Emerging Unconventional Resource Plays in the Onshore Gulf of Mexico: Assessing Agua Nueva and Tuscaloosa Play Potential*

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Abstract

The Agua Nueva Formation in Mexico and the Tuscaloosa Formation in Louisiana/Mississippi are emerging resource plays deposited during the CenomanianTuronian (mid-Cretaceous). These high-interest plays are the lateral extensions of the age-equivalent Eagle Ford Group, a prolific resource play in Texas. Production sweet spots within the Eagle Ford are well understood, and they are primarily controlled by maturity, mineralogy, net thickness and reservoir pressure. Are the Agua Nueva and Tuscaloosa plays comparable to the Eagle Ford? Can understanding gained through a data-rich play be applied to characterize emerging plays where data are more limited?

Diverse public domain datasets have been integrated within a sequence stratigraphic framework to evaluate the unconventional prospectivity of the Cenomanian-Turonian interval from Mexico to Mississippi. A regional evaluation of the depositional setting and organic-enrichment drivers for these units enables the prediction of source-rock quality, net thickness and mineralogy. A structural depth model is used to evaluate important parameters, such as maturity and reservoir pressure. These outputs enable mapping and high grading of the prospective play areas and provide the basis for a regional resource in-place assessment.

Organic enrichment within the Eagle Ford play is related to restriction behind a series of drowned paleo-shelf margins that constitute inherited paleobathymetric features with biological productivity enhanced by adjacent oceanic upwelling. These features extend into Mexico, but a large proportion of the Agua Nueva was deposited distal to this paleo-shelf margin where bottom waters were likely to have been more oxygenated. Behind the paleo-shelf margin, organic enrichment within the Agua Nueva is comparable to the Eagle Ford; however, screening results indicate that the play extent is only 20% of that within the Eagle Ford, and the high-graded areas are limited.

To the east, the paleo-shelf margin continues into Louisiana, but clastic influence from the Woodbine and Tuscaloosa deltas overwhelmed the carbonate system. Although the Tuscaloosa play has unconventional potential within the organic-rich Tuscaloosa Marine Shale (TMS) (Allen, 2014), the play is not analogous to the Eagle Ford because the timing and driver of organic enrichment are different, affecting net thickness. Low maturity, low pressure and high clay content are all likely to inhibit production relative to the Eagle Ford play.

Introduction

The Cenomanian-Turonian (Mid-Cretaceous) Eagle Ford play is one of the most prolific unconventional resources in the U.S., with more than 20,000 wells drilled and more than 4,000 MMBOE produced. The success of this play has driven exploration interest for potential lateral extensions; namely, the laterally continuous and age-equivalent Agua Nueva Formation in the Burgos, Sabinas and Tampico-Misantla basins of Mexico, and the TMS of Mississippi and Louisiana. To date, these resource plays have had minimal development, raising the question: does the Agua Nueva or the Tuscaloosa play have the potential to be the next Eagle Ford?

The Eagle Ford Group in Texas is both a conventional source rock with a long exploration history as well as an unconventional target. The first unconventional well was drilled in 2008, and by 2013, it had become the most prolific play in North America, producing more than 1 MMBOE/day (Clark et al., 2016) and accounting for a large proportion of the annual oil production of the U.S. Comparatively, exploration within the Agua Nueva and Tuscaloosa formations has been more limited, with only 13 unconventional wells targeting the Agua Nueva (Dyer, 2017) and 75 targeting the TMS (Rystad Energy, 2017) as of 2018. Will further exploration and development reap dividends, causing success on par with the Eagle Ford of Texas?

This article demonstrates that subsurface geological criteria, as well as in-place resource and completion practice, are important considerations for unconventional hydrocarbon production. Indeed, the distribution of established production sweet spots within the Eagle Ford play is related to four fundamental geological criteria: mineralogy, maturity, net thickness and reservoir pressure (Clark et al., 2016). Further, the article demonstrates how understanding gained in the data-rich Eagle Ford play can be applied to the Agua Nueva and Tuscaloosa resource plays. This understanding is important when evaluating resource play prospectivity and predicting the distribution of undiscovered production sweet spots.

