Understanding Production from Eagle Ford-Austin Chalk System
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Abstract
The US Energy Information Administration’s forecast gas price is below USD 5/Mcf through the 2011 calendar year, prompting many historically gas-focused companies to shift their portfolio emphasis to oil. South Texas has been a hotbed for oil development for the last half a century. The last great oil boom in south Texas occurred in the Austin Chalk formation in the 1970s and early 1990s. Today, the Eagle Ford Shale has renewed oil exploration interest in South Texas.

The Eagle Ford Shale is a very prolific play that for the most part is bounded on top by the Austin Chalk formation. Many operators are wondering if the oil being produced from the Eagle Ford Shale is essentially the same oil (from both a source and geochemical standpoint) as the Austin Chalk. Owing to the tight nature of the shale, it is highly unlikely that oil is being produced solely through pore flow into hydraulic fractures. The industry has not fully grasped the storage mechanism in the Eagle Ford Shale and the factors that indicate a good producing area versus a mediocre one.

This paper studies the possibility that the Austin Chalk and Eagle Ford Shale form a single hydrocarbon system. The potential source, generation, migration, storage, and production mechanisms of both formations will be analyzed from a geologic perspective. The implications of this theory for exploiting the Eagle Ford Shale will also be discussed. From a production standpoint, this paper will compare the production trends of horizontal wells in the Eagle Ford Shale and Austin Chalk formations, analyzing each in detail to determine if there are any similarities in initial production rates and decline trends.

This paper investigates the areal extent of production from the Eagle Ford Shale and Austin Chalk formations and discusses their interdependencies. In addition, geological and petrophysical attributes are evaluated to understand this phenomenon. Lastly, this paper describes the key mechanism(s) for oil/condensate flow in these oil-producing reservoirs and how to best exploit these unconventional formations.

Background
The move over the last seven years onshore in North America has been heavily toward shale plays. Most of these plays, with the exception of the Bakken Shale, have been primarily gas-rich plays. More recently, over the past two years, there has been a further shift toward unconventional liquids-rich plays onshore in the US and Canada, owing to lagging gas prices and increasing oil prices. This has the industry rethinking its methodology to evaluating oil and gas reservoirs. Operating companies are looking at past liquids-rich conventional reservoirs that were successfully exploited to determine if a source rock exists nearby that may contain recoverable oil and gas. One example of this is the Austin Chalk and Eagle Ford Shale of south Texas.

The Austin Chalk overlays the Eagle Ford Shale across parts of south Texas and has been a targeted reservoir for more than 80 years (IHS, 2011). Figs. 1 and 2 show the areal extent of the Austin Chalk and Eagle Ford Shale, respectively. Because the Austin Chalk covers a massive expanse, this paper will focus on the area from the Giddings field down through the Pearsall field and on to the US-Mexico border, encompassing the counties where the Eagle Ford Shale commercial drilling activity is currently focused (Figs. 1 and 2). In this south Texas area, the Austin Chalk trend covers approximately 4 million acres, and the Eagle Ford Shale covers approximately 11 million acres (IHS, 2011).
Fig. 1—Austin Chalk trend and main producing fields.

Fig. 2—Eagle Ford area of industry activity and associated geologic features.
The Eagle Ford is believed to be a self-sourced hydrocarbon reservoir (Liro et al., 1994; Dawson, 2000). It is the authors’ theory that the Eagle Ford Shale is the source rock for the oil and gas accumulated in the Austin Chalk in addition to that in the Eagle Ford Shale. The remainder of the paper will focus on this theory and examine some of the geologic properties of each play. Where applicable, evidence will be identified that links the Eagle Ford and Austin Chalk as a single hydrocarbon system. In addition, production will be analyzed to look for similarities in decline trends. Furthermore, higher producing areas in the Austin Chalk will be analyzed to determine if these same areas have similar, greater, or lower Eagle Ford Shale production. Only horizontal wells will be considered for this analysis, both to compare the decline behaviors of like well types and because both plays have a large portion of their producing wells drilled laterally.

