Mineral, Fluid, and Elastic Property Quantification from Well Logs and Core Data in the Eagle Ford Shale Play: A Comparative Study
Mineral, Fluid, and Elastic Property Quantification from Well Logs and Core Data in the Eagle Ford Shale Play: A Comparative Study

by

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Dedication

To my husband and children
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Abstract

Mineral, Fluid, and Elastic Property Quantification from Well Logs and Core Data in the Eagle Ford Shale Play: A Comparative Study

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Organic shales have become one of the greatest sources of hydrocarbon thanks to novel production techniques such as hydraulic fracturing. A successful hydraulic fracturing job, however, is dependent on several rock properties such as mineralogy and elasticity. A reliable estimation of such properties is therefore necessary to determine ideal rocks for horizontal well placement. In this study, rock types within the Eagle Ford shale that would be suitable for hydraulic fracturing are identified through interpretations of available well logs and core data. A comparative study of petrophysical properties such as mineral content, kerogen type and maturity, porosity, and saturation in six wells is performed to characterize the Eagle Ford shale. Two of the wells studied are within the wet gas window of the shale while the remaining four are in the oil window. Based on the calculated petrophysical properties, rock typing was performed using k-means clustering. Two rock types (RT1 and RT2) were identified and their compositions compared in each well. Elastic properties for the various rock types identified were then estimated using the
differential effective medium (DEM) theory and were validated through simulation of
slowness logs. The final rock type assessment was then performed to identify ideal rocks
for hydrofracturing. Results indicate that the Eagle Ford mineralogy varies greatly with
depth and with geographic location relative to the San Marcos Arch, a geological arching
prominence across the shale. Northeast of the arch, the Eagle Ford shale is clay-rich.
Preferred rocks for hydrocarbon production, RT1, are characterized by volumetric
concentrations of ~0.44 carbonate, ~0.09 kerogen, ~0.07 porosity, and ~0.42 clay; RT1
also exhibits high sonic velocities (> 3400 m/s and > 1500 m/s compressional and shear,
respectively) and high apparent electrical resistivity (> 2 ohm-m). In the Southwest
region, on the other hand, the Eagle Ford shale is mostly calcareous. Ideal rocks in the
region, RT1, are rich in kerogen (~0.1) with carbonate content of ~0.56, ~0.1 porosity,
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ratio displayed substantial effects on elastic properties. For example, over 80% decrease
in Young’s modulus was quantified when pore aspect ratio approached zero; high pore
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Nomenclature

\( \mu \) : Shear modulus, (GPa)

\( a \) : Archie’s Winsauer factor, ( )

\( \text{DTC} \) : Compressional sonic reading in organic shale, (us/ft)

\( \text{DTC}_{\text{base}} \) : Compressional sonic baseline reading in non-organic shale, (us/ft)

\( E \) : Young’s modulus, (GPa)

\( E_{\text{AVE}} \) : Averaged Young’s modulus estimated from elastic model, (GPa)

\( E_{\text{LOG}} \) : Young’s modulus calculated from field sonic logs, (GPa)

\( G_{\text{AVE}} \) : Averaged shear modulus estimated from elastic model, (GPa)

\( G_{\text{LOG}} \) : Shear modulus calculated from field sonic logs, (GPa)

\( K \) : Bulk modulus, (GPa)

\( K_{\text{AVE}} \) : Averaged bulk modulus estimated from elastic model, (GPa)

\( K_{\text{LOG}} \) : Bulk modulus calculated from field sonic logs, (GPa)

\( m \) : Archie’s porosity exponent, ( )

\( n \) : Archie’s saturation exponent, ( )

\( P \) : Effective medium geometric coefficient, ( )

\( \text{ppm} \) : Parts per million

\( Q \) : Effective medium geometric coefficient, ( )

\( \text{RES} \) : Apparent resistivity reading in organic shale, (ohm-m)

\( \text{RES}_{\text{base}} \) : Apparent resistivity baseline reading in non-organic shale, (ohm-m)

\( S_2 \) : Hydrocarbon amount generated through organic matter thermal cracking, (mg/g)

\( \text{Shc} \) : Hydrocarbon saturation, ( )

\( S_w \) : Water saturation, ( )
Tmax : Maximum temperature, (°C)

\( v_{\text{AVE}} \) : Averaged Poisson’s ratio estimated from elastic model, ( )

\( v_{\text{LOG}} \) : Poisson’s ratio calculated from field sonic logs, ( )

\( V_c \) : Volumetric concentration, ( )

\( V_p \) : Compressional velocity, (m/s)

\( V_{p\text{AVE}} \) : Averaged compressional velocity estimated from elastic model, (m/s)

\( V_{p\text{LOG}} \) : Compressional velocity calculated from field sonic log, (m/s)

\( V_s \) : Shear velocity, (m/s)

\( V_{s\text{AVE}} \) : Averaged shear velocity estimated from elastic model, (m/s)

\( V_{s\text{LOG}} \) : Shear velocity calculated from field sonic log, (m/s)

\( \alpha \) : Aspect ratio of penny crack, ( )

\( \beta \) : Variable in geometric factor calculation, (GPa)

\( \zeta \) : Variable in geometric factor calculation, (GPa)

\( \nu \) : Poisson’s ratio, ( )

\( \rho \) : Rock bulk density, (g/cc)
Acronyms

AO10 : 10-inch apparent resistivity log one foot resolution, (ohm-m)
AO20 : 20-inch apparent resistivity log one foot resolution, (ohm-m)
AO30 : 30-inch apparent resistivity log one foot resolution, (ohm-m)
AO60 : 60-inch apparent resistivity log one foot resolution, (ohm-m)
AO90 : 90-inch apparent resistivity log one foot resolution, (ohm-m)
CARB : Carbonate group
CLA : Clay group
CNC : Neutron porosity log (limestone matrix), (V/V)
CO₂ : Carbon dioxide
CORE POR : Porosity from core data, (V/V)
CORE Sw : Water saturation from core data, ( )
DEM : Differential effective medium
DEN : Density log, (g/cc)
DLogR : Separation between resistivity and sonic porosity logs, ( )
DT35 : Compressional sonic log, (us/ft)
DTCO : Compressional sonic log, (us/ft)
DTSM : Shear sonic log, (us/ft)
EFS : Eagle Ford shale
FIB-SEM : Focused ion beam-scanning electron microscopy
FTIR : Fourier transform infrared spectroscopy
GCGR : Uranium-free gamma ray log, (GAPI)
GR : Total gamma ray log, (GAPI)
GRSG : Total gamma ray log, (GAPI)
H/C : Hydrogen to carbon atomic ratio, ( )
HC : Hydrocarbon
HCGR : Uranium-free gamma ray log, (GAPI)
HI : Hydrogen index, (mg/g)
HSGR : Total gamma ray log, (GAPI)
HST : Highstand systems tract
KER : Kerogen
KTH : Uranium-free gamma ray log, (GAPI)
LEF : Lower Eagle Ford
LOM : Level of organic metamorphism, ( )
LST : Lowstand systems tract
LTU : Lower transgressive unit
M2R2 : 20-inch apparent resistivity log two feet resolution, (ohm-m)
M2R3 : 30-inch apparent resistivity log two feet resolution, (ohm-m)
M2R6 : 60-inch apparent resistivity log two feet resolution, (ohm-m)
M2R9 : 90-inch apparent resistivity log two feet resolution, (ohm-m)
M2RX : 120-inch apparent resistivity log two feet resolution, (ohm-m)
MFS : Maximum flooding surface
MxIS : Mixed Illite/Smectite clays
NaCl : Sodium chloride
NE : Northeast
NPHI : Neutron porosity log (limestone matrix), (V/V)
NPOR : Neutron porosity log (limestone matrix), (V/V)
O/C : Oxygen to carbon atomic ratio, ( )

xxviii
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>OM</td>
<td>Organic matter</td>
</tr>
<tr>
<td>OW</td>
<td>Oil well</td>
</tr>
<tr>
<td>PDPE</td>
<td>Photoelectric factor log, (b/e)</td>
</tr>
<tr>
<td>PEF</td>
<td>Photoelectric factor log, (b/e)</td>
</tr>
<tr>
<td>PEF8</td>
<td>Photoelectric factor log, (b/e)</td>
</tr>
<tr>
<td>QF</td>
<td>Quartz-feldspar group</td>
</tr>
<tr>
<td>R20O</td>
<td>20-inch apparent resistivity log one foot resolution, (ohm-m)</td>
</tr>
<tr>
<td>R30O</td>
<td>30-inch apparent resistivity log one foot resolution, (ohm-m)</td>
</tr>
<tr>
<td>R40O</td>
<td>40-inch apparent resistivity log one foot resolution, (ohm-m)</td>
</tr>
<tr>
<td>R60O</td>
<td>60-inch apparent resistivity log one foot resolution, (ohm-m)</td>
</tr>
<tr>
<td>R85O</td>
<td>85-inch apparent resistivity log one foot resolution, (ohm-m)</td>
</tr>
<tr>
<td>RHOZ</td>
<td>Density log, (g/cc)</td>
</tr>
<tr>
<td>RT</td>
<td>Rock type</td>
</tr>
<tr>
<td>SCA</td>
<td>Self-consistent approximation</td>
</tr>
<tr>
<td>SL</td>
<td>Sea level</td>
</tr>
<tr>
<td>SMA</td>
<td>San Marcos Arch</td>
</tr>
<tr>
<td>SNUPAR</td>
<td>Schlumberger nuclear parameter code</td>
</tr>
<tr>
<td>SW</td>
<td>Southwest</td>
</tr>
<tr>
<td>TOC</td>
<td>Total organic carbon, (%)</td>
</tr>
<tr>
<td>TOC_DLogR</td>
<td>Total organic carbon estimated from DLogR, (%)</td>
</tr>
<tr>
<td>TST</td>
<td>Transgressive systems tract</td>
</tr>
<tr>
<td>UEF</td>
<td>Upper Eagle Ford</td>
</tr>
<tr>
<td>URU</td>
<td>Upper regressive unit</td>
</tr>
<tr>
<td>V/V</td>
<td>Volume fraction</td>
</tr>
<tr>
<td>VTI</td>
<td>Vertical transverse isotropy</td>
</tr>
</tbody>
</table>
WG : Wet gas well
XRD : X-Ray diffraction
Chapter 1: Introduction

Organic shales have gained attention in the petroleum industry in recent years because of their ability to store large amounts of oil and natural gas. With the increasing demand for energy, organic shale plays have become important resources to explore. New techniques, such as horizontal drilling and hydraulic fracturing, have enabled petroleum production in these energy resources previously overlooked as reservoirs. Many large shale plays such as Haynesville, Marcellus, Bakken, and Barnett are being actively explored and produced in the United States. The Eagle Ford shale (EFS) is one of the most recent and active shales in the petroleum industry and is the subject of this thesis.

1.1 Background

Shales are fine-grained sedimentary rocks initially known as source and cap rocks for conventional siliciclastic and carbonate reservoirs. They have, however, been acknowledged as unconventional reservoirs due to their low permeability and unconventional techniques for hydrocarbon production. Besides grain size and permeability, shales are also characterized by the presence of organic matter (OM) originating from buried living organisms.