Stratigraphic Appraisal

Eagle Ford Group

The Eagle Ford Group was deposited during the Cenomanian-Turonian on the Comanche Platform in Texas within an epicontinental sea following the inundation and drowning of an established carbonate platform (Phelps et al., 2014). The Lower Eagle Ford Formation is the primary unconventional target within the play and consists of a series of interbedded, organic-rich marls and limestones (Bowman, 2015).

During the early part of the Late Cretaceous, inherited paleobathymetric features on the Comanche Platform (Stuart City and Sligo margins) had a strong control on deposition (Figure 1). These features limited bottom water circulation, causing highly anoxic/euxinic bottom water conditions, as demonstrated by high Mo and V enrichment factors within the Cenomanian Lower Eagle Ford Formation (Tinnin and Darmaoen, 2016). In addition to anoxic conditions, upwelling against the Sligo Margin and volcanic ash input lead to high primary productivity (Tinnin and Darmaoen, 2016), causing the widespread deposition of organic-rich marls in the area proximal to the shelf margins with 2-7 wt% TOC typical (Hammes et al., 2016).

During the latest Cenomanian, a change in oceanic circulation resulted in increased bottom water circulation on the Comanche Platform and brought to an end widespread organic enrichment in the Upper Eagle Ford Formation. This overturn in oceanic circulation coincides with oceanic anoxic event 2 (OAE2) and reflects a marked increase in oceanic connectivity between boreal and Tethyan water masses through the Western Interior Seaway while relative sea level peaked during the latest Cenomanian (Eldrett et al., 2017). The Upper Eagle Ford Formation is predominantly characterized by organic-lean carbonates with 1-2 wt% TOC typical (Hammes et al., 2016).

The Eagle Ford Group is primarily a carbonate-rich shale play across the Comanche Platform. However, to the east of the San Marcos Arch (Figure 1), clastic input from the Woodbine and Harris deltas modify the nature of the play. Moving progressively from west to east, the play transitions to a clay-rich resource play (Maness), a tight sand play (Eaglebine), and then finally to a conventional reservoir (Woodbine). Production from the clay-rich Eagle Ford play to the east of the San Marcos Arch is notably lower than from the carbonate-rich western sector of the play. This reflects the change in ductility of the target layer and the reduction of brittle carbonate interbeds that act to propagate fractures (Clark et al., 2016; Tian et al., 2017).

Agua Nueva Formation

The Sligo Margin, which has primary control on organic-matter deposition in Texas, continues into Mexico where it is known as the Cupido Margin (Figure 1; Goldhammer and Johnson, 2001). Behind this Margin, depositional environments, oceanic conditions and organic matter preservation within the Agua Nueva Formation are predicted to be comparable to the Eagle Ford Group. This is supported by the similarity of log and geochemical characteristics between the Chucla-1 well in Mexico (CNH, 2017) and wells such as Bridwell IV and East De Witt in Texas (Figure 2). All three wells exhibit high gamma log signatures throughout the Lower Eagle Ford Formation associated with a high TOC, as demonstrated by the Chula-1 well. After OAE2, there is an immediate drop off in gamma values related to a drop in TOC. High resistivity is associated with high carbonate content in the Lower Eagle Ford Formation. The drop off in resistivity within the Lower Eagle Ford Formation in East De Witt reflects an increase in clay content.

The play concept diagram for the Eagle Ford play (Figure 3b) demonstrates that target zone thickness increases from east to west because of decreasing siliciclastic input from the Harris Delta. For the northern Burgos and northern Sabinas basins, the thickness of the target zone within the Agua Nueva Formation is comparable to the western sector of the Eagle Ford play. The Agua Nueva play concept diagram (Figure 3a) shows a thick package of organic-rich stratigraphy associated with restriction before OAE2 in the area proximal to the Sligo/Cupido Margin.

