SEDIMENTARY AND DIAGENETIC CONTROLS ON PETROLEUM SYSTEM CHARACTERISTICS OF THE UPPER CRETACEOUS EAGLE FORD GROUP, SOUTH TEXAS

A Thesis

by

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Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

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May 2014

Major Subject: Geology

ABSTRACT

Early diagenetic carbonate cements can affect brittleness and total organic content in shale reservoirs. Predicting these effects could potentially improve recovery efficiency and field development costs, and decrease the environmental impact of developing the field. In this study, an X-ray fluorescence spectroscopic technique was used to test for correlations between primary depositional features, diagenetic carbonate cements, and organic content and fracture distributions in core samples from the Eagle Ford Group in McMullen County, Texas. Organic content varies significantly between diagenetic facies, with the least organic matter present in coarsely mineralized shales. This result is consistent with the hypothesis that diagenetic carbonate cementation that was early relative to compaction diluted primary organic matter. In contrast, total fracture length varies significantly between depositional facies, with the lowest total fracture length per length of core present in massive shales. Carbonate diagenesis therefore likely did not exert a significant control on the formation of the bedding-parallel fractures observed in this study; instead, laminated fabrics provided planes of weakness along which stress release fractures or hydrocarbon generation-induced fractures could develop. The suggested target reservoir facies for similar Eagle Ford wells is a finely to moderately mineralized laminated shale because of the likelihood of finding high organic content and horizontal fractures that would increase the effective rock volume in communication with primary hydraulically induced fractures.

DEDICATION

I would like to specially dedicate this thesis document to my parents, Mark and Sandy Hancock, and the entire family for all their support and love over the years. I would also like to dedicate this to my Grandfather, George Hancock Jr., who passed away, but with his hard work and success has provided me an opportunity of a lifetime.

ACKNOWLEDGEMENTS

I'd like to acknowledge the key people that made this thesis project possible. Mr. Paul Dore is a general manager of US onshore exploration with Murphy Exploration and Production Co., and provided me with the subsurface core data to be analyzed. I would also like to specially thank Dr. Michael M. Tice, who is a geo-biologist for spending countless hours with me reviewing data, and implementing new models using physical sedimentology to be used in the petroleum industry. Dr. Ernest A. Mancini, who was the director of the Berg- Hughes Center for Petroleum and Sedimentary Systems at Texas A&M University, played a vital role in the project assisting with the unconventional petroleum system problems and funding research. Dr. Walt Ayers, and Dr. Lee Billingsley play key roles with their professional input as petroleum geologists when discussing application in the oil and gas industry. I would also like to thank my research team for all their input and questions about this research project.

NOMENCLATURE

TOC	Total Organic Carbon
XRF	X-ray Fluorescence
SSTVD	Sub Sea True Vertical Depth
EUR	Estimated Ultimate Recovery

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INTRODUCTION AND STATEMENT OF PROBLEM

Late Cenomanian to early Turonian transgressive shales are known to have been deposited during a period of reduced sedimentation, oxygen depletion, and phosphogenesis (Dawson et al. 2006). The Eagle Ford Group is a transgressive organic-rich shale deposited during this interval (Donovan et al. 2010). The calcite content of Eagle Ford rocks, present as microfossils, shell fragments, or cement, ranges from 40-90% (Mullen, 2012). Carbonate cements can affect reservoir properties in several ways. They are thought to have a significant control on brittleness (Wilson et al. 1983). If cementation occurred prior to compaction, it could effectively reduce organic content by dilution. Identifying and predicting small scale fracture properties and organic content could potentially improve recovery efficiency, field development cost, and decrease the environmental impact of developing the field by optimizing well spacing (Moser et al. 2012).

The purpose of this thesis is to test the hypothesis that carbonate content controls both organic content and fracability in the Eagle Ford Group in southern McMullen Co., Texas. The alternate hypothesis that these rock properties were set by primary depositional processes, in which case they should correlate with sedimentary facies, is also tested. This will be achieved by combining organic geochemical characterizations with X-ray fluorescence and X-ray transmission data to test for correlations with depositional and diagenetic facies. TOC values will be compared with total carbonate content, timing of cementation, and the density of fractures to test for potential relations that could lead to highly productive facies. Well log characterization will be used to correlate reservoir properties of the Eagle Ford group to ultimately predict the highest quality reservoir facies.

GEOLOGICAL BACKGROUND

The Eagle Ford Group play extends for at least 640 km (400 mi) from the Texas-Mexico border northeastward to the East Texas Basin (Hentz and Ruppel, 2010). In south Texas, the Eagle Ford Group is a mixed siliciclastic/carbonate unconventional resource play with considerable oil and gas reserves (Workman et al. 2013). The contact between the Eagle Ford Group and the Austin Chalk represents the Turonian/Coniacian (92 Ma) boundary (Dawson, 2000). The Eagle Ford depositional sequence is commonly divided into two informal members, which have been further subdivided into four sequences (Adams et al. 2010). The lower Eagle Ford was deposited during marine transgression and youngs to the north, with older and more widespread deposits formed near the Sligo shelf margin to the south (Adams et al. 2010). The total Eagle Ford group ranges from less than 30 m (100 ft) to over 120 m (400 ft) thick. The area of study (**Fig. 1**) for this project is in the west Texas basin, where the Eagle Ford Group is characteristically a calcareous mudstone. The thickness of the unit in the study area is approximately 66 m (215 ft.). Regional geologic controls and thermal maturation processes that the Eagle Ford has undergone have resulted in an oil window updip (**Fig. 2**), and a gas window down dip.

Figure 1. Map of Eagle Ford core study location. (Modified from Cusack et al. 2010).