**Austin Chalk Overview**

The Austin Chalk formation is Upper Cretaceous in age and is found onshore in Texas and Louisiana paralleling the Gulf Coast. It is named for an outcrop near Austin, Texas. Significant Austin Chalk fields and the overall trend are shown in Fig. 1. The Austin Chalk overlies the Eagle Ford Shale and is itself overlain by the Anacacho or Upson formations in South Texas (Fig. 3). It is a low-permeability fractured reservoir that has been a target for horizontal drilling since the mid-1980s. The Austin Chalk consists of interbedded chalks, volcanic ash, and marls. In the Pearsall field, it produces from the fractured upper chalk (H-K sublayers in Fig. 5) and in the Giddings field from the lower fractured chalk (A-D sublayers in Fig. 5) (Hovorka and Nance, 1994). Before horizontal drilling became popular, numerous wells were drilled vertically—beginning in the 1920s—in the fields found along the Gulf Coast.

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**Fig. 3—Stratigraphic column of Upper Cretaceous rocks through the Austin Chalk trend (Pearson, 2010).**

The Austin Chalk experienced a boom in the late 1970s during the US oil crisis (Haymond, 1991). The next boom came to the Austin Chalk in the early 1990s, with horizontal boreholes making up most completions. Fig. 4 shows the activity level of Austin Chalk horizontal wells in Texas over the last 27 years. All permitted wells are not necessarily drilled, thus the difference in permits and confirmed completions from public sources. Another reason for the difference is that some wells may not have a completion record in the public database used for this analysis.
Austin Chalk Geology

The Upper Cretaceous Austin Chalk was deposited in Texas in a shallow marine setting in water depths that ranged from 30 ft or shallower to 300 ft (Pearson, 2010). Austin Chalk layers within marls and volcanic ash deposits have a matrix permeability that varies between 0.03 and 1.27 md. The overall thickness varies between 150 ft and 800 ft. The marls that are layered throughout the Austin Chalk terminate or impede growth of natural fractures from one chalk layer to the next (Stowell, 2001). Major producing fractures are both open and closed and parallel to the Lower Cretaceous shelf edge. For long-term production, an extensive fracture system must be connected with the horizontal lateral. An example of the target interval in the Giddings field and the interbedded chalks and marls is shown in Fig. 5. Lower-producing intervals (Zones A-D in Fig. 5) have less than 10% nonchalk minerals, and brittle rock is abundant. Higher-producing areas occur where the chalk is densely fractured. One source of the hydrocarbons is from the organic content found in the chalk and marl layers. However, the principal source of hydrocarbons is the Eagle Ford where vertical migration was sufficient to fill the fractured Chalk. Austin Chalk oils contain mostly type II kerogen and are thermally mature across the area (Pearson, 2010).
**Austin Chalk Completions**

Vertical wells drilled during the 1970s boom were completed with about 200,000 gal of crosslinked guar-based polymers conveying 250,000 lbm of 20/40 proppant. Most jobs were pumped between 40 and 60 bbl/min (Dees et al., 1990). Well completions made a massive step change in the late 1980s when boreholes went horizontal. These wells were mostly openhole or slotted liner laterals running from 500 to 4,500 ft in length (Pope and Handren, 1992). Wells of this era were completed in a single stage with slickwater fluid or acid. Stimulation treatments contained up to 20,000 lbm of proppant or no proppant and up to 120,000 gal of fluid (Hollabaugh and Dees, 1993). Graded salt, benzoic acid, paraformaldehyde, and naphthalene were used for diversion purposes with limited confirmed success. There was a move to using wax beads that shocked the formation to open up networks and then melt at a certain temperature (Bell et al., 1993). Numerous horizontals have been refracture stimulated—many more than once. The economic success of these operations is variable.

**Eagle Ford Overview**

The Eagle Ford Shale play began with the horizontal discovery well, STS #1, in October 2008 (initial production of 9.7 Mcf/d from a 3,200 ft lateral). The play has since expanded from the discovery well located in southwest La Salle County, Texas, to the Mexican border and northeast to the eastern border of Gonzales and Lavaca Counties (Fig. 2). The trend’s southern border subparallels the Sligo shelf edge and extends northward at the widest point to encompass the Maverick basin. To the northeast, the play ends where the Eagle Ford thins. The area of the trend is 102 miles long by an average of 60 miles wide.

