The second set of stresses is near-wellbore stresses, which occur on the interface between the fluid-filled wellbore and the formation, after a borehole has been created. The wellbore stresses are discussed further in Chapter 4.1.

Geomechanical stress modeling begins by establishing the far field stresses in the earth by four independent parameters. These include the direction of maximum horizontal stress and the three earth stresses, the minimum horizontal stress (\(\sigma_h\)), the
maximum horizontal stress ($\sigma_H$) and the vertical stress ($\sigma_V$). In the modeling I have assumed the three stresses, $\sigma_h$, $\sigma_H$ and $\sigma_V$ are principal stresses, although this may not always be valid. Also, because earth stresses are usually compressive, it is the convention in this paper that positive numbers indicate compression and negative numbers indicate tension.

3.3 Determining the Magnitude of Horizontal Stresses

For the four wells in the RCP survey area, the magnitude of the two horizontal stresses ($\sigma_h$, $\sigma_H$) was determined. Although there are numerous models which attempt to predict the in-situ horizontal stresses in the earth, I have estimated them with a simple gradient model, equation 3.1, which statistically honored all of my observations.

$$\sigma = \sigma_{ref} + \text{gradient} \ (TVD - TVD_{ref})$$

where $\sigma_{ref}$ and $TVD_{ref}$ are the stress and true vertical depth of the point above the point of interest, $\sigma$ is the stress magnitude and TVD is true vertical depth. The value chosen for the gradient was derived from mini-fracture tests and through wellbore simulation discussed in Chapter 4.

3.4 Determining the Magnitude of Overburden Stress

The in-situ vertical stresses in the earth result from the weight of the rock per unit area above each point in the earth. Therefore the magnitude of the overburden stress can
be determined by integrating the bulk density log measured in each well. The integration
equation is shown in equation 3.2.

\[ \sigma_v = \int_0^z \rho g \, dz \]  \hspace{1cm} (3.2)

where \( \rho \) is the density, \( g \) is acceleration due to gravity and \( z \) is depth.

An example of the bulk density integration for well RMV 60-17 is shown in
Figure 3.4. Because the bulk density log is not valid in casing, I have estimated the bulk
density above the casing shoe using an extrapolated density. This estimation is shown in
dark blue.

To accurately determine the overburden stress, I reconstructed the density logs to
account for “bad hole” associated with breakouts and washouts. I used the neutron
density crossplot to determine bad hole. Points which fell outside the triangle were
moved to the edge of the triangle along a constant neutron or density value. The result is
a bulk density log with “good hole” values shown in red. The black curve is the raw bulk
density curve. The overburden stress, shown in green, was then determined by
integrating the “good hole” bulk density log.
Figure 3.4: Integration of “good hole” bulk density log to determine overburden stress for RMV 60-17.

3.5 Mini-Fracture Analysis for Pore Pressure and Minimum Horizontal Stress

Mini-fracture tests were performed on eight wells in the RCP survey area. For geomechanical modeling mini-fracture tests are the source of data for both pore pressure and an estimation of minimum horizontal stress. Of the four wells being modeled, RWF 523-20 is the only well with mini-fracture test results. The other seven wells with mini-fracture tests are in the RCP survey area but are not the wells being modeled.

3.5.1 Mini-Fracture Tests

Mini-fracture tests are fracture tests where only a small amount of fluid is injected into the formation (Fjaer, et al., 1992). The intervals of interest are packed off and a pressure gauge measures pressure as fluid is injected into the formation at a constant flow rate (Thiercelin and Roegiers, 2000). A typical mini-fracture test result is shown in
Figure 3.5. Pumps inject fluid into the intervals of interest at a constant rate. At some point the increasing fluid pressure creates a fracture. This point is called the fracture initiation pressure (FIP) and is recognized by a deviation from the linear change of pressure with time. As more fluid is injected, the fracture will propagate away from the wellbore. At this point the pumps are turned off, the well is shut in and the pressure declines. The instantaneous shut-in pressure (ISIP) is a pressure measurement taken as soon as the pumps are turned off and measures pressure when there is still fluid holding the fracture open (GMI, 2005). The test continues and fluid dissipates into the formation. The pressure approaches an asymptote, which is an estimate of pore pressure of the formation. The closure stress is determined from a change in rate of pressure decline (De Bree and Walters, 1989). For this modeling I am assuming closure stress is minimum horizontal stress.
3.5.2 Pore Pressure

For seven of the eight wells with mini-fracture tests, pore pressure estimates were provided by Williams Production Company. For RWF 523-20 pore pressure was interpreted by Chris Green (2005). The results of these interpretations are shown in Figure 3.6. For proprietary reasons the well names have been labeled RU-1 through RU-8.
Figure 3.6: Pore pressure estimates from mini-fracture tests at Rulison.

From the interpreted pore pressure test results I have fit a gradient line, which is shown in black. This is not a virgin pore pressure line, but rather an estimate of pore pressure for the three wells without mini-fracture data. It is the best estimate of unknown pore pressure. The gradient line was fit using equation 3.1. From 0 feet to the UMV shale, a gradient of .433 psi/ft is appropriate (Rojas, 2005). Below the UMV shale, the reservoir is overpressured and a gradient of 1.11 psi/ft is used in equation 3.1. Because well RWF 523-20 has an actual mini-fracture test, I have fit a gradient line unique to its test results.
From Figure 3.6 it is evident that each well has different measurements of pore pressure. The scatter could be due to the errors in the mini-fracture test or interpretation. However, if the testing is accurate, it is likely that some of the wells with lower pore pressures, RU-6 and RU-7, may be in pressure communication with other wells in the field. Also, there may be varying initial pore pressure conditions due to seals and pressure release from faults and fractures. Lastly, there could be areas of locally high pressure due to gas generation.

3.5.3 Minimum Horizontal Stress

Minimum horizontal stress was also determined from the mini-fracture tests. The results from the tests are shown in Figure 3.7. The mini-fracture tests at the RCP survey site were only conducted in sandstone intervals. Therefore the estimate of minimum horizontal stress is only valid for sandstones.
Figure 3.7: Minimum horizontal stress magnitude from mini-fracture tests at Rulison.

From the scatter of mini-fracture values, equation 3.1 was used to approximate minimum horizontal stress. Three different gradient values were used in each well. Gradient (1) is from the surface to the UMV shale marker, gradient (2) is from the UMV shale to 7000 feet and gradient (3) goes from 7000 feet to TVD. The increase in the gradient at ~7000 feet is discussed in Chapter 5.3.3. The black line in Figure 3.7 represents the gradients I have selected. The slope between 5000 and 7000 feet is .85. Because RWF 523-20 has an actual mini-fracture test, the gradient for that well was
chosen specific to its stress measurements. Table 3.1 shows the gradients used in
equation 3.1 for each of the wells.

<table>
<thead>
<tr>
<th></th>
<th>Gradient 1</th>
<th>Gradient 2</th>
<th>Gradient 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>RWF 332-21</td>
<td>.55</td>
<td>1.147</td>
<td>1.68</td>
</tr>
<tr>
<td>RWF 542-20</td>
<td>.55</td>
<td>1.189</td>
<td>1.68</td>
</tr>
<tr>
<td>RWF 523-20</td>
<td>.55</td>
<td>1.29</td>
<td>1.29</td>
</tr>
<tr>
<td>RMV 60-17</td>
<td>.6</td>
<td>1.109</td>
<td>1.68</td>
</tr>
</tbody>
</table>

Table 3.1: Minimum horizontal stress gradients for the four wells being modeled.

3.5.4 Minimum Horizontal Stress for Other Lithologies

Minimum horizontal stress magnitude is lithology dependent (Warpinski, et al., 1985). The mini-fracture tests at the RCP survey site are limited to sandstone intervals. Therefore mini-fracture data from the MWX site was used to determine minimum horizontal stresses in the shales, coals and siltstones. In this thesis I am referring to the stress measurements as mini-fracture tests, although the tests performed at the MWX site might be considered more traditional micro-fracture tests. A micro-fracture test is usually limited to one zone and only a small amount of fluid is injected. In a mini-fracture test usually more than one zone is tested at once, and a higher volume of fluid is pumped. In the MWX stress tests, each zone tested was two feet thick and only 10 to 100 gallons of fluid were injected (Warpinski and Teufel, 1989).
Figure 3.8 shows a collection of mini-fracture test data from the MWX site. The values of minimum horizontal stress come from MWX well #2 and well #3 (Warpinski, et al., 1985; Warpinski and Teufel, 1989). I fit gradient lines to the sandstones and mudstones shown in blue and red. From the results shown in this figure, I have estimated the minimum horizontal stress is approximately 600 psi larger in the shales than sandstones. For my geomechanical model, I have assumed the results at the MWX site are consistent at the RCP survey site. I have modeled the coals with a 1000 psi greater stress than the sandstones. Figure 3.8 shows two coal points, and from this limited data I believe the value at 7200 feet to be more representative of in-situ coal stress, because it is reported that the coals have a larger stress than other lithologies (Warpinski and Teufel, 1989). However, due to the lack of data, this estimate of stress magnitude in the coals is largely an assumption.

Mini-fracture data measured at the MWX site in the siltstones varies with behavior similar to both the sandstones and mudstones. However, three of the four stress measurements model a behavior more similar to the sandstone gradient. Therefore, in my modeling I assumed the minimum horizontal stress is the same in sandstones and siltstones. Although these values are not certain to represent stresses at the RCP survey site, without better data, I believe this is the best available understanding of how stresses might behave in the modeled wells.
3.6 Modified Uniaxial Stress Model

When mini-fracture data is not available other calculations can be used to determine minimum horizontal stress. From my geomechanical model, a very close estimate of minimum horizontal stress can be found from the simple elastic uniaxial strain model shown in equation 3.3 (Green, 2006; Hubbert and Willis, 1956; Teufel, 1996).
\[ \sigma_h = \left( \frac{\nu}{1-v} \right) \sigma_v + \left( 1 - \left( \frac{\nu}{1-v} \right) \right) \alpha Pp \]  

(3.3)

where \( \nu \) is Poisson’s ratio, \( \sigma_v \) is overburden stress, \( \alpha \) is Biot’s constant and \( Pp \) is pore pressure. In this equation, the assumptions are that the reservoir is linear, homogenous, elastic and there is no tectonic strain. When this equation is applied to sandstones with a dynamic Poisson’s ratio and \( \alpha = 1 \), then the average error between the modeled and calculated minimum horizontal stress for the four wells is \( \sim 417 \) psi.