The Eagle Ford was deposited in a distal marine shelf environment during an interval spanning the Cenomanian/Turonian (92 Ma) boundary, and that deposition coincided with a prolonged episode of lowered oxygen content (Dawson, 2000; Charvart et al. 1981; Donovan et al. 2010). The southern portion of the Eagle Ford play, which is the area of interest for this particular project, occurs sub-parallel to the structural edge of the San Marcos Arch and the Sligo and Stuart City shelf margins. The Stuart City trend is the shallower of the two margins, both of which formed as early Cretaceous shallow-water carbonates accumulated on a broad shelf which completely encircled the Gulf of Mexico (Bebout and Loucks, 1974; Halbouty, 1966). Biogenic growth climaxed along the basin-ward edge, or shelf margin, where a complex of reefs, banks, bars, and islands developed. Limestones in the reef trend were not extremely porous initially, and late cementation had diminished even that porosity making the reservoir of lesser quality (Cook, 1979).

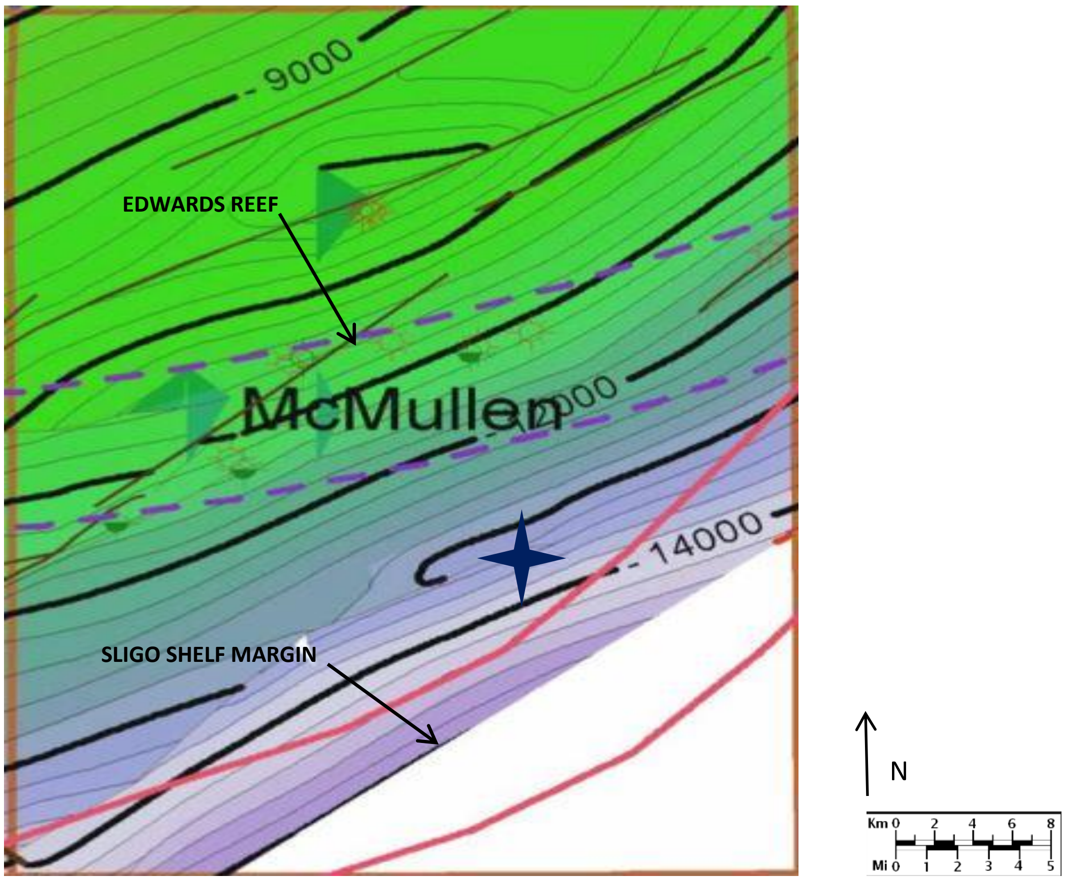

Figure 2. Lower Eagle Ford Structure Map.

During Eagle Ford deposition, warm seas were maintained throughout the world by an elevated greenhouse effect driven by high atmospheric carbon dioxide levels. Ultimately this caused an increase in organic productivity (Arthur, 1976). Consumption of organic matter by aerobic bacteria created widespread anoxic environments that ultimately enhanced preservation of organic material (Arthur, 1976). Increased preservation of organic matter produced thick black shales around the world.

The Upper Cretaceous stratigraphic column in South Texas is defined by the major lithostratigraphic units in order from oldest to youngest: the Del Rio Formation, the Buda Formation, the Eagle Ford Group, the Austin Chalk Formation, the Anacacho Formation, the San Miguel Formation, the Olmos Formation, and the Escondido Formation (**Fig. 3**).