Several large independents began exploring the basin, which provided an opportunity for numerous companies to obtain leases. Operators’ leasehold positions in the trend were identified using recent drilling permits and are indicated on a map showing reservoir quality and key geologic features (Fig. 6). The hotter colored areas in Fig. 6 indicate better-quality reservoir rock. Key geologic features are depicted in Fig. 6 by white rectangular boxes with black text. Approximately 1,000 horizontal wells have been drilled in the play at the writing of this paper. Activity has been increasing at a feverish pace because the number of permits and completions has been increasing quarter on quarter since the initial discovery well (Fig. 7) (IHS, 2011). The high level of drilling activity created a rich database to identify sweet spots and other important information. Now, as the acreage is tightly leased and productive potential better understood, new operators have to negotiate joint ventures to gain a position in the play.
Eagle Ford Geology

The Eagle Ford is a Late-Cretaceous (Cenomanian-Turonian) formation that disconformably overlies the Buda limestone and is overlain by the Austin Chalk. The Eagle Ford Shale is equivalent to the Boquillas formation in the Maverick basin and Tuscaloosa Shale in Louisiana and Mississippi (Fig. 8) (Lock and Peschier, 2006).
The Eagle Ford Shale outcrops from the Mexican border north of the Maverick basin through San Antonio, Austin, and Dallas, and northeast to the Sabine uplift where it is not present. From the outcrop, the Eagle Ford Shale dips to the Gulf of Mexico. Through the area of current activity, elevations range between 1,500 ft and 14,000 ft TVD (Fig. 9), and the thickness varies between 50 ft on the northeast side and 330 ft on the southwest side (Fig. 10). The pay thickness generally is classified between 125 ft and 300 ft. The downdip limit is closely associated with the underlying Edwards and Sligo shelf edges (Waite, 2009).
The Eagle Ford Shale changes stratigraphically through Texas owing to different structural and depositional settings. Near the Mexican border, the Eagle Ford Shale sedimentation was influenced by the Laramide Orogeny, which shed sediments into the Maverick basin and the restricted basin, commonly called Hawkville, between the Edwards and Sligo shelf edges (Scott, 2004). Moving to the northeast, the Eagle Ford Shale thins to approximately 50 ft over the San Marcos Arch. The area of current industry activity does not continue northeast of this point. Northeast of the San Marcos Arch, in the Brazos County area, an incised valley cuts the Eagle Ford Shale. Within this valley, several old fields produce from sands encased in the shale. Further to the northeast, in the east Texas Salt basin, the Eagle Ford Shale sourced the famous Woodbine Sands. Continuing northeast, the Eagle Ford Shale is not present over the Sabine Uplift in Panola County. In Louisiana, where it is present again, it is known as the Tuscaloosa Shale (Lock and Peschier, 2006).

Since the Eagle Ford Shale varies significantly across the area of industry activity, two type logs and associated information are shown in Fig. 11 that highlight the variability of the play. The Eagle Ford Shale consists of two intervals (Fig. 11) generically classified as lower and upper. The lower consists of a transgressive marine interval dominated by dark, well-laminated organically rich shales. The upper Eagle Ford Shale is the beginning of a regressive cycle characterized by a high stand system tract in which near-shore sediments were deposited. The regressive section consists of interstratified calcareous shales, bentonites, limestones, and quartzose siltstones. To the south in La Salle County, the Eagle Ford Shale is 220 ft thick, consisting of black shales throughout the transgressive and regressive intervals (left log in Fig. 11). Our interpretation of the black shales found in the upper regressive interval in La Salle County is that they were deposited further downdip in a more marine environment. The second log in Karnes County (right log in Fig. 11) highlights both the transgressive shales and the regressive intervals. The regressive interval typically consists of fractured limestones, calcareous shales, and bentonites, as seen in the upper picture in Fig. 11. In the area around Karnes County, the regressive interval has produced oil from vertical wells for many years with small acid treatments. The transgressive interval in Karnes County consists of organic-rich black shale, as seen in the core (Fig. 11).

