The Lower Woodbine Organic Shale of Burleson and Brazos Counties, Texas: Anatomy of a New "Old" Play

Richard L. Adams[1], John P. Carr[1], and John A. Ward[2]

[1]Carr Resources, Inc., 305 S. Broadway Ave., Ste. 900, Tyler, Texas 75702

[2]PetroEdge Energy III, 2925 Briarpark Dr., Ste. 150, Houston, Texas 77042

ABSTRACT

The Lower Woodbine Organic Shale, in the southwest portion of the East Texas Basin, is a very organic-rich shale with high resistivity, a hot gamma ray response, and very good mud log shows.

This zone owes its high organic content and the resultant well-established oil production to its deposition in a silled basin, the product of a prograding delta from the north and northeast, a shelf-rimming Sligo/Edwards barrier reef complex to the south and southeast, a large basement high that affected water depth to the east, and a constricted area between the Sligo-Edwards Shelf Margin and the San Marcos Arch to the west. Within this silled basin, the zone grades from producing 30–35 gravity oil in northern Brazos County to dry gas in southernmost Grimes County.

In 2008, concurrent with the development of the "Eagleford play" in South Texas, Apache began a program recompleting wells from the underlying Buda and the overlying Austin Chalk into the Giddings ("Eagleford") zone. The early recompletions were vertical completions with very small cumulative oil production. Later, they would drill several short lateral horizontal wells to better test this organic shale.

The data from the Apache wells would prove to be invaluable in the current round of evaluation and drilling that began in 2012. Data such as oil gravity, gas-oil ratios, and organic shale isolith values, when combined with the completed lengths of the few horizontal completions and the regional geologic stress-strain field, allow for both a reservoir and an economic evaluation to predict where sweet spots should exist in this newly redeveloping play and how to best exploit them. Datasets from multiple plays confirm that the sweet spots are most often located in the high oil gravity portion of the oil window where the oil-generating shale is the thickest.

This play demonstrates the economic necessity of a proper evaluation of all data in a play before acreage acquisition. The play covers portions of several counties, but the best sweet spots will be much smaller.

The Woodbine and Eagle Ford were first defined in the Dallas, Texas, area in the late 1800s. The Maness was defined in 1945, from a cored well interval in Cherokee County, Texas. Correlations back to the outcrops and Cherokee County suggest that this productive interval is neither Eagle Ford nor the true Maness Shale. Therefore, following correct North American Commission on Stratigraphic Nomenclature (NACSN) practices, these organic-rich shales should be called the Lower Woodbine Formation and not the Eagle Ford Shale. The name Maness Shale only truly applies to a portion of the section below the high resistive oil-generating shale and above the Buda Limestone. The Maness is separated from the Woodbine over most of its area by the Lower Cretaceous Unconformity. By definition, the reservoir/source interval may be called a portion of the Pepper Shale Member of the Woodbine Formation. For clarity, the authors will refer to this restricted interval as the Lower Woodbine Organic Shale (LWOS).

Adams, R. L., J. P. Carr, and J. A. Ward, 2014, The Lower Woodbine organic shale of Burleson and Brazos counties, Texas: Anatomy of a new "old" play: Gulf Coast Association of Geological Societies Transactions, v. 64, p. 3–31.

INTRODUCTION

In February 2008, Apache Corp. began production from an interval that the Texas Railroad Commission (RRC) had designated as the Giddings ("Eagleford") Field. See Figure 1 for location. Cumulative production from these original Apache wells to date is about 538,000 barrels of oil (BO). Our regional correlations clearly show that the zone Apache has completed is actually within the Lower Woodbine Organic Shale (LWOS), and just above the interval that correlates to the type locality of the Maness Shale. This reservoir/source interval is characterized by high resistivity, low density and high gamma ray response on logs. The hot gamma ray portion of this interval is 30–60 ft thick, but the total interval as completed by Apache in their vertical wells is up to three times thicker. The interval is an organic-rich shale, sometimes limy and/or sandy, which was deposited in an anoxic silled basin on the Lower Woodbine shelf (Adams and Carr, 2010). In the Burleson, Brazos, and Lee county area, this interval produces oil with gravities ranging from 30 in the north (updip) to 50 along the southern edge of the oil window. The same area has a range of gas-oil ratios from less than 100 in the very northernmost areas to over 10,000 in southern Burleson County.

Apache's early completions were mostly vertical recompletions of wells drilled in the early to mid 1980s by Getty. Results from the earliest wells were mixed, but all showed that the LWOS contained oil that could be produced. Apache also deepened some wells and drilled horizontal laterals of various lengths within the LWOS. Production from these horizontal wells suggested that a direct relationship exists between the length of the lateral and the resulting production. Nearly all of these wells were fracked. The data from these early Apache wells were used as the defining dataset to analyze this newly emerging play and to develop a leasing strategy. The area where the gravity is in the 44–50 range with a gas-oil ratio (GOR) from 1500 to about 3200 was anticipated to have the greatest reservoir energy to maximize production potential. A comparison of the early Apache data with the later drilling by subsequent operators confirm the validity of the evaluation model in high-grading the area to be leased.

This approach is presented as a template for future unconventional play evaluations. The details will be different but the play parameters will still be similar. Intra-particle porosity will always be generated by hydrocarbon maturation, and greater gas volumes will always assist in expelling oil from the reservoir/source rock (Modica and Lapierre, 2012; Loucks et al., 2009; Cander, 2012).

The Eagle Ford was originally defined as a group by Hill in 1887. The correct spelling per his description should be two words and not run together into a single word. The original type locality was near the Eagle Ford of the Trinity River, just west of Dallas, in Dallas County, Texas. Hill (1901) continued his discussion of the differences between the Eagle Ford and the underlying Woodbine based on paleontological differences based on both molluscan fauna and plant fossils, which bear an affinity to the fossils in the Dakota Formation of Colorado and Wyoming. Although the industry and academic standard spelling for South Texas has often been Eagleford we will adhere to Hill's (1887) spelling of Eagle Ford throughout except in reference to field names where the state of Texas RRC has used the single word form in the official field name. The Maness Shale was defined by Bailey et al. (1945) in Cherokee County, Texas. The Maness is Lower Cretaceous in age (Bailey et al., 1945) and separated from the overlying Woodbine by an unconformity in many areas.

The North American Commission on Stratigraphic Nomenclature (NACSN) has very specific rules on the usage and correlation of stratigraphic names. In this instance, we will show clearly that the reservoir/source interval with the hot gamma ray response is neither Eagle Ford or truly Maness. Therefore, this zone should be simply referred to as the Lower Woodbine Organic Shale, or a completely new name should be applied and a type log and type interval should be defined.

FIELD HISTORY

The Giddings (Eagleford) Field was defined in 1981 as completed from 8750–8820 ft in the Bar M #1 Harrell in Lee County of District 3. Despite a published initial production (IP) of 232 BO and 222 MCFG (thousand cubic ft of gas) per day, the recorded cumulative production is only 1417 BO and 1 MMCFG (million cubic ft of gas). This vertical zone was not fracked per today's completions, but was acidized with 6000 gal of 15% HCl with 15% non-emulsifiers (NE).

Our story however, begins 27 years later with the recompletion by Apache of the (Getty) C–#1 Giesenschlag in Burleson County, Texas, on February 5, 2008. After fracking the vertical perforations from 8840–8920 ft with ~68,000 lb of white sand the well flowed at a rate of 133 BOPD (barrels of oil per day) and 120 MCFGD (thousand cubic ft of gas per day. But unlike the earlier Harrell well, the Giesenschlag continues to produce oil. Throughout the remainder of 2008, Apache recompleted an additional 14 vertical and 6 horizontal wells into the Giddings (Eagleford) Field. In 2009, Apache added an additional vertical well and 4 additional horizontal recom-

Main Menu
Search
Author Index
Papers
Help

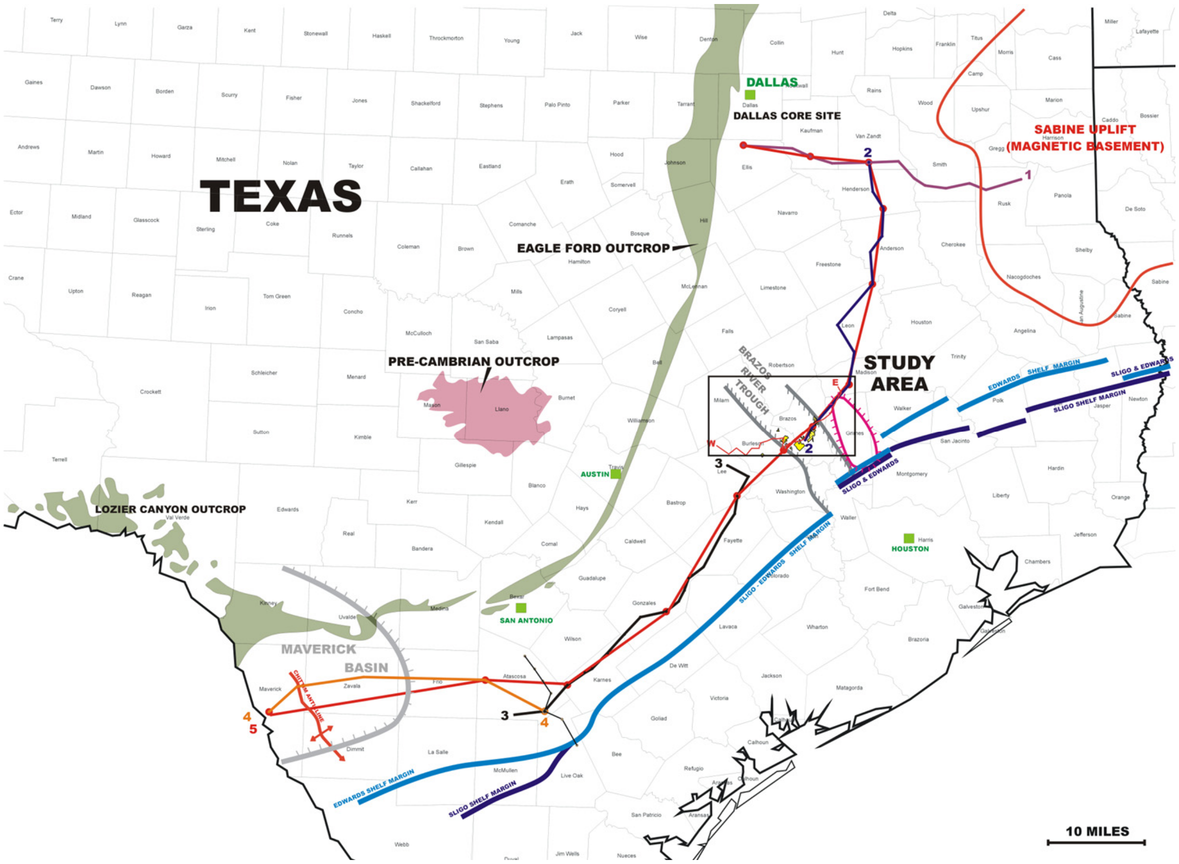


Figure 1. Location map of Texas showing the study area in relation to the outcrop belt of the Eagle Ford, major cities, major related structural and stratigraphic features, and the cross-sections used in this study.

pletions. Excluding gas/condensate wells, the vertical wells have only averaged 7123 BO cumulative production to date. The horizontal completions have averaged 38,361 BO per completion over the same time interval.

Why is the data from the sub-economic wells important? The important truth is that not all shale is created equal. Unlike non-organic-rich shales, as organic shales are buried, the kerogen is converted to hydrocarbons, consuming part of the original kerogen and creating additional porosity (Loucks et al., 2009). Loucks et al. (2009) measured intra-organic grain porosities of up to 20.2% in the Barnett Shale. Also, as the same shales are buried, the shales expel or consume nearly all of the originally contained water within the generating parts of the shales. Thus, the organic-rich shale portion of the Lower Woodbine can be expected to be oil-wet, comparable to the Mowry Shale in Powder River Basin (Modica and LaPierre, 2012). And third, as the oil continues to cook with additional heat and pressure, it changes viscosity from a thick black goo to a liquid with shorter chemical chain structures and significantly lower viscosity. In the relatively small distance from northern Brazos County to central Burleson County, the oil gravity increases from 34 degrees to 48 degrees.

Since Apache's first recompletions in 2008, the play has blossomed to include other operators such as Weber, Halcon, Petro-Max, Clayton Williams, EOG, Anadarko, XTO, Ursa, Woodbine Acquisitions, Buffco, Ausco, and Carr/PetroEdge III. The developed area now includes not only Giddings (Eagleford) Field, but wells completed in this interval are also permitted in Aguila Vado (Eagleford), Cooks Point (Woodbine), Briscoe Ranch (Eagleford), and Madisonville W. (Woodbine A).

The Burleson and Brazos county area is also blessed with a large number of wells previously drilled for other targets, including the Austin Chalk, the Woodbine sands, the Buda, and the Georgetown. This abundance of well data allows the mapping of both the extent and the thickness of the primary oil-generating shale facies. Combined, these data indicate that the best location in the reservoir for optimum oil recovery from the shale facies will be located in the deepest part of the oil window, just above the gas-generating window, and where the oil-generating shale is the thickest. The LWOS is oil-wet, while the adjacent silts and sands in the Lower Woodbine into which oil has migrated are often water-wet. The oil gravity and GOR data provides our north-south definition of the most likely sweet spot. Examination of logs in the area provide a western limit for this sweet spot as the hot portion of the shale disappears to the west and as the interval loses resistivity to the northeast.

Similar analysis techniques can be used successfully in other plays. Thus, this can become a template for use in other scenarios where less data is available and more assumptions must be made.

REGIONAL CORRELATION: EAST TEXAS

The Eagle Ford was named by Hill in 1887 for its type locality at the Eagle Ford of the Trinity River between Dallas and Fort Worth, Texas. Subsequently, the core of the well at the Mobil Field Research Laboratory in western Dallas County has been used as a type section (see Figure 1 for location). The Eagle Ford in outcrop is given Group status with three component formations—the Acadia Park, the Britton, and the Tarrant formations from top to bottom as defined by Dr. W. L. Moreman and published by Sellards (1932). All are named for localities in the Dallas, Texas, area. At the Mobil lab location the Acadia Park is 120 ft thick, the Britton is 334 ft thick, and the Tarrant is 20 ft thick. The Eagle Ford Group is separated from the overlying Austin Chalk by an unconformity with a strong palynologic break and a phosphatic pebble conglomerate (Brown and Pierce, 1962). The Eagle Ford Group is separated from the underlying Woodbine by an unconformity containing lignitic mudstone pebbles, siderite pebbles, borings, glauconite, and black phosphatic pebbles (Brown and Pierce, 1962). This unconformity at the base of the Eagle Ford is the Eagle Ford Unconformity of Adams and Carr (2010). Brown and Pierce (1962) provided a detailed palynologic evaluation of this interval. They confirm that the Eagle Ford as defined in Dallas is correlative over a large portion of the East Texas Basin. Figure 2 shows the correlation of this surface section to the Mitchell #1 Berry log in Dallas County.

The Maness Shale was defined as a subsurface-only formation within the Lower Cretaceous Washita Group by Bailey et al. (1945). The type log for this interval is from the Shell #1 Maness well in eastern Cherokee County, where the entire interval between the Austin Chalk and the Buda was cored. The Maness was defined as the 61 ft interval immediately above the Buda Limestone and below the lowest Woodbine sand. See Figure 3 for log of type area. Faunal analysis shows that this interval is Lower Cretaceous (Comanche) in age (Bailey et al., 1945). Bailey et al. (1945) interpreted an unconformity between the Maness and the overlying Woodbine sands. Thus, even the common practice of referring to the organic rich shale of Brazos and Burleson counties as Maness is incorrect. This organic facies is a Shale of the Woodbine Group, as it is neither Eagle Ford nor true Maness.