This is a reasonable approximation for minimum horizontal stress. However, the 417 psi error can be decreased by modifying equation 3.3 to include calibration constants. The new equation is shown in equation 3.4.

\[ \sigma_h = C_1 \left( \frac{\nu}{1-v} \right) \sigma_v + C_2 \left( 1 - \left( \frac{\nu}{1-v} \right) \right) \alpha Pp \]  

(3.4)

where \( C_1 \) and \( C_2 \) are calibration coefficients. Table 3.2 shows the best calibration coefficients for matching the calculated to modeled minimum horizontal stress. It also shows the average error in the estimation of \( \sigma_h \). The \( R^2 \) value shown represents the correlation coefficient when both modeled and calculated minimum horizontal stresses are mapped. For this analysis I am only reporting the \( C_1 \), \( C_2 \) and \( R^2 \) values for the sandstones. Also, I am setting \( \alpha = 1 \) and am using a static Poisson’s ratio from equations 2.25 through 2.27. It should be noted there may be other combinations of values for \( C_1 \) and \( C_2 \) which also minimize the errors.
<table>
<thead>
<tr>
<th>Well Name</th>
<th>C1</th>
<th>C2</th>
<th>Error (ps.)</th>
<th>R²</th>
</tr>
</thead>
<tbody>
<tr>
<td>RWF 523-20</td>
<td>.88</td>
<td>1.2</td>
<td>59.3</td>
<td>.99</td>
</tr>
<tr>
<td>RWF 332-21</td>
<td>.6</td>
<td>1.2</td>
<td>184</td>
<td>.94</td>
</tr>
<tr>
<td>RMV 60-17</td>
<td>1</td>
<td>1.21</td>
<td>109</td>
<td>.99</td>
</tr>
<tr>
<td>RWF 542-20</td>
<td>.55</td>
<td>1.19</td>
<td>273</td>
<td>.95</td>
</tr>
</tbody>
</table>

Table 3.2: Calibration coefficients for the uniaxial strain model and the match to the geomechanical model

Providing there is an appropriate estimation of Poisson’s ratio and pore pressure, applying the uniaxial strain model provides an accurate estimate of minimum horizontal stress without running expensive mini-fracture tests. Additionally, the validity of this equation demonstrates that the stresses in the earth are a strong function of pore pressure and overburden.

3.7 Horizontal Stress Direction

Determining the direction of minimum and maximum horizontal stress is essential for geomechanical modeling, hydraulic fracture design and reservoir characterization. To determine stress direction at Rulison Field, image logs, dipole sonic logs and microseismic data were used.
3.7.1 Image Log Basics

Image logs were used for modeling in three of the four wells, including RWF 523-20, RMV 60-17 and RWF 542-20. The image logs used are a Formation MicroImager (FMI), designed by Schlumberger, and an Electrical Micro Imaging Tool (EMI), designed by Halliburton. These tools utilize micro-resistivity electrodes located on pads to provide electronic images of the wellbore (Asquith, et al., 2004). While logging, the pads are pressed against the borehole wall and electrical current flows into the rock through electrodes. Remote sensors measure the current as it returns from the formation. Conductive features are darker on images while resistive features are lighter.

Present day stress direction can be identified on image logs from observations of breakouts and drilling induced tensile fractures. In a smooth cylindrical wellbore, drilling induced tensile fractures appear in the direction of maximum horizontal stress. Breakouts usually appear in the direction of minimum horizontal stress. Breakouts form because rocks along the wellbore wall have to support the load removed during drilling. This causes the sides of the wellbore wall to have an increased tangential compressive strength, which can cause breakouts with enlarged diameters on opposite sides of the wellbore (Koepsell, et al., 2003). Tensile failure occurs where fractures develop in the wellbore, usually due to increased mud weight. These concepts are illustrated in Figure 3.9 (Rezmer-Cooper and Bratton, 2000).
Figure 3.9: Stress orientation from image logs. The upper left image and lower image show how far-field stresses create breakouts and tensile failures. The upper right image shows examples of breakouts and tensile failure on an image log. The upper left image and the upper right image are from Rezmer-Cooper and Bratton (2000).

3.7.2 Stress Direction at Rulison

Stress direction was primarily determined from image logs at Rulison Field.

Figure 3.10 shows an FMI image from well RMV 60-17. The image on the left (static) is the same as the image on the right (dynamic); they appear different because of different processing. The dynamic image is processed by normalizing the image in a 5 ft window, which enhances geologic features (Asquith, et al., 2004). From Figure 3.10 it is evident
the maximum horizontal stress is in the west-northwest and east-southeast direction and the minimum horizontal stress direction is perpendicular. This in-situ stress direction is consistent with the Laramide compression discussed in Chapter 1.5.

Figure 3.10: Image log interpretation for stress direction from well RMV 60-17.

Schlumberger interpreted the image logs for wells RMV 60-17 and RWF 523-20. Halliburton interpreted the log from RWF 542-20. From their interpretation of breakouts and tensile fractures, the average maximum horizontal stress direction is shown for each
well in red in Figure 3.11. The maximum stress direction from well RWF 332-21 was
determined from the dipole sonic log. Reprocessing of the sonic log by Lauri Burke
provided the data for the maximum horizontal stress direction shown (Burke, 2005). The
direction of maximum horizontal stress aligns with the direction of anisotropy recorded
on sonic logs.

Figure 3.11: Average maximum horizontal stress direction for modeled wells in Rulison.
Results are from image logs and dipole sonic logs.

Thus the present day in-situ stress direction does vary slightly from well to well
but is predominantly east-west with a slight northwest, southeast trend. The stress seems
to be more northeast trending in well RWF 332-21. Without consistent image log data in all four wells, it is difficult to tell if the stress difference is real or due to a different measurement method.

### 3.7.3 Stress Rotation with Depth at Rulison

It is also important to understand how stress direction changes with depth in each well. Williams Production Company performed two micro-seismic tests in wells RU-1 and RU-2 (Wolhart, et al., 2005). This micro-seismic data clearly demonstrates the counterclockwise stress rotation with depth and is shown in Figure 3.12. Each point shown is the average hydraulic fracture direction from that zone. The error in this scatter is unknown because the raw data are proprietary.

![Graph showing stress rotation with depth](image)

Figure 3.12: Stress direction from micro-seismic testing for two wells in Rulison. Data points were provided by Williams Production Company.
The stress rotation with depth is not as apparent on the image logs and sonic logs. Figure 3.13 shows the maximum horizontal stress direction for each well from the image log and sonic log analysis. Each point shown is the average value of 500 feet of breakout and drilling induced fracture directions from the image logs. It should be mentioned that without averaging, there is a large scatter in the data and the stress rotation is not apparent. For RWF 332-21 each point shown is the average of 500 feet of recorded anisotropy direction. From Figure 3.13 it is evident that stress direction does change with depth. Maximum stress direction varies slightly from a more north-west trending direction to a more east-west direction with depth in the basin. From Figures 3.12 and 3.13 it appears there is stress rotation with depth, but due to the uncertainty in errors this rotation may not be real.

![Figure 3.13: Average maximum horizontal stress direction showing rotation with depth. Each point is average of 500 feet from image logs and dipole sonic logs](image)
The cause of this stress rotation is uncertain, but possible explanations are discussed in Chapter 5.4. Also discussed in Chapter 5.4 are the implications of this observation, which go beyond geomechanical modeling and affect hydraulic fracture direction of propagation and well placement.

3.8 Maximum Horizontal Stress

With current technology, maximum horizontal stress cannot be directly measured in-situ. Therefore, I have estimated maximum horizontal stress with a gradient model and constrained the model through observations matched by a wellbore stability simulator. To determine maximum horizontal stress, a wellbore stability simulator was run and the only unknown variable was maximum horizontal stress. The wellbore stability simulator is discussed in detail in Chapter 4.2. It combines rock strength, static elastic parameters, stress magnitude and orientation, and mud weights to simulate wellbore failure. Maximum horizontal stress magnitude was varied until the modeled wellbore failure matches failure from image logs.

To estimate maximum horizontal stress, I have assumed the same gradient is applied to maximum horizontal stress as is applied to minimum horizontal stress. However, I have added a constant to the minimum horizontal stress. To determine that constant, I varied the input until the simulator matched my observations. The final value added to the minimum horizontal stress for each well is shown in Table 3.3. Errors in this estimation are discussed in Chapter 4.5.
<table>
<thead>
<tr>
<th>Well #</th>
<th>Max Horz stress (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RWF 542-20</td>
<td>σh + 2000</td>
</tr>
<tr>
<td>RWF 332-21</td>
<td>σh + 2100</td>
</tr>
<tr>
<td>RWF 523-20</td>
<td>σh + 2250</td>
</tr>
<tr>
<td>RMV 60-17</td>
<td>σh + 2450</td>
</tr>
</tbody>
</table>

Table 3.3: Maximum horizontal stress values for the four wells being modeled.

3.9 Modeling Results and Conclusions

The magnitude and direction of stress at every depth, for each of the four wells, has been estimated. The magnitudes of horizontal stress were estimated from a simple gradient model that matches observations. The overburden stress was calculated by integrating a reconstructed density log. Mini-fracture tests and a wellbore stability simulation helped to constrain the values of pore pressure, σn and σh. Figure 3.14 shows the final modeling results for RMV 60-17.
Figure 3.14: Modeling results showing stress vs. depth for RMV 60-17.

Lithologies and a gamma ray log are shown in the left column and the estimates of pore pressure, minimum horizontal stress, maximum horizontal stress and overburden stress are shown as a function of depth in the right column. The variation for maximum and minimum horizontal stress is a function of lithology. The implications of this modeling are discussed in detail in Chapter 5.3.2.
CHAPTER 4
SIMULATION AND RESULTS

4.1 Introduction

To determine appropriate values of maximum horizontal stress, I have simulated
wellbore stability for four wells in Rulison. The details of the simulation are presented in
this chapter. Also, to better understand the simulation and model, I am showing both a
sensitivity analysis and error analysis.