Mineral content varies little in the two wells, but it can vary a bit more dramatically over other parts of the play. Approximate content is 20% quartz, 50% calcite, 20% clay, and 10% kerogen. Reservoir properties vary across the area of industry activity. For example, the key property of effective porosity ranges between 3% and 10% with a mean of 6%. Another key property, permeability, ranges between 3 nd and 405 nd, with an average value of 180 nd.
Fig. 11—Eagle Ford Shale type logs Dora Martin in La Salle Co. and Milton in Karnes Co. highlighting the stratigraphic differences across the area (Petrohawk, 2011; EOG, 2011; Ewing, 2010).

Regarding the depositional environment, it is interesting to note that the Eagle Ford Shale is considered one of many world-class source rocks that were deposited at the Upper Cretaceous Cenomanian–Turonian boundary. This boundary is the location in time where one of two anoxic extinction events occurred. During this later event, warm seas existed throughout the world. A worldwide greenhouse effect existed that resulted in an increased CO$_2$ level and consequently, increased organic productivity. Consumption by aerobic bacteria created an anoxic or oxygen-poor environment that preserved the organic material. The resulting increased level of carbon accounts for the accumulation of the thick black shale deposition seen around the world (Liro et al., 1994; Dawson, 2000).

In the Eagle Ford Shale area of industry activity, the transgressive interval is primarily the organic-rich shale deposited by the shallow warm seas mentioned above. The upper Eagle Ford Shale regressive interval is a transition to a near-shore environment. To the southwest, the depositional environment changes in the Hawkville area. This area is characterized as a restricted basin bounded by the Edwards shelf edge to the north and the shoreline to the south (Fig. 12). Within the area, the organic-rich shales were preserved in the oxygen-poor environment. The regressive upper Eagle Ford Shale is primarily black shale (Liro et al., 1994; Dawson, 2000).
Eagle Ford Completions

Eagle Ford Shale completions are almost exclusively horizontal wells with multiple fracture stages. Early in the play development, horizontals averaged 14 frac stages per lateral; today the average has increased to 20 frac stages per lateral. The average stage has 260,000 lbm of proppant and just over 11,000 bbl of fluid. Most treatments are slickwater with some wells having a crosslinked gel tail-in. Proppant types typically include 100 mesh, 40/70, and 30/50. Some wells have 20/40 or 16/30 mesh size proppant tailed in. Most wells use sand, with a minority of laterals incorporating resin-coated sand or low strength ceramic (IHS, 2011).

Austin Chalk—Eagle Ford Shale Hydrocarbon System

The Eagle Ford Shale is classified as a petroleum system in that it is a self-sourced reservoir with seals. Analysis of outcrops and samples from well control identified kerogen types II, II/III, and III. Maturation, expulsion, and migration took place as the Eagle Ford Shale dipped south, where it went through three maturation windows: oil, gas condensate, and dry gas, as shown in Fig. 13. The maturation window boundary between gas condensate and dry gas was confirmed from a Petrohawk-conducted analysis of samples by pyrolysis (Tuttle, 2010). The Hawkville area between the Edwards and Sligo shelf edges is at the transition point between wet gas and dry gas. In the area of the Karnes Trough, the hydrocarbons are primarily oil and condensate. As the elevations to the top of the Eagle Ford in the Hawkville area and the Karnes Trough are about the same, the difference in the hydrocarbon content is due to the kerogen type. Types II and II/III are found in the Hawkville area, and primarily type II is found in the area of the Karnes Trough (Tuttle, 2010; Edman et al., 2010).
Migration of Eagle Ford hydrocarbons was primarily along bedding planes during the expulsion phase. Absent of traps, hydrocarbons migrated updip or north, where vertical natural fractures were encountered. These natural fractures were associated with the regional fault trends. Here the hydrocarbons migrated into the extensively fractured Austin Chalk. In addition, in the current area of Eagle Ford Shale exploitation, both structural and stratigraphic traps are found. In the Hawkville area, trapping is restricted to the thick section of the Eagle Ford Shale found within the restricted basin, as portrayed in the depositional model shown in Fig. 12. Traps in the area of the Karnes Trough include natural fractures close to the numerous sealing faults associated with the Karnes Trough structural features. Fig. 14 is a cartoon of a north-south cross section from the outcrop through the Gonzales field and Karnes Trough. The cartoon illustrates trapping of Eagle Ford Shale hydrocarbons during updip migration. It is interesting to note that in the Haynesville shale play of Texas and Louisiana, the Haynesville and Bossier production is poor beneath the overlying Cotton Valley reservoirs. Downdip, the Cotton Valley reservoirs are not present, and the Bossier and Haynesville are both good reservoirs.
Production Comparison of the Austin Chalk and Eagle Ford Shale Formations