Correlations into the East Texas Basin clearly demonstrate that this Giddings (Eagleford) producing interval is not equivalent to the Eagle Ford/SubClarksville of East Texas (which is Turonian in age), but rather that it is Cenomanian in age and is correlative into the Lower Woodbine. The Maness as defined by Bailey (1945) is Comanchean in age and is separated from the overlying Woodbine by an unconformity, referred to here as the Lower Cretaceous Unconformity. This Lower Woodbine organic reservoir/source zone was deposited in a silled basin on the Lower Woodbine Shelf, south and west of a large delta system prograding southward off of the exposed Ouachita highlands of Oklahoma and Arkansas (Adams and Carr, 2010).

REGIONAL CROSS-SECTIONS: EAST TEXAS TO SOUTH TEXAS

A series of regional cross-sections were constructed to confirm regional correlations from the Woodbine and Eagle Ford outcrop areas near Dallas, Texas, to the Maverick Basin of South Texas and on further west to the Lozier Canyon outcrops of Terrell County (see Figure 1 for the location of cross-sections and major tectonic features as well as major cities for reference). Multiple cross-sections were constructed to keep the size of each cross-section manageable. These initial cross-sections were then combined by selecting only key wells from each cross-section to generate a single correlation from outcrop to outcrop.

Cross-Section 1

The first cross-section (Fig. 4) crosses the East Texas Basin from near Dallas, Texas, on the west to near Kilgore, Texas, on the east (see Figure 1 for the location of this cross-section). Dallas is located over the eastern edge of the Ouachita Structural Front while Kilgore is located on the Sabine Uplift, near the eastern edge of the giant East Texas (Woodbine) Oil Field. Of note is the Mitchell #1 Berry log on the left end of this cross-section.

Main Menu
Search
Author Index
Papers
Help

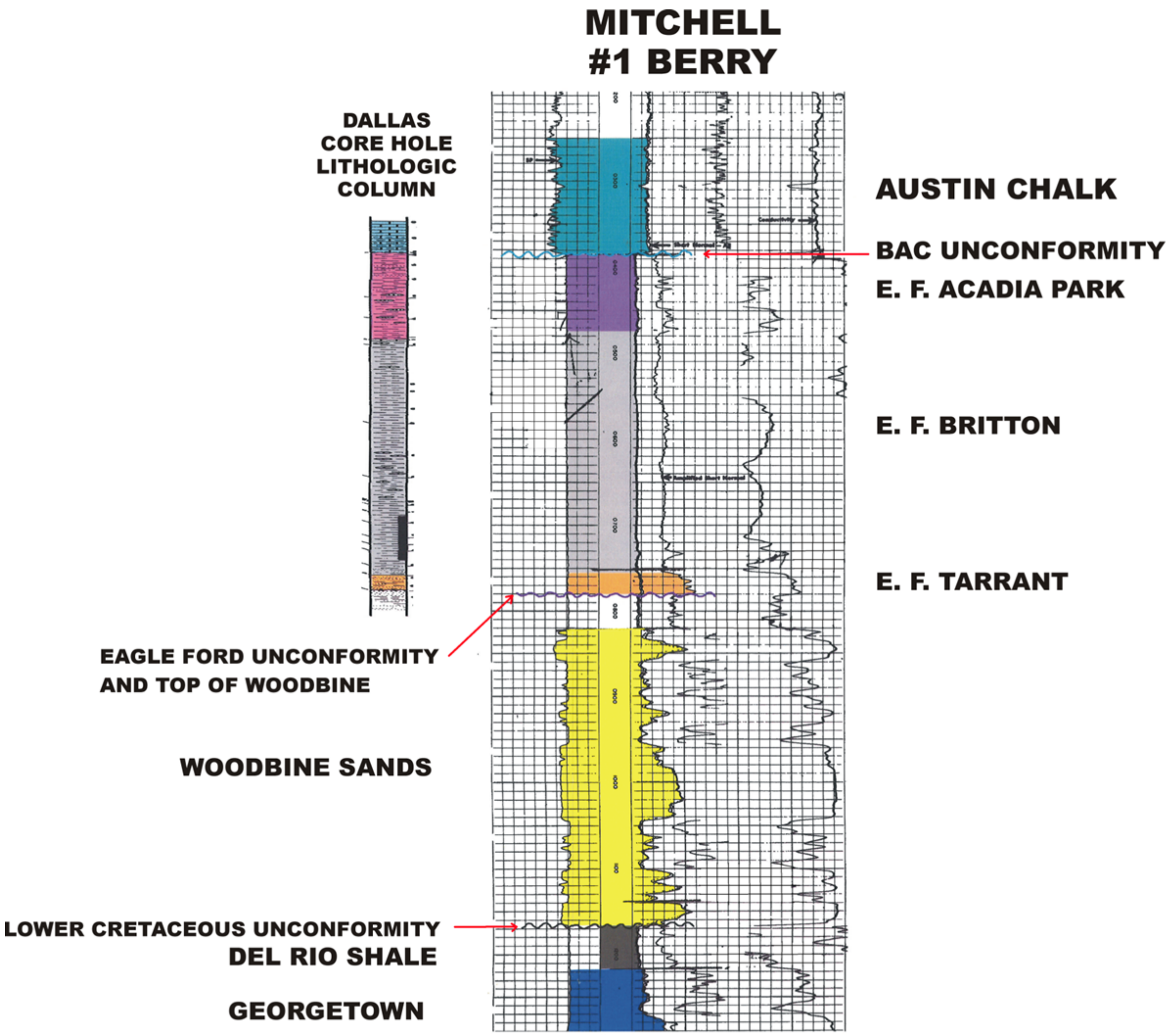


Figure 2. Correlation of Eagle Ford section in described core from Dallas core hole from Brown and Pierce (1962) to nearby well log of Mitchell #1 Berry (42–139–00003) in Dallas County, Texas. This demonstrates the log character of the three Eagle Ford formations, the Acadia Park, the Britton, and the Tarrant. The Dallas core hole is near the described surface type section of the Eagle Ford and is used as a proxy for the type section.

This log was also shown in Figure 2 with its correlation to the outcrop. This is the definition point, or it is our type section if you desire, for the Eagle Ford for our correlations. Proceeding from west to east, we see the Woodbine thicken downward as the effects of the Lower Cretaceous Unconformity lessen into the East Texas Basin. This cross-section confirms the observation of Brown and Pierce (1962) that the Eagle Ford is correlative into the East Texas Basin. The total Woodbine/Eagle Ford interval thickens gently into the deepest part of the basin, which is east of the geographic center of the basin, at which point it thins abruptly onto the Sabine Uplift. This cross-section reinforces the point that the East Texas Basin, like others along the Gulf Coast is an asymmetric basin with the steep flank on the east side (Adams, 2006). The abrupt thinning onto the Sabine Uplift is the result of both the Eagle Ford Unconformity at the base of the Eagle Ford and the unconformity at the Top of the Eagle Ford/Base of the Austin Chalk. This critical merging of unconformities defines the trapping of Lower Woodbine sands at East Texas (Woodbine) Oil Field (Ambrose et al., 2009; Adams and Carr, 2010).

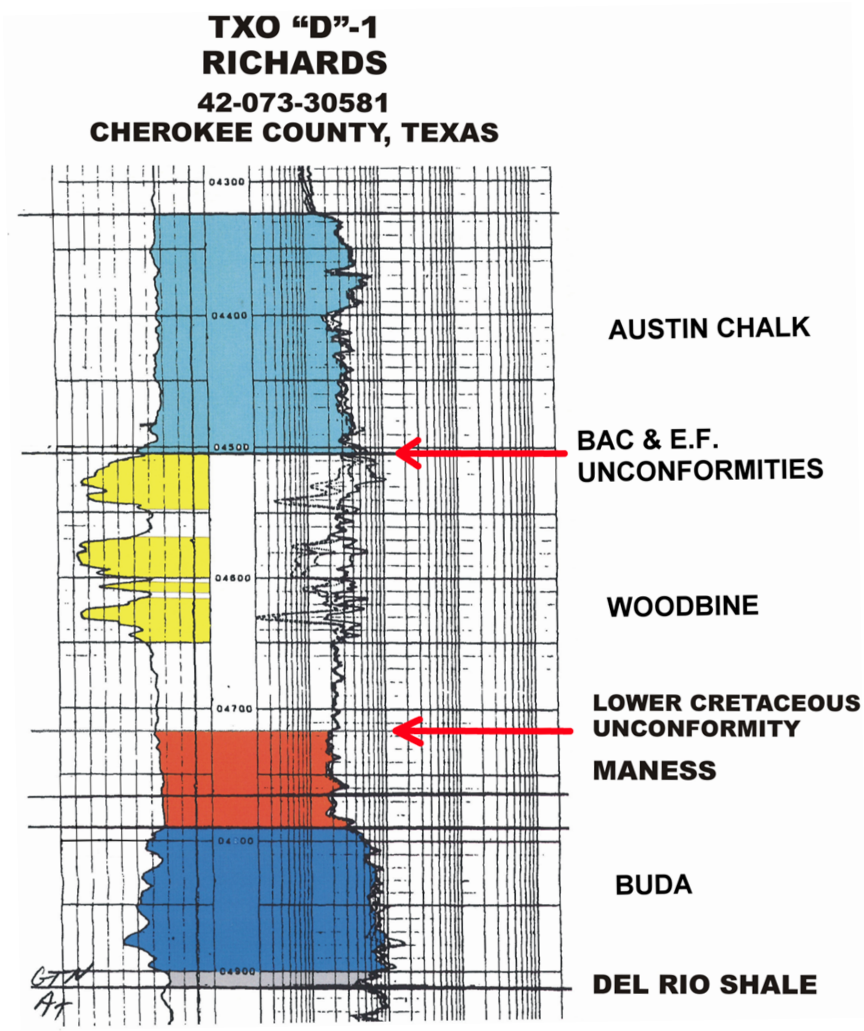


Figure 3. Type log of the Maness Formation. The Maness is immediately above the Lower Cretaceous Buda Formation and is also of Lower Cretaceous age. The Maness is unconformably separated from the overlying Woodbine Formation, which is Upper Cretaceous in age.

Cross-Section 2

A second cross-section (Fig. 5) starts with the Fair #1 Linker well, located in the middle of the prior west to east cross-section 1 across the East Texas Basin, and from that point goes south and then southwest through the center of the East Texas Basin and to the southwestern most corner of the basin. In cross-section 2, we see the thinning of the Acadia Park as well as the loss of the Britton and the Tarrant parts of the Eagle Ford. By log character, the Eagle Ford present in Brazos and Burleson counties is more similar to the Acadia Park than either the Britton or the Tarrant. The Eagle Ford of Brazos and Burleson counties is the result of deposition in incised valleys related to river channel downcutting by the paleo-Brazos River as evidenced in this area by the Eagle Ford Unconformity (Adams and Carr, 2010). Whether this post-Eagle Ford Unconformity section in Brazos and Burleson counties is fully time equivalent to the type section of the Acadia Park in Dallas is unknown at this time.

Main Menu

Search

Author Index

Papers

Help

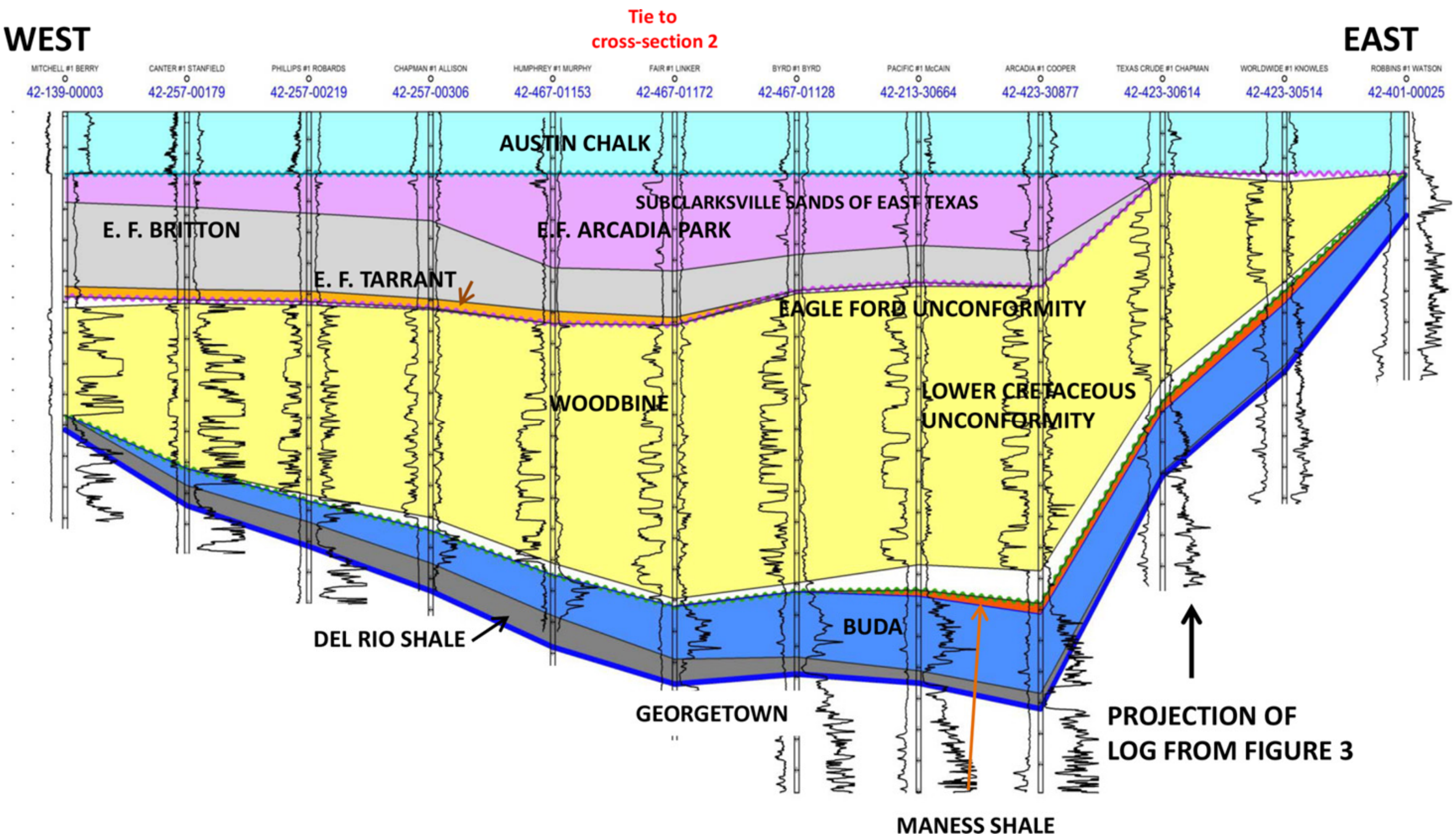


Figure 4. Cross-section 1. West to east cross-section of the Eagle Ford and Woodbine across the East Texas Basin from near the Dallas core hole to the Woodbine and Eagle Ford pinch-out on the Sabine Uplift. This cross-section demonstrates the lateral continuity of the Eagle Ford and Woodbine into the East Texas Basin, as well as the influence of the Lower Cretaceous Unconformity.