4.2 Wellbore Stability Simulation

To determine maximum horizontal stress, a wellbore stability simulation was
performed for each of the four wells. The procedure was to run the simulation, varying
maximum horizontal stress, until the simulation results matched the observations of
failure in the image and caliper logs. RWF 332-21 is the only well modeled without an
image log and therefore breakouts from that well were matched only against “bad hole”
identified on the caliper log.

4.2.1 Coordinate Transformation

The wellbore stability simulator package called STARS, Stand Alone Rock Solid,
was provided by Schlumberger. The simulator code assumes the reservoir is behaving in
a linear elastic fashion that is homogeneous and isotropic. The objective is to convert the effective far-field stresses to near-wellbore stresses. Near-wellbore stresses occur on the face between the wellbore and earth. The far-field stress is first rotated to a Cartesian coordinate system and then that is rotated into cylindrical polar coordinates at the wellbore wall. Figure 4.1 is a schematic showing far-field and near-wellbore stresses.

![Diagram of stress components](image)

Figure 4.1: Far-field stress and near-wellbore stresses. Figure is modified from Bratton, et al. (1999).

The basis of converting far-field stresses to near-wellbore stresses and predicting failure comes from a classic set of equations by Kirsch, which describes the stress state on an inclined borehole (Bradley, 1979). The nomenclature of the coordinate
transformation in the wellbore stability code of STARS is from papers by Bratton (1994)
and Aadony and Hansen (2004).

To begin, the effective far-field stress tensor is defined. \( \sigma' \) shown in equation 4.1, is the far-field effective stress tensor which has been rotated such that there are only three
principal stresses and no shear stress components.

\[
\sigma' = \begin{pmatrix}
\sigma'_{xx} & 0 & 0 \\
0 & \sigma'_{yy} & 0 \\
0 & 0 & \sigma'_{zz}
\end{pmatrix}
\]  

(4.1)

where \( \sigma'_{xx} \) is the minimum effective horizontal stress, \( \sigma'_{yy} \) is the maximum effective
horizontal stress and \( \sigma'_{zz} \) is the effective vertical stress. Because the four wells in Rulison
are not entirely vertical, the far-field coordinate system is converted to a Cartesian
coordinate system. In the Cartesian coordinate system, the b-axis is aligned along the
borehole, the h-axis lies on the vertical plane from the high side of the borehole and the
p-axis is perpendicular to the b and h axes. The b axis is at an angle \( \psi \) to vertical and the
h-b plane is at an angle \( \Phi \) to the minimum horizontal stress. The hpb stress tensor is
shown in equation 4.2. The coordinate transformation is given in equations 4.3-4.11.
\[ hpb = \begin{pmatrix} 
\sigma'_{hh} & \tau'_{hp} & \tau'_{hb} \\
\tau'_{ph} & \sigma'_{pp} & \tau'_{pb} \\
\tau'_{bh} & \tau'_{bp} & \sigma'_{bb} 
\end{pmatrix} \] \tag{4.2}

\[ \sigma'_{hh} = \cos \Psi \cos \Phi \cos \Phi (\sigma'_{xx} + \sin \Phi \sin \Phi \sigma'_{yy}) + \sin \Psi \sin \Phi \sigma'_{zz} \] \tag{4.3}

\[ \tau'_{hp} = \sin \Phi \cos \Phi \cos \Phi (\sigma'_{yy} - \sigma'_{xx}) \] \tag{4.4}

\[ \tau'_{hh} = \sin \Psi \cos \Phi (\cos \Phi \cos \Phi \sigma'_{xx} + \sin \Phi \sin \Phi \sigma'_{yy} - \sigma'_{zz}) \] \tag{4.5}

\[ \tau'_{ph} = \tau'_{hp} \] \tag{4.6}

\[ \sigma'_{pp} = \sin \Phi \sin \Phi \sigma'_{xx} + \cos \Phi \cos \Phi \sigma'_{yy} \] \tag{4.7}

\[ \tau'_{pb} = \cos \Phi \sin \Phi \sin \Phi (\sigma'_{yy} - \sigma'_{xx}) \] \tag{4.8}

\[ \tau'_{bh} = \tau'_{hb} \] \tag{4.9}

\[ \tau'_{bp} = \tau'_{pb} \] \tag{4.10}

\[ \sigma'_{bb} = \sin \Psi \sin \Phi (\cos \Phi \cos \Phi \sigma'_{xx} + \sin \Phi \sin \Phi \sigma'_{yy}) + \cos \Psi \cos \Phi \sigma'_{zz} \] \tag{4.11}

Equations 4.3 through 4.11 are then solved and defined by cylindrical coordinates, which include radial, tangential (hoop) and axial stresses. The derivation for solving these equations is given in Jaeger and Cook (1976). The radial stress is caused by the mud weight or pressure of the mud used to drill the well. The tangential and axial stresses are caused by the far-field stresses. The new stress tensor, equation 4.12, is aligned in the same direction as the Cartesian system. \( \theta \) is the angle measured counter-
clockwise around the wellbore from the high side of the wellbore. After simplification, the coordinate transformation is given in equations 4.13 through 4.17.

\[
\begin{pmatrix}
\sigma'_{rr} & \tau'_r \theta & \tau'_{ra} \\
\tau'_r \theta & \sigma'_{\theta \theta} & \tau'_{\theta a} \\
\tau'_{ar} & \tau'_{a \theta} & \sigma'_{aa}
\end{pmatrix}
\]

\[r \theta a = (4.12)\]

\[\sigma'_{rr} = P_w\]  \[\text{(4.13)}\]

\[\tau'_{r \theta} = \tau'_{r a} = \tau'_{\theta r} = \tau'_{a r} = 0\]  \[\text{(4.14)}\]

\[\sigma'_{\theta \theta} = (\sigma'_{hh} + \sigma'_{pp} - P_w) - (\sigma'_{pp} - \sigma'_{hh})2\cos(2\theta) - 4\tau'_{hp} \sin(2\theta)\]  \[\text{(4.15)}\]

\[\tau'_{a \theta} = \tau'_{a \theta} = 2(\tau'_{hh} \cos \theta - \tau'_{hp} \sin \theta)\]  \[\text{(4.16)}\]

\[\sigma'_{aa} = \sigma'_{bb} - \nu[2(\sigma'_{pp} - \sigma'_{hh}) \cos(2\theta) + 4\tau'_{hp} \sin(2\theta)]\]  \[\text{(4.17)}\]

where \(P_w\) is wellbore pressure and \(\nu\) is Poisson's ratio. For the modeling, \(P_w\) is the mud weight used to drill the well. The radial stress is a principal stress but the axial and tangential stresses are not necessarily principal stresses. The principal stresses, labeled \(\sigma'_{pA}, \sigma'_{pB}\) and \(\sigma'_{pC}\), are given in equations 4.18 through 4.20.

\[\sigma_{pA} = \sigma'_{rr} = P_w\]  \[\text{(4.18)}\]

\[\sigma_{pB} = \frac{1}{2}[\sigma'_{\theta \theta} + \sigma'_{aa} - \sqrt{(\sigma'_{\theta \theta} - \sigma'_{aa})^2 - 4\sigma'_{a a}^2}]\]  \[\text{(4.19)}\]
\[
\sigma_{pc} = \frac{1}{2} \left[ \sigma'_{\theta\theta} + \sigma'_{\phi\phi} + \sqrt{(\sigma'_{\theta\theta} - \sigma'_{\phi\phi})^2 - 4\sigma'_{\theta\phi}^2} \right]
\] (4.20)

The principal stress that is the largest is called \( \sigma'_1 \), the intermediate is \( \sigma'_2 \) and the smallest is \( \sigma'_3 \).

### 4.2.2 Wellbore Failure

Two types of yield and/or failure are common. The first is shear and is caused by grains being forced together by two orthogonal stresses. The second is tensile and is caused when a single tensile stress pulls the grains apart. Figure 4.2 demonstrates the two types of failure and they are described in equations 4.21 through 4.23 (Bratton, et al., 1999).

---

![Figure 4.2: Shear and tensile failure. Figure is modified after Bratton, et al. (1999).](image-url)
When a well is drilled, the surrounding rock must support the load that was initially carried by the removed rock. This causes a stress concentration at the wellbore, which can cause the near wellbore rocks to fail. A rock will fail compressively if the maximum compressive stress is larger than the properties which resist deformation, unconfined compressive strength, UCS and the angle of internal friction, FA. The equation for failure is shown in equation 4.21 (Bratton, et al., 1999).

\[ \sigma_1 = UCS + \sigma_3 \tan^2 \gamma \]  \hspace{1cm} (4.21)

where \( \gamma \) is the angle at which the grains will be sheared apart and is measured between the direction of maximum stress and perpendicular to the failure plane. It is related to friction angle by equation 4.22 (Bratton, et al., 1999).

\[ \gamma = 45^\circ + \frac{FA}{2} \]  \hspace{1cm} (4.22)

During tensile failure the grains are pulled apart and a fracture forms when the stress exceeds the tensile strength. This is given in equation 4.23 (Bratton, et al., 1999).

\[ \sigma_3 = T_0 \]  \hspace{1cm} (4.23)

### 4.2.3 Wellbore Stability at Rulison

Using equations 4.1 through 4.23, wellbore stability was simulated for the four wells in Rulison. The only unknown in the simulation was maximum horizontal stress. Therefore the maximum horizontal stress was varied until the simulation matched the observations from the image logs and caliper. An example of the output of the simulation is shown below in Figure 4.3.
Figure 4.3: Wellbore stability simulation for RMV 60-17.

The left column shows lithology. The second column predicts a safe mud weight window. The black lines represent the minimum and maximum mud weight exposed to the formation. Where the black lines pass through the other colors, the simulation is predicting some type of failure. The area in maroon predicts the well will experience a kick, the area in red predicts breakouts and the area in purple predicts a drilling-induced tensile failure. The third column shows the extent of the failure and the circumference where the failure will occur. The last column is the actual FMI image from RMV 60-17. In the sixteen feet shown, the simulation predicts three different breakouts and one tensile
failure, which are shown in the FMI image. It is also evident that the breakouts occur at ~10 and ~100 degrees and the tensile cracks occur at 90 degrees to the breakouts, which is consistent with the maximum horizontal stress direction discussed in Chapter 3.7.