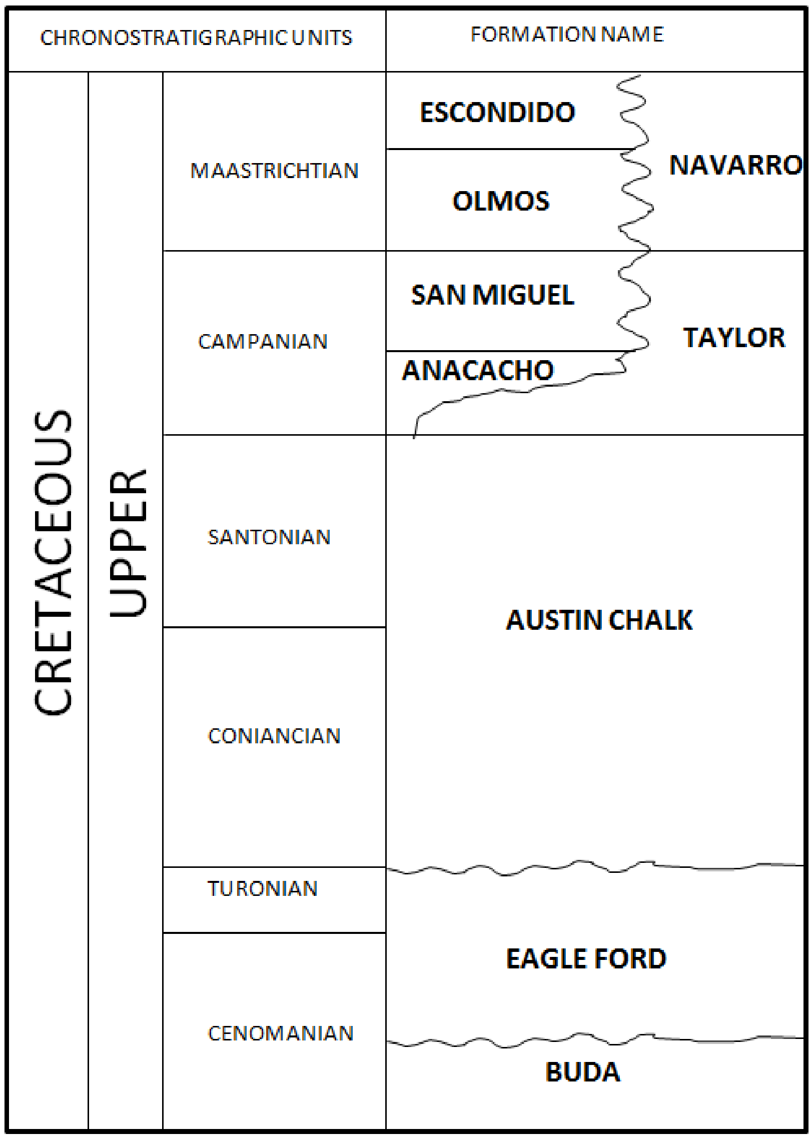

Figure 3. Stratigraphic Column of South Texas. (Modified from Cuasck et al 2010).

The western interior seaway was restricted from communication with the open ocean, providing opportunities for periods of anoxia (Dean et al. 1998). Within the western interior sea way the southern Eagle Ford Group was deposited in a deep water distal environment on an inter shelf margin between the Sligo and Edwards shelf margins. The sea deepened dramatically at the shelf margin parallel to the reef trend (Cook, 1979).

METHODS

Murphy Exploration Company donated core samples through the full thickness of Eagle Ford Group preserved in the study area. The core was visually described at the Core Laboratories, Inc. facility in Houston, TX. Both depositional and diagenetic facies were identified based on the degree of lamination and the presence and size of visible diagenetic carbonate and sulfide minerals, respectively. After the visual core description was complete, thirty seven samples were collected systematically by facies and core depth for further analysis. All samples were scanned using a Horiba XGT-7000 X-ray Analytical Microscope in order to map the distribution of elements from Na-U, with particular focus on Ca, S, and Fe. Fluorescence spectra and x-ray transmission intensities highlight compositional and density contrasts that allow identification of bed types, sedimentary structures, burrows, and fractures invisible to the naked eye or otherwise hidden beneath the sample surface. Calcium fluorescence was used to proxy for carbonate content. Iron and sulfur fluorescence maps were used to investigate diagenesis as well as to characterize cryptic sedimentary structures, and were thus useful for refining visually defined depositional and diagenetic facies. Scans were conducted at 100 μm resolution over sample areas of up to 5.12×5.12 cm^2. Fractures identified as thin, roughly tabular features having high x-ray transmissivity were characterized by number density per unit length of core (cm^{-1}), length per unit length of core (unitless), and number of apparently connecting fractures per unit length of core (cm^{-1}). Total organic carbon (TOC) was measured in all samples by Weatherford Laboratories. Well log signatures that best correlated with identified facies distributions were compare with reservoir attributes related to TOC and fracability (e.g., Porosity, resistivity).

RESULTS

Depositional Facies

Three depositional facies were identified: 1) well laminated shale; 2) crudely laminated shale; and 3) massive shale.

Well Laminated Shale. The second most abundant depositional facies (**Fig. 4**) is the well laminated shale with approximately 21 m (69 ft) of total section. This facies is defined laterally continuous laminations up to 4 mm thick. In X-ray fluorescence maps, these laminations exhibit cyclic variations in thickness, suggesting cyclic changes in the sediment supply during deposition, likely either as the distal deposits of storms or as low-density turbidites. Bioturbation is absent suggesting anoxic conditions. Rare soft sediment deformation features, including isolated flame structures, likely indicate occasionally rapid deposition, possibly over a gentle slope.

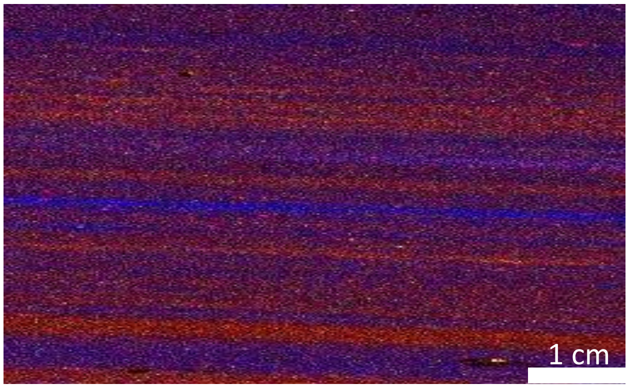

Figure 4. Well laminated shale. Fase color compositional image with red = Fe $K_{\alpha 1}$ fluorescence; green = S $K_{\alpha 1}$ fluorescence; blue = Ca $K_{\alpha 1}$ fluorescence.

Crudely Laminated Shale. The dominant depositional facies within the Eagle Ford Group is the crudely laminated shale (**Fig. 5**) with approximately 24 m (80 ft) of total section. In slabbed core, this facies is defined by thin discontinuous laminations up to 1 mm thick. Compositional maps of Fe fluorescence show many of these laminations to be gently concave-up cuspate swales interpreted here to represent minor scour marks formed under the action of gentle currents.