Main Menu
Search
Author Index
Papers
Help

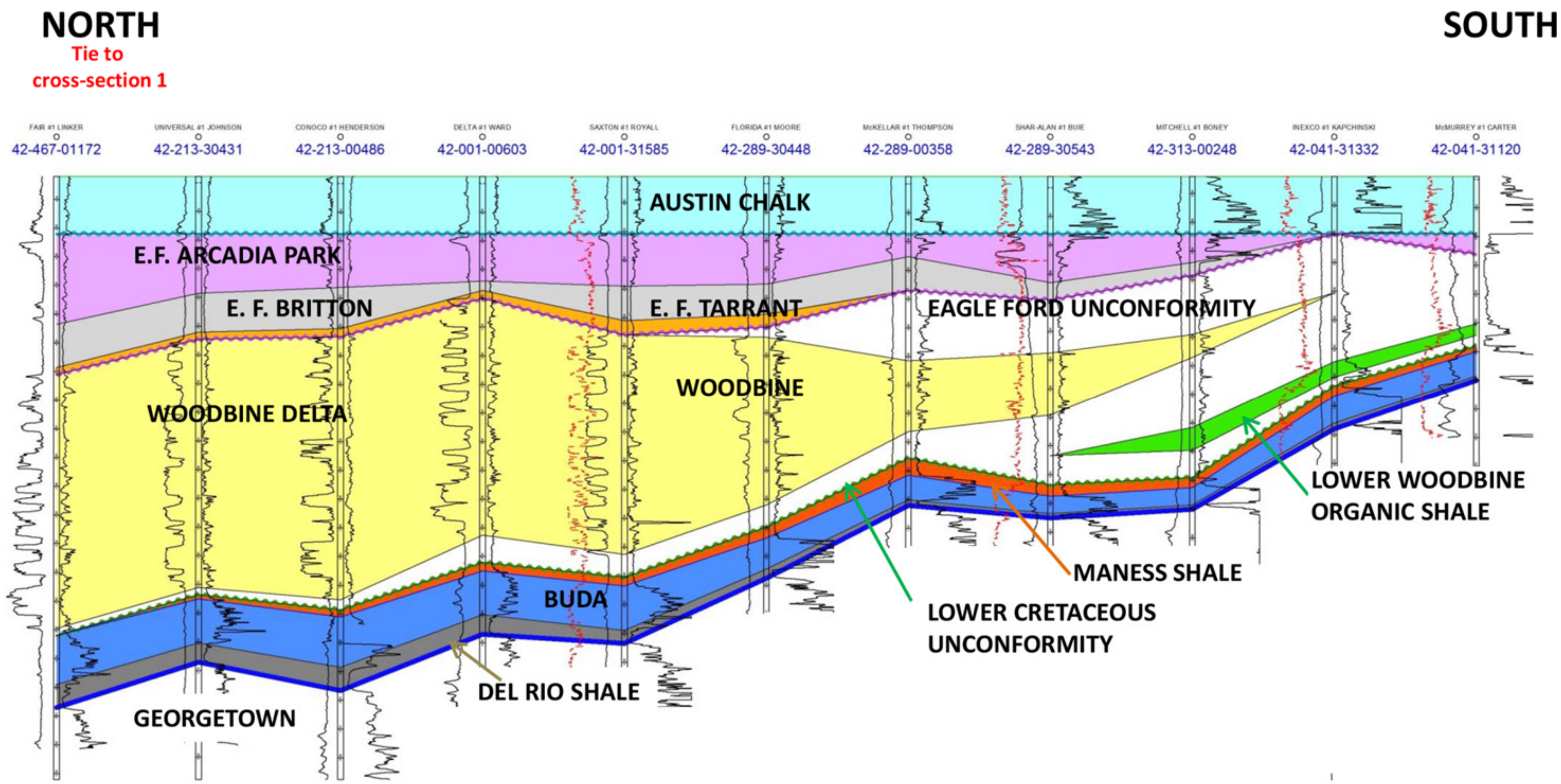


Figure 5. Cross-section 2. North to south cross-section of the Eagle Ford and Woodbine through the East Texas Basin from cross-section 1 southward to the current study area. This cross-section demonstrates the southward loss of sands in the Woodbine, as well as the southward thinning of the Eagle Ford. Most importantly, it demonstrates the appearance of the LWOS below the Woodbine sands and above the Maness.

In cross-section 2, we also see the southward loss of Woodbine sands into the Pepper Shale facies. This is the southern limit of the Ouachita-fed deltaic systems of Oliver (1971). On cross-section 2 we also see the northeasternmost extent of the LWOS. Compare the log response of this interval between the Mitchell #1 Boney well, located at Madisonville Field in Madison County, with the log character of the same interval in the Inexco #1 Kapchinski well in Brazos County (see Figure 1 for locations). The interval is barely discernible from the shales above and below in the #1 Boney well, but in the #1 Kapchinski well the interval is immediately apparent. This is the interval we will correlate across the San Marcos Arch into the Maverick Basin and beyond.

We have already looked at two of the regional cross-sections from the Eagle Ford outcrop into and south through the East Texas Basin. Additional cross-sections have been constructed from this point across the south end of the San Marcos Arch and finally west to the Maverick Basin and, by using the correlations of Donovan and Staerker (2010), on to Lozier Canyon in Terrell County, Texas. In sum, these cross-sections demonstrate the lithostratigraphic correlations from Dallas southwestward to Terrell County. They show clearly that the high resistivity/hot gamma ray of the LWOS correlates with the Lower Eagle Ford of South Texas (of current terminology), but that that interval is not correlative at all with the Eagle Ford of Hill (1887) as defined at its type locality.

Cross-Section 3

Cross-section 3 (Fig. 6) crosses the San Marcos Arch from eastern Lee County to Atascosa County in South Texas (see Figure 1 for cross-section and well log locations). The large number of close-spaced wells is used to demonstrate the lateral continuity of this high resistivity zone. The cross-section location was chosen to stay south, away from the interval pinch-out to provide sufficient interval for correlation from northeast to southwest. From this section it is easy to see that the LWOS of Brazos County is the Lower Eagle Ford of Atascosa County. Three additional cross-sections were constructed at right angles to this cross-section to confirm the regional aspects of the correlation. They are not shown here for brevities sake.

Cross-Section 4

This cross-section (Fig. 7) utilizes recent cross-sections and correlations published by Hentz and Ruppel (2010) and by Donovan and Staerker (2010). Figure 5 of Hentz and Ruppel (2010) is a southwest to northeast cross section from Maverick County across Atascosa County to Wilson County in South Texas. The Santa Fe-Windsor #1 James of the Hentz and Ruppel (2010) cross-section is very close to the Mickelson #1 Tom well, at the southwest end of our cross-section 3. I have substituted the Mickelson well into their cross-section and added additional data from Donovan and Staerker (2010). Donovan and Staerker (2010, their fig. 11) provided a detailed sequence stratigraphic correlation from their type log in Maverick County, Texas, to the classic surface outcrops of the Boquillas/Eagle Ford in Lozier Canyon in Terrell County, near Langtry, Texas (their fig. 10). The reader is referred to Donovan and Staerker (2010) for more details of this section. Importantly, they recognized an unconformity at the same location as the Eagle Ford Unconformity of this study.

The outcrop at Lozier Canyon was also studied extensively in Pessagno (1969). Based on his planktonic foraminifera studies, he subdivided the West Texas Eagle Ford into three substages. At Lozier Canyon, the lower 136 ft was in his lowest substage, the Lozierian. He tentatively correlates the Lozierian to be Upper Cenomanian in age. His middle substage, the Bocian, is missing at Lozier Canyon and is dated as Early Turonian. His third and upper substage is the Sycamorian and is represented by the upper 28–51 ft of the Lozier Canyon outcrop. It is Late Turonian in age.

Thus, Pessagno's work of 1969 strongly supports Donovan and Staerker's (2010) interpretation of their K69SB unconformity between their Eagle Ford and Langtry members. In age, the missing Early Turonian of his Bocian stage is comparable to the missing interval between the Woodbine and Eagle Ford of the East Texas Basin. His missing Bocian stage may thus be equivalent in time to the Eagle Ford Unconformity of Adams and Carr (2010).

Cross-Section 5

It is now a simple matter of selecting representative wells from cross-sections 1, 2, 3 and 4 to make a single simple cross-section from Dallas, Texas, where the Woodbine and Eagle Ford were both defined to the Maverick Basin (Fig. 8). This is cross-section 5. Through the work of Donovan and Staerker (2010), we could extend

Main Menu
Search
Author Index
Papers
Help

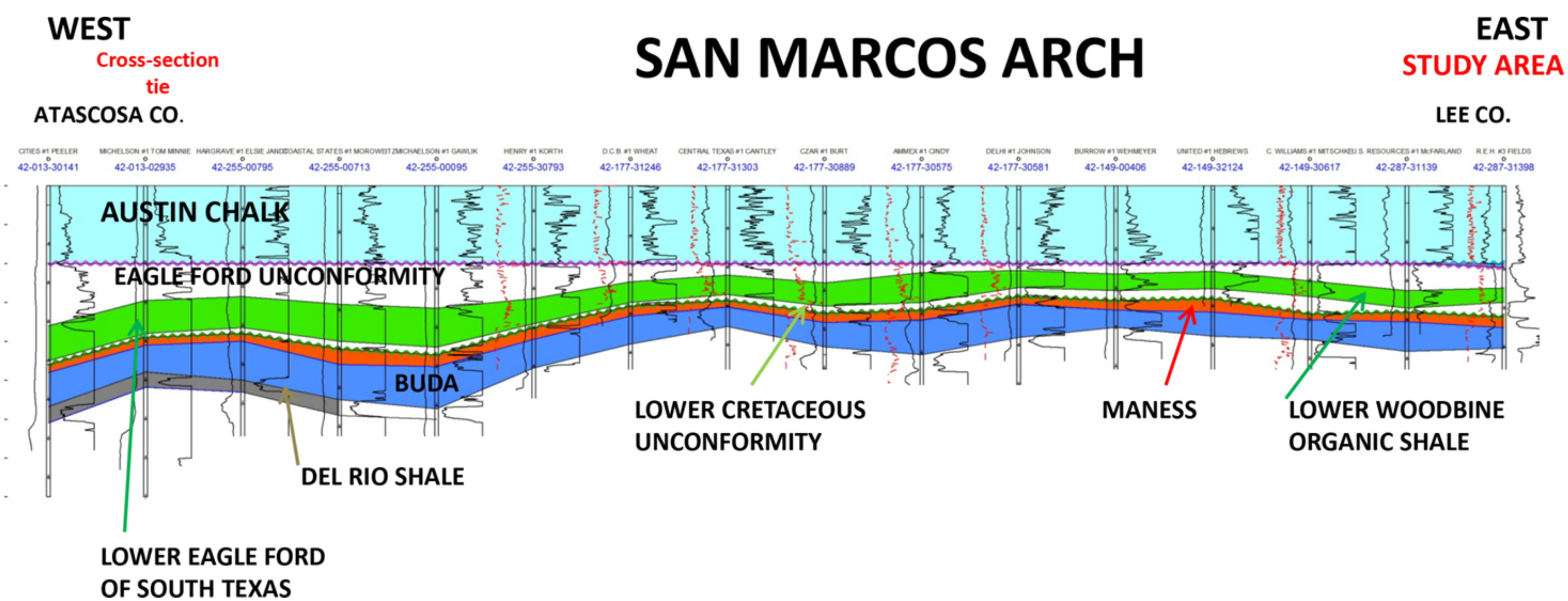


Figure 6. Cross-section 3. West to east cross-section of the Woodbine and Eagle Ford from the study area across the San Marcos Arch to the South Texas Basin. Note the consistence of the correlation of the LWOS from end to end.

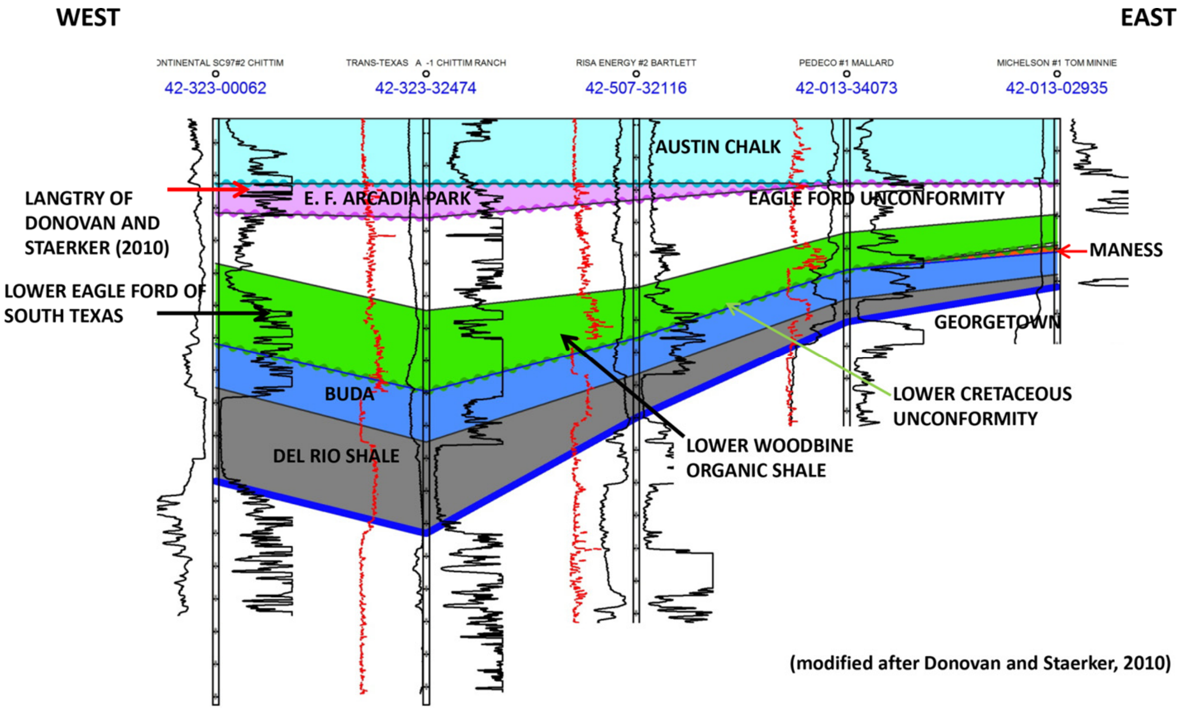


Figure 7. Cross-section 4. West to east cross-section extending cross-section 3 into the Maverick Basin. Note the thickening of the LWOS into the Maverick Basin and the appearance of true Eagle Ford (Langtry of Donovan and Staerker, 2010). The LWOS is clearly equivalent to the Lower Eagleford/ Eagle Ford of South Texas terminology.

these correlations further to the other West Texas surface outcrops where the Boquillas/Eagle Ford have been extensively studied. However, there is not sufficient room here to reproduce that work. Please refer to Donovan and Staerker (2010) for that extension.

In cross-section 5, we see the thinning and then loss of the Eagle Ford away from Dallas, we see the thickening then thinning and disappearance of the Woodbine sands, and we also can see the Eagle Ford Unconformity separating the Eagle Ford above from the Woodbine below. We also see the appearance of the LWOS and its continuation into the South Texas Maverick Basin and on to West Texas as the Lower Eagle Ford of South Texas. This then is the same zone as the primary source rock for South Texas and the primary target of thousands of horizontal Eagle Ford Shale wells from Webb and Maverick County, and extending eastward past Karnes, DeWitt, and Lavaca counties.