Public production data for the Austin Chalk and Eagle Ford Shale formations were collected and mapped from publicly available sources for comparison purposes. Fig. 15 indicates the average daily oil production rate for the maximum month of oil production in the Austin Chalk using green circles. The larger the green circle, the greater the daily production during the maximum month of oil production (Fig. 15). The thickness of the Eagle Ford Shale provides the backdrop for Fig. 15. Fig. 16 indicates the average daily gas production rate for the maximum month of gas production in the Austin Chalk using red circles. The larger the red circle, the greater the daily production during the maximum month of gas production (Fig. 16). The thickness of the Eagle Ford Shale provides the backdrop for Fig. 16. Austin Chalk oil and gas production (Figs. 15 and 16) primarily occurs in the Pearsall and Gonzales fields. Austin Chalk production from the two fields is 13 million bbl of oil and 72 Bcf of gas to date. The two fields were primarily sourced by Eagle Ford oil and gas, which formed down-dip in the oil and gas windows (Pearson, 2010). Northward migration along bedding planes continued until the hydrocarbons became trapped in the highly fractured Austin Chalk. The thickness of the Eagle Ford appears to be unrelated to oil or gas production across the two fields.
Fig. 15—Austin Chalk average daily oil production (circles) based on maximum month of oil production, overlaying a thickness map of the Eagle Ford Shale.

Fig. 16—Austin Chalk average daily gas production (circles) based on maximum month of gas production, overlaying a thickness map of the Eagle Ford Shale.

Fig. 17 indicates the average daily oil production rate for the maximum month of oil production in the Eagle Ford Shale using green circles. The larger the green circle, the greater the daily production during the maximum month of oil production (Fig. 17). The thickness of the Eagle Ford Shale provides the backdrop for Fig. 17. Fig. 18 indicates the average daily gas production rate for the maximum month of gas production in the Eagle Ford Shale using red circles. The larger the red circle, the greater the daily production during the maximum month of gas production (Fig. 18). The thickness of the Eagle Ford Shale provides the backdrop for Fig. 18. Oil is found throughout the Maverick basin, with the best oil producers in the southern sector of the basin. Oil in the Hawkville area is condensate-rich gas, primarily found along the northern edge of the Hawkville area. In the Karnes Trough, the Eagle Ford Shale section is more than 200 ft thick. Oil from continued generation in the Karnes Trough was trapped in the fractured Eagle Ford Shale close to the faults. This resulted in the largest accumulation of oil across the trend. Data from the First Shot field in the Karnes Trough suggests that the oil was generated locally and was not migrated a long distance (Edman et al., 2010). From the map, our conclusion is that good Eagle Ford production is related to stratigraphy, structure (faults and fractures), and thickness.
Fig. 17—Eagle Ford Shale average daily oil production (circles) based on maximum month of oil production, overlaying a thickness map of the Eagle Ford Shale.

Fig. 18—Eagle Ford Shale average daily gas production (circles) based on maximum month of gas production, overlaying a thickness map of the Eagle Ford Shale.

Production from the Eagle Ford Shale and Austin Chalk were placed in the same graph and scaled to facilitate comparing their overall production. **Fig. 19** shows the average daily oil rate from the maximum oil production month of Austin Chalk horizontal wells (gray circles) and Eagle Ford Shale wells (green circles). **Fig. 20** shows the average daily gas rate from the maximum gas production month of Austin Chalk horizontal wells (yellow circles) and Eagle Ford Shale wells (red circles). One item of note is that the Pearsall field is the larger of the two Austin Chalk fields. Eagle Ford hydrocarbons in this field migrated farther to the north before encountering the fractured Austin Chalk. Austin Chalk production in the Gonzales field is in close proximity to the Karnes Trough and most likely was trapped in natural fractures associated with the faulting in the area.
Fig. 19—Eagle Ford Shale (green) and Austin Chalk (gray) average daily oil production (circles) based on maximum month of oil production, overlaying a thickness map of the Eagle Ford Shale.