Kerogen is the main component of OM and, under adequate temperature and pressure, it releases hydrocarbons (oil or gas) into the shale. To enable adequate hydrocarbon generation, shales have to be sufficiently rich in OM and buried deep enough to attain thermal maturity. Maturation stage is determined from thermal history or, more often, from vitrinite reflectance measurements (Tissot, 1984; Orr, 1983). Vitrinite reflectance increases as kerogen transitions from “immature” to “mature-oil
window” (in shale-oil reservoirs), then “mature-gas window” (in shale-gas reservoirs), and finally “overmature”. At the onset of hydrocarbon generation (oil window), kerogen is believed to develop OM pores (Loucks et al., 2012; Sondergeld et al., 2010; Ambrose et al., 2010; Curtis et al., 2010). However, the abundance of these pores varies, not only with increasing kerogen maturity, but also with kerogen type, amount, and lithofacies (Loucks et al., 2009; Milliken et al., 2013; Ozkan et al., 2013). Kerogen types are defined according to their origin: type I is algal, type II is marine, type III is terrestrial, and type IV is OM residue. With such diversity in kerogen characteristics, one wonders how kerogen properties affect well logs and other shale properties.

Because of their low permeability, shales need to be fractured to enable hydrocarbon flow into the borehole. Production flow is enhanced with natural or induced fractures, but is also governed by topology (connectivity) of the pores in shale. Both OM pores and matrix pores form a complex network for hydrocarbon storage and production. In shale reservoirs, gas can be either adsorbed on OM or free in matrix pores. Successful implementation of induced fractures requires good understanding of shale fracturability (ability to hold and propagate fractures). Fracturability is believed to be associated with rock properties such as mineral composition, brittleness, ductility, rock fabric (mineral and pore arrangements), kerogen maturity, and elastic properties; however, fracture development paths in shales are complex and not easily predictable unless development of stresses can be explained (King, 2010). This is because many shales display anisotropy and also because spatial variations in mineral composition and properties are rather common.

Due to the complex nature of mineralogy in shales and associated heterogeneity, accurate interpretation of well logs is necessary to estimate not only petrophysical properties, but also elastic properties. Mineralogy, porosity, facies determination, and
elastic properties help to identify ideal rocks for production in unconventional plays (Sondhi, 2011; Kale et al., 2010; Adiguna, 2012; Popielski, 2011). The amount and types of minerals, total organic carbon (TOC), and porosity are quantified by means of well log inversion (Adiguna, 2012; Popielski, 2011; Heidari, 2011) or measured directly from core plugs (Sondhi, 2011; Kale et al., 2010). The distribution of minerals, TOC, and porosity are believed to be related to depositional environment (Popielski, 2011; Hammes et al., 2011; Mullen, 2010). Furthermore, the spatial arrangement of the minerals, kerogen, and porosity is important in understanding how well a rock can hold a fracture open. Several effective medium theories have been developed to estimate elastic properties of rocks. Examples include Wyllie’s empirical equation (Wyllie et al., 1956, 1958), which takes a volume-weighted average of sonic travel time through each constituent of the rock without accounting for geometry; Berryman’s Self Consistent Approximation (SCA) theory (Berryman, 1980), which takes the various material shapes into account without defining a specific host material; and Berryman’s Differential Effective Medium (DEM) theory (Berryman, 1992), in which inclusions of a defined shape are incrementally added to a host material to determine elastic properties of the effective medium.

Heidari (2011) developed a nonlinear inversion technique that estimates mineralogy in thinly bedded formations such as shales. Adiguna (2012) subsequently utilized a mineral grouping method to reduce non-uniqueness of the nonlinear inversion technique. The nonlinear inversion and mineral grouping techniques were applied in the Haynesville and Barnett shales by the aforementioned authors. This thesis investigates the application of the same techniques to the EFS. For elastic property estimations, a combination of two theories, the SCA and the DEM, were shown by Montaut (2012) to provide good estimates in the Barnett and Haynesville shales. This thesis verifies the application of those theories to the EFS.
1.2 Objectives

The goals of this study are to (1) identify and compare effects of minerals, porosity, and kerogen characteristics (e.g., pore aspect ratio, clay type and abundance, and kerogen type, maturity, and topology) on petrophysical and elastic properties, and (2) identify best zones for horizontal well placement by recognizing rocks that exhibit suitable properties for successful hydrofracturing in the EFS. This is achieved by interpreting available conventional well logs and core data. First, the nonlinear inversion algorithm and the mineral grouping methodology are used to quantify mineral and fluid components in hydrocarbon-bearing shale intervals where core data have been acquired. Core data was used to calibrate the mineral volumetric compositions, organic richness, and storage properties estimated by the algorithm; they also provide an estimate of physical properties of kerogen and of complex minerals such as clays. Calibrated physical properties are then extended to wells devoid of core data. A forward simulation of the inversion results to obtain well logs such as Gamma-Ray (GR), Density, Neutron, Photoelectric Factor (PEF), and Resistivity is used to validate the results obtained in each well. A good agreement between simulated and field logs suggests a reliable estimate of petrophysical properties. Second, mineralogy results, kerogen content, and porosity are used to perform preliminary rock typing using k-means clustering. This rock typing enables classification of rocks in shale based on similarities in their petrophysical properties. Third, an elastic model is assumed for each rock type and used to estimate sonic velocities. Berryman’s DEM theory (1995) is used for elastic property estimations. Finally, favorable zones for fracture propagation are assessed based on the combined appraisal of rock petrophysical and elastic properties. Suitable properties include not only adequate porosity and hydrocarbon saturation, but also rock brittleness and its ability to propagate fracture.
1.3 **Outline**

Chapter 2 is an overview of the EFS, its underlying geology, and its geochemical characteristics. Chapter 3 describes the methods used for the well log interpretations including mineral and rock physics models, inversion method, mineral-based rock typing method, and elastic-petrophysical rock typing approach. Chapter 4 documents synthetic cases to evaluate the sensitivity of the methods to various petrophysical properties. Chapter 5 analyzes field cases from the EFS and discusses the results of the study. Finally, Chapter 6 concludes the study and offers suggestions for future work.
Chapter 2: Eagle Ford Shale Formation

The EFS is one of the most recently explored organic shale plays in the United States. Because it contains both liquid and gas, it is attractive to petroleum companies and thus offers more economical viability than other shale plays in the nation. With increasing drilling and hydraulic fracturing activities in the EFS, it is important to understand its mineral composition and fracturability across the play to determine the most favorable zones for well placement.

2.1 Reservoir Background

The EFS was first produced in 2007 by Apache from vertical well recompletions and deepenings. In 2008, Apache continued to produce from multi-fractured horizontals in the Northeast part of the play, but Petrohawk demonstrated the economic success of the Southwest portion of the play (Comisky, 2013). The EFS covers approximately 20,000 square miles (Railroad Commission of Texas, 2013) and lies between 4,000 and 15,000ft deep, with thickness ranging from 0 to over 400ft. Three petroleum windows are present in the shale: oil, wet gas/condensate, and dry gas windows, successively, as the shale deepens from the Northwest to the Southeast. Figure 2.1 shows the EFS geographic extent, its thickness, and the three petroleum windows. The shale extends Northeast from Maverick and Hawkville basins at the Texas-Mexico border, across the San Marcos Arch (SMA), and into the East Texas basin. The EFS is unconformably overlain by the Austin Chalk and overlies the Buda formation in the Southwest (SW) region and the Woodbine and Pepper shale in the Northeast (NE) region. It has been known to be the source rock for the Austin Chalk (Martin et al., 2011).
Figure 2.2 shows the different basins and other geological structures across the shale and Figure 2.3 is a stratigraphic chart of the western Gulf of Mexico margin, highlighting the EFS.

Figure 2.1. Eagle Ford shale map showing depth, thickness, and petroleum windows (U.S. Energy Information Administration, 2010).
Figure 2.2. Eagle Ford shale map displaying the geological structures across the play (Tuttle, 2010).
Figure 2.3. Stratigraphic chart of the western Gulf of Mexico margin highlighting the EFS (Driskill et al., 2012). LST: lowstand systems tract; TST: transgressive systems tract; HST: highstand systems tract; MFS: maximum flooding surface; SL: sea level.
The EFS was deposited in the Upper Cretaceous era (Liro et al., 1994). It is primarily composed of organic rich fossiliferous marine shale. It displays a complex geologic structure which varies based on its location relative to the SMA (Hentz and Ruppel, 2010). Figure 2.4 is a SW to NE cross section of the EFS showing the variation in thickness and geologic structure observed across the shale.

Southwest of the SMA, the EFS is divided into two stratigraphic units: a lower transgressive unit (LTU) and an upper highstand regressive unit (URU). The lower unit is made of dark shales, is well laminated, and contains minor bioturbation; it includes a condensed upper layer (Liro et al., 1994; Dawson, 2000) and accumulated in an anoxic, low energy environment, thus contains large quantities of organic matter. This transgressive unit is mostly oil-prone due to preservation of marine remains that constitute its organic matter. The upper unit consists of carbonates, siltstone, and calcareous shale interbeddings. It has large amounts of fossils and visible bioturbations (Dawson, 2000). It was deposited in more oxygenated conditions, which facilitates organism activity, and thus has low overall organic content. The regressive nature of the upper unit is associated with deposition of woody terrestrial, near-shore sediments, making its organic matter gas-prone. Variations in shale type in the upper unit (dark vs. calcareous) have been observed and associated with proximity to the coast (Liro et al., 1994, Martin et al., 2011). Figure 2.5 is an EFS outcrop image from the Lozier Canyon in West Texas, highlighting upper and lower EFS, underlying the Buda formation, and overlying the Austin Chalk. Figure 2.6 is a close-up view of the EFS. The dark material represents organic matter, which forms multiple visible layers concentrated at the bottom section of the outcrop. This bottom section corresponds to the lower EFS.

Northeast of the SMA, the EFS is devoid of the upper unit and is a combination of lower EFS and underlying Maness and Pepper shale facies (Hentz and Ruppel, 2010).
Figure 2.4. Southwest (SW)-Northeast (NE) cross section of the EFS (Hentz and Ruppel, 2011). The Southwest region consists of upper and lower units. The Northeast region consists of one unit. The two regions are separated by the San Marcos Arch.
Figure 2.5. Eagle Ford outcrop in Lozier Canyon, Northwest of Del Rio, West Texas (Photograph courtesy of Heidari, 2013).
Figure 2.6 Close-up view of lower Eagle Ford outcrop in Lozier Canyon, Northwest of Del Rio, West Texas (Photograph courtesy of Heidari, 2013).
2.2 Geochemical Properties

Organic richness in shale can be evaluated by measuring TOC content. The measurement is performed using two main analytical methods: Leco and Rock-Eval pyrolysis (Jarvie, 1991). In addition to TOC content, the Rock-Eval pyrolysis method provides information on kerogen type and maturity. Kerogen types are identified according to hydrogen to carbon (H/C) and oxygen to carbon (O/C) atomic ratios. The H/C ratio decreases from kerogen type I to type III whereas O/C ratio increases with kerogen type. Figure 2.7 shows the van Krevelen diagram typically used to identify kerogen types based on atomic ratios, and the associated hydrocarbon type. In the figure, the zones identified correspond to maturity intervals for each kerogen type.

In laboratory settings, H/C, O/C, and maturity can be estimated from hydrogen index, oxygen index, and Tmax, respectively. Hydrogen index is the amount of hydrocarbon (HC) per gram of TOC; oxygen index is the amount of carbon dioxide (CO₂) per gram of TOC; and Tmax is the temperature at which the maximum amount of hydrocarbon is generated through thermal cracking of organic matter.

In the EFS, kerogen type and maturity display variability with transgressive and regressive intervals (Liro et al., 1994; Dawson, 2000). Predominant kerogen types observed in the EFS by previous authors are II, mixture of II and III (usually referred to as II-III), and III (Liro et al., 1994; Edman and Pitman, 2010; Martin et al., 2011; Sondhi, 2011).