We now find ourselves in a quandary. We have multiple names for the same interval, based on correlations from opposite directions. Based on recent usage we are tempted to call everything Eagleford (one word), but the NACSN rule of precedence indicates that the nomenclature of Hill (1887, 1901) should be followed. Therefore, all of the South Texas and West Texas Eagleford (again one word) should be called lower Woodbine, with the exception of the Langtry Member and its equivalents in South Texas, which appear to be true Eagle Ford equivalents (cross-section 5).

SOUTH TEXAS EAGLE FORD DATA

The increase in drilling for the South Texas Eagle Ford (STE) Shale has had the added benefit of providing a wealth of core, log and outcrop data about this interval. This interval has been the subject of multiple theses and dissertations (Trevino, 1988; Jiang, 1989; Harbor, 2011; Sondhi, 2011; Cardneaux, 2012; Hendershott, 2012; Workman, 2013; McGarity, 2013). Most provide detailed lithologic, sequence stratigraphic and/or log-

Main Menu

Search

Author Index

Papers

Help

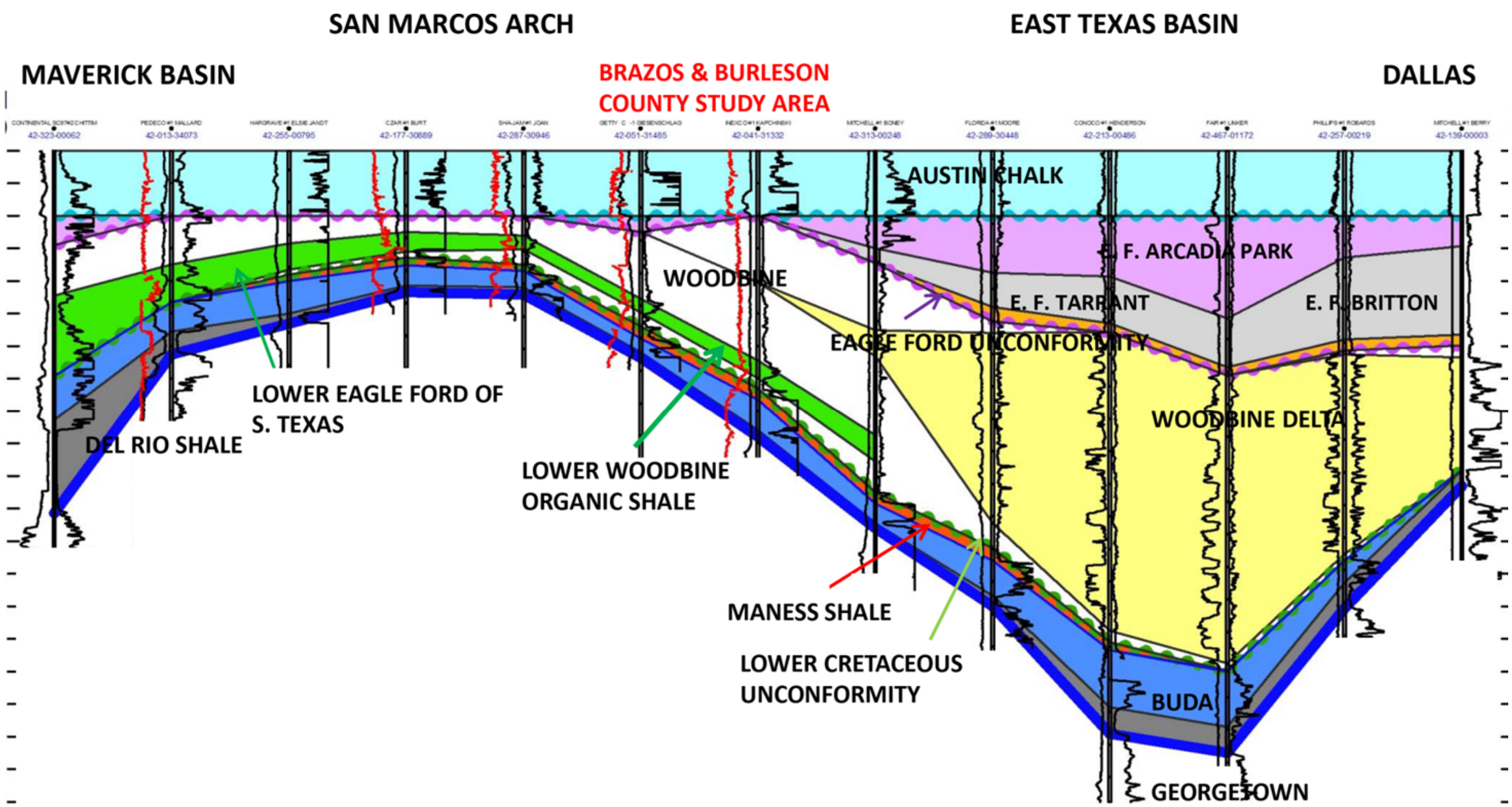


Figure 8. Cross-section 5. West to east cross-section from the type section of the Eagle Ford in Dallas, on the right, to the Maverick Basin of South Texas on the left. The LWOS of our study area is clearly correlative to the Lower Eagle Ford of South Texas. The Eagle Ford of South Texas is clearly older than the type section of the Eagle Ford in the Dallas area as defined by Hill (1887).

production analysis of this interval. We now have data that implies that the bulk of the STE production is coming from the Lower Eagle Ford (of South Texas). The Lower Eagle Ford has much higher total organic carbon (TOC) values, has a hotter gamma ray signature, and higher resistivity than the Upper Eagle Ford (South Texas).

But at the time of this initial analysis (2010), much of that data was still proprietary. So other research was required for analysis of TOC, especially the vertical distribution of TOC, environments of deposition, kerogen types, and specific oil yields. Many of these questions were fortunately answered by Grabowski in 1995. As many of these questions have been answered in detail in the literature I will not belabor the points regarding TOC, kerogen types, or environments of deposition. However, one point does bear emphasis. Grabowski (1995) discussed the difference in specific oil yield as a function of depth. We now understand that this is a response to the consumption of kerogen to generate more oil as the kerogen is buried more deeply with increased pressure, temperature and time (Modica and Lapierre, 2012). In the immature Eagle Ford (at or about 6000 ft depth), the Lower Eagle Ford has the capability to generate 340 to 400 BO/ac-ft (Grabowski, 1995). In the mature Eagle Ford at depths from 9000 to 11,500 ft, the Lower Eagle Ford can generate 1200 BO/ac-ft. Carrying this data back into our Brazos and Burleson county area of interest, this data supports our earlier conclusion that our sweet spot should be in the deeper part of the oil window. Not only can we expect lighter oil, and more reservoir energy in the form of associated gas to push it out of the rock into our wellbore, but the source rocks in the deeper, more mature part of the play have the capability to generate three times as much oil per unit volume!

INTERVAL MAPPING

Using the large log database available across the Brazos-Burleson area, we made an interval isolith of the oil -generating shale. This value can be easily determined on basic electric logs by its high resistivity and its hot gamma ray signature. Figure 9 is a type log from near our projected sweet spot. The gamma ray is important, because as you move from east to west across the area, the resistivity interval thickness remains fairly constant, but the interval with the hot gamma ray character thins and is progressively lower in the section. Thus, the LWOS interval isolith map (Fig. 10) goes to zero in eastern Lee County, even though the resistivity interval is still present. Are we implying that there is no oil-generating shale in Lee County? No. We are high-grading where the oil-generating capacity appears to be the greatest. The presence of oil producing wells from this horizon with no hot gamma ray is proof that this cut-off is not intended as a edge determinant for oil productive versus non oil productive, but rather a method to help determine where the oil generation and thus our expectations of oil production will be the greatest.

Figure 11 is a detailed log cross-section across the area of our LWOS interval isolith. Going eastward from our core area, into Grimes and Madison counties, we see the resistivity character of our shale change. The average deep resistivity drops from 10 ohm-m to less than 5 ohm-m. Clearly, either the shale has more clay and less organic material, or it may be water-wet and not oil-wet. Regardless of the reason, this puts an eastern boundary on the sweet spot. As we go west, we see that the LWOS interval is gradually replaced from above by a similar shale with comparable resistivity, but lacking the characteristic hot gamma ray character. Note the detailed correlation of the shale within this interval and the change from hot to not on the gamma ray log in moving from east to west. Thus this interval isolith helps provide east and west boundaries for our sweet spot.

GEOCHEMISTRY

Organic shales cannot be treated as normal reservoirs. Unlike conventional reservoir rocks that owe their oil saturation to oil that has migrated into the rocks pore network, organic shales owe their oil saturation to oil that has generated in place. Several important observations follow from this difference. We will touch on these differences, but the reader is referred to the original articles cited for more definitive treatment of each point. They are listed here only to acquaint the reader with their importance in the exploration and evaluation of organic shale properties and plays, and to explain how they were used in our sweet spot definition.

Organic Shales Contain Self-Generated Hydrocarbons

Much has been written about the importance of TOC values, or richness, in high-grading shale plays. There are three components to TOC (Jarvie, 1991). They are extractable organic matter (EOM), convertible carbon, and a residual carbon fraction. EOM is carbon contained in oil and gas that have already formed. Convertible carbon is contained in kerogen and is the remaining potential to generate additional oil and gas. The residual

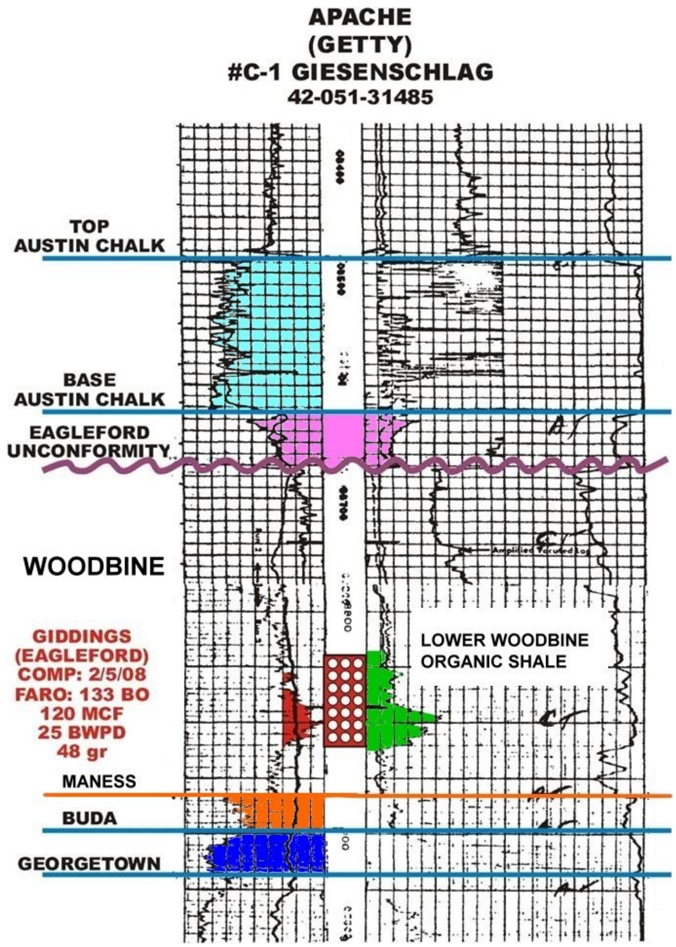


Figure 9. Type log of LWOS in Brazos and Burleson county area. In the study area, we are mapping only the interval with both the hot gamma ray and the higher resistivity.

carbon fraction is the organic carbon present with no potential to generate oil and gas (Jarvie, 1991). The fraction of the TOC that represents producible hydrocarbons from an organic shale is the EOM. Thus it is important to know more about the shale than just its TOC; you should investigate its EOM. Increased burial time, pressure and temperature will eventually convert most of the convertible carbon to EOM. In an organic shale play, we are concerned with determining where we are located in the system and what is the magic mix of convertible carbon to EOM as oil in an extractable form in our area.

Organic Shales Contain Self-Generated Porosity

As organic shales are buried and as convertible carbon becomes EOM, the kerogen consumed by this reaction leaves voids in the remaining kerogen grains (Modica and Lapierre, 2012).

The amount of generated porosity is directly proportional to the amount of convertible carbon (kerogen) that has been consumed and converted into EOM (Modica and Lapierre, 2012). For a striking visual comparison of early and late oil generated nano-porosity, the reader is referred to Loucks et al. (2009, their figs. 10 and 5, respectively). Loucks et al. (2009) recorded porosities as high as 20.2% within kerogen macerals in the Barnett Shale. This porosity must be accounted for in calculations of total porosity. The reader is also referred to Sondhi (2011) for images of this nano-porosity within the LWOS within our study area.

Main Menu
Search
Author Index
Papers
Help

Main Menu
Search
Author Index
Papers
Help

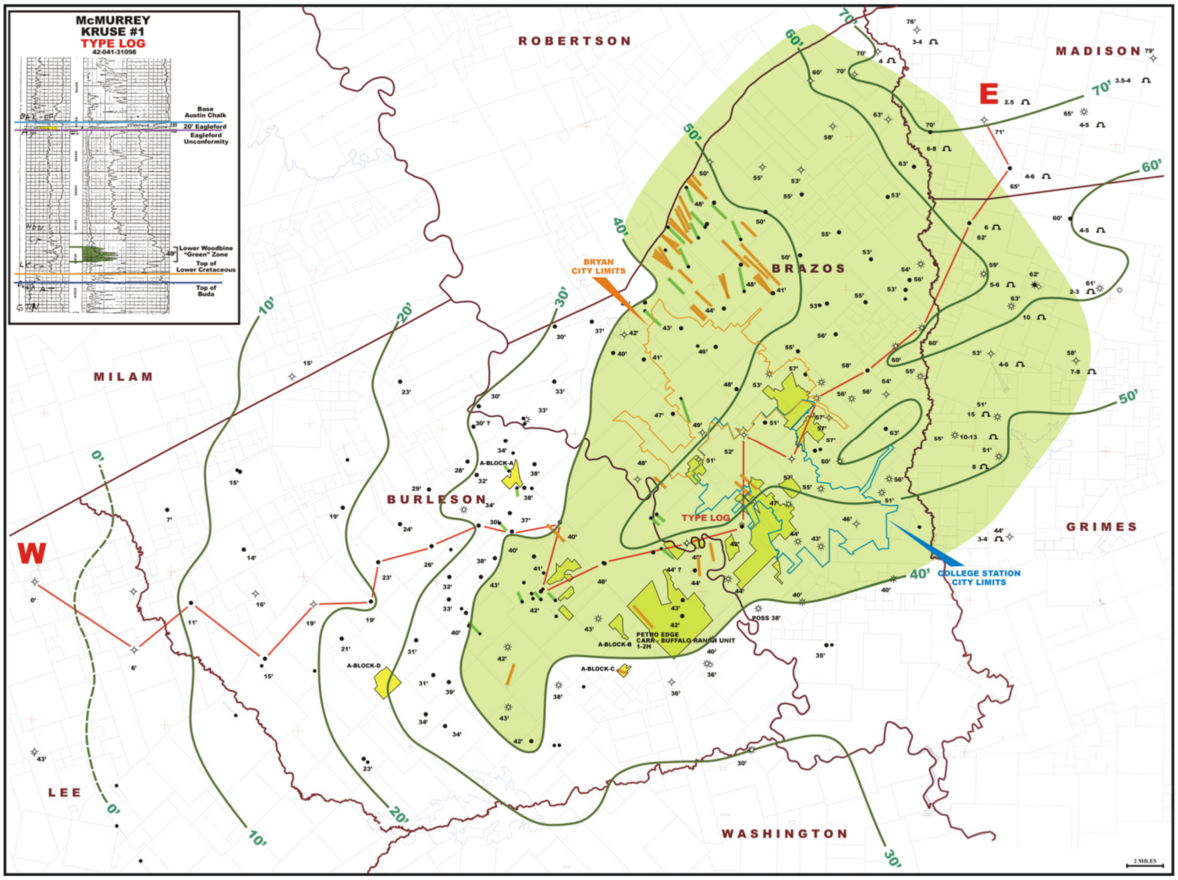


Figure 10. Interval isolith of the LWOS in the study area. Note that the interval goes to zero to the west. To the east, the edge of the green shaded area represents where the interval is losing both resistivity and gamma ray signature. To the west, the interval is replaced vertically with a resistive shale without the hot gamma ray signature.