Fig. 20—Eagle Ford Shale (red) and Austin Chalk (yellow) average daily gas production (circles) based on maximum month of gas production, overlaying a thickness map of the Eagle Ford Shale.

Based upon production data analysis, it appears that the best oil-producing area in the Eagle Ford Shale is the Karnes Trough region (Fig. 21). The best gas-producing area is near Hawkville (Fig. 21).
Production Analysis of the Austin Chalk and Eagle Ford Shale

Horizontal well production data in both the Eagle Ford Shale and Austin Chalk were extracted and analyzed from publicly available sources. Horizontal Eagle Ford Shale wells in Webb, Maverick, Dimmit, Zavala, Frio, La Salle, McMullen, Live Oak, Atascosa, Wilson, Karnes, Dewitt, and Gonzales with at least one month of production data were analyzed. From this data query, 392 horizontal wells were obtained and are identified as the blue dots on Fig. 22. Wells were then separated into groups based on oil and gas production. An oil-gas ratio (OGR) of 80 bbl/MMcf was used as the cutoff. Wells above this value were considered oil producers. Fig. 23 shows the location of the gas-producing wells versus the oil-producing wells based on the aforementioned cutoff. The Eagle Ford Shale well breakdown by gas and oil over time can be observed in Fig. 24. The wells are categorized by date of first production (DOFP) in Fig. 24. The new gas-producing well count in the Eagle Ford Shale has remained fairly constant since mid 2009, while the new oil-producing horizontal well count increased significantly over the same time frame (Fig. 24). This clearly shows the general trend of movement from gas to oil wells by operators. The maximum oil- and gas-producing months for all of the 392 horizontal Eagle Ford Shale wells is shown in Fig. 25 and Fig. 26, respectively. The average maximum month oil rate for the oil wells is approximately 340 bbl/D, and the average maximum productive month gas rate for the gas wells is approximately 4,250 Mcf/D. The oil-producing wells showed an upward trend in the maximum month rates since mid 2009, while gas-producing wells exhibited little change in the maximum month rates.
Fig. 22—Eagle Ford Shale and Austin Chalk well locations used in the initial portion of the study.

Fig. 23—Eagle Ford Shale oil and gas horizontal well locations.
Fig. 24—Eagle Ford Shale oil and gas horizontal well count by month of first production.

Fig. 25—Eagle Ford Shale horizontal oil well maximum monthly production over time.

Max Month Oil vs. DOFP

Max Month Average ~ 340 bbl/D
To compare the decline behavior of Eagle Ford Shale wells to that of the Austin Chalk horizontal producers, the 392 Eagle Ford Shale horizontal wells were pared down by cutting wells with less than six months of production history and by removing wells that had sporadic production profiles. This left 113 wells. Austin Chalk horizontal well production was pulled from Maverick, Dimmit, Zavala, Frio, La Salle, McMullen, Atascosa, Bexar, Wilson, Karnes, Dewitt, Gonzales, Guadalupe, and Caldwell counties to compare to the refined Eagle Ford data set. The same cutoff that was applied to the Eagle Ford Shale to differentiate between oil and gas wells was applied to the Austin Chalk wells, but since all Austin Chalk wells were oil producers, this was a moot point. The Austin Chalk data search resulted in 1,964 horizontal producers; their location is highlighted by brown dots in Fig. 22. The daily average oil production for the maximum monthly cumulative oil production of these two data sets was overlain and plotted on the same graph (Fig. 27). This plot indicates Karnes Trough area has overall higher production.
Wells from both formations were grouped based upon produced fluid type (oil or gas) and geographic location. This was done to compare the wells’ production within a localized area. The Eagle Ford Shale horizontal well groups were broken down into two oil and one gas study groups (Fig. 28). Oil Group 1 in Fig. 28 is focused on the western half of the study area across Dimmit, La Salle, Frio, Zavala, Webb, Maverick, and western McMullen counties. This area is focused primarily in the Maverick basin with a few wells in the Hawkville area. Oil Group 2 is toward the eastern half of the study area in the Karnes Trough and covers Gonzales, De Witt, Karnes, Live Oak, Wilson, Atascosa, Live Oak, and eastern McMullen counties (Fig. 28). The Gas Group is primarily located in the Hawkville area, across Webb, La Salle, Dimmit, and McMullen counties (Fig. 28). Fig. 29 shows the location of the oil-producing groups for both formations and indicates their respective horizontal well counts.