Figure 2.8 is a focused ion beam-scanning electron microscopy (FIB-SEM) image of a lower EFS well located in the Maverick basin (Shabro et al., 2013), displaying the complexity of the EFS. Black regions correspond to pore spaces, light gray is clay minerals, dark gray is kerogen, and light (white) corresponds to matrix grains (calcite). A
A couple of kerogen pores can also be observed in the image. Kerogen in this sample is type I or II according to the authors.

Figure 2.7. Van Krevelen diagram showing kerogen types and associated hydrocarbon products (Tissot, 1984).
Figure 2.8. FIB-SEM image of a Maverick basin lower EFS sample (modified from Shabro et al., 2013). Light gray: clay; dark gray: kerogen; black: pores.
Chapter 3: Methods

The assessment methods implemented in this thesis involve three steps. First, petrophysical properties (mineral volumetric concentrations, porosity and fluid saturation) are obtained using a nonlinear joint inversion algorithm. Second, different rock types are identified based on mineralogy results obtained from the inversion. Finally, rock elastic properties are estimated using the DEM theory. Mineral and elastic properties results in various wells are then compared to appraise variability. Figure 3.1 describes the workflow implemented for the estimation of petrophysical and elastic properties.
Figure 3.1. Workflow implemented in this thesis for the estimation of petrophysical and elastic properties.
3.1 Estimation of Mineral Concentration, Porosity, and Fluid Saturation

Organic shales usually exhibit complex mineralogy, which varies rapidly with depth. This variability, coupled with presence of kerogen, whose physical properties are not always known, render estimation of shale rock petrophysical properties particularly challenging. To estimate mineralogy in reservoirs including shales, commercial software provides options such as mineral solver or multiple regression methods. However, these options often fail to correct well logs for shoulder bed effects. A nonlinear inversion method was used instead to estimate shale petrophysical properties.

3.1.1 Nonlinear Joint Inversion Method

Heidari (2011) developed an algorithm to estimate mineralogy, porosity, and saturation from conventional well logs using a nonlinear joint inversion method. The method can be used in three modes: the first is applied in thinly bedded reservoirs and corrects for shoulder-bed effects and radial variations of fluid saturation caused by drilling mud filtrate invasion into the reservoir; the second is applied in thinly bedded formations with negligible mud filtrate invasion, estimates physical properties of each bed separately (layer-by-layer), and corrects logs for shoulder-bed effects; the third mode is applied in formations with thick beds and negligible invasion, requiring no correction to well logs for shoulder-bed effects or invasion. In shale formations, permeability is very low whereby mud filtrate invasion is negligible. Therefore, the layer-by-layer inversion method is most appropriate to estimate petrophysical properties in shales and was used in this study.

Available input logs to the inversion algorithm are density, neutron porosity, PEF, GR and spectral GR, and electrical resistivity. Bed boundaries are chosen based on
inflection points in either one or a combination of the named logs. Once individual layers are defined, separate inversion of well logs determines layer physical properties: density, migration length, PEF, total GR, uranium, thorium, and potassium concentrations, and electrical resistivity are obtained from their respective logs. Joint nonlinear inversion is then implemented to assess mineralogy, porosity and fluid saturations. The inversion method requires an initial guess for each petrophysical property. When core and XRD data are available, they can provide initial guesses; otherwise, initial guesses can be obtained from well logs. Mineral and fluid concentrations estimated from inversion are used in a forward simulation to simulate well logs. Density, migration length, and PEF of each layer are obtained using Schlumberger’s nuclear simulator SNUPAR (McKeon and Scott, 1989). SNUPAR invokes chemical composition, density, and volumetric concentration of each layer petrophysical constituent to determine layer properties. Total GR is determined from the linear combination of uranium, thorium, and potassium content in the layer. Electrical conductivity is calculated using a chosen resistivity model (Archie, Dual-Water, Poupon, etc.). A good agreement of simulated logs and volumetric concentrations with actual field logs and laboratory core data, respectively, verifies reliable petrophysical properties estimations.

### 3.1.2 Mineral and Fluid Model

Organic shales display a variety of minerals including quartz, calcite, plagioclase, potassium feldspar (k-feldspar), dolomite, pyrite, clays, and kerogen. Solving for all minerals, porosity, and fluid saturations using only the conventional well logs previously mentioned renders the inversion unstable and its results non-unique. Therefore, Minerals with negligible concentrations should be ignored or grouped with other minerals (Heidari,
Adiguna (2012) developed a mineral grouping method that reduces the number of unknowns hence improving inversion stability and reducing non-uniqueness of results. Figure 3.2 is a schematic representation of the mineral/fluid petrophysical model suggested by Adiguna (2012). The simplified mineral model consists of quartz-feldspar group (QF), carbonate group (CARB), clay group (CLA), and kerogen. Inversion estimates concentrations of these four mineral groups, porosity, and water saturation (Sw). Porosity represents total porosity including matrix and clay porosity. Water saturation is total water saturation including matrix, clay-bound, and capillary-bound water. Hydrocarbon saturation (Shc) is calculated from water saturation (Shc = 1-Sw).

<table>
<thead>
<tr>
<th>MINERALS</th>
<th>FLUIDS</th>
</tr>
</thead>
<tbody>
<tr>
<td>QF</td>
<td>WATER</td>
</tr>
<tr>
<td>CARB</td>
<td>HYDRO CARBON</td>
</tr>
<tr>
<td>CLA</td>
<td></td>
</tr>
<tr>
<td>KEROGEN</td>
<td></td>
</tr>
</tbody>
</table>

Figure 3.2. Schematic representation of mineral and fluid components used for nonlinear inversion of petrophysical properties in an organic shale formation. QF: quartz-feldspar group; CARB: carbonate group; CLA: clay group.

3.2 Petrophysical Classification of Reservoir Rocks

Rock typing in unconventional reservoirs can be performed using well logs (Popielski, 2011), core data (Sondhi, 2011; Kale et al., 2011) or mineral compositions (Montaut, 2012; Popielski, 2011; Sondhi, 2011; Kale et al., 2011). Mineralogy-based rock classification has been used by these researchers to identify rock types in Barnett,
Hayneville, and Eagle Ford shales. The “k-means” clustering method (MacQueen, 1967) implemented in the commercial software Interactive Petrophysics™ is used in this study to identify rock types. Inputs for clustering are mineralogy and porosity results obtained from the previously described inversion process. Mineralogy-based rock classification is preferred over the other two options for the following reasons: first, well logs are affected by shoulder-bed effects and averaging, therefore, well-log based cluster analysis can misclassify rock types in thinly-bedded areas of a reservoir (Popielski, 2011); second, core analysis-based classification would require coring of the entire reservoir, which can be tedious and impractical.

3.3 Estimation of Elastic Properties and Final Rock Typing

Elastic properties of each rock type are estimated by constructing a rock physics model and simulating sonic velocities. Sonic properties give insight to rock softness or brittleness, which in turn can help to identify favorable rocks for hydraulic fracturing.

3.3.1 Rock Physics Model

The rock model is constructed using an algorithm formulated by Montaut (2012). The frame of the model consists of a dry isotropic medium to which inclusions are added in sequence. In the algorithm, elastic moduli of the dry isotropic portion of the rock frame are obtained using a combination of SCA and DEM mixing laws. The SCA mixes two or more minerals without requiring that either mineral be a preferentially load bearing host. In the DEM method, one or two minerals are considered host material to which other minerals are incrementally added one after another. In the case where more than one mineral is assumed host in the DEM method, SCA is invoked to obtain elastic properties.
of the aggregate of host materials before implementing the DEM theory. In this study, however, a single host mineral is assumed, therefore, the SCA medium theory is not implemented in the model. The DEM is described as follows (Berryman, 1992):

\[
\begin{align*}
(1 - x) \frac{\partial}{\partial x} [K^*(x)] &= (K_2 - K^*)P^*^2(x) \\
(1 - x) \frac{\partial}{\partial x} [\mu^*(x)] &= (\mu_2 - \mu^*)Q^*^2(x)
\end{align*}
\]  

(3.1)

where \( K \) is bulk modulus, \( \mu \) is shear modulus, 1 and 2 refer to host and inclusion, respectively, \( x \) is volumetric fraction of the inclusion, \( P \) and \( Q \) are geometric coefficients defined in Table 3.1., and * represents the background medium; at initial conditions where \( x=0 \), the background medium is the host material.

| Table 3.1. Coefficients P and Q for spherical and penny crack shapes (Berryman, 1995). Subscripts m and i indicate background medium and i-th inclusion, respectively, and \( \alpha \) is penny crack aspect ratio. |
|---|---|
| **P^{mi}** | **Q^{ni}** |
| Sphere | \( \frac{K_m + \frac{4}{3}\mu_m}{K_1 + \frac{4}{3}\mu_m} \) | \( \frac{\mu_m + \zeta_m}{\mu_i + \zeta_m} \) |
| Penny Crack | \( \frac{K_m + \frac{4}{3}\mu_i}{K_1 + \frac{4}{3}\mu_i + \pi\alpha\beta_m} \) | \( \frac{1}{5} \left[ 1 + \frac{8\mu_m}{\pi\alpha(\mu_m + 2\beta_m)} + 2 \frac{K_1 + \frac{2}{3}(\mu_i + \mu_m)}{K_1 + \frac{4}{3}\mu_i + \pi\alpha\beta_m} \right] \) |

Notes: \( \beta = \frac{\mu}{(3K+4\mu)} \) and \( \zeta = \frac{\mu(9K+8\mu)}{6(K+2\mu)} \)
where $\beta$ and $\zeta$ are variables as defined in Table 3.1 for calculating geometric factors, and $\alpha$ is aspect ratio (ratio of short to long axes) of a penny crack. To construct the dry rock frame, each material is assigned a shape while porosity is added at the end of the process. The frame is then saturated with reservoir fluid using Gassmann’s theory (Gassmann, 1951) and sonic velocities are obtained from the elastic moduli as follows (Mavko et al., 2009):

$$
\begin{align*}
V_p &= \sqrt{\frac{K + \frac{4}{3}\mu}{\rho}}, \\
V_s &= \sqrt{\frac{\mu}{\rho}}.
\end{align*}
$$

(3.2)

where $V_p$ is compressional velocity, $V_s$ is shear velocity, $K$ is bulk modulus, $\mu$ is shear modulus, and $\rho$ is density of the saturated rock.

Because mineral compositions used to estimate elastic properties are computed from well logs that have been corrected for bed-boundary effects and averaging, they represent the true mineralogy for each layer. Consequently, the corresponding velocities calculated are non-averaged values. Therefore, averaging is necessary for comparison to field data and is performed as described by Montaut (2011) with a simple moving average of calculated velocities.

### 3.3.2 Elastic and Petrophysical Rock Typing

Rock typing based on elastic properties consists of identifying regions that exhibit favorable elastic properties (sonic velocities, bulk, shear, and Young’s moduli, and Poisson’s ratio). Young’s modulus, $E$, is calculated as follows:

$$
E = \frac{9K\mu}{3K + \mu},
$$

(3.3)
and Poisson’s ratio, $v$, is given by

$$v = \frac{3K - 2\mu}{2(3K + \mu)}.$$  \hspace{1cm} (3.4)

Brittle rocks display high Young’s modulus and low Poisson’s ratio and are preferable for hydrofracturing because they will hold fractures open upon release of fracturing pressure (Rickman et al., 2008; King, 2010). In contrast, ductile rocks heal and close fractures upon release of fracture pressure. It should be noted that Young’s modulus and Poisson’s ratio estimates are in the vertical direction. In an anisotropic shale such as the EFS, estimating elastic properties in all direction would provide a better appraisal of brittleness of the rocks. However, wells studied in this thesis are vertical and the layers are horizontal, therefore, only vertical elastic moduli are considered. Favorable rocks are identified based on a combination of their mineral composition, hydrocarbon saturation, and elastic moduli.
Chapter 4: Synthetic Cases

This chapter documents synthetic cases to study the effects of various shale properties on well logs. Synthetic cases are constructed to simulate kerogen content, type, and maturity observed in the EFS. Because kerogen does not have a specific formula, the effect of kerogen with different HI on well logs needs to be understood for log inversion purposes. Also, kerogen is less dense and softer than other shale minerals; consequently log response to kerogen may be similar to that of porosity. The synthetic cases analyze kerogen and porosity effects on well logs and also quantify material geometry (shape) effects on elastic properties.