Organic Shales Contain Oil-Wet Porosity

Water saturation is always a critical factor in low-porosity conventional reservoirs. Where hydrocarbon migration must displace water to move into a reservoir, the rock is still in a water-wet state. This water-wet state greatly reduces the storage capacity for hydrocarbons in tight conventional reservoirs.

In organic-rich shales, the oil is generated in place. Implicit in this assumption of an intra-kerogen porosity system generated as the kerogen is converted to EOM is the lack of appreciable water in the system. Thus, the intra-kerogen porosity system will be oil wet (Modica and Lapierre, 2012). Log analysis models for water-wet reservoirs do not work well in this type of pore system.

The above conditions must be considered in predicting a reservoir sweet spot. If porosity increases as more oil is generated, and if oil recovery is related to original oil in place, then it follows that better conditions for oil recovery will be located near the deepest parts of the oil-generating window. Cander (2012) used a GOR of 3200 as his division between an oil reservoir and a gas-condensate reservoir for the South Texas Eagle Ford. He also considered reservoir pressure as the most critical element in successful oil production. Therefore, by analogy, the deepest part of the oil window should be our target.

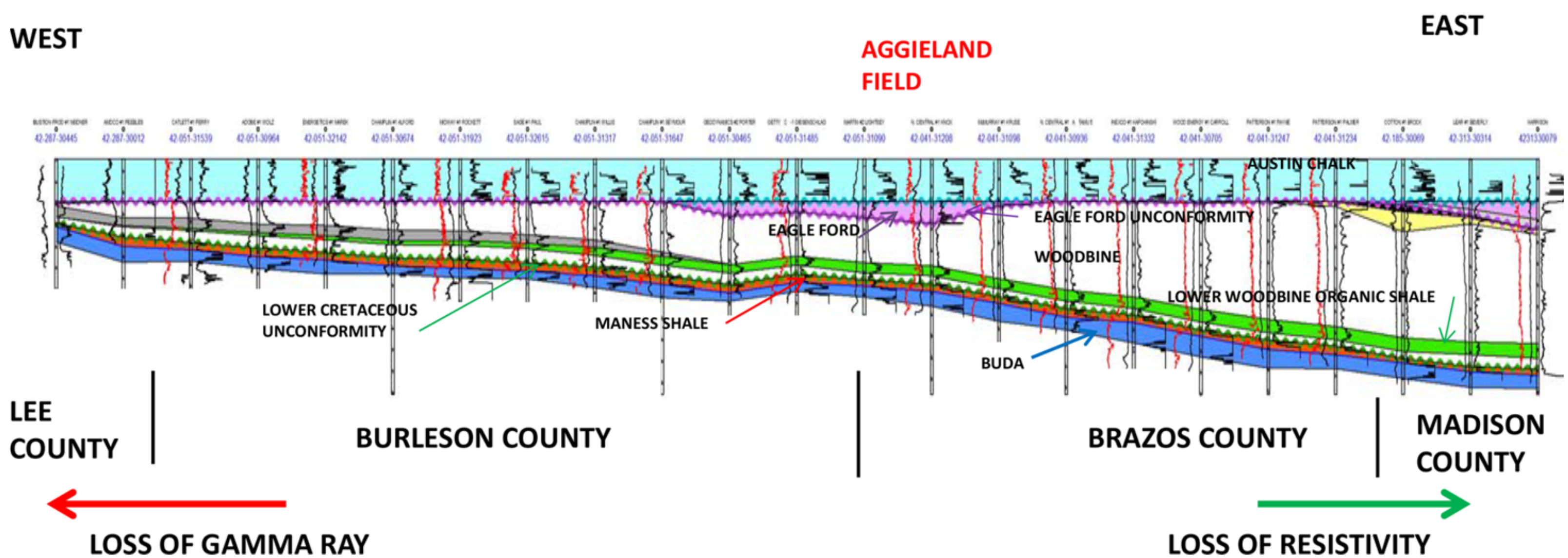


Figure 11. West to east cross-section of the Woodbine and Eagle Ford across the study area. Note the loss of resistivity in the LWOS to the east and the replacement of the hot gamma ray interval (colored green) with a resistive shale without the hot gamma ray signature (colored gray) to the west.

SUMMARY OF EARLY APACHE WELL DATA

Vertical Wells

To ensure that our comparison, when initially run in early 2011, was not biased by the length of time each well had produced, all wells were normalized by using the cumulative oil production through the first 24 months of production. This number was chosen to maximize the number of wells that could be utilized in the evaluation. After excluding some of the very earliest wells which had only minimal production; 9 vertical wells were selected from the Burleson county area. These 9 wells, completed in 2008 and 2009, had 24 month production ranging from 2621 BO to 11,479 BO, with an average of 5726 BO. Through August 2013, that average per well production is 7123 BO. The true value of these vertical wells is unfortunately not in their well economics, but rather in their production data. They provide an aerial distribution of both oil gravity and gas-oil ratios. These data are necessary for proper play evaluation.

Main Menu
Search
Author Index
Papers
Help

Horizontal Wells

Subsequent to the analysis of the vertical wells, the horizontal wells were analyzed for not just their distribution of oil-gravities and GOR values, but for their production characteristics. From an initial selection of 11 wells, one was too far out of the area (within the gas/condensate area) and one had no fracking indicated. Of the remaining 9 wells, a graph was made plotting cumulative production through the first 24 months versus the length of completed interval in the lateral (see Figure 12). Seven of the 9 wells graphed on nearly a straight line, indicating that a relationship does exist between lateral length and cumulative production. By connecting the origin point on this graph with lines that bracket these 7 wells, a range of expected recovery (for the first 24 months) per unit of lateral length can be estimated. A well from within this field range can then be used to calculate future production via decline curve analysis and adjusted to the expected lateral length to calculate future well production for economic analysis of future drilling opportunities.

The bracket lines on the accompanying graph indicate a range of 19,000 to 28,000 BO for the first 24 months per 1000 ft of lateral length with a median at 23,500 BO. For a well with a 8000 ft lateral, that would suggest the well should produce 152,000 to 224,000 BO during its first 24 months of production (median value = 188,000 BO). With a GOR of 1000, the well would also produce 152 to 224 MCFG during that first 24 months (median value = 188 MCFG).

Plotting the average 24 month cumulative production from the vertical wells on the graph of the horizontal completions intersects the frack length brackets at about 200–300 ft. This suggests that the average frack length associated with the vertical wells may be on the order of 200–300 ft. This number allows us to make an estimate of drainage area for the vertical wells and to calculate the number of vertical wells that a long horizontal well would replace. A 250 ft radius yields a circle with an area of 4.5 ac. Given that the frack drains an ellipse rather than a circle; and that that ellipse will be perpendicular to the wellbore azimuth if the wellbore is oriented perpendicular to the known preferred frack orientation; frack spacing should be optimal at near the calculated frack length. Thus, a 8000 ft lateral might contain 33 fracks and replace 33 vertical wells if fracs are spaced at 240 ft. That would yield a 24 month production of 5726 x 33 = 188,958 BO. That number is almost exactly the median value of the horizontal wells (188,000 BO) projected to an 8000 ft lateral. This number also supports recent work by several companies in the South Texas Eagle Ford that optimal inter-well spacing should be 500 ft or even less to optimize oil drainage.

OIL GRAVITY AND GAS-OIL RATIOS

As previously noted, the data from the Apache recompletions and new drilled wells has been invaluable in defining the projected best producing area for the LWOS in the Brazos and Burleson county area. Figure 13 is a map of the reported oil gravities from all of the wells in the play area. In addition to the earlier Apache wells, we have added wells drilled and completed by Clayton Williams, Weber, Halcon, PetroMax, Buffco, and Ausco in making this map. Although some numbers appear to fit only poorly, a well defined general trend is apparent; with values in the 30–35 degrees gravity in the northern parts of both Brazos and Burleson counties and increasing to the south and east. It is possible that some wells may also have a portion of their production coming from outside of the LWOS. Poor stratigraphic control during horizontal drilling could easily place the well either into the underlying Buda or above the LWOS in thin oil-filled (but water-wet) conventional siltstones and very fine-

ANALYSIS OF PRODUCTION FROM APACHE HORIZONTAL WELLS

Lower Woodbine Shale

Burleson, Brazos and Lee Counties, Texas

WELL NAME	PERF'D LATERAL FT	24 MO OIL PROD	24MO GAS PROD	
Apache 1-"C" Tarver	515	5559	12089	
Apache #1 Chachere	915	25649	8486	
A 2-H Giesenschlag-Groce	3640	39785	27262	
Apache #2 H Hullabaloo	2140	40011	44454	
Apache #6 Reveille	911	24350	31843	
Apache #3H Childers	635	18780	8352	
A 3-H "C" Giesenschlag	856	22488	21597	
Apache #4 Elsik	2312	12796	10890	
Apache #1H Fenn Ranch	1209	32525	27735	
		221943	192708	GOR 869-1

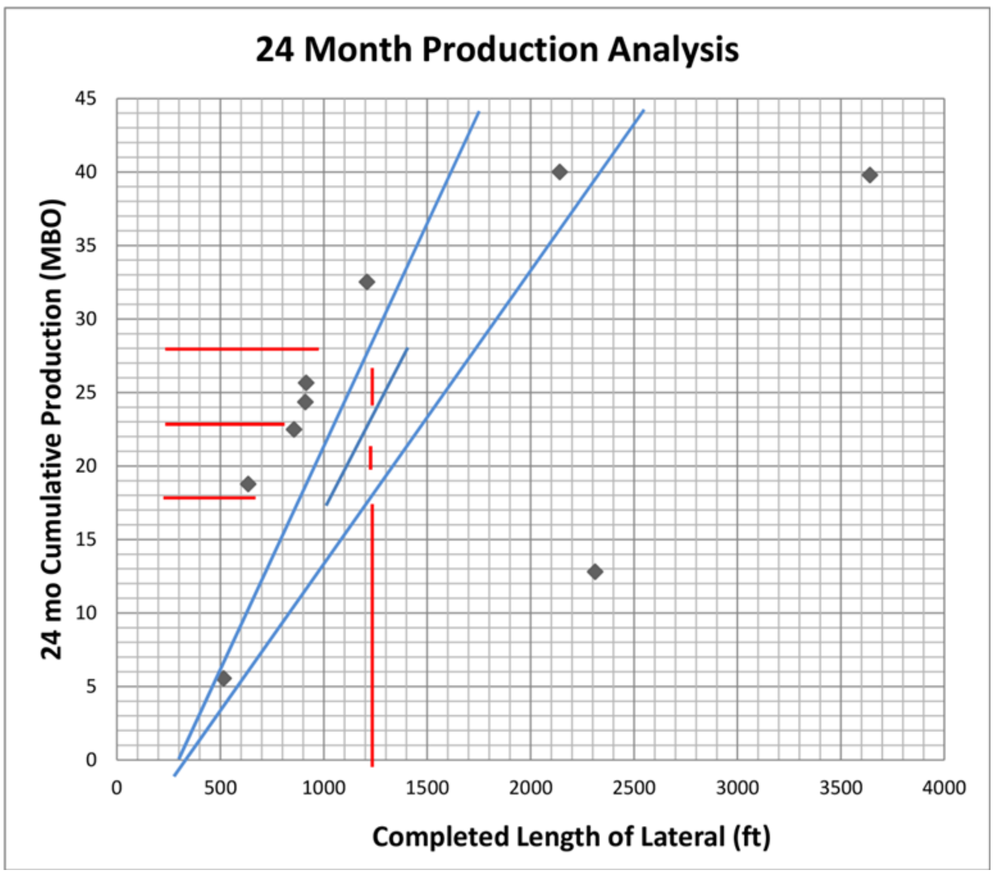


Figure 12. Graph of 24 mont cumulative production versus completed length of lateral for 9 short Apache horizontal wells completed in the LWOS. Average production is 23,000 BO per 1000 ft of lateral for the first 24 months.

Main Menu
Search
Author Index
Papers
Help

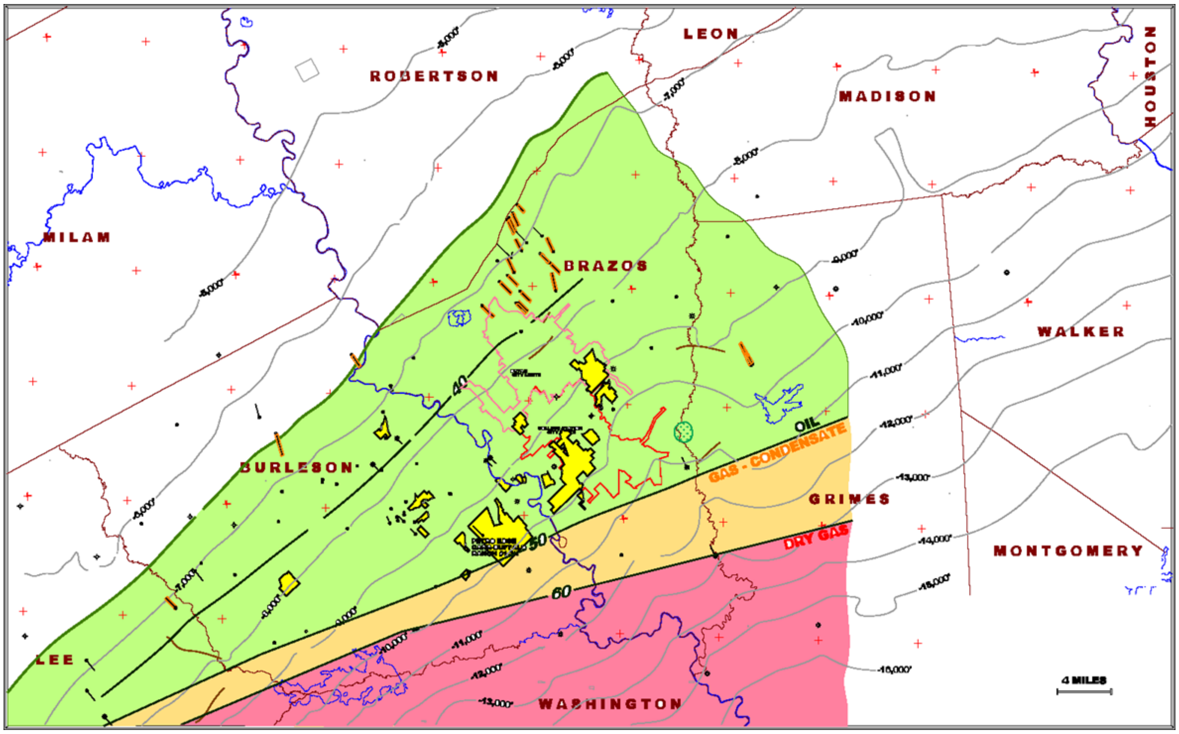


Figure 13. Map of produced oil gravity from the LWOS across the study area. 50 degree gravity is used here as the arbitrary boundary between the oil and gas-condensate windows.

grained sandstones. Note that the shallow contours appear to parallel structural contours, while at the higher gravities there is a divergence of oil gravity from depth. This is related to late tilting and salt uplift at Hill Dome in Grimes County. This divergence has the effect of widening the oil gravity contour spacing in the eastern part of the map. This leads to a larger area within the optimum oil gravity interval.