![Fig. 28—Eagle Ford Shale horizontal well study group locations.](image-url)
Type curves for each group for both formations were built using Arps decline curve analysis (Arps, 1945). All of the wells in the study were shifted with respect to time by setting the first day of production to the same date, i.e., “time zero.” An auto function that best fit the Arps decline curve was applied to each data set. When the well count fell significantly, the decline curve best fit analysis was stopped. This occurred after nine months of production in all areas of the Eagle Ford Shale. The best-fit Arps curve was then extended to 60 months of production for forecasting. This process was similar to the one followed in SPE 135555 (Baihly et al., 2010). A similar process was followed for the Austin Chalk study groups, but in this case the wells produced for more than 60 months, so the forecast was not needed.

The resulting 60-month decline curve for Eagle Ford Shale wells in Group 1 can be observed in Fig. 30. The solid blue line in Fig. 30 represents actual data, and the dashed line is the forecast. The Austin Chalk Group 1 decline curve can be observed in Fig. 31. Both the Eagle Ford Shale and Austin Chalk have a similar IP and decline trend over the first 60 months of well production.
The resulting 60-month decline curve for Eagle Ford Shale wells in Group 2 can be observed in Fig. 32. The solid black line in Fig. 32 represents actual data, and the dashed line is the forecast. The Austin Chalk Group 2 decline curve can be observed in Fig. 33. In this study group, the Eagle Ford Shale has a significantly greater IP than the Austin Chalk. However, the Eagle Ford Shale declines much faster than the Austin Chalk.
Fig. 32—Eagle Ford Shale study Group 2 decline curve.

Fig. 33—Austin Chalk study Group 2 decline curve.

Fig. 34 shows the comparison of the decline curves for Groups 1 and 2 for both the Austin Chalk and Eagle Ford Shale for 60 months. The Austin Chalk well groups have 60 months of actual data, while the Eagle Ford Shale well groups have been forecast with the Arps decline curve analysis after the first nine months of production; as indicated by the dashed line in Fig. 34. Both Austin Chalk groups have nearly identical decline profiles after 22 months of production. The Eagle Ford Shale Group 1 well data set appears to have a forecast decline profile very similar to that of both Austin Chalk well groups.
A normalized production plot of both Austin Chalk and Eagle Ford Shale well groups can be observed in Fig. 35. The production was normalized for each data set by taking each month’s cumulative production divided by the oil production of the maximum month for the respective data set. For example, the maximum month divided by the maximum month results in a normalized value of 1.0. The dashed lines in Fig. 35 for the Eagle Ford Shale well groups are based on Arps decline curve forecast values. The normalized production decline profiles are similar for both Austin Chalk well groups and for the Eagle Ford Shale well Group 1 for the first 12 months of production; after this point some divergence occurs. The Eagle Ford Shale well Group 2 has the steepest decline profile throughout the 60 months analyzed. After 24 months of production, all groups have a fairly narrow band of production decline values that are not overlapping, but are parallel.

In addition to the Eagle Ford Shale oil-producing well groups, an Eagle Ford gas well group was also analyzed. Fig. 36 shows the decline curve behavior of the Eagle Ford Gas well group based on actual data for the first 13 months, followed by a forecast based on the Arps decline curve analysis for the remainder of the 60-month analysis. The dashed line in Fig. 36 denotes the forecast decline behavior.
To compare the Eagle Ford Shale gas group decline profile to the oil areas, the gas production was converted from Mcf to barrel of oil equivalent (BOE). To convert from gas to oil, 6 Mcf of gas was set equal to 1 BOE. The new decline profile from the Eagle Ford Shale gas group in Fig. 36 converted into BOE can be observed in Fig. 37. Similar to Fig. 36, the dashed portion of the line in Fig. 37 represents the forecast from the Arps decline curve analysis.