4.1 Case 1: Effect of Kerogen and Porosity on Formation Properties

Synthetic Case 1 aims to study the effect of kerogen type and maturity and rock matrix porosity on formation nuclear and sonic properties. These effects are appraised by evaluating variations in nuclear properties and sonic velocities. Table 4.1 summarizes the volumetric concentrations assumed for each mineral group used to construct Synthetic Case 1. Kerogen types are defined using empirical formulas: C100H120O5 for type II and C100H85O8 for type III. Maturity is assumed defined by hydrocarbon type that kerogen generates: gas and oil for type III and II, respectively. Intervals XX00-XX15ft and XX15-XX30ft are similar in composition, but contain kerogen type III and II, respectively.
Table 4.1. Mineral composition assumed for Synthetic Case 1. The first three depth intervals study kerogen type III, whereas the last three intervals study kerogen type II. Grayed cells indicate changes in material concentrations with respect to values in depth intervals 1 and 4. CLA: clay group; KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; Sw: water saturation.

<table>
<thead>
<tr>
<th>Depth (ft)</th>
<th>CLA (V/V)</th>
<th>KER (V/V)</th>
<th>CARB (V/V)</th>
<th>QF (V/V)</th>
<th>Sw (V/V)</th>
<th>Porosity (%)</th>
<th>Kerogen type</th>
<th>Kerogen maturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>XX00-XX05</td>
<td>0.2</td>
<td>0.1</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.1</td>
<td>III</td>
<td>Gas</td>
</tr>
<tr>
<td>XX05-XX10</td>
<td>0.15</td>
<td>0.15</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.1</td>
<td>III</td>
<td>Gas</td>
</tr>
<tr>
<td>XX10-XX15</td>
<td>0.15</td>
<td>0.1</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.15</td>
<td>III</td>
<td>Gas</td>
</tr>
<tr>
<td>XX15-XX20</td>
<td>0.2</td>
<td>0.1</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.1</td>
<td>II</td>
<td>Oil</td>
</tr>
<tr>
<td>XX20-XX25</td>
<td>0.15</td>
<td>0.15</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.1</td>
<td>II</td>
<td>Oil</td>
</tr>
<tr>
<td>XX25-XX30</td>
<td>0.15</td>
<td>0.1</td>
<td>0.55</td>
<td>0.05</td>
<td>0.25</td>
<td>0.15</td>
<td>II</td>
<td>Oil</td>
</tr>
</tbody>
</table>

Figure 4.1 shows the results obtained for density, migration length, PEF, compressional velocity, and shear velocity. For velocity simulations (Vp and Vs), all materials are assumed spherical to exclude any effect of aspect ratio on the velocities. Results suggest that density, Vp, and Vs are predominantly affected by porosity and kerogen content, but not kerogen type or maturity; migration length is significantly
affected by kerogen type, whereas PEF is not significantly affected by either kerogen type, maturity, or matrix porosity.

Formation density is not greatly affected by kerogen type: less than 1.5% change in layer density is observed from kerogen type III to II and this change can be attributed to fluid density hence to kerogen maturity. It should be noted that kerogen density for both types was assumed equal to 1.3 g/cc. Kerogen concentration and matrix porosity, however, exhibit a slightly higher impact on density: 50% increase in kerogen and porosity volume fractions cause a decrease in density of about 3% and 5%, respectively.

Migration length is greatly affected by kerogen type and maturity. Approximately 14% decrease in migration length is observed from kerogen type III to type II. This behavior occurs because kerogen types differ in their hydrogen content. Neutron porosity is inversely proportional to migration length; therefore, an increase in neutron porosity is expected in rocks with type II kerogen.

Compressional and shear velocities, similarly to density, exhibit marginal changes with kerogen type (0.5% and 0.7% decrease in compressional and shear velocities, respectively), which can be attributed to the saturating hydrocarbon hence to kerogen maturity; a 50% increase in kerogen and porosity volume fractions cause approximately 1.6% and 2.6% increase in velocities, respectively.

Table 4.2 summarizes the parameters assumed for each component of the synthetic rock.
Figure 4.1. Calculated density, migration length, PEF, compressional velocity ($V_p$), and shear velocity ($V_s$) in Synthetic Case 1.
Table 4.2. Bulk modulus (K), shear modulus (µ), density, and chemical composition of mineral and fluid components of the synthetic rock. CLA: clay group; KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group.

<table>
<thead>
<tr>
<th>Unit</th>
<th>K</th>
<th>µ</th>
<th>Density</th>
<th>Chemical formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>CLA</td>
<td>21</td>
<td>7</td>
<td>2.9</td>
<td>K0.8Al1.6Fe0.2Mg0.2Si3.4Al0.6O10O2H2</td>
</tr>
<tr>
<td>KER</td>
<td>8</td>
<td>4</td>
<td>1.3</td>
<td>type II C100H120O5; type III C100H85O8</td>
</tr>
<tr>
<td>CARB</td>
<td>73</td>
<td>32</td>
<td>2.71</td>
<td>CaCO3</td>
</tr>
<tr>
<td>QF</td>
<td>36.6</td>
<td>45</td>
<td>2.65</td>
<td>SiO2</td>
</tr>
<tr>
<td>Gas</td>
<td>0.21</td>
<td>0</td>
<td>0.24</td>
<td>80% CH4, 20% C6H14</td>
</tr>
<tr>
<td>Oil</td>
<td>0.6</td>
<td>0</td>
<td>0.63</td>
<td>80% C16H34, 20% CH4</td>
</tr>
<tr>
<td>Water</td>
<td>2.2</td>
<td>0</td>
<td>1.07</td>
<td>H2O</td>
</tr>
</tbody>
</table>
4.2 Case 2: Effect of Material Aspect Ratio on Sonic Velocities

This synthetic case examines mineral aspect ratio and pore shape effects on compressional and shear velocities. The volumetric composition of the synthetic rock is 0.2 clay minerals, 0.1 kerogen, 0.55 carbonate, 0.05 quartz-feldspar, and 0.1 total porosity. Pore space is 75% gas-saturated. Velocities are calculated using the DEM model wherein mineral groups are added in the order in which they are listed above. All mineral and porosity are first assumed spherical; this assumption is considered a reference point. Each mineral group and porosity is then assumed ellipsoidal and their aspect ratios varied from 0 to 0.1, one mineral or porosity at a time. For example, as kerogen aspect ratio is changed, all other minerals and porosity remain spherical. Variations in compressional and shear velocities are then recorded as a percent change from the reference point.

Figure 4.2 summarizes the obtained results. Pore aspect ratio causes more variation in velocities than any individual mineral. The change is a decrease in velocities of up to 75% for compressional velocity and up to 100% for shear velocity as the pore-space aspect ratio approaches 0. Kerogen and QF cause negligible changes while CARB cause an increase of less than 10% in both velocities. Note that the observed percentage change in velocities for each material is expected to vary with rock composition and with host material; here, the synthetic rock is carbonate rich and clay minerals are the host material. However, regardless of composition and host material, the effect of pore aspect ratio was observed to remain dominant. Table 4.2 summarizes the parameters assumed for each component of the synthetic rock.
Figure 4.2. Percent change in compressional and shear velocities with varying mineral or pore aspect ratio. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on velocities. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.

4.3 DISCUSSION OF SYNTHETIC CASES

Synthetic case 1 suggests that well logs do not readily hint on the type of kerogen or hydrocarbon in the rock. However, neutron porosity logs may display high readings in the presence of type II kerogen, when clay properties are assumed constant with depth.
When geochemical data are not available for a well, choosing appropriate parameters for inversion can be challenging, but is important in securing convergence and accurate estimations. For example, assuming a type III kerogen instead of a type II may overestimate kerogen content. The clay mineral assumed here is illite; in field cases, once kerogen type is established, clay mineral composition can be adjusted to secure a good match between simulated and field neutron responses.

In Synthetic case 2, the pore aspect ratio greatly affects sonic logs to the extent that the effect of mineral and kerogen aspect ratio become insignificant. As a consequence, mineral and kerogen aspect ratios cannot be accurately predicted because estimation results would be non-unique. Porosity estimations from the inversion method, however, should be accurate to ensure reliable sonic simulations, hence, reliable elastic moduli estimation.
Chapter 5: Eagle Ford Shale Field Cases

This chapter documents field case studies undertaken in the EFS formation and evaluates various properties of the organic shale, including kerogen type and maturation, hydrocarbon produced, mineral and clay abundance and properties, and elastic properties.

5.1 Kerogen Characterization

Field case studies consist of six vertical wells available for this study: four are oil-producing (OW1, OW2, OW3, and OW4) and two are wet gas-producing (WG1 and WG2). The OW1 and WG1 wells are located NE of the SMA, and do not include the two distinct EFS geological units previously described (LTU and URU); these wells correspond to wells A and B, respectively, in Sondhi’s (2011) studies. The remaining wells, however, are in the SW region, thus include the two units LTU and URU, hereon referred to as lower Eagle Ford (LEF) and upper Eagle Ford (UEF), respectively. Figure 5.1 shows rock evaluation pyrolysis data obtained for four wells. The type and maturity of kerogen in the EFS vary from one well to another, but they are not dependent on the position of the well relative to the SMA. Predominant kerogen types are II, III, and a mixture of II-III. Maturity ranges from immature to postmature, with oil-producing wells falling within “immature” and “oil” windows, and gas-producing wells within “condensate-wet gas” and “dry gas” windows; few data points from well WG2 were observed to fall outside the wet and dry gas windows possibly due to measurements errors. Geochemical data acquired from laboratory measurements did not reveal significant changes in kerogen type and maturity with depth within individual wells, except for OW3, where UEF appears to have a mixture of type II and II-III immature
kerogen, and LEF exhibits type II mature-oil window kerogen. Table 5.1 summarizes the organic concentration and kerogen type and maturity within each well. For SW wells, LEF is more organic rich than UEF.
Figure 5.1. Kerogen types and maturity in four EFS wells. Types vary between II, II-III, and III. Maturity ranges from immature to postmature.
Table 5.1. Summary of organic concentration, kerogen type, and kerogen maturity by well and depth based on rock evaluation pyrolysis data. TOC: total organic carbon; UEF: upper Eagle Ford; LEF: lower Eagle Ford.