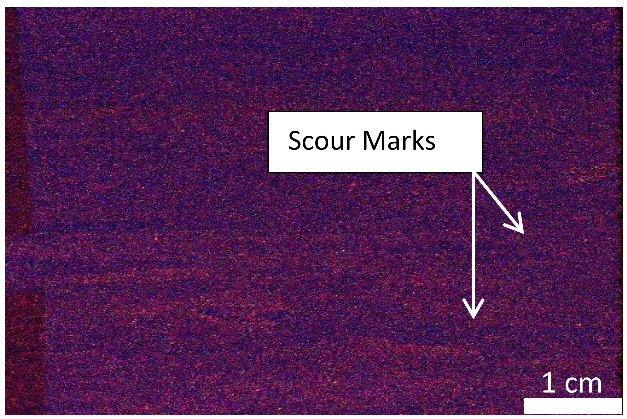

Figure 5. Crudely laminated shale. Fase color compositional image with red = Fe $K_{\alpha 1}$ fluorescence; green = S $K_{\alpha 1}$ fluorescence; blue = Ca $K_{\alpha 1}$ fluorescence.

Massive Shale. The third most abundant depositional facies (**Fig. 6**) is massive shale with approximately 20 m (66 ft) of total section. Sedimentary structures are not visible in slabbed samples or in X-ray fluorescence maps. Rocks of this facies may have been deposited from suspension during intervals of little to no current activity.

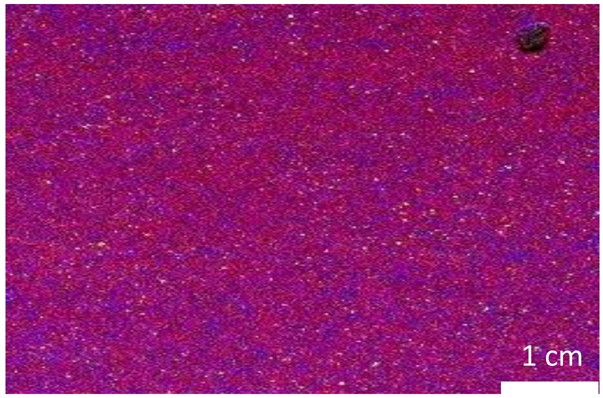

Figure 6. Massive shale. Fase color compositional image with red = Fe $K_{\alpha 1}$ fluorescence; green = S $K_{\alpha 1}$ fluorescence; blue = Ca $K_{\alpha 1}$ fluorescence.

Diagenetic Facies

Three diagenetic facies were also identified independently of the depositional facies: 1) finely mineralized shale with no visible diagenetic carbonate or pyrite grains; 2) moderately mineralized shale with visible diagenetic carbonate grains < 0.1 mm diameter; and 3) coarsely mineralized shale with densely packed carbonate grains > 0.1 mm diameter.

Finely Mineralized Shale. The most common diagenetic facies is finely mineralized shale (**Fig. 7**) with approximately 49 m (160 ft.) of total section. It is defined by its lack of visible diagenetic carbonate and pyrite grains.

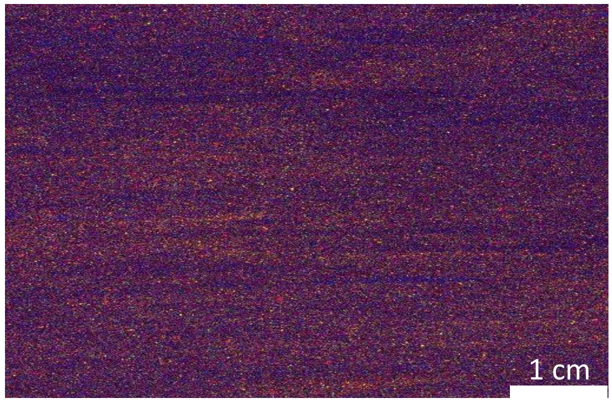

Figure 7. Finely mineralized shale. Fase color compositional image with red = Fe $K_{\alpha 1}$ fluorescence; green = S $K_{\alpha 1}$ fluorescence; blue = Ca $K_{\alpha 1}$ fluorescence.

Moderately Mineralized Shale. The second most abundant diagenetic facies (**Fig. 8**) is moderately mineralized shale with approximately 10 m (33 ft.) of total section. It is defined by the presence of visible diagenetic carbonate grains < 0.1 mm diameter.

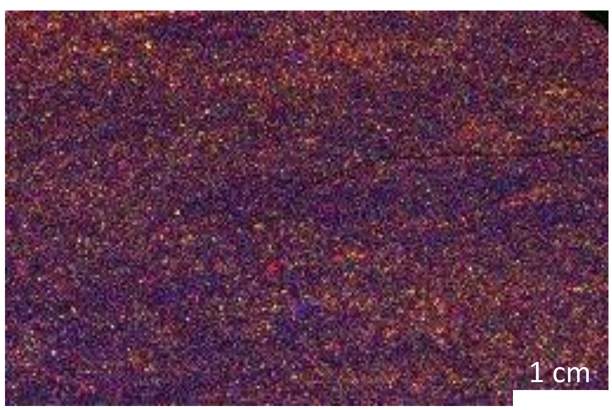

Figure 8. Moderately mineralized shale**.** Fase color compositional image with red = Fe $K_{\alpha 1}$ fluorescence; green = S $K_{\alpha 1}$ fluorescence; blue = Ca $K_{\alpha 1}$ fluorescence.

Coarsely Mineralized Shale. The third most abundant diagenetic facies (**Fig. 9**) is a coarsely mineralized shale with approximately 7 m (22 ft.) of total section. It is defined by the presence of densely packed diagenetic carbonate grains > 0.1 mm diameter.