Fig. 38 shows the decline profiles of all Austin Chalk and Eagle Ford Shale area well groups. The Eagle Ford Shale area gas group is shown with the BOE conversion. The Eagle Ford Shale gas well group converted to BOE has the highest monthly production rate and the shallowest late time decline profile of all well groups. The dashed lines, as in previous graphs, are forecasts based on the Arps decline curve analysis for the Eagle Ford Shale area groups.
The normalized decline profile for the data in Fig. 38 can be observed in Fig. 39. A similar process to the data analyzed in Fig. 35 was followed for the data in Fig. 39. The Eagle Ford Shale gas well group BOE data set has a similar decline trend to the Eagle Ford Shale oil Group 2 data initially; then the trend changes and follows the other data sets after 10 months of production. The Eagle Ford Shale gas group with BOE data has the shallowest forecast decline trend of all the groups analyzed.

The average lateral length for the various Austin Chalk and Eagle Ford Shale well groups can be seen in Table 1. The Austin Chalk wells, being a bit older vintage of horizontal well, have a shorter average lateral length compared to the Eagle Ford Shale well groups. Table 1 also shows the best six months of BOE production. The Eagle Ford Shale Group 2 has the highest liquid production, while the Eagle Ford Shale gas group area wells have the greatest overall BOE production of all the areas analyzed. The Austin Chalk Group 1 wells and the Eagle Ford Shale Group 1 wells had almost identical six month cumulative oil production. The Austin Chalk Groups 1 and 2 and the Eagle Ford Shale Group 1 had fairly similar normalized six month cumulative oil production per lateral foot.
Table 1—Austin Chalk (AC) and Eagle Ford Shale (EF) study groups’ average lateral length and six month oil production data.

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<th>Avg. lateral length</th>
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Interdependencies between the Eagle Ford Shale and Austin Chalk

From a geologic viewpoint, good Austin Chalk production is related to the primary Eagle Ford source rock. In the area of good Eagle Ford production, two Austin Chalk points of control exist. In Area 1 (Pearsall) of the Austin Chalk and Eagle Ford Shale area data set, the production is fairly similar. This could indicate that there is some migration of Eagle Ford Shale oil into the Austin Chalk formation. Across the Group 2 area (Karnes Trough), the Austin Chalk has poorer production than the Eagle Ford Shale. This could be an indication that there is a better sealing mechanism in the Eagle Ford Shale than in Area 1. The source rock is better in the Group 2 area as the total cumulative production from both the Austin Chalk and Eagle Ford Shale is significantly greater than the Group 1 area, even though this area has the lowest Austin Chalk production of the areas analyzed.

Conclusions

The following conclusions can be made from the analysis of geologic and production data in the Austin Chalk–Eagle Ford Shale production system:

1. The Eagle Ford Shale had sufficient organic matter during the time of deposition to source hydrocarbons in both plays.
2. Burial in the Eagle Ford Shale is sufficient for maturation, accumulation, and expulsion.
3. Migration of Eagle Ford Shale hydrocarbons into the Austin Chalk occurred along the bedding plane and entered via natural fractures oftentimes associated with regional faults.
4. Mineral content (low clay, high calcite, quartz, and kerogen) occurs in areas of good production.
5. The Austin Chalk has the same kerogen type to one of the kerogen types found in the Eagle Ford Shale.
6. Eagle Ford production is related to stratigraphy, structures (faults and fractures), and thickness.
7. The oil-producing wells showed upward trend in the max month rates since mid 2009, while gas-producing wells exhibited a little change in the max month rates.
8. Best oil production is found in the Karnes Trough (Group 1) and best gas is found in the Hawkville restricted basin from Eagle Ford.
9. The Karnes Trough Eagle Ford Shale area had the best overall stratigraphic traps, presence of natural fractures needed for storage, and the smallest amount of hydrocarbon migration.
10. In the Pearsall (Group 1) area, oil-producing wells in Austin Chalk and Eagle Ford Shale showed similar initial production and decline profile.
11. The Austin Chalk appears to have better overall reservoir connectivity as it took shorter laterals and less fracturing stages to obtain similar oil production in the Pearsall (Group 2) area.
12. In the Karnes Trough (Group 2) area, oil-producing wells in Eagle Ford Shale showed higher initial production and higher decline profile in comparison with Austin Chalk wells.

Acknowledgments

The authors would like to thank the management of Schlumberger for allowing us to publish this paper. A special thanks to John Thompson and Valerie Jochen for providing feedback on this paper.

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