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth</th>
<th>TOC (average weight %)</th>
<th>Kerogen type</th>
<th>Kerogen maturity window</th>
</tr>
</thead>
<tbody>
<tr>
<td>OW1</td>
<td>-</td>
<td>3.27</td>
<td>II-III</td>
<td>Mature-oil</td>
</tr>
<tr>
<td>OW2</td>
<td>UEF</td>
<td>1.48</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>LEF</td>
<td>3.88</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OW3</td>
<td>UEF</td>
<td>2.96</td>
<td>II and II-III</td>
<td>Immature</td>
</tr>
<tr>
<td></td>
<td>LEF</td>
<td>7.98</td>
<td>II</td>
<td>Mature-oil</td>
</tr>
<tr>
<td>WG1</td>
<td>-</td>
<td>2.29</td>
<td>II-III</td>
<td>Mature-wet gas</td>
</tr>
<tr>
<td>WG2</td>
<td>UEF</td>
<td>2.16</td>
<td>III</td>
<td>Mature-oil/gas</td>
</tr>
<tr>
<td></td>
<td>LEF</td>
<td>4.98</td>
<td>III</td>
<td>Mature-oil/gas</td>
</tr>
</tbody>
</table>

TOC content is usually estimated from well logs using Passey’s DLogR method (Passey et al., 1990). The method estimates organic content by calculating the separation between resistivity and porosity logs when plotted together. Porosity can be density, neutron, or sonic, but the most commonly used is the sonic log. Separation (DLogR) is obtained using the empirical formula

\[
\text{DLogR} = \left(\frac{\text{RES}}{\text{RES}_{\text{base}}} \right) + 0.02 \times (\text{DTC} - \text{DTC}_{\text{base}}),
\]

where RES is the apparent resistivity, RES_{base} is apparent resistivity baseline value in non-organic shale, DTC is compressional sonic and DTC_{base} is compressional sonic baseline value in non-organic shale. TOC is then obtained in weight percent from DLogR using the formula
where LOM is level of organic metamorphism, a measure of thermal maturity. LOM can be estimated from vitrinite reflectance laboratory measurements or graphically, from a cross-plot of TOC and S2 measurements. S2 is the amount of hydrocarbon generated through organic matter thermal cracking and is measured in milligrams of hydrocarbon per gram of TOC (mg/g). Laboratory measured vitrinite reflectance were not available for the wells studied in this thesis; LOM values for TOC calculation was thus estimated using primarily the graphical method described by Passey et al. (1990).

Because of variability in kerogen types and maturity in the wells studied, Passey’s TOC estimation in EFS did not always provide good agreement with core data. Core TOC were measured using Leco method for wells OW1 and WG1, and Rock-Eval method for WG2 and OW3. Leco method provides a direct measurement of TOC whereas Rock-Eval pyrolysis method determines the carbon present in free hydrocarbon, convertible hydrocarbon in kerogen, and residual carbon. Challenges that may affect accurate TOC estimates include (1) estimation of LOM values without laboratory measured vitrinite reflectance, (2) identification of a wet shale baseline for resistivity and porosity logs, and (3) reliability of laboratory measurements.

Figure 5.2 is the TOC-S2 cross-plots for type III (5.2a) and type II (5.2b) kerogen for the approximation of LOM in four EFS wells. LOM is estimated at 10.5, 11.2, 10, and 4-6, for wells WG1, WG2, OW1, and OW3, respectively. Figure 5.3 shows the results obtained for WG2. TOC is underestimated in LEF section of the well when LOM is assumed 11.2 (Track 4). Estimation is improved when LOM in LEF is adjusted to 9.8 to match laboratory TOC data. This result suggests that kerogen maturity in WG2 is not uniform, but varies with transgressive and regressive units, as suggested by Liro et al. (1994). However, in OW3, TOC estimation can be obtained using a single LOM value

\[
TOC = D\log R \times 10^{(0.297 - 0.1688 \times LOM)},
\]
across the shale depth interval, but not the value predicted from the TOC-S2 cross-plot. LOM in this well was estimated at 9 using an average vitrinite reflectance value of 0.7, which was calculated from Rock-Eval pyrolysis Tmax values. Figure 5.4 shows results obtained for TOC in well OW3. Using LOM values of 4-6 suggested from Figure 5.2b largely overestimates TOC. The reason for this inconsistency is unclear but could be because kerogen type is a mixture of types II and III, whereas Passey’s TOC-S2 cross-plot is for a type II kerogen. Overall, regardless of kerogen type, level of maturity does not appear to depend on location of the well relative to the SMA (i.e. NE vs. SW), but is slightly higher in the wet gas wells than in the oil wells.
Figure 5.2. Level of organic metamorphism estimation for (a) type III, and (b) type II kerogen in four EFS wells. Cross-plots adopted from Passey et al. (1990).
Figure 5.3. Total organic carbon estimation in well WG2. Track 1: depth; Track 2: total and uranium-free gamma-ray; Track 3: DLogR separation; Track 4: TOC from core (dots) and estimated TOC using a constant LOM value of 11.2 (solid line); Track 5: TOC from core (dots) and estimated TOC using a LOM value of 11.2 for upper Eagle Ford and 9.8 for lower Eagle Ford (dotted line).
Figure 5.4. Total organic carbon estimation in well WG2. Track 1: depth; Track 2: total and uranium-free gamma-ray; Track 3: DLogR separation; Track 4: TOC from core (dots) and estimated TOC using LOM value of 9 (solid line).
5.2 ESTIMATION OF PETROPHYSICAL PROPERTIES AND MINERAL COMPOSITION

Mineralogy of the EF wells was determined using the previously described layer-by-layer nonlinear inversion method. Conventional well logs (density, neutron, PEF, and electrical resistivity) were used as input to the algorithm. Because thorium and potassium content vary in clay minerals, and uranium content in kerogen and clays, GR and spectral GR logs can be excluded from the inversion (Adiguna, 2012). However, uranium-free gamma ray, upon calibration to core data, provided an initial guess for volumetric concentration of clay minerals to initiate the inversion.

5.2.1 EF Mineral and Fluid Model

The EFS exhibits a variety of minerals including chlorite, kaolinite, illite, mixed illite/smectite (MxIS), calcite, dolomite, quartz, k-feldspar, plagioclase, pyrite, apatite, siderite, marcasite, and kerogen. Table 5.2 summarizes the average weight percent and mineral value ranges obtained from X-ray diffraction (XRD) measurements in three wells and Fourier Transform Infrared spectroscopy (FTIR) measurements in one well. Calcite is the predominant mineral present in EFS (over 56% by weight), followed by clay minerals (~ 20%) and silicates (~ 16%). Other minerals are present in minor quantities.

Figure 5.5 is a pie chart representation of minerals contained in four EFS wells. It shows the average weight percentage of each mineral identified in the core samples.
Table 5.2. Average weight percentage of the minerals detected with XRD measurements in three EFS wells and FTIR in one well. Calcite is the predominant mineral in EFS.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Average weight (%)</th>
<th>Range (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chlorite</td>
<td>0.95</td>
<td>0- 8</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>4.37</td>
<td>0-23</td>
</tr>
<tr>
<td>Illite</td>
<td>6.32</td>
<td>0-20</td>
</tr>
<tr>
<td>Mixed Illite/Smectite</td>
<td>8.87</td>
<td>0-67</td>
</tr>
<tr>
<td>Calcite</td>
<td>56.67</td>
<td>2-95</td>
</tr>
<tr>
<td>Dolomite</td>
<td>1.99</td>
<td>0-45</td>
</tr>
<tr>
<td>Quartz</td>
<td>12.51</td>
<td>2-29</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>1.28</td>
<td>0-8</td>
</tr>
<tr>
<td>Plagioclase</td>
<td>2.75</td>
<td>0-29</td>
</tr>
<tr>
<td>Pyrite</td>
<td>4.54</td>
<td>0-36</td>
</tr>
<tr>
<td>Siderite</td>
<td>0.06</td>
<td>0-1</td>
</tr>
<tr>
<td>Marcasite</td>
<td>0.05</td>
<td>0-2</td>
</tr>
<tr>
<td>Apatite</td>
<td>0.24</td>
<td>0-5</td>
</tr>
</tbody>
</table>
Figure 5.5. Pie chart showing the average weight percent of minerals detected from core samples in four EFS wells. MxIS: mixed illite/smectite clays.
Clay type was observed to vary greatly with wells. Figure 5.6 shows the normalized weight percent average and range of four clay types in three different wells. The concentration of each clay type appears to vary significantly from one well to another.

![Figure 5.6. Normalized weight percent average and range of four clay types in three EFS wells. There is significant variability in clay types in the wells. MxIS: mixed illite/smectite clays.](image)

Figure 5.7 describes the mineral grouping model implemented for EFS wells. The QF group consists of quartz, k-feldspar, and plagioclase; the CARB group consists of calcite, dolomite, and siderite; KER is kerogen; and CLA group designates clays and all
remaining minerals. Water saturation corresponds to total water saturation including matrix, clay-bound, and capillary-bound water. Hydrocarbon is either oil or gas depending on kerogen maturity window. Any kerogen porosity present is assumed to be part of the total porosity estimation.

<table>
<thead>
<tr>
<th>MINERALS</th>
<th>FLUIDS</th>
</tr>
</thead>
<tbody>
<tr>
<td>QF: Quartz K-feldspar Plagioclase</td>
<td>CARB: Calcite Dolomite Siderite</td>
</tr>
<tr>
<td>CLA: Chlorite Kaolinite Illite MxIS Pyrite Apatite Marcasite</td>
<td>KER: Kerogen</td>
</tr>
<tr>
<td>WATER</td>
<td>HYDRO CARBON</td>
</tr>
</tbody>
</table>

Figure 5.7. EFS mineral and fluid model. QF: quartz-feldspar group; CARB: carbonate group; KER: kerogen; CLA: clays and all remaining minerals; MxIS: mixed illite/smectite clays.

To account for kerogen type and maturity, hydrocarbon type, and clay variability while minimizing the number of unknown parameters in the inversion algorithm, a set of formulas and properties was assigned to kerogen and hydrocarbon. Clay properties were then determined by calibrating core data to available well logs (Adiguna, 2012). Table 5.3 summarizes the composition assumed for kerogen and hydrocarbon types. Kerogen does not have a unique formula, therefore, empirical formulas of the form CnHmOp were assumed, wherein n, m, and p represent the number of carbon, hydrogen, and oxygen atoms, respectively. To honor kerogen type in each well, HI of kerogen is modified by changing the values of m. Higher values of m indicate high HI and kerogen,
consequently, would be of type II. Lower values, on the other hand, are indicative of type III kerogen. Formulas for other minerals are obtained from Schlumberger’s Log Interpretation Chart Book (Schlumberger, 2009; Adiguna, 2012).

Table 5.3. Chemical formulas and density assumed for kerogen and hydrocarbon types.

<table>
<thead>
<tr>
<th>Kerogen type II</th>
<th>CnH1.2nO0.05n</th>
<th>1.3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kerogen type II-III</td>
<td>CnHnO0.08n</td>
<td>1.3</td>
</tr>
<tr>
<td>Kerogen type III</td>
<td>CnH0.85nO0.08n</td>
<td>1.3</td>
</tr>
<tr>
<td>Oil</td>
<td>80% C16H34, 20% CH4</td>
<td>0.63</td>
</tr>
<tr>
<td>Wet Gas</td>
<td>80% CH4, 20% C6H14</td>
<td>0.24</td>
</tr>
</tbody>
</table>

Table 5.4 summarizes the parameters assumed in the inversion algorithm in each well. The resistivity model used in the calculation of water saturation is that of Archie. Connate water salinity was estimated at 165,000 ppm NaCl equivalent and porosity and saturation exponents (m and n) were estimated by calibrating core salinity and porosity to field resistivity measurements. CLA group density and composition were estimated from mineral grouping and calibration to neutron log responses, respectively.
Table 5.4. Petrophysical parameters used for estimating mineralogy, porosity, and saturation in six EFS wells. Parameters a, m, and n are Archie’s Winsauer factor, porosity exponent, and saturation exponent, respectively, calibrated to core data. The first value of n corresponds to the high resistivity zone and lower Eagle Ford unit in NE and SW wells, respectively; second value of n corresponds to the remaining intervals. Density is given in g/cc and salinity in NaCl equivalent parts per million (ppm).