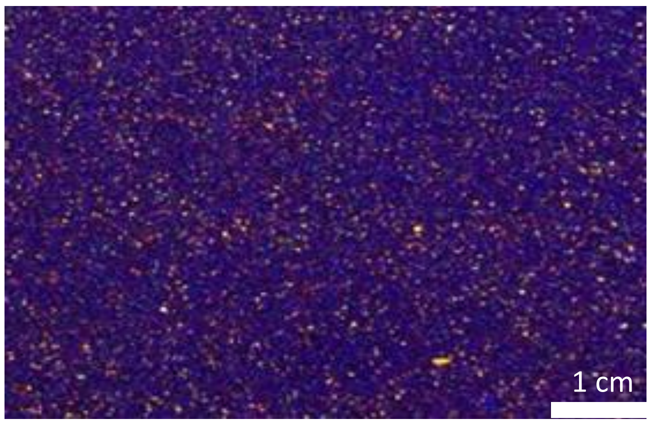

Figure 9. Coarsely mineralized shale.

Well Log Characterization

The Eagle Ford Group is informally divided into lower and upper members in other locations, with the boundary commonly identified on the gamma ray logs by a regionally correlative ~120 API horizon indicating a likely ash layer. Neither the gamma ray peak nor the ash layer were identified in the study core (**Fig. 10**), suggesting that the upper Eagle Ford Group may not be preserved in the study area. However, chemical composition, TOC, lithofacies distributions, and vitrinite reflectance vary between the lower and upper sections of the studied core. The lower Eagle Ford Group is therefore tentatively divided into two submembers for this study, the “lower-lower” submember and the “upper-lower” submember. The boundary between these submembers was placed at approximately 4005 m (13,140 ft.) where predominantly laminated shales transition to crudely laminated shale. The lower-lower Eagle Ford Group also exhibits generally higher TOC, and less visible diagenetic carbonate and sulfide minerals.

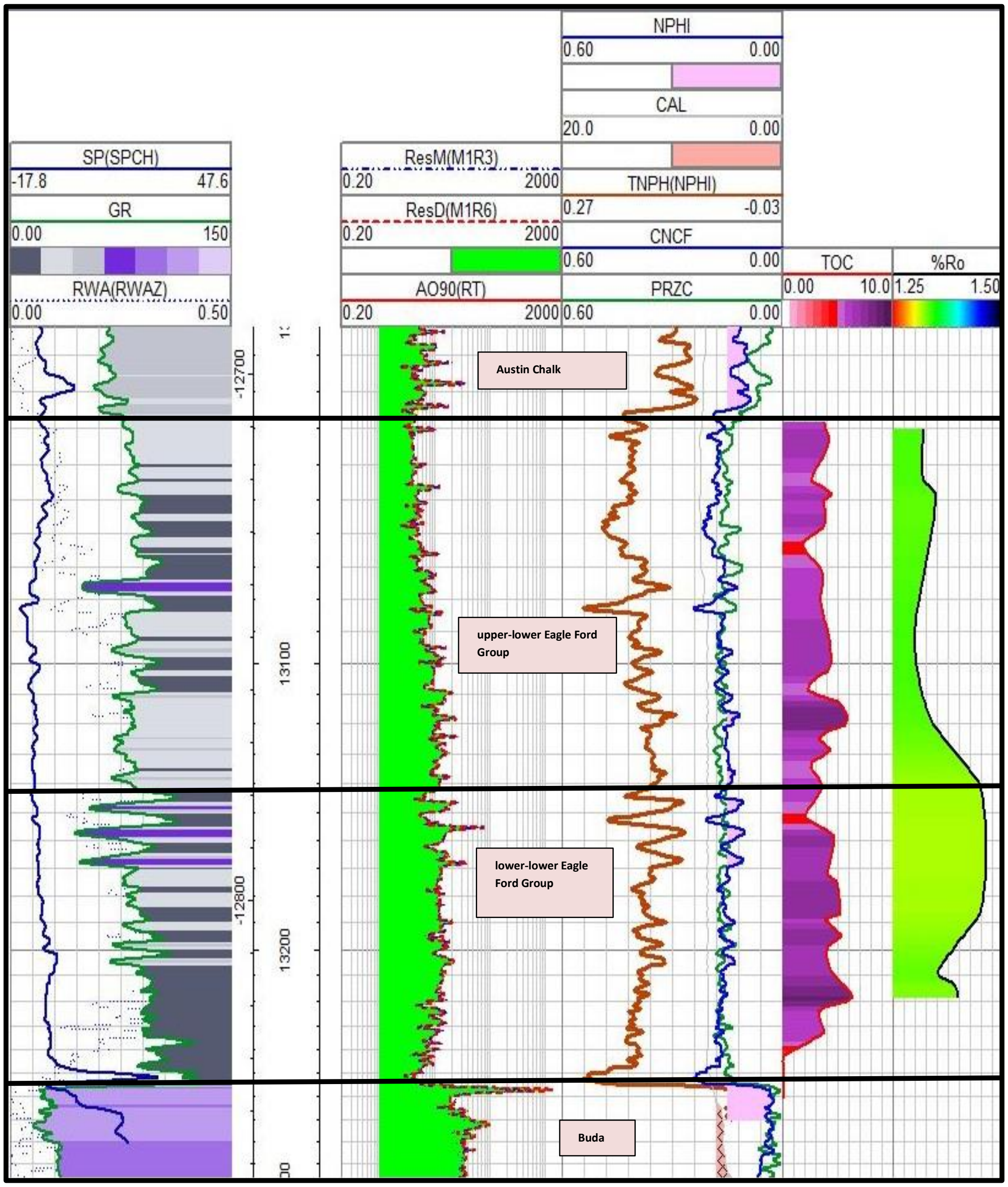

Figure 10. The Upper Cretaceous Austin Chalk, Eagle Ford, and Buda Limestone**.**

The lower-lower submember of the Eagle Ford Group is less calcareous than the upper-lower submember. The lower-lower submember also show higher resistivity and porosity suggesting a higher-quality source interval. The upper eagle ford does show good TOC values, and high calcium carbonate content, i.e. brittle, indicated on the gamma ray log. The upper eagle ford is also potentially a productive zone as indicated by relatively high TOC, and its high carbonate content suggested by higher gamma radioactivity may make it brittle, but the lack of porosity may decrease the storage capacity of the hydrocarbons. Hydraulic stimulation in the lower-lower Eagle Ford Group would network vertically up through the upper-lower Eagle Ford Group and propagate through the brittle carbonate zones making the lower-lower submember an attractive target for hydraulic stimulation. In this particular wellbore, the upper-lower Eagle Ford submember is predominantly within the condensate-wet gas window, and the lower-lower submember is within the dry-gas window. Wellbore placement within this lower eagle ford zone is still being studied, but these data suggest that the best initial placement would be approximately 14 m (45 ft) from the top of the Buda Limestone.