4.3 Final Stress Results

After running the simulation, the final result is a stress profile at every depth for each well. Figures 4.4 to 4.7 show the final results. In each figure lithology is shown with a gamma ray log in the left column. The middle column shows the pore pressure and the modeled stresses σ_h, σ_H and σ_V. The right column shows the azimuth of maximum horizontal stress from 0 to 90 degrees. It should be noted that the interval of interest in the stress profile is from 5000 feet to TD. Above 5000 feet the stresses were extrapolated to the surface.
Figure 4.4: Final stress modeling results for RMV 60-17.

Figure 4.5: Final stress modeling results for RWF 332-21.
Figure 4.6: Final stress modeling results for RWF 523-20.

Figure 4.7: Final stress modeling results for RWF 542-20.
From this modeling it is clear that $\sigma_h < \sigma_H - \sigma_V$. The results of this modeling have substantial significance on completion and drilling strategies at Rulison Field, which are discussed in Chapter 5.

4.4 Sensitivity Analysis

Wellbore instability costs the drilling industry ~ $6 billion per year (Spath, 2006). Because of this problem, I have performed a sensitivity analysis on the wellbore stability simulation to determine the effect each input has on wellbore stability. To reduce instability costs, it is essential to know which variables dominate instability.

For the sensitivity analysis, I have changed one variable at a time while keeping the other inputs constant. In particular, I have changed a variable and monitored how sensitive the change is to the minimum and maximum equivalent circulating density, ECD, required to maintain a stable wellbore. The ECD is the effective density exerted by a circulating fluid against the wellbore (Schlumberger, 2006).

For this analysis I analyzed a nine foot sand interval at 6774 measured depth in well RMV 60-17. Each variable was increased and decreased by 10% to see the effect the parameter had on wellbore stability. Table 4.1 shows the original inputs before changing any of the parameters. Table 4.2 shows the safe ECD’s with the original inputs before the sensitivity analysis.
<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical Stress</td>
<td>7382.65 psi</td>
</tr>
<tr>
<td>Min Horz Stress</td>
<td>5776.44 psi</td>
</tr>
<tr>
<td>Max Horz Stress</td>
<td>8226.44 psi</td>
</tr>
<tr>
<td>Pore Pressure</td>
<td>3901.3 psi</td>
</tr>
<tr>
<td>UCS</td>
<td>19292.6 psi</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>.07</td>
</tr>
<tr>
<td>Friction Angle</td>
<td>30.3 degrees</td>
</tr>
<tr>
<td>Tensile Strength</td>
<td>1099.67 psi</td>
</tr>
</tbody>
</table>

Table 4.1: Original inputs for wellbore stability before a sensitivity study.

<table>
<thead>
<tr>
<th>Failure</th>
<th>Safe ECD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shear Failure</td>
<td>5.32 (minimum) / 27.45 (max)</td>
</tr>
<tr>
<td>Tensile Failure</td>
<td>17.9 (max)</td>
</tr>
<tr>
<td>Mud Loss</td>
<td>16.41 (max)</td>
</tr>
<tr>
<td>Kick</td>
<td>11.0878 (min)</td>
</tr>
</tbody>
</table>

Table 4.2: Original ECDs for failure before a sensitivity study.

The results of increasing each variable by 10% are shown in Table 4.3. Each value shown in the table is the percent change of the ECD. Percent change is given by equation 4.24.

\[
\%CHANGE = \left| \frac{Original\ ECD - New\ ECD}{Original\ ECD} \right| \times 100 \quad (4.24)
\]

where the original ECD is from Table 4.2 and the new ECD is the result of changing the variable by 10%.

For a sample calculation of the values in Table 4.3, consider a condition where \( \sigma_h = 5776.44 \) psi and the lower bound for a safe ECD in shear failure is 5.32 ppg. When \( \sigma_h \) is increased by 10% it has a new value is 6354 psi. With all other variables remaining constant and the change in \( \sigma_h \), the new lower bound to the ECD is 4.91 ppg. The percent
difference is 7.64 % which is shown in equation 4.25. The percent difference for each variable is shown in Table 4.3.

\[
7.64 \% = \left( \frac{5.32032 - 4.9138}{5.32032} \right) \times 100 \tag{4.25}
\]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>% Shear ECD MIN</th>
<th>% Shear ECD MAX</th>
<th>% Tensile ECD MAX</th>
<th>% Loss ECD MAX</th>
<th>% Kick ECD MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical Stress</td>
<td>.01</td>
<td>.01</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Min Horz Stress</td>
<td>7.64</td>
<td>13.48</td>
<td>27.45</td>
<td>9.98</td>
<td>0</td>
</tr>
<tr>
<td>Max Horz Stress</td>
<td>32.62</td>
<td>6.4</td>
<td>13.05</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Pore Pressure</td>
<td>10.48</td>
<td>2.03</td>
<td>6.18</td>
<td>0</td>
<td>9.99</td>
</tr>
<tr>
<td>UCS</td>
<td>25.55</td>
<td>4.96</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
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<td>.01</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Friction Angle</td>
<td>9.72</td>
<td>4.14</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Tensile Strength</td>
<td>.02</td>
<td>.01</td>
<td>1.74</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 4.3: Percent of sensitivity for a safe ECD.

It makes sense that the only affected variable for a “loss” is minimum horizontal stress because a loss is expected when the ECD exceeds the minimum horizontal stress, assuming there is a pathway between the wellbore and the far-field stress. Similarly, the only affected variable in a “kick” is pore pressure because a kick is expected when ECD drops below pore pressure. From this analysis, it is evident that the main inputs affecting
shear failures are UCS, FA, pore pressure and the largest and smallest far-field stresses. In this case, that is minimum horizontal stress and maximum horizontal stress. The main inputs affecting tensile failure are the largest and smallest far field stress, as well as pore pressure. Poisson’s ratio seems to have very little impact on wellbore stability.

Therefore, to reduce costs associated with wellbore instability, it is most important to have an accurate understanding of the in-situ stress magnitudes, pore pressure and unconfined compressive strength.

4.5 Error Analysis

To accurately assess the validity of my model, it is important to understand the errors and uncertainty of the input parameters. The intent is not to include a complete error analysis, but rather to state the known errors associated with each input parameter. The input parameters for the modeling are (1) minimum horizontal stress, (2) maximum horizontal stress, (3) vertical stress, (4) pore pressure, (5) UCS, (6) Poisson’s ratio, (7) friction angle and (8) tensile strength.

(1) Minimum horizontal stress: As shown in Figure 3.7, there is a large scatter in the interpreted minimum horizontal stress from the mini-fracture tests. The standard deviation of minimum horizontal stress values from wells RU-1 to RU-8 is 686.42 psi. The correlation coefficient for the fit regression is .84.

(2) Maximum horizontal stress: For the wellbore stability simulation there is more than one appropriate value of maximum horizontal stress which matches the
observed observations from the image logs. In general, the maximum horizontal stress values can be varied +/- 350 psi and still be accurate.

(3) Vertical stress: There is some error in this measurement because the density log was not corrected for the gas effect. However, if the borehole was 100% sandstone filled with 100% gas the density log would only change an average of 3%.

(4) Pore Pressure: Similar to minimum horizontal stress, there is scatter in estimated pore pressure from mini-fracture tests. From the data points in Figure 3.6, the standard deviation of pore pressure is 688.1 psi. The correlation coefficient for the fit regression is .73.

(5) Unconfined compressive strength: Assuming the log measurements of Young’s modulus are accurate, the error in estimating UCS occurs in converting dynamic to static Young’s modulus and static Young’s modulus to UCS. The $R^2$ values for static to dynamic Young’s modulus are sandstone $R^2 = .55$, siltstone $R^2 = .8$ and shale $R^2 = .31$. From static Young’s modulus to UCS the $R^2$ values for the three lithologies are .61, .88 and .97 respectively.

(6) Poisson’s ratio: Providing the travel time measurements from the sonic logs are accurate, error in Poisson’s ratio can be assessed by its $R^2$ value from the empirical correlations relating dynamic to static values. In sandstones the $R^2$ is .14, siltstones’ $R^2$ is .19 and shales’ $R^2$ is .56. This error is further increased in wells where sonic logs are not available. The synthetic compressional and shear waves are given in equations 2.28 and 2.29 with $R^2$ values of .94 and .82 respectively.
(7) Friction Angle: Errors in friction angle can be associated with the $R^2$ values in the empirical correlations relating FA to UCS. In addition to the errors in defining UCS, the $R^2$ values between FA and UCS are .47 for sandstones, .91 for siltstones and .95 for shales.

(8) Tensile Strength: Only five core samples had tensile strength measurements, and the correlation coefficients between tensile strength and UCS is .24.

Additionally, the main assumptions in this model relate to the core data and the mini-fracture tests. I have assumed that the core data from the MWX site accurately represents rocks at Rulison. This assumption is incorporated in the empirical correlations as well as the stress magnitude change with lithology. Additionally, in the model I have assumed that the empirical correlations accurately represent rock strength and static moduli from log data. In terms of the mini-fracture tests, I assumed that the gradient fit to the mini-fracture data is an accurate value of pore pressure and minimum horizontal stress for the entire field. However, the mini-fracture results show there is a large scatter in values.

A model is a design which attempts to represent something that cannot be seen. As with any modeling there are errors, assumptions and uncertainties. Nevertheless, the model built is the best estimation of the subsurface at Rulison. Without this model, one may make assumptions about the reservoir which are invalid. For example, one may assume that the maximum horizontal stress is at the midpoint between the overburden and minimum stress. Or one may assume static elastic moduli are the same as dynamic
elastic moduli. Therefore, despite the possible uncertainties, I believe with the data available, all necessary steps have been taken to build a model that best represents the in-situ earth.