<table>
<thead>
<tr>
<th>Water density</th>
<th>WG1</th>
<th>WG2</th>
<th>OW1</th>
<th>OW2</th>
<th>OW3</th>
<th>OW4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water salinity</td>
<td>165,000</td>
<td>165,000</td>
<td>165,000</td>
<td>165,000</td>
<td>165,000</td>
<td>165,000</td>
</tr>
<tr>
<td>a</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>m</td>
<td>1.8</td>
<td>2.1</td>
<td>1.8</td>
<td>2.1</td>
<td>1.8</td>
<td>2.1</td>
</tr>
<tr>
<td>n</td>
<td>2.1 / 2</td>
<td>2 / 2.1</td>
<td>2.1 / 2</td>
<td>2 / 2.1</td>
<td>2 / 2.1</td>
<td>2 / 2.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Kerogen type</th>
<th>III</th>
<th>III</th>
<th>II-III</th>
<th>II-III</th>
<th>II</th>
<th>II-III</th>
</tr>
</thead>
<tbody>
<tr>
<td>CLA group composition</td>
<td>70% Illite</td>
<td>95% Illite</td>
<td>70% Illite</td>
<td>75% Illite</td>
<td>85% Illite</td>
<td>75% Illite</td>
</tr>
<tr>
<td></td>
<td>12% FeChlorite</td>
<td>5%</td>
<td>12% FeChlorite</td>
<td>25% FeChlorite</td>
<td>5% FeChlorite</td>
<td>25% FeChlorite</td>
</tr>
<tr>
<td></td>
<td>18% Kaolinite</td>
<td>Montmorillonite</td>
<td>18% Kaolinite</td>
<td>10% Kaolinite</td>
<td>10% Kaolinite</td>
<td></td>
</tr>
</tbody>
</table>

| CLA group density | 2.95 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 |

| Shale porosity | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
5.2.2 Mineralogy Results and Discussion

Figures 5.8 to 5.13 describe the petrophysical properties obtained for all six wells. Figures 5.8 and 5.9 correspond to the wet-gas wells and Figures 5.10-5.13 correspond to the oil wells.

As observed in Figures 5.8 and 5.10, results from wells in the NE region of the EFS (wells WG1 and OW1, respectively) indicate that EFS is clay rich (Track 7). Total porosity (Track 6) slightly decreases with depth, possibly due to increased carbonate content. The lower section displays a carbonate-rich interval (X120-X220ft for WG1 and X120-X160ft for OW1) which also exhibits low water saturation and high organic content. This interval corresponds to a hydrocarbon region where the organic layer of the EFS thins out. High resistivity readings (Track 3) are observed within this interval of the shale. The overall high water saturation (> 0.5) in the region could be attributed to the abundance of clay, hence an increase in clay-bound water.

Figures 5.9 and 5.11-5.13 describe the results obtained for the wells in the SW region of the EFS. In these wells, total porosity increases with depth (Track 6), water saturation decreases with depth (Track 5), and clay content is much lower than that in the NE wells. The estimated mineralogy shows highly calcareous lithology with a lower organic-rich region. In each well, this high-porosity, organic-rich region corresponds to the LEF. Organic richness in this section is consistent with increased TOC values observed in rock evaluation pyrolysis data.

Figure 5.14 describes mineralogy results from each well in ternary diagram form. Mineral group values are normalized without kerogen and are given in weight percent. As shown, wells in the NE region (OW1 and WG1) display data points close to the “clays” vertex, whereas wells in the SW region (all remaining wells) exhibit data points
predominantly close to the “carbonate” vertex. Mineralogy differences within the EFS across geographic locations suggest different depositional environments. According to Condon and Dyman (2006), the NE region subsided less than the SW region in the late Cretaceous, which suggests shallow, high-clay deposits in the NE and deep, carbonate-rich deposits in the SW. The kerogen maturity window does not appear to relate to mineral composition. For example, there are no immediate similarities in mineralogy between wet gas wells in the SW and NE regions.
Figure 5.8. Petrophysical description of wet gas well WG1. The high resistivity interval (~X120-X220ft) corresponds to an area of low water saturation, high carbonate, and high kerogen content. Porosity slightly decreases with depth.

Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation and core water saturation; Track 6: estimated porosity and core porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Figure 5.9. Petrophysical description of wet gas well WG2. Porosity and organic content increase in the lower section, which corresponds to the lower unit of the EFS. Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation and core water saturation; Track 6: estimated porosity and core porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Figure 5.10. Petrophysical description of oil well OW1. Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation and core water saturation; Track 6: estimated porosity and core porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Figure 5.11. Petrophysical description of oil well OW2. Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation and core water saturation; Track 6: estimated porosity and core porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Figure 5.12. Petrophysical description of oil well OW3. Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation and core water saturation; Track 6: estimated porosity and core porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Figure 5.13. Petrophysical description of oil well OW4. Track 1: depth; Track 2: total and uranium-free gamma ray logs; Track 3: apparent resistivity logs; Track 4: PEF, density, and neutron porosity (limestone matrix) logs; Track 5: estimated water saturation; Track 6: estimated porosity; Track 7: estimated mineralogy in volumetric concentration (Vc); Track 8: bulk volume.
Northeast wells (Wells OW1 and WG1) are clay-rich, whereas Southwest wells are carbonate-rich.
5.3 ROCK TYPING

Rock types in the EFS are classified based on their relative volumetric concentrations of carbonate, clay, kerogen, and porosity. Table 5.5 summarizes the rock types obtained through k-means clustering. Mean values of each mineral and porosity are shown in the table. In all the wells, rock type (RT) 1 represents the organic rich rock. In the SW wells, RT1 has a higher amount of clay, lower carbonate content, and higher porosity than RT2. By contrast, in the NE wells, RT1 is clay-poor relatively to RT2.

Table 5.5. Average volumetric concentrations of mineral groups and porosity in six EFS wells according to rock types and geographic region. CLA: clay group; CARB: carbonate group; KER: kerogen; RT: Rock type; NE: Northeast; SW: Southwest.

<table>
<thead>
<tr>
<th>Rock type</th>
<th>Region</th>
<th>Well</th>
<th>CLA (V/V)</th>
<th>CARB (V/V)</th>
<th>KER (V/V)</th>
<th>POROSITY (V/V)</th>
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<td>RT1</td>
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<td></td>
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<tr>
<td></td>
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<td>0.62</td>
<td>0.1</td>
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<tr>
<td></td>
<td></td>
<td>OW2</td>
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<td>0.06</td>
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<td></td>
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<td>0.07</td>
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<tr>
<td>RT2</td>
<td>NE</td>
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<td>0.25</td>
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<tr>
<td></td>
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carbonate-rich, and has lower porosity than RT2; RT1 is the main rock type found in the LEF in SW wells and in the organic layer in NE wells. In both regions, RT1 is associated with relatively low values of water saturation (~20% in the SW and ~48% in the NE), and thus high hydrocarbon saturation. Water saturation in RT2 is relatively high, ~35% in SW and ~58% in NE on average; therefore, RT1 can be considered a better candidate for hydrocarbon production. However, elastic property estimation is necessary to assess fracturability. Such estimation is performed in the subsequent section.

5.4 Elastic Property Estimation

Isotropic compressional and shear velocities and elastic moduli are estimated using Berryman’s DEM method implemented by Montaut (2012). This method uses mineral composition, porosity, and fluid saturation to estimate elastic properties. When sonic logs are not available in a well, elastic moduli can be obtained by applying the DEM model from wells with similar petrophysical properties and calibrated elastic properties.

5.4.1 Logs and Mineral Correlations

Compressional and shear velocities in the studied wells can be calculated from the inverse of the borehole compressional and shear sonic logs, respectively, when available. Because the wells are vertical and layers are horizontal, velocities reported here are vertical velocities (wave propagation is perpendicular to formation bedding plane). Figure 5.15 shows the correlation observed between log-based calculated sonic velocities and minerals and porosity obtained in four wells. A positive correlation is observed between sonic velocities and volumetric concentration of carbonate (CARB). A negative
correlation is observed between velocities and clay group (CLA), and between velocities and porosity (POR). The relation between velocities and kerogen (KER), however, is not uniform across the EFS: positive correlation is observed for NW wells, whereas SW wells display negative correlation. Velocities in the NE wells are generally lower than those in the SW wells. Considering that the porosity range (~0.02-0.16) is similar in both regions, softness in the NE wells could be attributed to (1) high water saturation and (2) clay type.
Figure 5.15. Left: cross-plot of compressional velocity from sonic logs (Vp) with minerals and porosity obtained from inversion. Right: cross-plot of shear velocity from sonic logs (Vs) with minerals and porosity from inversion; POR: porosity; CARB: carbonate group; CLA: clay group; KER: kerogen; Blue data points are for two wells from the SW region (OW2 and WG2) and brown data points are for two wells from the NE region (OW1 and WG1).

Figure 5.16 is a plot of available compressional velocities, resistivity, and density logs from EFS wells. Depths are normalized to begin from the top of the Buda formation for better comparison of various wells. Only the last 140 ft of EFS in each well are displayed in the figure. We observe that Vp, but mostly Vs in the NE region display the lowest values. As a consequence the Vp/Vs ratio in the region is distinctly higher. Resistivity values are also distinctly lower in the region, further attesting that high water saturation is a plausible factor contributing to the slowness of the rock. No obvious relationship between kerogen maturity and well log responses can be observed because wet-gas window wells (WG1 and WG2) cannot be distinguished from oil-window wells (OW1 to 4) from the corresponding well logs. Density logs in all wells mostly overlap, but low density values are observed in the LEF section, where porosity and kerogen
content increase. Figure 5.17 shows the correlation between kerogen concentration and well logs in the form of cross-plots.
Figure 5.16. Compressional velocities (Vp), shear velocities (Vs), Vp/Vs ratio, resistivity, and density measurements acquired in six EFS wells. Northeast wells (WG1 and OW1) display lower Vs and resistivity values than the Southwest wells. Reference depth (0ft) is the top of the underlying Buda formation.
Figure 5.17. Correlation between kerogen concentration and available resistivity, density, compressional velocity ($V_p$) and shear velocity ($V_s$) logs in EFS wells. Red data points designate wells in the wet-gas maturity window while green data points designate wells in the oil maturity window.
5.4.2 EF Elastic Model

The EFS has been found to exhibit vertical transverse isotropy (VTI) in elastic properties at some depths (Sondhi, 2011). However, because wells studied in this thesis are vertical and VTI anisotropy cannot be detected from well logs, the elastic model used here for simulations is assumed isotropic. Sonic velocities are simulated using the DEM theory, where constituents of the rock are added in the following order: CLA, KER, CARB, QF, and porosity. This order suggests CLA as host material and all others as inclusions. Low velocities in the EFS indicate that a soft material such as clay can be assumed to be the host. The order in which minerals are added does not necessarily represent the depositional sequence of rock materials (Montaut, 2012; Mavko et al., 2009), but merely a model that best reproduces sonic velocities from well logs and that can be extrapolated to wells devoid of sonic logs.