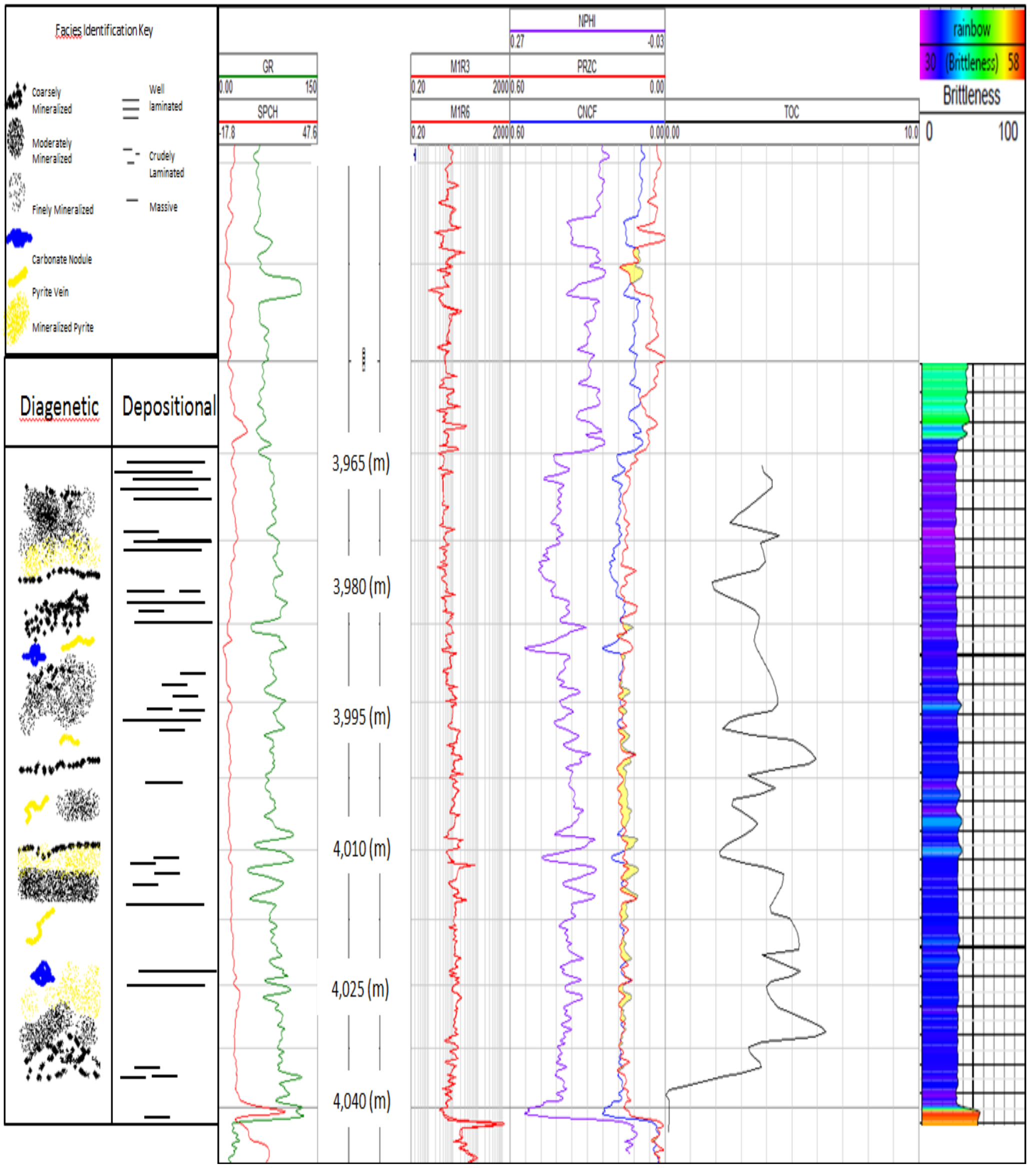

Figure 11. Integrated facies well log characterization

Fractures

All fractures identified in this study were bedding parallel or sub-parallel (e.g. **Fig. 12**) and not mineralized. Hydraulically induced fractures should be formed approximately perpendicular to the lowest principal stress. Therefore, in tectonically relaxed areas such as the study area, they should be vertical, whereas in tectonically compressed areas, they should be horizontal. Observed fractures are likely stress release fractures induced by coring or fractures formed by overpressure during hydrocarbon generation.

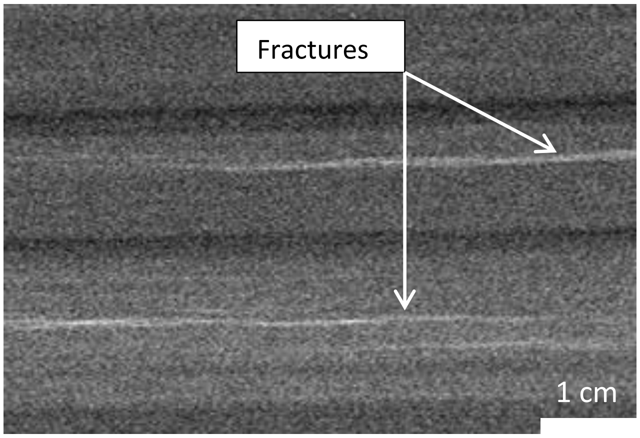

Figure 12. Well laminated shale exhibiting fractures parallel to bedding planes.