4.6 Conclusions

From a wellbore stability simulation, a strength and stress profile has been determined for four wells in Rulison. Additionally, the modeling results are accurately represented by demonstrating both the sensitivity to the modeling inputs and the errors associated with the modeling inputs. The results of this modeling have important applications for reservoir characterization, which are presented in Chapter 5.
CHAPTER 5
MODELING FOR PRACTICAL APPLICATIONS AT RULISON

5.1 Introduction

The results of the geomechanical modeling have vast importance for practical applications at Rulison. Knowledge of the magnitude of stresses is vital to understanding how to drill, complete and re-complete wells. One practical application of this modeling is a better comprehension of hydraulic fracture and completion techniques. The variation of stress magnitude with lithology affects the ability of a fracture to stay within the zone of interest and therefore affects production. Knowing the direction of past and present day stress also affects hydraulic and natural fracture orientation and interaction and can ultimately aid in optimal well placement and economics. Lastly, the modeling shows a variation in stress magnitude and stress direction between the RCP survey site and the MWX site, which are less than two miles apart. This suggests the need to include geomechanics in reservoir characterization. The geomechanical modeling at Rulison provides a better understanding of the role that stress plays in optimizing production at Rulison Field.
5.2 Fault Classification at Rulison

Production at Rulison is largely dependent on natural fractures and these natural fractures are presumably linked to faults (Jansen, 2005). The type of faults present at Rulison can be classified by the order of magnitude of in-situ stresses. A classic model, described by Anderson, shows that the order of the three far-field stress magnitudes, $\sigma_H$, $\sigma_h$, and $\sigma_v$, will distinguish which type of faulting will occur in the reservoir (Anderson, 1951). A representation of Anderson’s model is shown in Figure 5.1 (Anderson, 1951; Bratton, 2005).

![Fault Classification Diagram]

Figure 5.1: Anderson Fault Model. Figure is modified from Bratton (2005).
My geomechanical modeling indicates that $\sigma_H \sim \sigma_V > \sigma_h$. Because the overburden stress is very close to the maximum horizontal stress, the reservoir is currently in the strike-slip or normal faulting regime. The faults that currently help control production at Rulison were formed in the past when stress orientations and magnitudes were different. From an interpretation of a regional seismic survey over Rulison, it is evident that the faulting present at Rulison is predominantly strike-slip (Cumella and Ostby, 2003). Jansen supports this interpretation with evidence of a wrench faulting system (Jansen, 2005). Figure 5.2 shows how compressive stresses in the past could cause lateral strike-slip faulting movement. This is supported by an interpretation of predominantly W-NW to S-SE faulting at Rulison (Jansen, 2005). Therefore, the presence of strike-slip faults suggests these faults were formed when the regional stress system had a stress magnitude order of $\sigma_H > \sigma_V > \sigma_h$. 

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Figure 5.2: The upper image demonstrates how compressive stresses can cause lateral movement on strike-slip faults. The lower left image is a fault interpretation at 1200 ms (lower reservoir) from Jansen (2005). The lower right image shows the dominant direction of faulting overlaid on a time structure map of the Cameo horizon. Image is from Jansen (2005).

The presence of older strike-slip faults is also supported by Warpinski at the MWX site (Warpinski, 1989). Figure 5.3 shows his interpretation of the stress history over time for the Cozzette sandstone. The Cozzette sandstone is a marine sand at the base of the Mesaverde group, ~7,900 feet. Warpinski’s interpretation is based on modeling strain as a function of burial history. The left column shows total stress while the right column shows effective stress. It is evident that from 75 million years ago to
present, the maximum horizontal stress, $\sigma_H$, has been larger than the overburden stress, $\sigma_V$. This is the cause for the strike-slip faults that occur at Rulison.

Figure 5.3: Stress modeling during MWX depositional history. Figures are from Warpinski (1989).

Warpinski's results also support my model, because his estimation of the relationship between the present day stresses is similar to mine. From Figure 5.3 it is clear that at the present time the overburden stress is approximately equal to the maximum horizontal stress at MWX site, while the minimum horizontal stress is significantly less than the overburden and maximum horizontal stress. My model shows similar results. However, the similarities between the two should be taken with caution, because I will show in Chapter 5.4 that the stresses vary between the MWX site and the RCP survey site.
5.3 Modeling Implications for Hydraulic Fracturing

Because Rulison has permeabilities in the microdarcy range, one of the most important aspects for economic production is the ability to hydraulically fracture multiple pay zones. The direction of stress affects the direction hydraulic fractures propagate and helps constrain targeted drilling locations. In hydraulic fracturing, net pressure, the difference between the minimum horizontal stress and the well pressure, controls hydraulic fracture growth and is directly related to the geometry of the hydraulic fracture (Hopkins, 1997). Stress magnitudes often control the ability of the fracture to stay within zone. They also may affect an operator’s decision to re-fracture multiple times over the life of a well.

5.3.1 Hydraulic Fracture Direction of Propagation

Hydraulic fractures will usually propagate in the direction of current maximum horizontal stress. This is assuming the wellbore is cylindrical and smooth, and natural fractures or other cracks in the earth do not affect or change the hydraulic fracture direction of travel. From the geomechanical modeling, the average maximum horizontal stress direction for the four wells in the RCP survey area is N 72° W with an average standard deviation of 10.7°. Because hydraulic fractures drain the reservoir in an elliptical pattern, especially in low permeability tight reservoirs, knowing the direction of propagation allows for optimal well placement and helps to avoid drilling wells in locations that are already depleted.
At Rulison, production is dependent on successful connection of hydraulic fractures with natural fractures. Figures 5.4 through 5.6 show a comparison from image log rose diagrams between maximum horizontal stress direction from drilling induced fractures and natural fractures. These images are from Schlumberger and Halliburton. It is evident that at the RCP survey site the present day maximum horizontal stress direction is also the direction of most of the pre-existing natural fractures.

Figure 5.4: Image log rose diagrams for RWF 523-20 for depths of 5688 to 6801 feet. In the left image the blue shows the direction of natural fractures. In the right image the green shows the direction of drilling induced fractures (maximum horizontal stress direction) and the red shows the direction of breakouts (minimum horizontal stress direction).
Figure 5.5: Image log rose diagrams for RWF 542-20 for depths of 4000 to 7950 feet. In the left image the yellow shows the direction of natural fractures. In the right image the yellow shows the direction of drilling induced fractures (maximum horizontal stress).

Figure 5.6: Image log rose diagrams for RMV 60-17 for depths of 5507 to 7896 feet. In the upper left image the light blue shows the direction of healed natural fractures. In the upper right image the blue shows the direction of natural fractures. In the lower image the green shows the direction of drilling induced fractures (maximum horizontal stress direction) and the red shows the direction of breakouts (minimum horizontal stress direction).
Figures 5.4 through 5.6 show that although there is some variation, the direction of natural fractures is fairly consistent with the direction of maximum horizontal stress, which is shown by drilling induced fractures. From processing the dipole sonic log in RWF 332-21, the average direction of maximum horizontal stress was determined to be N 63° W (Burke, 2005). The direction of anisotropy from a VSP log in Rulison is also an average of N 63° W (Davis, 2006). The direction of anisotropy shown in these logs is probably influenced by both stress and natural fractures.

Understanding the interaction between hydraulic fractures and natural fractures is important in making realistic estimates of the ability to economically produce the reservoir. Because the direction of propagation is the same for both hydraulic fractures and most natural fractures, productivity may be less than if the two orientations were at an angle to each other. If the orientations were at an angle to each other, then the hydraulic fracture would intersect more of the natural fractures, which would enhance permeability and increase production. However, this could also cause complex fracturing and limit fracture growth. Complex fracturing could occur where hydraulic fractures change orientation due to natural fractures. This concept is illustrated on the right side in Figure 5.7. Without complex fracturing hydraulic fractures can maintain or exceed their desired length. Therefore the relationship between hydraulic fractures and natural fractures at Rulison may be advantageous for fracture growth and production.
Figure 5.7: The left image shows the scenario where hydraulic fractures do not intersect many natural fractures but maintain their desired length. The right image shows the scenario where the hydraulic fracture intersects more natural fractures but complex fracturing occurs, which limits fracture length.

Understanding natural fracture direction and hydraulic fracture direction of propagation is also important in selecting target well locations. Most of the natural fractures are aligned with the direction of hydraulic fracture propagation, and in tight gas sandstones, gas drainage can be conceptualized in an elliptical manner. To avoid drilling wells in gas depleted areas, new wells should not be drilled near existing wells in the direction of hydraulic fracture propagation. Figure 5.8 demonstrates how drilling a new well in close proximity to a pre-existing well in the west-northwest to east-southeast direction can result in overlapped zones and missed pay.
Figure 5.8: Ellipses show gas draining in a W-NW to E-SE direction. New wells should not be drilled to the W-NW to S-SE direction in close proximity to existing wells. This results in possible missed pay and overlapped zones. Figure modified from Bratton (2005).

5.3.2 Stress Magnitude Affects Zone Completions

The variation of magnitude of stress with lithology has important applications for hydraulic fracture design. There are many variables which affect a hydraulic fracture’s ability to stay within the desired zone. These include stress, rock strength, natural fractures, pump rate and fluid viscosity. An important aspect is the stress contrast between the different lithologies. Because the shales have a higher stress magnitude than the sandstones, fractures tend to terminate at shale boundaries and stay within the desired sandstone zone. This is fortunate for Rulison because the thin interbedded nature of the reservoir enables multiple-zone completions to stay within the zones of interest. Image
log evidence supports a high stress contrast between the sandstones and shales. In most sandstones with fractures, both drilling induced and natural, the fractures stop at the shale boundary. An example is shown in Figure 5.9. This is an image log for RWF 523-20. From this figure it is evident that even a thin shale layer stops the drilling induced fracture. However, by studying the entire image log it is apparent that the thickness of beds does matter, and not all thin shales terminate fractures.

![Image log from RWF 523-20 showing fracture termination at shale boundaries.](image)

Another important application of the stress magnitude variation with lithology is the implication of high stresses in the coals. It is believed these coals are the source of
most of the gas at Rulison (Scheevel and Cumella, 2005). Therefore, fracturing into the
coals to produce gas may seem plausible for enhanced production. However, if the
assumption is correct that the coals have a ~1000 psi higher stress than the sands,
completion in coal intervals will be problematic because hydraulic fractures may travel
out of zone. Fractures in coals rarely travel beyond 200 feet (Olsen, 2004). Fracture
containment within the coals will be even more challenging in the RCP survey area,
because the coals are relatively thin. The best production strategy may be to complete
sands that are in communication with the coals. If the coals are generating gas, then
creating fractures in sandstone zones that are in communication with coals will increase
gas production, while allowing for fracture length and growth.