The same data that allowed us to map the regional distribution of oil gravity also allows us to map the distribution of produced gas-oil ratios (GOR) for the area (see Figure 14). Some wells drilled and completed by Clayton Williams have no reported gas production, so those wells were ignored for purposes of this map. Some caveats must be observed in evaluating this data:

(1) Many operators may not begin gas sales at the same time as they start oil production. In these wells, the mapped GOR may be slightly low.
(2) The produced GOR will change through the life of a well, so the date of calculation will change individual numbers slightly.
(3) Several wells, especially in the deeper portion of the trend, were completed with 2 7/8 inch tubing, even though daily rates dropped very quickly below the rate where liquids could be lifted through 2 7/8 inch tubing. These wells will produce gas by bubbling through an increasingly large head of oil/condensate. Infrequently, a slug of liquid will be produced. These wells will exhibit an anomalously high GOR.

GOR is a critical factor in determining the sweet spot in this type of play. Shale matrix permeability is measured in microdarcys or normally in nanodarcys. Not only are extensively fracked long laterals required, but sufficient gas in the reservoir aids in pushing the oil out of the micro- and nano-pores into the frack channels and thus into the wellbore. Increased heat and pressure as proxied by depth, generate more gas relative to oil, thus increasing the GOR. A higher GOR in organic shales leads to higher reservoir energy, which is a crucial element necessary to push oil out of the nano-pores into the wellbore vial the frack system. Cander (2012) used 3200 as his GOR boundary between oil productive and gas productive Eagle Ford in South Texas. That line becomes the approximate south boundary of our sweet spot.

Main Menu
Search
Author Index
Papers
Help

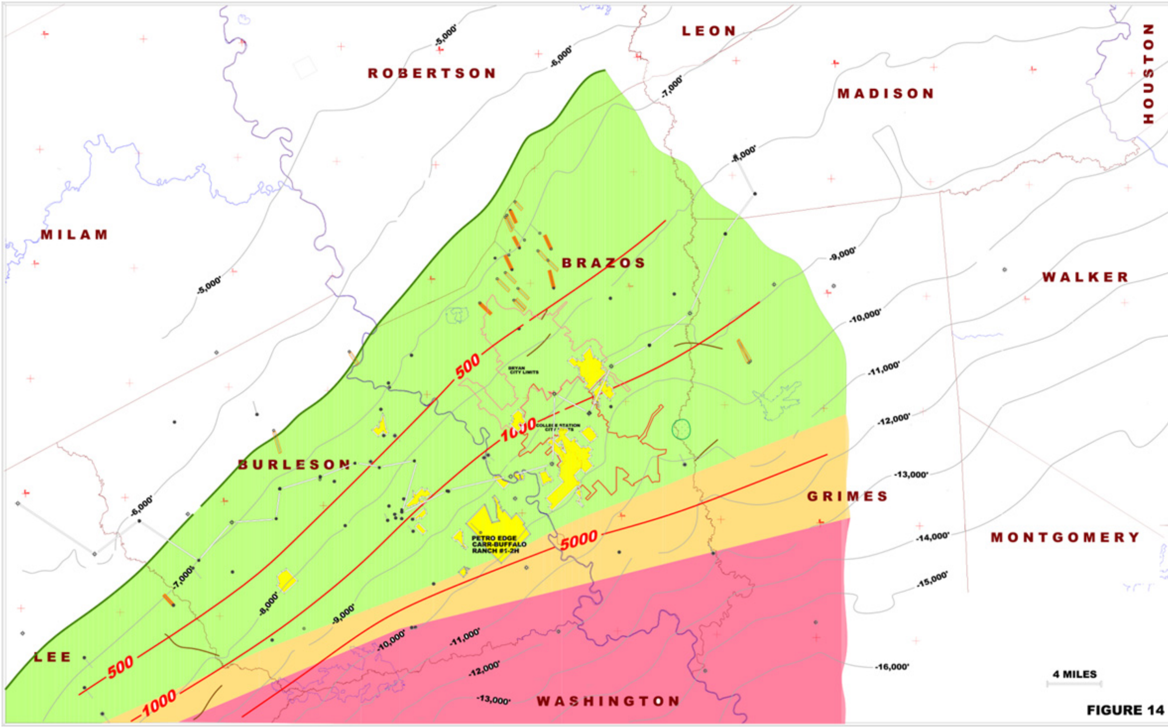
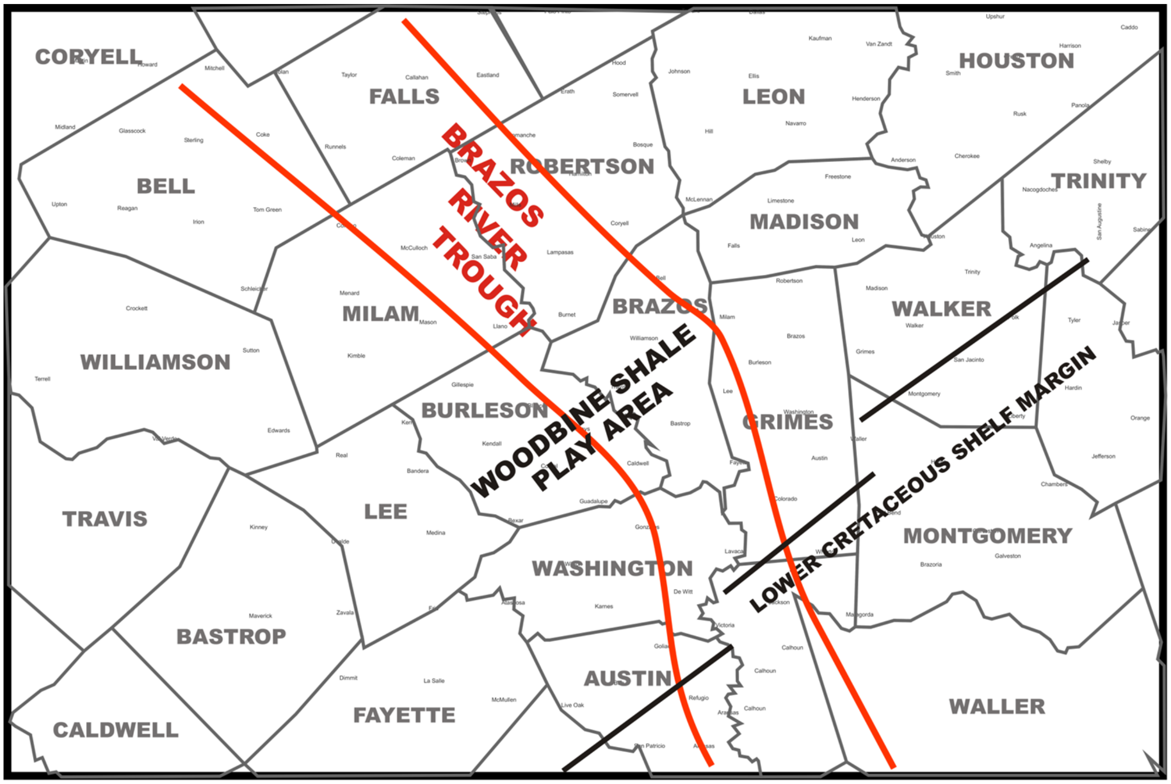


Figure 14. Map of the produced GOR from the LWOS across the study area. Across much of the area, a GOR of 4000 seems to approximate the 50 degree gravity oil line.

PROPER LATERAL ORIENTATION

This is a part of the analysis that requires very little work. Previous work by GRE and the Texas Bureau of Economic Geology (Dix and Jackson, 1981; Laubach et. al., 1987; Baumgardner, 1987; Laubach, 1989) show an average fracture orientation of N60–80E, which is supported by recent analysis by Telker (2013), who confirmed a preferred fracture orientation of approximately N70E. Therefore, we should orient our laterals near N20W for maximum effectiveness. Fracture alignment is related to both coastal orientation and basement structure. Within the study area, a basement low, referred to as the paleo-Brazos River trough, crosses from northwest to southeast (see Figure 15). This trough is interpreted from a depth to magnetic basement map from Earthfield Technology. The orientation of this trough is approximately N35W, so it is very close to the calculated fracture orientation of GRE and Telker (2013). The boundaries of this basement trough are very close to the south-west and north-east boundaries we had chosen based on the thickness and resistivity of the oil-generative shale. It has been noted in the Bakken Shale of Elm Coullee Field of Montana that there is a correlation between the estimated ultimate recovery (EUR) of Bakken wells and their position in blocks defined by basement faults mapped on 3D seismic (E. Honsberger as quoted in Freeman, 2012). Her conclusion was that “structural lineaments provide strong evidence for tectonic activity that could have influenced Bakken reservoir quality in multiple ways by impacting the depositional environment and the diagenetic alteration processes, and also through the creation of a natural fracture network” (E. Honsberger as quoted in Freeman, 2012). It is suspected here that the paleo-Brazos River trough may have had a similar impact on the LWOS. There is a noticeable correlation between the boundaries of the trough and the interpreted best portion of the interval isolith map. If the paleo-Brazos River trough does indeed represent a basement lineament/zone of weakness, it may follow that additional fracturing may be present within the boundaries of the trough.



(TROUGH INTERPRETED TO DEPTH TO MAGNETIC BASEMENT)

Figure 15. Map of the interpreted paleo-Brazos River trough across the study area. This trough is interpreted from the depth to magnetic basement map from Earthfield Technology.

ECONOMIC ANALYSIS OF EARLY HORIZONTAL WELLS

Combining geochemical considerations with the oil gravity map, the gas-oil ratio map, the interval isolith of the LWOS best oil generating zone, and the map of the basement trough provides a set of boundaries to establish the location of our projected sweet spot for the LWOS Play. This is shown on Figure 16. Again be aware that this is not the only part of the play that will be productive, rather, this represents the area where all of the primary factors controlling optimum oil production are joined. Note the approximate boundaries of the entire play are much larger than the projected sweet spot.

Having a complete dataset to determine the location of the best area for drilling is only one part of the problem. It is necessary to determine if the play as a whole is of sufficient quality that the sweet spot is worth pursuing. In this play, we have several short lateral horizontal wells that can be modeled up from their original lengths to 8000 ft; the length we expect to use as an average modern lateral. Figure 17 shows the practical IP for eight Apache horizontal wells plotted against the length of the completed lateral. Practical IP is a term used by Drillinginfo.com, referring to the wells second month recorded production. It is used to minimize the effects of publicly traded operators that may declare very high IP values to help promote stock values or small operators selecting a time with low rates to minimize publicity while continuing to acquire leases in the area. It is a repeatable, yet easily determined value. Although we expect modern completion practices to generate better IP rates than 4 years ago, nonetheless, this analysis gives us a baseline against which to measure our expectations for per well IP values and thus per well reserves. If we can generate good economics from a model based on 4–5 yr old frack and drilling technology, we should expect real-life results to be better. Figure 17 shows an average practical IP of 85 BOPD per 1000 ft of completed lateral. This would project to about 680 BOPD for a 8000 ft lateral.

Main Menu
Search
Author Index
Papers
Help

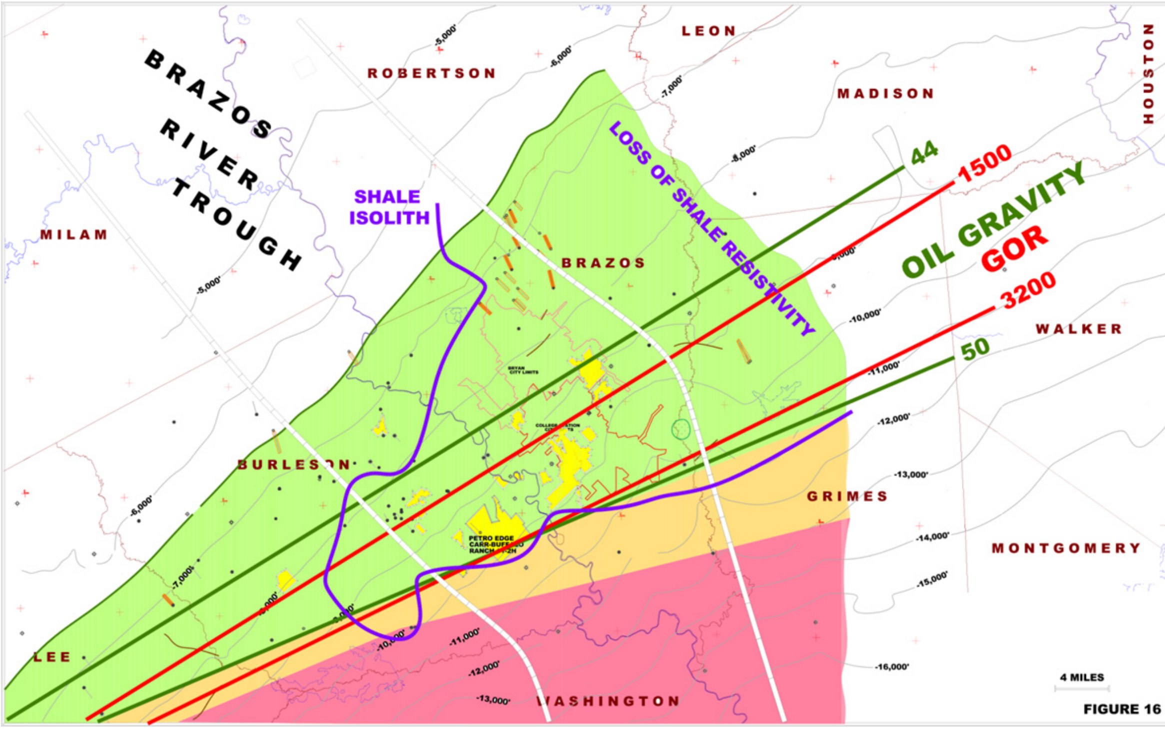


Figure 16. Map of the four discriminants used to select the most favorable acreage for development of the LWOS in the study area. The oil gravity interval from 44 to 50 degrees API was determined to be optimum. The GOR range from 1500 to 3200 has been determined by Cander (2012) to be the most economic in the South Texas Eagle Ford. The LWOS interval isolith greater than 40 ft was selected as being most favorable. The presence of the paleo-Brazos River trough is considered to be a positive discriminant based on analogies of E. Honsberger (as quoted in Freeman, 2012). The intersection of these 4 separate but interrelated factors is considered to be the sweet spot for the LWOS in the study area. Hence, acreage acquisition (as shown by the yellow on the map) was limited to the areas where these 4 outlines overlap.

Main Menu
Search
Author Index
Papers
Help

RECOVERY ANALYSIS

An 8000 ft lateral with a total of 500 ft frack wings would drain an area approximately 8500 ft x 500 ft (with rounded corners) that totals 97 ac. For our purposes we will call that 100 ac drainage. If laterals are spaced 500 ft apart you would get 6.4 wellbores per 640 ac. That yields potential reserves of just over 2,220,000 BO/mi^2 or 3470 BO/ac. If our assumption of 500 ft total drainage width is too narrow, and the actual drainage is 600 ft, the well drainage area is 120 ac and the per-acre production becomes 2890 BO/ac.