DISCUSSION

Diagenetic and Depositional Controls on Total Organic Carbon

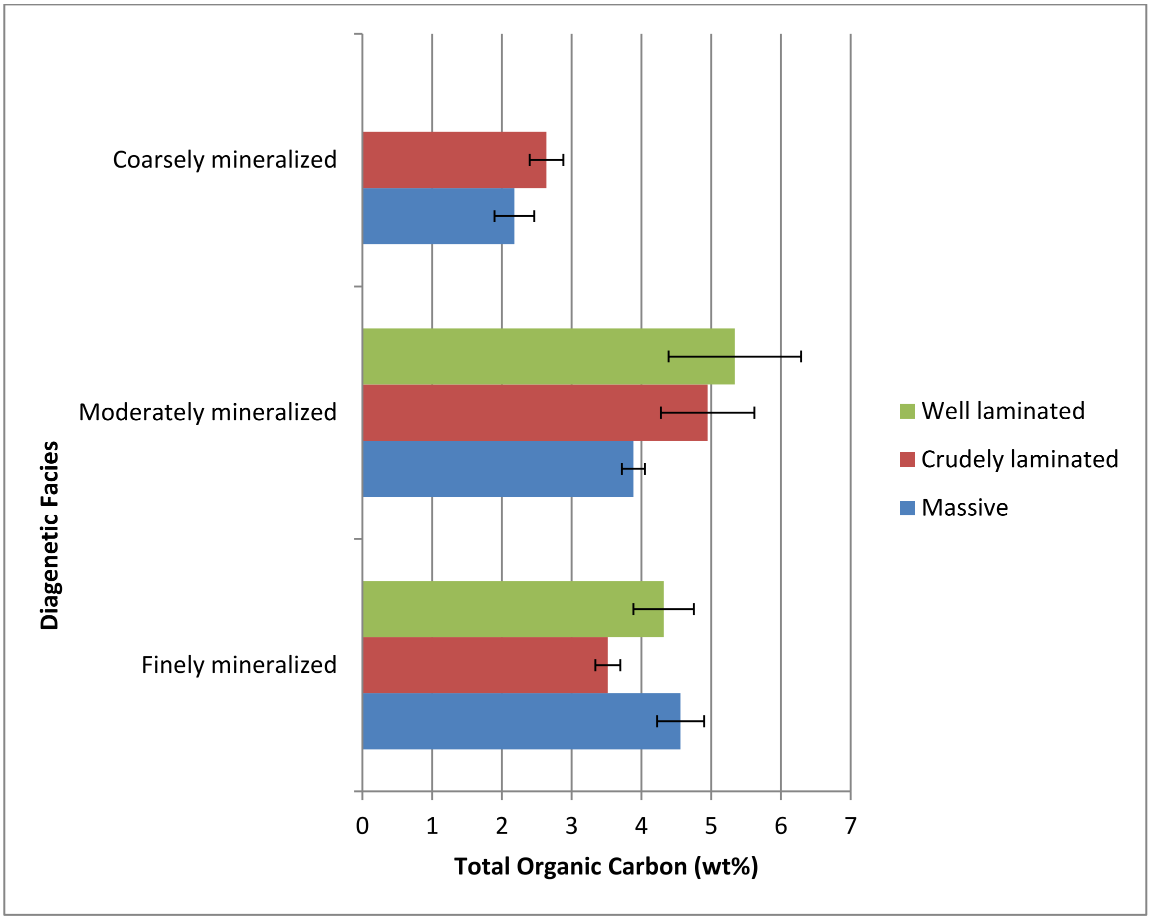

Figure 13. Total organic carbon associated with depositional and diagenetic facies. Error bars indicate standard errors for the mean. No coarsely mineralized, well laminated samples were identified.

TOC varies significantly between diagenetic facies (**Table 1**; $p = 2.2\times10^{-5}$ for ANOVA), with the least organic matter present in coarsely mineralized shales (**Fig.13**).

Although there is a marginally significant relationship between TOC and depositional facies ($p = 0.038$ for ANOVA), this result is likely an artifact of the lack of coarsely mineralized well laminated samples. Indeed, the relationship loses significance when all coarsely mineralized samples are excluded from the analysis ($p = 0.062$). In contrast, the relationship between TOC is robust to removal of all well laminated samples ($p = 9.4\times10^{-5}$). Carbonate diagenesis therefore likely exerted significant control on final organic content, with coarsely mineralized rocks having the lowest average TOC. This result is consistent with the hypothesis that diagenetic carbonate cementation that was early relative to compaction diluted primary organic matter. Alternatively, concentration of organic matter and carbonate as cement or foraminifera tests in condensed sections or accumulation of organic matter and microfossils during foraminifera blooms would have resulted in coarsely mineralized rocks with high average TOC. Isolated carbonate nodules with surrounding laminations deformed by compaction around them provide evidence of local cementation before compaction **(Fig. 14)**.

Table 1. ANOVA for Total Organic Carbon Associated with Diagenetic Facies.

TOC-Diagenetic Facies

SUMMARY- TOC

Groups	*Count*	*Sum*	*Average*	*Variance*
Moderately	6	28.35	4.725	1.00523
Finely	27	105.84	3.92	0.8585
coarsely	9	21.92	**2.435556**	0.324228

ANOVA

Source of Variation	*SS*	*Df*	*MS*	*F*	*P-value*	*F crit*
Between Groups	21.98793	2	10.99396	14.32033	2.17E-05	3.238096
Within Groups	29.94097	39	0.767717			
Total	51.9289	41				

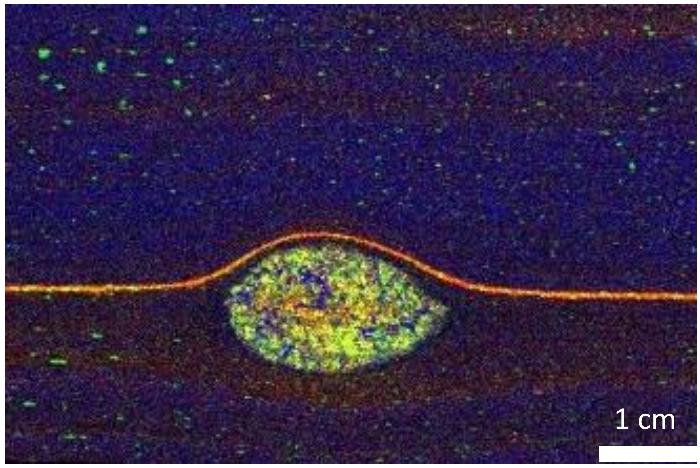

Figure 14. Early carbonate cementation.