Figure 5.18 describes the sensitivity of sonic velocities, Young’s modulus, and Poisson’s ratio to changes in volumetric concentration of minerals and porosity. Sensitivity is appraised as a percent change in these properties when mineral or porosity concentration obtained from the inversion is increased up to 10% of the original mineral or porosity concentration. The mineral composition assumed is the same as that in Synthetic Case 2 in section 4.2. Pore aspect ratio is assumed equal to 0.06. Less than 1% change in sonic velocities, Young’s modulus, and Poisson’s ratio is observed for increased quartz-feldspar and kerogen concentration estimates. Approximately 5% change in velocities is observed with 10% increase in CARB concentration; meanwhile, this increase causes up to 9.5% increase and 2.1% decrease in Young’s modulus and Poisson’s ratio, respectively. For porosity, the greatest effect observed was on Young’s modulus with over 6% decrease in value. These results suggest that reliable estimation of carbonate content and porosity is needed for calculation of elastic properties.
Because velocities and elastic moduli are mostly sensitive to pore aspect ratio, mineral groups are assumed spherical while porosity is composed of ellipsoidal inclusions. The aspect ratio of the ellipse is then modified to secure a good agreement with field data. Table 5.6 summarizes elastic constants and pore aspect ratio used to simulate sonic velocities in the EFS wells. Pore aspect ratio varies from one well to another and sometimes within the same well. This variation can be associated with rock types present (e.g. OW1) or to geological units (e.g. OW2 and OW4) in the shale. It is possible that pore aspect ratio be related to pore pressure and fracturability of the rock. A small pore aspect ratio could indicate that ellipsoid pores would provide points of mechanical weaknesses along their long axis; therefore, pores would create a preferential path for fracture propagation if they were aligned. However, high pore aspect ratio indicates high values of Young’s modulus, and, therefore, a stiff rock; such rock is preferred for hydrofracturing if pore alignment can be confirmed using an anisotropic elastic model. Bulk and shear moduli of the CLA group are adjusted in each well for best results. Variations in CLA properties and pore aspect ratio suggest heterogeneity within the EFS. Hydrocarbon bulk modulus in the NE wells required a higher value than that of SW wells to secure a good agreement between DEM- and log-based simulations. Variation in kerogen type and maturity did not provide conclusive evidence concerning kerogen impact on rock fracturability.
Figure 5.18. Sensitivity of compressional velocity (Vp), shear velocity (Vs), Young’s modulus (E), and Poisson’s ratio (v) to changes in volumetric concentration (Vc) of minerals and porosity. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material; pore aspect ratio is 0.06.
Table 5.6. Summary of elastic properties and pore aspect ratio used to simulate sonic velocities in six EFS wells. Shear modulus of hydrocarbon and water is 0. Densities of hydrocarbons and water are the same as those listed in Tables 5.3 and 5.4, respectively. Elastic moduli and density of kerogen, carbonate, and quartz-feldspar groups are as listed in Table 4.2. CLA: clay group; RT: rock type; UEF: upper Eagle Ford; LEF: lower Eagle Ford.

<table>
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<th>Unit</th>
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<th>WG2</th>
<th>OW1</th>
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<th>OW3</th>
<th>OW4</th>
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<td>2.2</td>
<td>2.2</td>
<td>2.2</td>
<td>2.2</td>
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</tr>
<tr>
<td>Hydrocarbon bulk modulus</td>
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<td>0.6</td>
<td>0.9</td>
<td>0.6</td>
<td>0.6</td>
<td>0.6</td>
</tr>
<tr>
<td>CLA group bulk modulus</td>
<td>GPa</td>
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<td>21</td>
<td>80</td>
<td>21</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>CLA group shear modulus</td>
<td>GPa</td>
<td>4</td>
<td>7</td>
<td>4</td>
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<td>4</td>
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<tr>
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<td></td>
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<td>0.055</td>
<td></td>
<td>RT1 0.05</td>
<td>UEF 0.045</td>
<td></td>
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<tr>
<td></td>
<td></td>
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<td></td>
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<td>LEF 0.06</td>
<td>0.1</td>
<td>LEF 0.06</td>
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</table>
5.4.3 Results and Discussion concerning Elastic Properties

Figures 5.19 to 5.30 describe the reproduction of field sonic velocities and elastic moduli obtained for the EFS wells, their corresponding mineralogy, saturation, and rock types. Velocities follow closely the trend of the porosity log (POR) in each well (Figures 5.19, 5.21, 5.23, 5.25, 5.27, and 5.29). This is because, as observed in Synthetic Case 2 (in Chapter 4), porosity appears to have a greater effect on velocities than mineral concentrations do. Elastic moduli estimates from well logs could be reproduced with the DEM model. However, Poisson’s ratio was reproduced better in the NE wells (Figures 5.20 and 5.22) than in the SW wells (Figures 5.24 and 5.26): less than 5% matching error was recorded in the NW versus over 13% average error in the SW. Mismatch of Poisson’s ratio from well logs and DEM model was also observed by Montaut (2011) and attributed to high sensitivity of Poisson’s ratio to errors in sonic measurements. For wells without compressional and shear sonic logs (wells OW3 and OW4), elastic properties are estimated from matching the compressional velocity log only (well OW3 in Figure 5.27 and 5.28), or from implementing the parameters assumed in Table 5.6 (well OW4 in Figures 5.29 and 5.30).

Figures 5.31 to 5.36 describe the sensitivity of Young’s modulus and Poisson’s ratio to pore and mineral aspect ratios in the six wells. The percent changes are given with respect to elastic moduli values of a model with spherical minerals and pores. Volumetric compositions used for the sensitivity analysis in each well are listed in Table 5.7. Quartz-feldspar, carbonate, and kerogen aspect ratios cause negligible changes in elastic moduli (nearly horizontal lines are observed in each well). Pore aspect ratio causes the most significant effect on elastic properties. This observation is consistent with results from Synthetic Case 2 in section 4.2. Percentage change in Young’s modulus varies
between 10 and 100% decrease, and Poisson’s ratio varies between a 40% decrease and a 90% increase, as pore aspect ratio is changed from 0.1 to 0. These results suggest that the estimated elastic properties have a greater dependence on pore shape than kerogen and mineral shapes. As pore aspect ratio decreases, rocks may develop hidden mechanical weaknesses which may result in natural fractures. These natural fractures would provide paths for hydrocarbon migration into conventional reservoirs; such migration could then cause reduction in pore pressure in the source rock.

Silica- and carbonate-rich rocks are known to be more brittle than clay-rich rocks, whereby EFS rocks are favorable for hydraulic fracturing (Bazan et al., 2012; Henning et al., 2010). Figure 5.37 is a cross-plot of Poisson’s ratio and Young’s modulus estimated from available well logs and from the DEM method. High Young’s modulus and low Poisson’s ratio are indicative of brittle rocks. Rocks in the SW are more brittle than those in the NE, which makes the SW region more attractive for hydrofracturing. The average Young’s modulus and Poisson’s ratio are ~36GPa and ~0.26, respectively, in SW wells, and ~18GPa and ~0.4, respectively, in NE wells. Figure 5.38 is a cross-plot of estimated Young’s modulus from the DEM method and volumetric concentration of kerogen and carbonate. Because Poisson’s ratio obtained with the DEM method was not accurately reproduced in all wells, it is not being used to assess brittle rocks in the EFS. Much like the correlations observed in section 5.4.1 between sonic velocities and material volumetric concentration, Young’s modulus correlates with kerogen concentration in the NE wells, but anti-correlates in the SW wells; Young’s modulus and carbonate concentration also exhibit a positive correlation. The approximate location of RT1 is indicated on the cross-plots (RT1 was previously shown in section 5.3 to possess higher hydrocarbon saturation than RT2). As observed in Figure 5.38, in NE wells (brown data points) RT1 exhibits the highest values of Young’s modulus in the region (over 18 GPa).
The corresponding depth intervals in WG1 and OW1 are X160-X185ft and X130-X150ft, respectively. Unlike these two wells, the SW wells do not necessarily display the highest sonic velocities (or carbonate concentration) in preferred RT1 rocks in the region; however, Young’s modulus values average over 21GPa. Intervals of interest for hydrofracturing are identified as X370-395ft, X160-X190ft, X000-X060ft and X510-X540ft for wells WG2, OW2, OW3, and OW4, respectively.

In this thesis, the Young’s modulus used for interpretation is the dynamic Young’s modulus. Dynamic (log derived) Young’s modulus displays a strong correlation with static (core derived) Young’s modulus (Britt and Schoeffler, 2009; King, 2010); using dynamic properties to appraise brittleness is therefore reliable.
Figure 5.19. Vertical distribution of compressional and shear velocities in well WG1. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: compressional velocities from sonic logs (Vp_LOG) and from averaged DEM model (Vp_AVE); Track 4: shear velocities from sonic logs (Vs_LOG) and from averaged DEM model (Vs_AVE); Track 5: estimated mineralogy in volumetric concentration (Vc); Track 6: bulk volume; Track 7: mineralogy-based rock typing.
Figure 5.20. Vertical distribution of elastic properties in well WG1. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: bulk modulus from sonic logs (K_LOG) and from averaged DEM model (K_AVE); Track 4: shear modulus from sonic logs (G_LOG) and from averaged DEM model (G_AVE); Track 5: Young’s modulus from sonic logs (E_LOG) and from averaged DEM model (E_AVE); Track 6: Poisson’s ratio from sonic logs (v_LOG) and from averaged DEM model (v_AVE).
Figure 5.21. Vertical distribution of compressional and shear velocities in well OW1. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: compressional velocities from sonic logs (Vp_LOG) and from averaged DEM model (Vp_AVE); Track 4: shear velocities from sonic logs (Vs_LOG) and from averaged DEM model (Vs_AVE); Track 5: estimated mineralogy in volumetric concentration (Vc); Track 6: bulk volume; Track 7: mineralogy-based rock typing.
Figure 5.22. Vertical distribution of elastic properties in well OW1. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: bulk modulus from sonic logs (K_LOG) and from averaged DEM model (K_AVE); Track 4: shear modulus from sonic logs (G_LOG) and from averaged DEM model (G_AVE); Track 5: Young’s modulus from sonic logs (E_LOG) and from averaged DEM model (E_AVE); Track 6: Poisson’s ratio from sonic logs (v_LOG) and from averaged DEM model (v_AVE).
Figure 5.23. Vertical distribution of compressional and shear velocities in well WG2. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: compressional velocities from sonic logs (Vp_LOG) and from averaged DEM model (Vp_AVE); Track 4: shear velocities from sonic logs (Vs_LOG) and from averaged DEM model (Vs_AVE); Track 5: estimated mineralogy in volumetric concentration (Vc); Track 6: bulk volume; Track 7: mineralogy-based rock typing.
Figure 5.24. Vertical distribution of elastic properties in well WG2. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: bulk modulus from sonic logs (K_LOG) and from averaged DEM model (K_AVE); Track 4: shear modulus from sonic logs (G_LOG) and from averaged DEM model (G_AVE); Track 5: Young’s modulus from sonic logs (E_LOG) and from averaged DEM model (E_AVE); Track 6: Poisson’s ratio from sonic logs (v_LOG) and from averaged DEM model (v_AVE).
Figure 5.25. Vertical distribution of compressional and shear velocities in well OW2. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: compressional velocities from sonic logs (Vp_LOG) and from averaged DEM model (Vp_AVE); Track 4: shear velocities from sonic logs (Vs_LOG) and from averaged DEM model (Vs_AVE); Track 5: estimated mineralogy in volumetric concentration (Vc); Track 6: bulk volume; Track 7: mineralogy-based rock typing.
Figure 5.26. Vertical distribution of elastic properties in well OW2. Track 1: depth; Track 2: P- and S-wave sonic logs; Track 3: bulk modulus from sonic logs (K_LOG) and from averaged DEM model (K_AVE); Track 4: shear modulus from sonic logs (G_LOG) and from averaged DEM model (G_AVE); Track 5: Young’s modulus from sonic logs (E_LOG) and from averaged DEM model (E_AVE); Track 6: Poisson’s ratio from sonic logs (v_LOG) and from averaged DEM model (v_AVE).
Figure 5.27. Vertical distribution of compressional and shear velocities in well OW3. Track 1: depth; Track 2: P-wave sonic log; Track 3: compressional velocities from sonic logs (Vp_LOG) and from averaged DEM model (Vp_AVE); Track 4: shear velocity from averaged DEM model (Vs_AVE); Track 5: estimated mineralogy in volumetric concentration (Vc); Track 6: bulk volume; Track 7: mineralogy-based rock typing.
Figure 5.28. Vertical distribution of elastic properties in well OW3. Track 1: depth; Track 2: P-wave sonic log; Track 3: bulk modulus from averaged DEM model (K_AVE); Track 4: shear modulus from averaged DEM model (G_AVE); Track 5: Young’s modulus from averaged DEM model (E_AVE); Track 6: Poisson’s ratio from averaged DEM model (v_AVE).
Figure 5.29. Vertical distribution of compressional and shear velocities in well OW4. Track 1: depth; Track 2: compressional velocity from averaged DEM model; Track 3: shear velocity from averaged DEM model; Track 4: estimated mineralogy in volumetric concentration (Vc); Track 5: bulk volume; Track 6: mineralogy-based rock typing.
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<th>YOUNG’S MODULUS</th>
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<td>30.</td>
<td>70.</td>
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Figure 5.30. Vertical distribution of elastic properties in well OW4. Track 1: depth; Track 2: bulk modulus from averaged DEM model ($K_{AVE}$); Track 3: shear modulus from averaged DEM model ($G_{AVE}$); Track 4: Young’s modulus from averaged DEM model ($E_{AVE}$); Track 5: Poisson’s ratio from averaged DEM model ($v_{AVE}$).
Table 5.7. Summary of the volumetric compositions used to appraise the sensitivity of Young’s modulus and Poisson’s ratio to mineral and pore aspect ratios in six EFS wells. CARB: carbonate group; KER: kerogen; QF: quartz-feldspar group; clay group (CLA) is the host material; Sw: water saturation.