These numbers are in complete agreement with analysis of the same interval by Grabowski in 1995. In his paper on the Austin Chalk and South Texas Eagle Ford, he found that the oil-generative capacity for both intervals (based on cores from current depths of 6000 to 7000 ft) ranged from 340 to 400 BO/ac-ft. What he referred to as the "deeper Eagle Ford" (below 9000 ft) had a calculated oil generative capacity of 1200 BO/ac-ft. Regional correlations from this Brazos-Burleson county area into the South Texas Eagle Ford play show definitively that the Lower Eagle Ford of South Texas is the LWOS of East Texas.

The log of the Apache (originally drilled by Getty) #C–1 Giesenschlag is attached (Fig. 9). It shows that the mapped LWOS interval for this well is 42 ft. However, the interval perforated by Apache was 84 ft, and the total LWOS porosity interval is 120 ft. The 42 ft interval used for mapping purposes was selected because the high resistivity associated with that portion of the LWOS interval can be seen and counted from a 1-in electric log, which is all that is available for nearly all of the wells in the mapped area. That number does not reflect the entire oil generative window.

Main Menu
Search
Author Index
Papers
Help

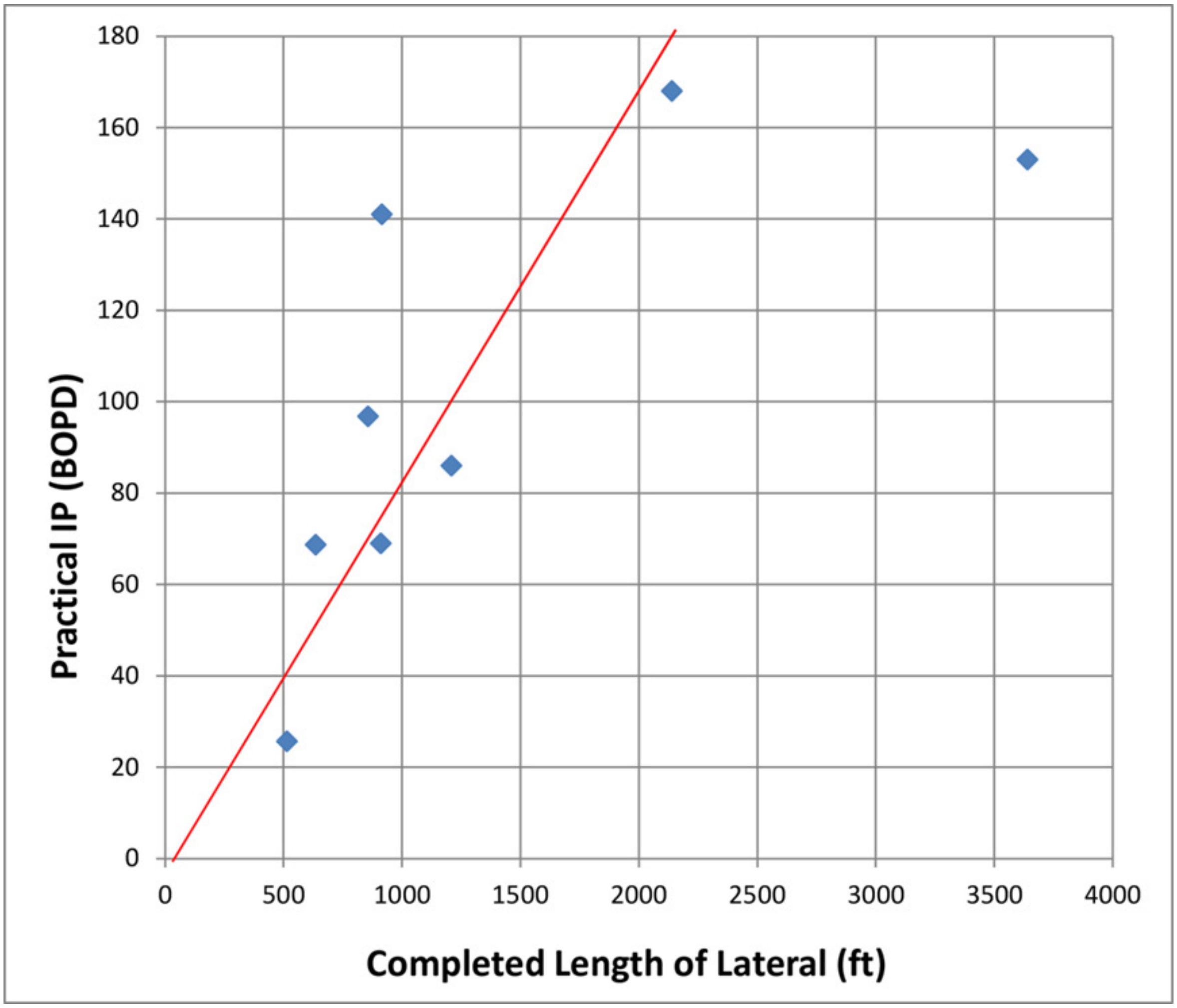


Figure 17. Practical IP versus completed length of lateral for the 8 early Apache wells completed in the LWOS in Brazos and Burleson counties. This excludes the #1 Fenn Ranch well in Lee County, which is not in the same facies.

Using our earlier assumption of 347,000 BO production from 120 ac with a total oil-generative interval of 84 ft (the perforated interval in the C–1 Giesenschlag), requires a recovery of 34.4 BO/ac-ft. That is only 2.86% of the "deeper Eagle Ford" oil generative capacity of Graboowski (1995). If we use only the thickness of the "hot" gamma ray in the C–1 Giesenschlag, we require 68.8 BO/ac-ft recovery to reach our model of 347,000 BO per well. That is 5.7% recovery for Grabowski's (1995) deeper Eagle Ford generative capacity. The LWOS is at a depth of 8900 ft in the Getty #C–1 Giesenschlag. If the same calculation is run on the 100 ac premise, the 84 ft total interval requires 41.3 BO/ac-ft recovery (3.4% recovery); and the 42 ft interval requires 82.6 BO/ac-ft (6.8% recovery). These numbers are well within accepted oil shale recovery expectations of other plays. Recovery efficiency of the Eagle Ford was calculated by Chaudhary (2011). His model, using planar fractures, worked out to a recovery of 11.64% of original oil in place (OOIP) for the Eagle Ford of South Texas.

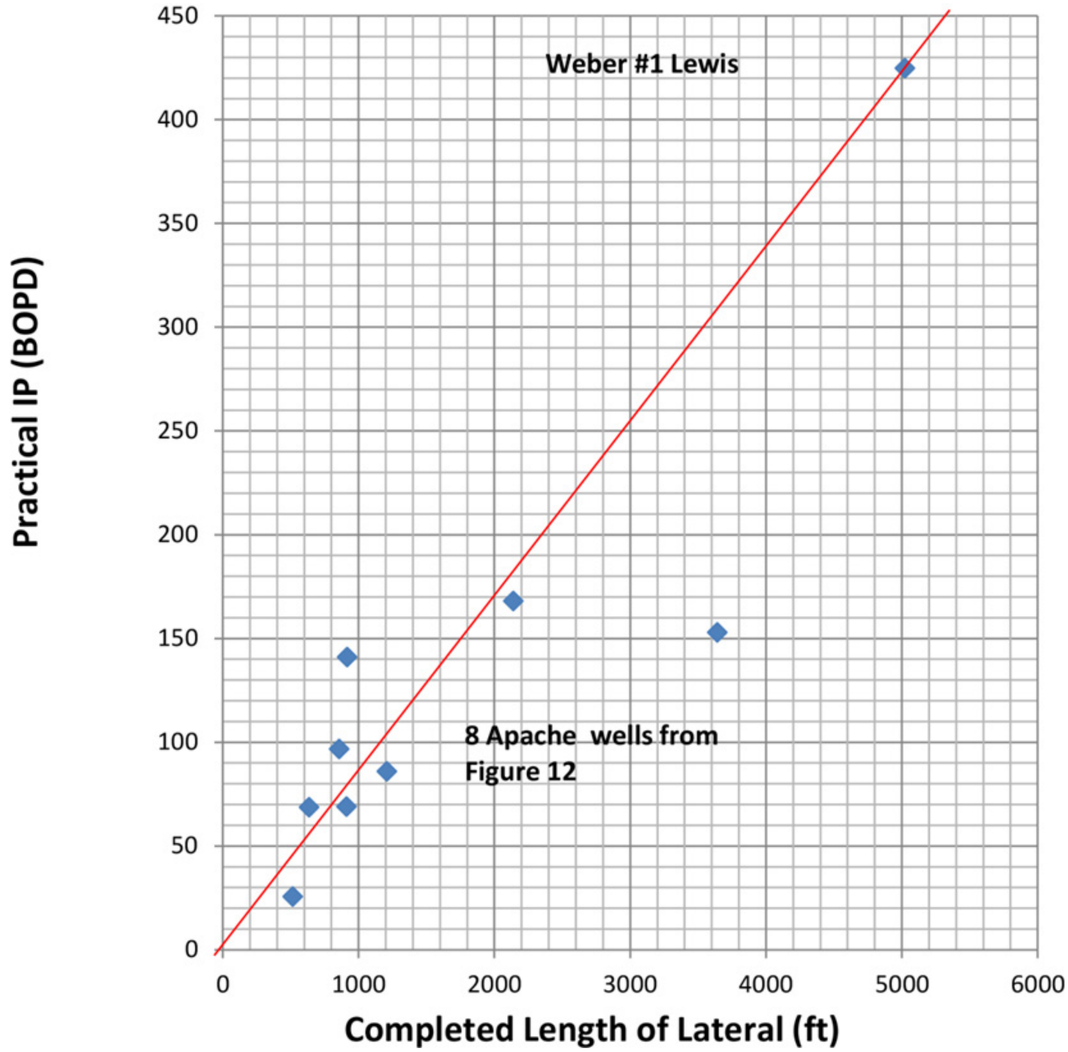


Figure 18. Practical IP versus completed length of lateral for the 8 Apache wells in Figure 17 plus the 2012 completion in the Weber #1 Lewis well in northern Brazos County. The #1 Lewis well has a 5021 ft completed lateral and demonstrated that this analysis can be upscaled.

RECENT ACTIVITY

Weber Energy Corporation began 2012 by drilling their #1 Lewis Unit, a 5021 ft horizontal well in the Woodbine Shale in northern Brazos County. First production was in February of 2012, with a recorded rate of 684 BOPD of 38 degree gravity oil and 425 MCFGD. This is the first well in this play to drill a long lateral and utilize better completion technology. The completed lateral of 5021 ft had practical IP of 424.8 BOPD, or 84.6 BO per 1000 ft of completed lateral. Referring to Figure 18, you see that our earlier analysis based solely on the Apache drilling projected practical IPs of 85 BO per 1000 ft of completed lateral. Thus, the Weber #1 Lewis Unit well has confirmed our analysis method to be valid. Since the #1 Lewis well was drilled, many more wells have been permitted, drilled, completed and are now producing.

As more wells were evaluated in 2013, it appeared that certain wells did not meet the expected practical IP for their lateral length (see Figure 19). These wells all seemed to under-perform for their potential lateral length. For clarity, on this figure, they are grouped by operator. Note that the most deficient completions are all by Clay-

Main Menu
Search
Author Index
Papers
Help

Main Menu
Search
Author Index
Papers
Help

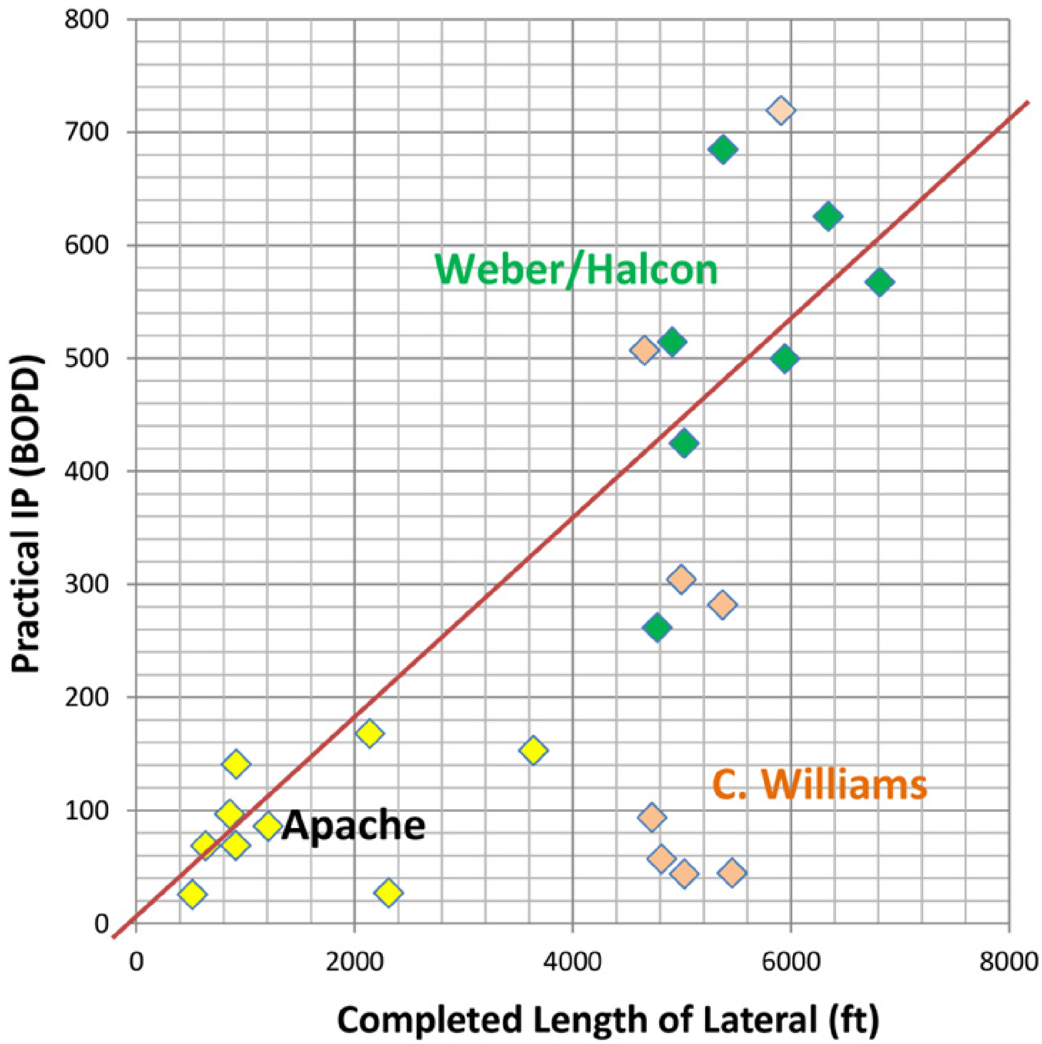


Figure 19. Practical IP versus completed length of lateral of Figure 18 plus 8 wells by C. Williams and the first 7 wells by Weber/Halcon. Note that most wells except those by C. Williams fit this graph.

ton Williams. This caused us to look at the individual completions more closely. We then graphed the practical IP against the total amount of frack sand pumped per well (Fig. 20), rather than the lateral length (Fig. 19). Figure 20 shows that the practical IP does match very closely with the total amount of frack sand pumped. The longer laterals shown on Figure 19 are simply a proxy for more sand. Clearly, Williams was varying the amount of sand pumped per well to determine the best completion procedure for the best economics.