In contrast, total fracture length varies significantly between depositional facies ($p = 0.017$ for ANOVA), with the lowest total fracture length per length of core present in massive shales (**Fig. 15**). There is no significant relationship between fracture length and diagenetic facies ($p = 0.22$ for ANOVA). Carbonate diagenesis therefore likely did not exert a significant control on the formation of the bedding-parallel fractures observed in this study; instead, laminated fabrics provided planes of weakness along which stress release fractures or hydrocarbon generation-induced fractures could develop. If similar fractures exist in the subsurface or open off of hydraulically induced fractures, they could result in a higher volume of rock in connectivity to the wellbore.

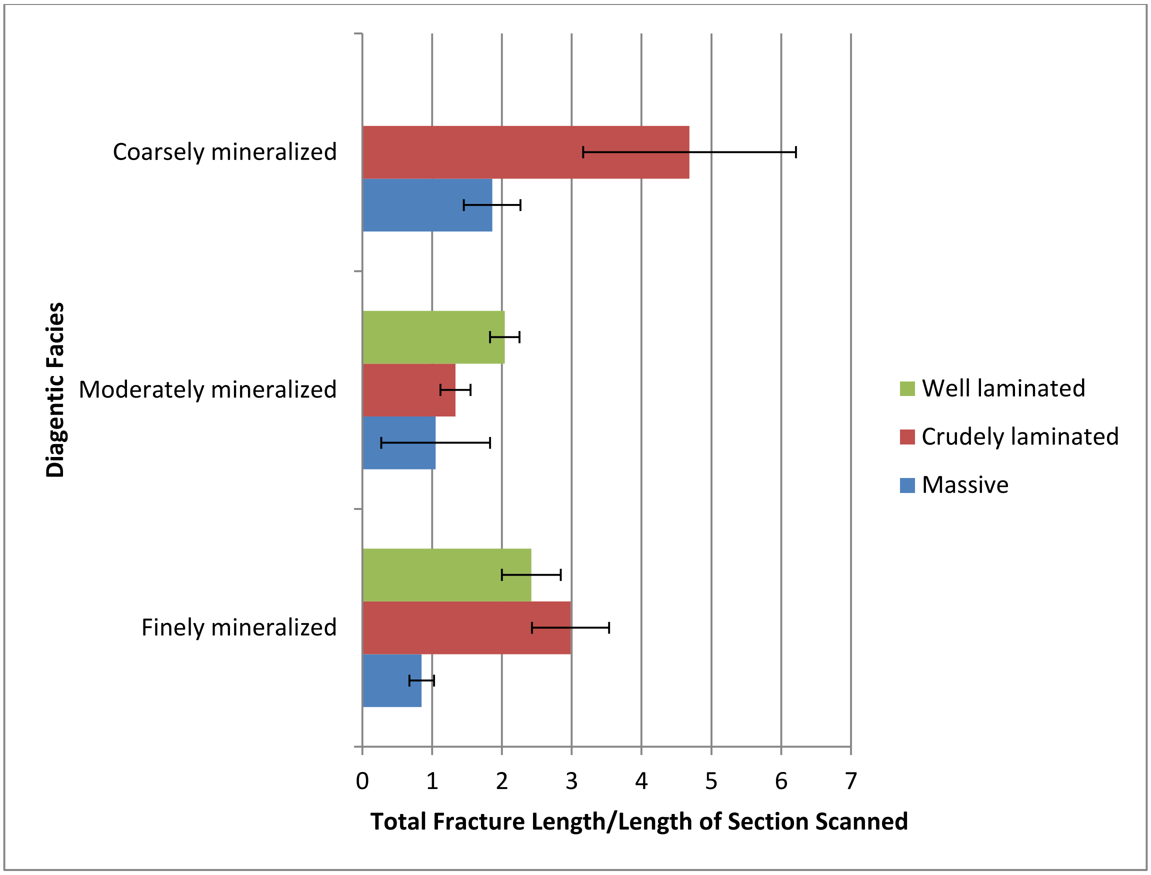

Figure 15. Fracture length associated with depositional and diagenetic facies. No coarsely mineralized, well laminated samples were identified.

CONCLUSIONS

Dilution by carbonate cementation prior to compaction was the most important factor in determining final total organic carbon in the lower Eagle Ford Group in the study site. The anisotropy of the rock with respect to fracture susceptibility is controlled by the presence or absence of primary sedimentary laminations rather than carbonate cementation. Depending on the volume of rock targeted, this could have a good or a bad impact when hydraulically stimulating crudely and well laminated microfacies. The upper-lower Eagle Ford Group is dominated by coarsely mineralized crudely or well laminated laminated shale. The lower-lower Eagle Ford Group is dominated by finely to moderately mineralized crudely laminated or massive shale. The suggested target reservoir facies for similar Eagle Ford wells is a finely to moderately mineralized laminated shale because of the likelihood of finding high organic content and developing abundant bedding parallel fractures that would increase the effective rock volume in communication with primary hydraulically induced fractures. Ultimately correlating zones with abundant TOC that has not been diluted by diagenesis throughout the sedimentary basin will aid in hydrocarbon production. The innovative use of X-ray data for this rock could be a productive technique for analyzing very different systems where this specific model may not apply.

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