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<td>X378</td>
<td>X131</td>
<td>X180</td>
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<td>X513</td>
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<td>CARB V/V</td>
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<td>0.57</td>
<td>0.45</td>
<td>0.49</td>
<td>0.32</td>
<td>0.46</td>
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<tr>
<td>CLA V/V</td>
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<td>0.12</td>
<td>0.35</td>
<td>0.14</td>
<td>0.21</td>
<td>0.13</td>
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<tr>
<td>KER V/V</td>
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<td>0.1</td>
<td>0.11</td>
<td>0.11</td>
<td>0.17</td>
<td>0.09</td>
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<tr>
<td>QF V/V</td>
<td>0.06</td>
<td>0.1</td>
<td>0.03</td>
<td>0.15</td>
<td>0.07</td>
<td>0.27</td>
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<tr>
<td>Porosity V/V</td>
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<td>0.07</td>
<td>0.11</td>
<td>0.23</td>
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<tr>
<td>Sw</td>
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<td>0.19</td>
<td>0.62</td>
<td>0.19</td>
<td>0.06</td>
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Figure 5.31. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well WG1. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.32. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well OW1. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.33. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well WG2. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.34. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well OW2. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.35. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well OW3. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.36. Percent change in Young’s modulus (E) and Poisson’s ratio (v) with varying mineral or pore aspect ratio in well OW4. For each curve, the designated mineral or pore is ellipsoidal while other components remain spherical. Pore aspect ratio has the largest effect on elastic moduli. KER: kerogen; CARB: carbonate group; QF: quartz-feldspar group; clay group is the host material.
Figure 5.37. Poisson’s ratio-Young’s modulus cross-plot in EFS wells; left: estimates from sonic logs; right: estimates from DEM. Blue data points are for wells from the SW region and brown data points are for wells from the NE region. High Young’s modulus and low Poisson’s ratio indicate brittle rocks; SW wells are more brittle than NE wells.
Figure 5.38. Left: cross-plot of Young’s modulus and kerogen (KER) concentration. The approximate location of the preferred rock type for hydrocarbon production (RT1) is indicated with a red circle. Blue data points are for the SW wells while brown data points are for the NE wells.

Right: cross-plot of Young’s modulus and carbonate (CARB) concentration.
Chapter 6: Conclusions

Studies performed in this thesis revealed the complexity and spatial variability within the Eagle Ford shale and the corresponding technical challenges associated with the estimation of petrophysical and elastic properties across the shale. The present chapter summarizes the conclusions stemming from the studies and provides suggestions for future work.

6.1 Conclusions

Interpretation of well logs and core data from wells in the Eagle Ford shale was performed to appraise mineral and elastic properties. Petrophysical properties such as mineral and kerogen concentrations, porosity, and fluids saturation were estimated with a nonlinear inversion method that combines all available well logs; elastic properties were subsequently estimated from the estimated petrophysical properties. Ideal rocks for hydrocarbon production and hydraulic fracturing were then identified based on the combined evaluation of petrophysical and elastic properties. The following conclusions stem from the studies:

1. The Eagle Ford shale exhibits significant spatial variations in kerogen type, kerogen maturity, and mineral composition. These variations can be attributed to changes in depositional environment, geological units, geographical location and, to some extent, type of clay, type of hydrocarbon present, and pore pressure. The present study indicated that the Eagle Ford shale is mostly calcareous, whose mineralogy is dominated by carbonates in the Southwest region (over 0.6 average volumetric concentration of carbonate), but becomes rich in clay in the Northeast region (over 0.5 average volumetric concentration of clay).
Two rock types were identified in each region by way of k-means clustering of the mineralogy obtained from inversion of well logs. In the Northeast region, preferred rocks for hydrocarbon production, RT1, are characterized by volumetric concentrations of ~0.44 carbonate, ~0.09 kerogen, ~0.07 porosity, and ~0.42 clay; RT1 corresponds to organic-rich layers in the Eagle Ford shale. In the Southwest region, on the other hand, the Eagle Ford shale is mostly calcareous. Ideal rocks in the region, RT1, are rich in kerogen (~0.1) with carbonate content of ~0.56, ~0.1 porosity, and ~0.19 clay content; this RT1 is mostly found in the lower transgressive section of the Eagle Ford shale.

Laboratory data, mineralogy, and elastic property estimations showed that clay properties such as clay mineral composition and bulk and shear moduli, vary significantly from one well to another within the shale. Therefore, the interpolation of such parameters for assessment of petrophysical and elastic properties from one well to another may not be reliable and should be done with caution. Preferably, each well should be interpreted individually.

Kerogen was found to be of type II, III, and a mixture of II and III. Kerogen maturity in the studied wells ranged between immature and overmature. This variation in type and maturity was taken into account when constructing a mineral model for the estimation of petrophysical properties. However, a fixed set of kerogen and hydrocarbon properties was assumed for each kerogen type and hydrocarbon type, respectively. This assumption simplifies the mineral model such that clays are the only mineral group that exhibits variable composition and elastic moduli.

Comparison of logs from the various wells showed distinct responses within the shale. The variation in responses, however, did not appear to depend on kerogen
characteristics as much as it did on geographic location with respect to the San Marcos Arch. For example, resistivity and shear sonic logs exhibit low overall values (<20 ohm-m and <2000 m/s, respectively) in Northeast wells compared to Southwest wells. These low values are likely due to high volumetric concentration of clay and water saturation in the Northeast region.

(6) Synthetic examples showed that porosity and pore aspect ratio are inversely proportional to compressional and shear slownesses in a given rock type. Porosity and pore aspect ratio caused the highest relative change in velocities compared to mineral concentration and mineral aspect ratio. Kerogen concentration caused non-negligible increase in sonic velocities, possibly because of kerogen softness (low bulk and shear moduli).

(7) A simple elastic property model assuming an isotropic frame in which all minerals are spherical and porosity is ellipsoidal was sufficient to estimate elastic properties in the Eagle Ford shale. A single rock frame model can be used for the entire shale interval in the well in most cases but, when necessary, rock typing was invoked and a rock model was assigned to each rock type to perform the estimation. As a result, fracturability could not be directly linked to mineral type or concentration, or kerogen type/shape. An anisotropic frame could be assumed to better predict mineral shapes and rock fracturability, but this option has limitations in vertical wells penetrating horizontal layers where sonic wave velocities are measured only in the vertical direction.

(8) Elastic properties can be calculated by adjusting the pore aspect ratio to secure a good agreement between simulations and well logs; however, an increase in hydrocarbon elastic moduli was necessary to secure a good agreement in the
Northeast wells. In addition, variations in clay concentration and properties gave rise to non-uniqueness in sonic log simulations.

(9) There is a positive correlation between elastic properties (Young’s modulus and sonic velocities) and kerogen content in the Northeast region, whereas in the Southwest region, the correlation is negative. This behavior is because in the Northeast region, kerogen-rich rocks exhibit low matrix porosity, while in the Southwest region they exhibit high matrix porosity. Porosity and volumetric concentration of calcite, however, remain proportional to compressional and shear velocities in both regions.

(10) Porosity and pore aspect ratio had substantial effects on elastic properties. For example, over 80% decrease in Young’s modulus was quantified when pore aspect ratio approached zero; high pore aspect ratio is preferred for stiff rocks. Poisson’s ratio estimation was not always reliable, therefore, was not used in the interpretations considered in this thesis; fracturability was assessed based on Young’s modulus estimates. The best zones for hydrofracturing correspond to intervals which exhibit the highest Young’s modulus and are within the kerogen rich rock RT1. Young’s modulus values above 18GPa and 21GPa in the Northeast and Southwest region, respectively, were characteristic of these intervals. The depth intervals are identified as X160-X185ft, X130-X150ft, X370-395ft, X160-X190ft, X000-X060ft, and X510-X540ft for wells WG1, OW1, WG2, OW2, OW3, and OW4, respectively.
6.2 SUGGESTIONS FOR FUTURE WORK AND BEST PRACTICES

The method used for elastic property estimation in this thesis assumes a simple isotropic model. Because the wells studied in this thesis are vertical and the layers are horizontal, anisotropy could not be verified solely from sonic logs available (which represent responses from only vertical wave propagation). For more reliable elastic property estimation, further studies on deviated wells are needed preferably in wells with core geomechanical measurements (for calibration purposes).

Properties such as temperature, pore pressure, and stress regime are believed to change with depth and, therefore, with maturity windows in the Eagle Ford shale; however, they were not included in the present studies. Further investigations are needed to quantify the effect of these properties on in-situ reservoir fluids, rock moduli, and fracture propagation.

Clay minerals were assumed to comprise the load-bearing/host matrix in elastic property simulations. However, the simulation method was observed to produce non-unique results. In other words, results can be reproduced when other minerals, such as carbonate, are assumed the load-bearing/host, particularly in the Southwest wells. Host mineral was therefore not a factor in determining rock brittleness. An advanced mineral model that reduces non-uniqueness of results would be ideal to incorporate the host mineral into the identification of favorable intervals for hydrofracturing.

Our studies revealed the heterogeneity of the Eagle Ford shale in terms of its mineral composition and elastic properties. This behavior confirms that wells in the same shale play will not necessarily respond to the same hydraulic fracture design, for example. Evaluation of elastic properties in Southwest wells also revealed that rocks with hydrocarbon potential were not always the most brittle within the shale. Recommended best practices involve: (1) estimating mineralogy from inversion of available well logs
after mineral grouping and calibration to core; (2) identifying favorable production zones based on mineralogy, porosity, and hydrocarbon saturation using k-means clustering; (3) estimating sonic velocities and elastic moduli using the Differential Effective Medium theory; and (4) identifying intervals that exhibit sonic velocities and elastic moduli above a given cut-off and which are located within the previously selected production zones.
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