PROPER NAMES: EAGLE FORD OR EAGLEFORD

To space or not to space, that is the question. Whether it is better to be correct factually or to “go with what sells”? And what about those pesky formation names that change along strike? A century ago it was perfectly reasonable to have an Eagle Ford and Woodbine section in East Texas and a Boquillas Flags in the Big Bend of West Texas. Then as additional outcrops were examined the Boquillas Flags became just the Boquillas and the term Eagle Ford was also being applied in Terrell County of West Texas (Hazzard, 1959). Skipping ahead to

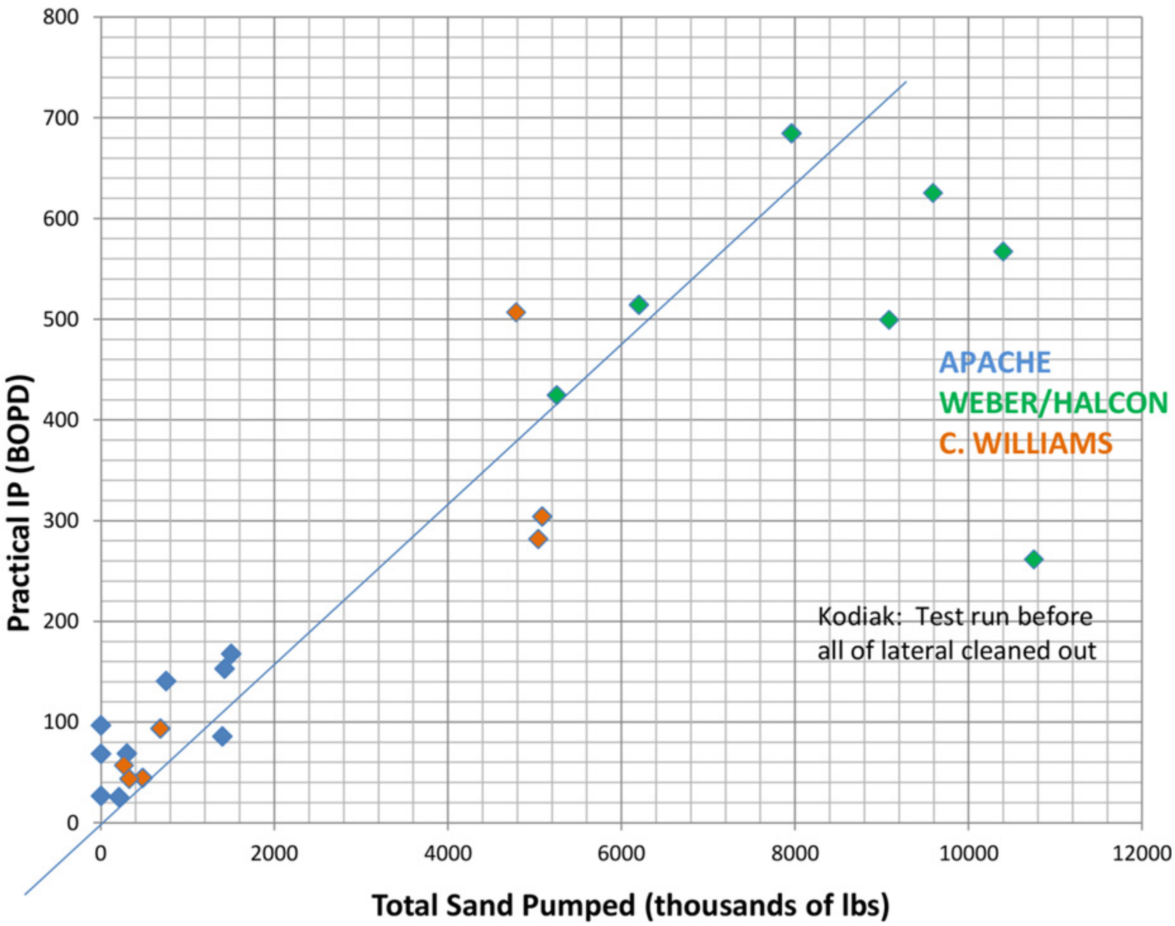


Figure 20. Practical IP versus total sand pumped for the same wells shown in Figure 19. Note the better fit when total sand pumped is used instead of length of lateral.

today, we now have the data at our disposal to determine that the Eagle Ford of West Texas is equivalent to the entire Woodbine/Eagle Ford section in the East Texas Basin, and most importantly to determine correlations back to the type sections of the Woodbine and Eagle Ford in the vicinity of Dallas, Texas (Fig. 8).

So how do we address this nomenclatural confusion? The North American Commission on Stratigraphic Nomenclature (NACSN), a joint effort of the American Association of Petroleum Geologists (AAPG) and the Geological Society of America (GSA), has specific procedures to cover this type of confusion (NACSN, 1983). The names Woodbine and Eagle Ford as proposed by Hill in 1901 and 1887, respectively, have precedence over later names. Therefore, we should either:

(1) Uniformly apply only the names Woodbine and Eagle Ford across the entire state of Texas, or (2) assign a new name for the South Texas Eagleford that is not in conflict with earlier names of Hill (1887, 1901). In the latter case, discrete geographic boundaries should be defined for each naming convention. Because of both chronological and geographic considerations, The terms Eagle Ford and Woodbine should remain in use for the East Texas Basin and its immediate surrounding areas.

Finally, we as geologists are first and foremost scientists. We have a moral and ethical obligation to follow this code of the NACSN in our work. This means we should strive to use correct nomenclature both within our companies and especially in our public or published work. Terms such as “Eaglebine,” “Wolfbone,” and others may be fine descriptive terms for land men and drillers, but we have a professional obligation to scientific honesty that is lacking in these non-scientific terms.

CONCLUSIONS

It should be emphasized that the LWOS play is not an exploratory play, but rather a development opportunity. Like any other unconventional play, defining the play is not the hard part, but rather defining the best place to be within that play. The outline of the total productive LWOS area is quite extensive, and the limits of the established field are also extensive. Within those limits the most optimum area for development may be determined by utilizing multiple datasets. The identified parameters of oil gravity, GOR, shale isolith mapping, and basement analysis as shown on the accompanying maps, when combined with geochemical considerations, all convincingly demonstrate that within this extensive play area, one area exists that should have the best per well production. The production analysis of the short-lateral wells drilled by Apache within this area confirm that high-quality completions can be made and that very economic production can be expected if long-lateral wells are drilled. This provides a template for analysis of other shale plays. It also emphasizes the critical importance of truly regional geology prior to leasing in any play.

Geologists have a stratigraphic code to follow in naming formations. Sometimes new data shows that earlier naming conventions were incorrect, or in conflict with newer data. It is incumbent on us as professionals to adhere to correct procedures in resolving these naming conflicts and especially to avoid using non-geologic pseudo-stratigraphic names such as "Eaglebine" or "Wolfbone" just because they are easier or more popular, when the correct terminology is available and with a small amount of research can be verified. We are first and foremost professional scientists and not land promoters.

ACKNOWLEDGMENTS

Most of the figures were drafted by Randy Permenter of AFAD Graphics in Tyler, Texas. The depth to magnetic basement map from which Figure 15 was interpreted is available from Earthfield Technology of Houston, Texas. The lithologic column in Figure 2 is after a column by Brown and Pierce (1962) in the *American Association of Petroleum Geologists Bulletin*. Figure 10 references figures from Donovan and Staerker (2010) and from Hentz and Ruppel (2010), both of which were published in the 2010 *GCAGS Transactions*. Johnnie Wanger assisted with the preparation of cross-sections. We thank the Management of both Carr Resources, Inc. and PetroEdge III for permission to publish this manuscript.

REFERENCES CITED

Adams, R. L., 2006, Basement tectonics and origin of the Sabine Uplift, *in* R. Turner, ed., The Gulf Coast Mesozoic Gas Province: East Texas Geological Society, Tyler, p. 1–31.

Adams, R. L., and J. P. Carr, 2010, Regional depositional systems of the Woodbine, Eagle Ford and Tuscaloosa of the U.S. Gulf Coast: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 3–28.

Ambrose, W. A., T. F. Hentz, F. Bonnaffé, R. G. Loucks, L. F. Brown, Jr., F. P. Wang, and E. C. Potter, 2009, Sequence-stratigraphic controls on complex reservoir architecture of high-stand fluvial deltaic and low-stand valley-fill deposits of the Upper Cretaceous (Cenomanian) Woodbine Group, East Texas Field: Regional and local perspectives: American Association of Petroleum Geologists Bulletin, v. 93, p. 231–269.

Bailey, T. L., F. G. Evans, and W. S. Adkins, 1945, Revision of stratigraphy of part of Cretaceous in Tyler Basin, northeast Texas: American Association of Petroleum Geologists Bulletin, v. 29, p. 170–186.

Baumgardner, R. W., Jr., 1988, Relationship between radar lineaments, geologic structure, and in situ stress in East Texas: Report prepared by the Texas Bureau of Economic Geology (Austin) for the Gas Research Institute (Chicago, Illinois) under Contract 5082–211–0708, 43 p.

Brown, C. W., and R. L. Pierce, 1962, Palynologic correlations in Cretaceous Eagle Ford Group, northeast Texas: American Association of Petroleum Geologists Bulletin, v. 46, p. 2133–2147.

Cander, H., 2012, Sweet spots in shale liquids plays: American Association of Petroleum Geologists Search and Discovery Article 41093, Tulsa, Oklahoma, <http://www.searchanddiscovery.com/pdfz/documents/2013/41093cander/ndx_cander.pdf.html> Last accessed September 14, 2014.

Cardneaux, A. P., 2012, Mapping of the oil window in the Eagle Ford Shale Play of southwest Texas using thermal modeling and log overlay analysis: Master's Thesis, Louisiana State University, Baton Rouge, 74 p.

Chaudary, A. S., 2011, Shale oil production from a simulated reservoir volume: Master's Thesis, Texas A&M University, College Station, 78 p.

Dix, O. R., and M. P. A. Jackson, 1981, Statistical analysis of lineaments and their relation to fracturing, faulting and halokinesis in the East Texas Basin: Texas Bureau of Economic Geology Report of Investigations 110, Austin, 30 p.

Donovan, A. D., and T. S. Staerker, 2010, Sequence stratigraphy of the Eagle Ford (Boquillas) Formation in the subsurface of South Texas and outcrops of West Texas: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 861–899.

Grabowski, G. J., Jr., 1995, Organic-rich chalks and calcareous mudstones of the Upper Cretaceous Austin Chalk and Eagleford Formation, south-central Texas, *in* B. J. Katz, ed., Petroleum source rocks: Springer-Verlag, Berlin, Germany, p. 209–234.

Harbor, R. L., 2011, Facies characterization and stratigraphic architecture of organic-rich mudstones, Upper Cretaceous Eagle Ford Formation, South Texas: Master's Thesis, University of Texas at Austin, 184 p.

Hazzard, R. T., 1959, Measured section, in geology of the Val Verde Basin: West Texas Geological Society Guidebook, Midland, 118 p.

Hendershott, Z. P., 2012, Evaluation of the depositional environment of the Eagle Ford Formation using well log, seismic, and core data in the Hawkville Trough, LaSalle and McMullen counties, South Texas: Master's Thesis, Louisiana State University, Baton Rouge, 52 p.

Hentz, T. F., and S. C. Ruppel, 2010, Regional lithostratigraphy of the Eagle Ford Shale: Maverick Basin to East Texas Basin: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 325–338.

Hill, R. T., 1887, The topography and geology of the Crosstimbers and surrounding regions in North Texas: American Journal of Science, April 1887, 3rd Series, v. 33, p. 291–303.

Hill, R. T., 1901, Geography and geology of the Black and Grand prairies, Texas: 21st Annual Report of the U.S. Geological Survey, Part 7, 666 p.

Freeman, D., 2012, Integrated data helps spot high EUR wells: American Association of Petroleum Geologists Explorer, <http://www.aapg.org/publications/news/explorer/emphasis/articleid/1907/integrated-data-helps-spot-high-eur-wells> Last accessed September 14, 2014.

Jarvie, D. M., 1991, Total organic carbon (TOC) analysis, *in* R. K. Merrill, ed., Treatise of petroleum geology: Handbook of petroleum geology, source and migration processes and evaluation techniques: American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 113–118.

Jiang, M.-J., 1989, Biostratigraphy and geochronology of the Eagle Ford Shale, Austin Chalk, and Lower Taylor Marl in Texas based on calcareous nanofossils: Ph.D. Dissertation, Texas A&M University, College Station, 496 p.

Laubach, S. E., 1989, Fracture analysis of the Travis Peak Formation, western flank of the Sabine Arch, East Texas: Texas Bureau of Economic Geology Report of Investigations 185, Austin, 55 p.

Laubach, S. S., R. W. Baumgardner, Jr., and K. J. Meador, 1987, Analysis of natural fractures and borehole ellipticity, Travis Peak Formatiom, East Texas: Report prepared by the Texas Bureau of Economic Geology (Austin) for Gas Research Institute (Chicago, Illinois) under Contract 5082–211–0708, 128 p.

Loucks, R. G., R. M. Reed, S. C. Ruppel, and D. M. Jarvie, 2009, Morphology, genesis, and distribution of nanometer-scale pores in silicious mudstones of the Mississippian Barnett Shale: Journal of Sedimentary Research, v. 79, p. 848–861.

McGarity, H. A., 2013, Facies and stratigraphic framework of the Eagle Ford Shale in South Texas: Master's Thesis, University of Houston, Texas, p. 95.

Modica, C. J., and S. G. Lapierre, 2012, Estimation of kerogen porosity in source rocks as a function of thermal transformation: Example from the Mowry Shale in the Powder River Basin of Wyoming: American Association of Petroleum Geologists Bulletin, v. 96, p. 87–108.

Moreman, W. L., 1932, Subdivisions of the Eagle Ford Shale, *in* E. H. Sellards, W. S. Adkins, and F. B. Plummer, eds., The geology of Texas, stratigraphy, v. 1: University of Texas Bulletin 3232, Austin, p. 424–426.

North American Commission on Stratigraphic Nomenclature, 1983, North American stratigraphic code: American Association of Petroleum Geologists Bulletin, v. 67, p. 841–875.

Oliver, W. B., 1971, Depositional systems in the Woodbine Formation (Upper Cretaceous), northeast Texas: Texas Bureau of Economic Geology Report of Investigations 73, Austin, 28 p.

Pessagno, E. A., Jr., 1969, Upper Cretaceous stratigraphy of the western Gulf Coast area of Mexico, Texas and Arkansas: Geological Society of America Memoir 111, Boulder, Colorado, 139 p.

Sondhi, N., 2011, Petrophysical characterization of Eagle Ford Shale: Master’s Thesis, University of Oklahoma, Norman, 176 p.

Telker, C., 2013, Source mechanism analysis to determine optimal wellbore orientation in the Eagle Ford play: Search and Discovery Article 41196, Tulsa, Oklahoma, <http://www.searchanddiscovery.com/pdfz/documents/2013/41196telker/ndx_telker.pdf.html> Last accessed September 12, 2014.

Trevino, R. H., III, 1988, Facies and depositional environments of the Boquillas Formation, Upper Cretaceous of southwest Texas: Master’s Thesis, University of Texas at Arlington, 120 p.

Workman, S. J., 2013, Integrating depositional facies and sequence stratigraphy in characterizing unconventional reservoirs: Eagle Ford Shale, South Texas: Master’s Thesis, Western Michigan University, Kalamazoo, 141 p.

Main Menu
Search
Author Index
Papers
Help

NOTES

Main Menu

Search

Author Index

Papers

Help