5.3.3 Minimum Horizontal Stress Increases at Depth

From the mini-fracture test results there appears to be a marked increase in
minimum horizontal stress values at a depth of ~ 7000 feet. Of the eight wells with mini-
fracture tests, five of them display a larger minimum horizontal stress gradient at ~7000
feet than in the shallower reservoir. Understanding the magnitude of minimum
horizontal stress is essential not only for geomechanical modeling but also for hydraulic
fracture design.

Figure 5.10 shows the stress magnitudes from the mini-fracture testing for well
RU-1. The blue points represent interpreted pore pressure results and the purple line
represents the appropriate gradient used for pore pressure. The red points are the
interpreted minimum horizontal stress and the black line shows the minimum horizontal
stress gradient, without an increase at 7000 feet. It is evident from this figure that starting slightly below 7000 feet, the minimum horizontal stress is larger than the gradient line shown.

Figure 5.10: Minimum horizontal stress and pore pressure measurements for well RU-1 from mini-fracture tests.

This is an interesting observation, but it should be noted that the abnormal increase of stress at ~7000 feet is not generally noted in the literature and therefore, it is possible that this observation is a product of the mini-fracture testing interpretation. However, assuming the observation actually occurs in nature, it is worth discussion. The
reason for this increase at depth is not well understood. However, I believe that the source of the increase of stress at depth is probably due to pore pressure controlled by source gas in the coals and permeability barriers or seals. It may also be related to faulting.

The reservoir is overpressured and the top of gas seal varies, but is on average 400 feet below the UMV shale (Cumella, 2006; Davis, 2006). This would cause a consistent increase in pore pressure and stress with depth, providing there is no stress release mechanism. However, the stress seems to increase more rapidly at greater depths. Also, most of the coal beds found in the well logs are below 6000 feet and are more numerous at greater depths. Therefore, these coals may be generating gas which is being trapped at depth by permeability barriers such as shale. Without pore pressure release, this generation of gas may be causing a stress increase.

Also, it is important to note the apparent large stress increase at depth is only shown in five of the eight wells with mini-fracture tests. This may be because of the presence of the wrench fault system at Rulison. Figure 5.11, from Jansen, shows that Rulison has a major wrench fault system which starts with significant faulting at depth and splays into smaller faults in shallower sections (Jansen, 2005). It is possible that the wrench faults are allowing pressure release into the shallower reservoir. The relationship between the well locations and fault locations may explain why only 5 of the 8 wells show a pore pressure and stress increase. This scenario is further complicated by the
presence of both sealing and open faults. This hypothesis requires a more detailed fault interpretation to confirm its validity.

There may be other explanations for the stress increase in addition to pore pressure. From Figure 5.10 it is evident that the overburden stress, shown in brown, is not increasing as rapidly as the minimum horizontal stress at depth. I am therefore eliminating the overburden as a possible cause. Another reason for the stress increase may be tectonics. The stress anisotropy in the reservoir is caused by an east-west compression primarily due to the Laramide orogeny. The compressional stress may have been larger at the time of deposition of the lower section of the reservoir. Alternatively, the stress may have formed evenly, but with time the stresses nearer to the surface have been able to relax at a more rapid rate than the deeper sediments. It may also be a function of unloading during uplift. Shown in Figure 1.6, during the last 30 million years the reservoir rocks have been uplifted more than 10,000 feet. Figure 5.3 shows that during this same time the stress magnitudes have decreased. This unloading could be causing abnormal differences in stress magnitudes with depth.

Although the cause of this increase is not well understood, the implications are important. Hydraulic fracture design largely depends on the magnitude of horizontal stress and therefore an increase in stress due to permeability barriers is important to recognize.
Figure 5.11: Wrench fault system at Rulison with upward splaying. RCP survey area is in dashed lines. Figure is from Jansen (2005).

5.3.4 Zone Specific Fracture Design

There is a large scatter in pore pressure and minimum horizontal stress values from the mini-fracture tests, shown in Figure 5.10. These variations suggest that optimal fracture design incorporate zone specific completions.

Fracture mechanics are complicated, however, the pressure required to initiate and propagate a hydraulic fracture can be simply expressed in equation 5.1 (Bratton, 2006).

\[ P = \sigma_h + Y + C \]  \hspace{1cm} (5.1)

where \( P \) is the total injection pressure, \( \sigma_h \) is the minimum horizontal stress, \( Y \) is some additional pressure required to propagate a fracture and \( C \) is additional pressure needed to account for friction losses between the fracture opening and the fracture tip. This
suggests variations in minimum horizontal stress will require different initial fracture propagation pressures in each zone.

The variation in pore pressure, due to depletion, is also important in hydraulic fracture design. It appears that some zones are still at virgin pore pressure and some are depleted, shown in Figure 3.6. Pressure depletion can cause the minimum horizontal stress to decrease in individual zones. Because of the stacked nature of the reservoir, sands are often completed with multiple-zone fracture techniques. This can be problematic because fluid and proppant will often build-up in zones of lower stress. Therefore zones that are not depleted will have insufficient fracture propagation. These observations suggest that optimal production may be achieved by zone specific completions. However, due to the cost of completions, I recognize this recommendation is currently not economical and therefore is probably not realistic.

To optimally complete wells, it is essential to know which zones are depleting and which zones are in pressure communication with offsetting wells. To determine which zones are depleted and which are not, requires new technologies such as time lapse seismic.

5.3.5 Stress Modeling Shows Fracture Reorientation is Unlikely

Because of high horizontal stress anisotropy, hydraulic re-fracturing techniques may be difficult at Rulison. At Rulison most of the natural fractures have the same azimuth as the present day direction of maximum horizontal stress. Therefore hydraulic fractures propagate in the same direction as the natural fractures. One method often
applied by operators is to hydraulically fracture zones multiple times over the life of the reservoir. Stress fields change due to production, and in some reservoirs this can cause the direction of hydraulic fracture propagation to change. If this were successfully achieved at Rulison, the hydraulic fractures could intersect more natural fractures and increase productivity.

Numerical modeling has shown that, due to production, the stresses will change faster parallel to initial hydraulic fracture direction (Wright and Weijers, 2001). Therefore the magnitude of the original maximum horizontal stress can become smaller than the magnitude of original minimum horizontal stress. This will allow hydraulic fractures to initiate perpendicular to the original fracture.

Although this technique is not well understood, it has been successfully applied. Figure 5.12 shows stress re-orientation images from two successful fields. In both cases tiltmeters mapped fracture orientations. The figure on the left is from the Barnett Shale (Siebrits, et al., 2000). The figure on the right is from the Van Austin Chalk in East Texas (Wright and Weijers, 2001). For the Van Austin Chalk, the hydraulic fractures re-completion technique was applied after four years of production.
Figure 5.12: Examples of successful stress re-orientation completions. The image on the left is from the Barnett Shale and is from Siebrits, et al. (2000). The image on the right is from the Van Austin Chalk from East Texas and is from Wright and Weijers (2001).

The results of my modeling show high horizontal stress anisotropy, $\sigma_H >> \sigma_h$, and therefore, this area of Rulison is not a likely candidate for fracture re-orientation. In order to have fracture re-orientation, the magnitudes of stress have to be affected such that, after depletion, the original minimum horizontal stress magnitude exceeds the original maximum horizontal stress magnitude. The more horizontal stress anisotropy present in a field, the more the stress field will have to change for re-orientation to occur. In areas with little horizontal stress anisotropy, $\sigma_H \sim \sigma_h$, there is a greater chance for stress changes and reorientation (Henk, 2005).

It should be noted that although stress reorientation has been observed in nature, the mechanics are poorly understood (Elbel and Mack, 1993; Miskimins, 2006; Siebrits, et al., 1998). The relationship between the pressure decline and far-field stress changes is
not clear and is not well documented. Additional factors such as faults and fractures also complicate an already poorly understood phenomenon. Therefore, although Rulison is an unlikely candidate for fracture re-orientation due to high horizontal stress anisotropy, with a better understanding of the mechanics of fracture re-orientation it may be feasible.

The best opportunity for re-fracturing is to find bypassed pay. With the lenticular discontinuous nature of the reservoir, it is likely that gas is being missed either from missed perforation intervals, ineffective hydraulic fractures in some intervals or well locations. The difficulty in optimally producing this reservoir is in knowing where that bypassed pay is located. Technologies such as tiltmeter mapping, time lapse seismic data, multi-component seismic data and better hydraulic fracture design may prove useful.

5.4 Geomechanical Comparison between the RCP Survey Area and the MWX Site

The geomechanical modeling results of the four wells in the RCP survey area are different than reported stress results at the MWX site. Observing differences in stress magnitude and orientation between fields, only a few miles away, emphasizes the importance of reservoir characterization for every field. The direction of stress and stress magnitude control well placement and hydraulic fracture design, and ultimately impact production.
5.4.1 A Comparison of Stress Direction

The average direction of maximum horizontal stress is very similar between the RCP survey area and the MWX site. Clark describes the results of 10 different methods for determining maximum horizontal stress at the MWX site and concludes that the maximum horizontal stress direction at the MWX site is on average N79°W (Clark, 1983). From my interpretation of image logs and the dipole sonic log, the average maximum horizontal stress direction is N72°W. This difference of 7° is likely within the range of errors from both sources.

The stress direction differences between the sites are apparent in the stress direction rotation with depth. It is shown in Chapter 3 at the RCP survey site, Figures 3.12 and 3.13, that the present day maximum horizontal stress directions rotates 5 to 25 degrees in a counterclockwise direction with depth. At the MWX site it has been reported that stress rotates about 30 degrees in a clockwise direction with depth (Warpinski and Teufel, 1989). Figure 5.13 shows the stress rotation for the MWX well #3. This data were obtained through anelastic strain recovery, ASR, testing (Warpinski and Teufel, 1989). This stress rotation is also supported by azimuth measurements in borehole geophones.
Stress rotation with depth is important because it implies hydraulic fracture direction of propagation changes with depth. Thus, production ellipsoids will rotate differently at the two sites and if an operator were trying to effectively produce both fields, the operator would need to design different well placement schemes.

The reason for stress rotation differences between the RCP survey site and MWX is not clear. However, due to the close proximity of the sites, I am proposing that the
difference is likely due to their location relative to the Colorado River Valley. It may also be a result of local structures such as faults.

Clark suggests that the stress rotation with depth at the MWX site is due to topography. The MWX site sits in an area of topographic low, cut out by the Colorado River. A cross section from Clark is shown in Figure 5.14. He proposes that at shallow depths the maximum horizontal stress will follow the path cut by the Colorado River and at greater depths the maximum horizontal stress direction will remain similar to the direction that was originally deposited by tectonic stress.

![Cross section showing topographic relief at MWX site](image)

**Figure 5.14:** Cross section showing topographic relief at MWX site. Figure is modified from Clark (1983).

Because the Colorado River cuts between the two surveys, this hypothesis may help explain the stress rotation differences between the RCP survey site and the MWX site. The RCP survey site is also in a topographic low and the stress direction rotates toward the direction of the river at shallower depths. Figure 5.15 shows the location of
the Colorado River as well as the stress rotations with depth for both the MWX site and the RCP survey site. For each well the blue azimuth represents the stress direction at the most shallow point and the red azimuth represents the stress direction at the deepest point. The represented points are from Figure 3.11 and Figure 5.13.

Figure 5.15: Stress rotation with depth for the MWX and RCP survey sites. The blue azimuth represents shallow depths and the red azimuth represents deeper depths. Shallow depths seem to follow the path of the Colorado River Valley. Well locations are approximate.

For each of the wells it seems that the shallower sediments, shown in blue, follow the channel cut out by the Colorado River. It is likely that the red azimuth, representing
deeper sediments, is primarily controlled by the tectonic compressive loading from the Laramide orogeny. It is possible that the Colorado River was developed from previous planes of weakness, such as faults and fractures. There are many interpreted faults in this area that vary significantly in azimuth (Jansen, 2005).

Another reason for local stress rotation may be the proximity of faults to a wellbore. There are numerous faults in the region which start below the reservoir interval and splay toward the shallower reservoir, shown in Figure 5.11. The effect of the splaying faults may cause changes in the earth which exhibit the stress rotation shown.

5.4.2 A Comparison of Stress Magnitude

Reported stress magnitudes and pore pressure are larger at the MWX site than magnitudes at the RCP survey site. This has important applications as the values of pore pressure and minimum horizontal stress control hydraulic fracture design and propagation.

Interpreted pore pressure from the MWX site and the RCP survey site are shown in Figure 5.16. The estimated pore pressure for the RCP survey site is from the mini-fracture tests shown in Figure 3.6. The estimated MWX pore pressure is from well tests (Spencer, 1989; Rojas, 2005).
Figure 5.16: Comparison of pore pressure at the MWX and RCP survey sites. Original MWX data is approximate and is from Spencer (1989).

In addition to pore pressure, there is also a reportedly higher minimum horizontal stress magnitude at the MWX site. Mini-fracture tests were performed on the MWX well #2 and are shown in red in Figure 5.17 (Teufel, 1996; Warpinski and Teufel, 1989). The mini-fracture tests performed in the RCP survey site on wells RU #1-8 are shown in blue and are from Figure 3.7.
Figure 5.17: Mini-fracture estimates of minimum horizontal stress at the MWX and RCP survey sites.

If the tests accurately compare the pore pressure and minimum horizontal stress, then the MWX site has larger values of pore pressure and minimum horizontal stress than the RCP survey site. The overburden stresses are similar between the two sites. From my modeling, the overburden gradient is ~1.09 psi/ft and the reported overburden at the MWX site is ~1.05 psi/ft (Warpinski, et al., 1985).

The cause of the higher stresses at the MWX site could be due to greater stress relaxation at the RCP survey site. It could also be due to wrench faulting which may
allow pore pressure and stress to release from depth at the RCP survey site. Regardless of the cause of the stress difference, it is important to have an accurate understanding of pore pressure and minimum in-situ stress magnitudes for hydraulic fracture design and propagation.

The observed differences between the RCP survey site and the MWX site reinforce the concept that reservoir characterization is essential in every field. Making assumptions that one well will behave the same as another well, even at a scale of a few miles or less, can be erroneous.

5.5 Spatial Variation Within the RCP Survey Area

The four modeled wells show very little spatial variation in geomechanical properties. The lack of spatial variability may be because the wells in the RCP survey site all behave very similarly or it may be because of data extrapolation. For example, the same pore pressure and minimum horizontal stress gradients were used for the three wells without mini-fracture data. However, Figures 3.6 and 3.7 show there is a large variation in values between wells.

Therefore, to understand the extent of spatial variation, it will be essential to have mini-fracture tests (or pore pressure with the uniaxial strain model as presented in Chapter 3.6), image logs and sonic logs in each of the wells being modeled. It will also be necessary to measure stress in the shales and coals.
5.6 Conclusions

Geomechanical modeling of Rulison is shown to be a valuable tool for reservoir characterization. From the stress magnitudes there is a better understanding of how faults, natural fractures and hydraulic fractures interact and aid in the production of Rulison Field. The stress model also aids in completion and well placement strategies. The conclusions that are relevant for improvements in drilling and completion practices at Rulison include:

(1) Optimal production will require hydraulic fractures to be designed in a zone-specific manner because the pore pressure and minimum horizontal stresses vary in each zone.

(2) Stress magnitude varies with lithology. This means multiple zone completions in sandstones will likely have hydraulic fractures containment within desired zones. Because stresses are probably highest in the coals, coal completions will be difficult. The best zones to complete are probably sands which are in communication with gas-generating coals.

(3) Fracture re-orientation completions will be difficult. A better enhancement strategy is to look for bypassed pay with new target well locations or missed zones.

(4) The maximum horizontal stress direction is closely aligned with the direction of most of the natural fractures in the reservoir. This means hydraulic fractures should maintain or exceed their desired length without complex fracturing.
(5) Because hydraulic fractures will travel west-northwest to east-southeast, target well locations should be placed strategically.

(6) The modeled stress results are specific to Rulison. I expect a large variability in different parts of the world and even in different tight gas reservoirs. For example, there are stress and pore pressure differences between Rulison and MWX, which show the need for each field to be characterized separately.
CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

I have shown that geomechanics is a powerful tool to aid in reservoir characterization. I followed a ten-step methodology to design a geomechanical model for four wells in Rulison. From this research I have contributed nine specific results related to production at Rulison Field.

(1) Rock strength and static elastic moduli can now be determined from log data with empirical correlations.

(2) Present day stress magnitudes, $\sigma_h \sim \sigma_y > \sigma_h$, suggest both strike-slip and normal faulting regimes. Evidence of past strike-slip faulting suggests earlier stress magnitude orderings of $\sigma_h > \sigma_y > \sigma_h$.

(3) Most natural fractures are aligned in the same direction as the present day maximum horizontal stress direction. This suggests there will be hydraulic fracture growth without complex fracturing.

(4) There is a consistent direction of average maximum horizontal stress direction. Therefore, to avoid draining the same area with two wells, target well
locations should not be placed in a west-northwest to east-southeast orientation relative to other wells.

(5) Stress magnitudes are lithology dependent. Stress magnitudes are higher in shales than sandstones, which likely enables hydraulic fracture containment within sandstone zones. Stresses are probably highest in coals, making completions in coals difficult. The best zones to complete may be sandstones that are in communication with coal intervals.

(6) There is a horizontal stress anisotropy of ~2000 psi which makes stress re-orientation completions difficult.

(7) For the four wells modeled, there is little spatial variability in geomechanical parameters.

(8) Optimal production will require zone specific completions.

(9) Stress magnitudes and rotation directions are different at the RCP survey site and MWX site. These differences suggest the need for reservoir characterization in each individual field.

From this work, it is evident that geomechanics needs to be used in the future in well planning and fracture design.

6.2 Recommendations for Future Research

Geomechanics aids in reservoir characterization of Rulison Field. However, I also believe that the work here can be expanded greatly to further characterize this and
other tight gas plays. The best opportunity to understand this field and improve production is likely through flow simulation. However, due to the heterogeneity of this field, flow simulation will be challenging. It will be difficult to understand the reservoir properties in areas without well control information. One solution to this problem is the use of seismic data. Seismic data can provide reservoir properties throughout the entire field. I believe that the best opportunity to understand this reservoir is to integrate seismic information into a fully coupled flow simulation. Flow simulation will be useful in simulating production and determining the economic potential of the reservoir. From flow simulation models, areas of depletion can be estimated and new well locations can be identified in un-depleted areas. Additionally, with flow simulation, estimates can be made on remaining reservoir potential and ultimately help assess the future economic viability of the field.

I also suggest an improvement in understanding the relationship between production and stress, and how that affects velocity. This could partially be accomplished through finite element modeling. However, it will also be important to understand this relationship at the well scale. It has been shown in the lab that velocity changes as a function of stress (Rojas, 2005; Sayers, 2005). Through full field modeling it has also been shown that stress changes due to pressure changes from production (Holt, et al., 2005). However, this relationship is not well understood at the well scale. Some of this understanding could be achieved through time-lapse logging. It will also be necessary to have a large amount of data collected in the same wellbore. To see how
pressure relates to stress, a dipole sonic log, image log and mini-fracture log should be collected in the same wellbore.

The mini-fracture results show a large variability in pore pressure and minimum horizontal stress. The key to increasing production will be to identify which zones are producing the most gas and which zones can be re-completed for bypassed pay. It may be that the majority of gas production is from random zones in each well or there may be a trend for the field. If a trend for the field is discovered, gas production could increase dramatically. To determine which zones are depleting the most gas, time-lapse seismic attribute analysis will be valuable. For example, over time the ratio of the compressional velocity to shear velocity may indicate areas of gas depletion and pressure depletion (Rojas, 2005). If depleted zones are identified, then un-depleted zones can be re-fractured. Also, identifying sweet spots that are highly fractured will increase production. This could be done through seismic anisotropy analysis.

Because of the thin interbedded nature of this reservoir, permanent pressure testing may be one option for determining which zones are producing and which zones have pressure decline. This would allow for the reservoir to be monitored in real-time. If a coupled geomechanical model is developed, then real time pressure measurements could be used to update the model periodically. With an updated model new target well locations could be optimally chosen, and bypassed pay identified. Time-lapse seismic data will also aid in understanding pressure changes in the inter-well spacing. If this type
of data could be used to save the cost of drilling just a few wells that would have been in pressure communication with other near-by wells, then it will be advantageous.

In the future, I also think this reservoir could be better produced through improved engineering practices. I have shown that completions could be optimized with zone specific designs. I have also shown fracture re-orientation will be difficult. The findings are important, but I believe more engineering aspects should be studied. As engineering technologies increase, there will be opportunities to design better hydraulic fractures to increase production.

Using accurate empirical correlations for rock strength and elastic moduli is valuable for reservoir modeling and hydraulic fracture design. The empirical correlations I have built could be improved by obtaining core within the RCP survey site. I believe that the work presented in this thesis shows the value of using geomechanics in reservoir characterization. The challenge for the future will be to integrate the geomechanics with the engineering, geology, well logs and geophysics to optimally produce tight gas reservoirs.
REFERENCES


APPENDIX A

Table A.1 shows the data for the 17, MWX well #1, core samples used for my empirical correlations. Data are from Finely (1985) and Senseny (1983). Table A.2 shows my calculated values for rock strength from the Mohr-Coulomb failure criteria.

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<td>0.21</td>
<td></td>
</tr>
<tr>
<td></td>
<td>20.00</td>
<td>301.80</td>
<td>40.40</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td></td>
<td>30.00</td>
<td>275.60</td>
<td>42.20</td>
<td>0.17</td>
<td></td>
</tr>
</tbody>
</table>

Table A.1: Data from core tests.
<table>
<thead>
<tr>
<th>Sample #</th>
<th>Core Depth</th>
<th>Log Depth</th>
<th>Lithology</th>
<th>FA</th>
<th>So</th>
<th>UCS</th>
<th>mR2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4946.00-4946.70</td>
<td>4935.00</td>
<td>Sandstone</td>
<td>32.08</td>
<td>4452.17</td>
<td>16089.54</td>
<td>0.99</td>
</tr>
<tr>
<td>2</td>
<td>5199.20-5200.20</td>
<td>5183.50</td>
<td>Siltstone</td>
<td>25.97</td>
<td>9662.35</td>
<td>30906.69</td>
<td>0.31</td>
</tr>
<tr>
<td>3</td>
<td>5722.20-5723.50</td>
<td>5724.00</td>
<td>Sandstone</td>
<td>31.55</td>
<td>5013.23</td>
<td>17921.85</td>
<td>0.90</td>
</tr>
<tr>
<td>4</td>
<td>5815.40-5816.00</td>
<td>5816.00</td>
<td>Mudstone</td>
<td>14.70</td>
<td>3502.44</td>
<td>9079.37</td>
<td>0.97</td>
</tr>
<tr>
<td>5</td>
<td>5835.20-5836.30</td>
<td>5834.00</td>
<td>Sandstone</td>
<td>39.66</td>
<td>2442.47</td>
<td>10394.51</td>
<td>0.90</td>
</tr>
<tr>
<td>6</td>
<td>5940.60-5941.20</td>
<td>5939.50</td>
<td>Siltstone</td>
<td>39.02</td>
<td>4714.48</td>
<td>19778.33</td>
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<td>7</td>
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<td>5961.50</td>
<td>Sandstone</td>
<td>32.63</td>
<td>6456.03</td>
<td>23597.66</td>
<td>0.99</td>
</tr>
<tr>
<td>8</td>
<td>6025.00-6025.80</td>
<td>6021.00</td>
<td>Mudstone</td>
<td>21.47</td>
<td>2358.85</td>
<td>6925.56</td>
<td>0.75</td>
</tr>
<tr>
<td>9</td>
<td>6054.90-6055.90</td>
<td>6052.50</td>
<td>Siltstone</td>
<td>50.58</td>
<td>2589.35</td>
<td>14455.93</td>
<td>0.99</td>
</tr>
<tr>
<td>10</td>
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<td>6068.00</td>
<td>Sandstone</td>
<td>29.79</td>
<td>5303.20</td>
<td>18294.11</td>
<td>1.00</td>
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<tr>
<td>11</td>
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<td>6417.00</td>
<td>Siltstone</td>
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<td>7960.25</td>
<td>30344.47</td>
<td>0.79</td>
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<tr>
<td>12</td>
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<td>6423.00</td>
<td>Mudstone</td>
<td>17.96</td>
<td>3104.28</td>
<td>8538.42</td>
<td>0.96</td>
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<tr>
<td>13</td>
<td>6438.00-6438.90</td>
<td>6434.00</td>
<td>Sandstone</td>
<td>43.04</td>
<td>3432.47</td>
<td>15804.30</td>
<td>0.98</td>
</tr>
<tr>
<td>14</td>
<td>6451.50-6452.60</td>
<td>6448.00</td>
<td>Sandstone</td>
<td>32.74</td>
<td>3767.16</td>
<td>13800.36</td>
<td>0.98</td>
</tr>
<tr>
<td>15</td>
<td>6491.50-6492.50</td>
<td>6488.00</td>
<td>Mudstone</td>
<td>6.42</td>
<td>7739.74</td>
<td>17320.42</td>
<td>0.50</td>
</tr>
<tr>
<td>16</td>
<td>6517.30-6518.50</td>
<td>6513.50</td>
<td>Sandstone</td>
<td>33.11</td>
<td>4275.75</td>
<td>15785.41</td>
<td>0.97</td>
</tr>
<tr>
<td>17</td>
<td>6564.30-6564.80</td>
<td>6564.00</td>
<td>Siltstone</td>
<td>7.76</td>
<td>15951.44</td>
<td>36544.37</td>
<td>0.48</td>
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</tbody>
</table>

Table A.2: Data from core tests and Mohr Coulomb failure criteria.
APPENDIX B

B.1 Published Correlations between Static Young’s Modulus and UCS

I developed empirical correlations between UCS and static Young’s modulus, which are shown in Figure 2.5 and given in equations 2.14 through 2.16. Other published correlations confirm a similar relationship between the variables. A common empirical correlation developed by Deere and Miller, shows a linear increase in UCS with static E (Deere and Miller, 1966). Figures B.1 and B.2 illustrate two other examples where UCS increases as static E increases. Figure B.1 is an example from the Travis Peak formation in East Texas (Plumb, et al., 1992). Figure B.2 is an example of sandstones from the Sarir Field in Lybia (Qiu, et al., 2005).
Figure B.1: Young's modulus vs. UCS for different lithologies from the Travis Peak formation in East Texas. Figure is from Plumb and Herron (1992).

Figure B.2: Young's modulus vs. UCS for sandstones from the Sarir Field. Figure is modified from Qui, et al. (2005).
B.2 Published Correlations between Static and Dynamic Young’s Modulus

I developed empirical correlations between static and dynamic Young’s modulus, which are shown in Figure 2.8 and given in equations 2.22 through 2.24. Other people have also developed and published numerous empirical correlations between static and dynamic Young’s modulus. Figures B.3 and B.4 show two examples of these correlations for various collected sandstones. Figure B.3 is from a collection of consolidated cores from the Berea sandstones, Indonesian sandstones and Denver region sandstones (Montmayour and Graves, 1986). Figure B.4 is a collection of tight gas sandstones. SFE #1 is from Travis Peak and SFE #2 is from Wyoming (Tutuncu and Sharma, 1992). Consistent with my empirical correlations, it is clear that dynamic Young’s modulus is generally higher than static Young’s modulus.
Figure B.3: Static vs. dynamic Young’s modulus for a collection of sandstones. These include Berea sandstones, Indonesian sandstones and Denver area sandstones. Figure is from Montmayour and Graves (1996).

Figure B.4: Static vs. dynamic Young’s modulus from a collection of tight gas sandstones. Figure is from Tutuncu and Sharma (1992).
B.3 Published Correlations between Static and Dynamic Poisson’s Ratio

I developed empirical correlations between static and dynamic Poisson’s ratio, which are shown in Figure 2.9 and given in equations 2.25 through 2.27. The empirical correlations that I have developed are not typical for expected correlations. This may be due to erroneous lab measurements or errors associated with creating a synthetic shear wave. Figures B.5, B.6 and B.7 show three different examples of published empirical correlations from static to dynamic Poisson’s ratio. Figure B.5 is from a collection of consolidated cores from the Berea sandstones, Indonesian sandstones and Denver region sandstones (Montmayour and Graves, 1986). Figure B.6 is a collection of tight gas sandstones. SFE #1 is from Travis Peak and SFE #2 is from Wyoming (Tutuncu and Sharma, 1992). Figure B.7 is from various lithologies in Hugoton and Panoma Fields in Kansas (Yale and Jamieson, 1994). From these figures, it is evident that there are generally not consistent, good correlations between static and dynamic Poisson’s ratio.
Figure B.5: Static vs. dynamic Poisson's ratio for a collection of sandstones including Berea sandstones, Indonesian sandstones and Denver area sandstones. Figure is from Montmayour and Graves (1996).

Figure B.6: Static vs. dynamic Poisson's ratio from a collection of tight gas sandstones. Figure is from Tutuncu and Sharma (1992).
Figure B.7: Static vs. dynamic Poisson's ratio from the Hugoton and Panama Fields in Kansas. Figure is from Yale and Jameison (1994).
B.4. Published Correlations between Sonic Velocities and Porosity

In equations 2.28 through 2.29, I developed correlations between compressional and shear travel times from porosity at RWF 332-21. For comparison, Table B.1 shows published empirical correlations between porosity and compressional and shear velocities. Most of this table was compiled by Medlin and Alhilail, 1992. Φ is porosity.

<table>
<thead>
<tr>
<th>Source of correlation</th>
<th>(1/V_s) (µs/ft)</th>
<th>(1/V_s) (µs/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Higgins: Equations 2.28 and 2.29)</td>
<td>64.395+95.708(\Phi)</td>
<td>107.04+225.49(\Phi)</td>
</tr>
<tr>
<td>(Pickett, 1963)</td>
<td>49.7+113(\Phi)</td>
<td>68.5+273(\Phi)</td>
</tr>
<tr>
<td>(Han et al., 1986)</td>
<td>59.2+100(\Phi)</td>
<td>98.2+192(\Phi)</td>
</tr>
<tr>
<td>(Medlin and Alhilail, 1992)</td>
<td>50.3</td>
<td>73.4</td>
</tr>
</tbody>
</table>

Table B.1: Published empirical correlations between velocity and porosity.