For the southern Burgos, southern Sabinas and Tampico basins, distal to the Sligo/Cupido Shelf Margin, organic-rich horizons within the Agua Nueva Formation are expected to be thinner and more discontinuous (Figure 3a). Log characteristics of the Agua Nueva Formation for the Cacaliao Field in the Tampico-Misantla Basin are notably different from Eagle Ford wells, such as Bridwell IV, with high gamma values in the Agua Nueva Formation associated with the influx of fine-grained siliciclastics rather than organic-rich stratigraphy (Figure 2). Organic matter preservation in this area is likely to be limited to OAE2 and driven by the expansion of the oxygen minimum zone, which enabled anoxic bottom water in the Gulf of Mexico to impinge the continental slope of Mexico (Núñez-Useche et al., 2016). This is notably different from the Comanche Platform where OAE2 is associated with bottom water oxygenation and a reduction in TOC. Highest organic matter preservation within the Agua Nueva Formation for the frontier basins in Mexico is expected to be limited to the area northwest of the Sligo/Cupido Margin

(Figure 2). Therefore, the most prospective area within the Agua Nueva resource play appears to be limited to the northern part of the Burgos Basin, proximal to the Sligo/Cupido Margin (Figure 3a).

Tuscaloosa Formation

The Sligo Margin, a primary control on organic enrichment within the Cenomanian-Turonian interval in Texas, continues to the east into Mississippi and Louisiana. However, in this region, the Early Cenomanian Lower Tuscaloosa delta overwhelms the carbonate margin system, smoothing the shelf paleobathymetry. The delta ultimately prograded beyond the Sligo Margin, causing a perched delta system that supplied siliciclastic sediment into the central Gulf of Mexico (Figure 3c). Rising sea level during the Cenomanian transgression forced the retreat of this system, culminating in the deposition of organic-rich siliciclastic mudstones of the TMS during OAE2. The timing of organic enrichment for the TMS is confirmed in the SUN 1 SPINKS well, which exhibits peak TOC coinciding with the characteristic OAE2 carbon isotope signature and diagnostic planktonic foraminiferal zone (Figure 2) (Lowery et al., 2017).

Unconventional potential within the Tuscaloosa system appears limited to a well-mapped hydrocarbon-saturated resistive zone within the TMS (Allen, 2015). The timing, duration and magnitude of organic enrichment within the TMS are all different to the Eagle Ford play. In addition, XRD/XRF data from the TMS indicate a high clay content (>50 wt%), which is typically much higher than the Eagle Ford and other well-established North American unconventional plays (Lowery et al., 2017). Therefore, the TMS is likely to have considerably different reservoir completion properties to the carbonate-dominated Eagle Ford because increased clay content is strongly associated with an increase in the ductility of the target horizon, which typically results in a reduction in production rate.

Identifying Extensions to the Eagle Ford Play

The stratigraphic appraisal has demonstrated significant differences between the established Eagle Ford play and the frontier to emerging Agua Nueva and Tuscaloosa plays. The Agua Nueva play distal the Sligo (Cupido) Shelf Margin and the Tuscaloosa play are not comparable to the Eagle Ford play because the timing, duration and magnitude of organic enrichment appear to be fundamentally different. However, the Agua Nueva play proximal to the Sligo (Cupido) is comparable to the Eagle Ford play and is an area that warrants further assessment.

A workflow for in-place resource volume evaluation presented in Bromhead et al. (2017) was used to compare the resource concentration across the Eagle Ford, Agua Nueva and Tuscaloosa plays. This assessment revealed that resource concentration within northern Burgos and Sabinas basins, proximal to the Sligo/Cupido Margin, is comparable to core areas within the Eagle Ford play. This highlights the Agua Nueva play in the northern Burgos and Sabinas basins as a fundamental extension with comparable stratigraphic character and resource in-place per section. Elsewhere, resource concentrations are less than a third of that calculated for the Eagle Ford.

Eagle Ford Sweet-Spot Assessment

Resource in-place is not the only important factor in the development of a successful unconventional play - completion practices and subsurface geological factors that impact hydrocarbon flow rates should be considered. It is known that there are multiple fundamental geological controls on production sweet-spot development in the Eagle Ford play (Cander, 2012). Do these characteristics carry through to the Agua Nueva play? Can we expect similar "Eagle Ford" style production sweet spots for the high-graded area in the northern Burgos and Sabinas basins?

This study defines the sweet spot as "an area(s) within the play characterized by a consistently superior production rate relative to the remainder of the play". Production trends within the mature Eagle Ford province are primarily controlled by four geological factors (maturity, mineralogy, net thickness and reservoir pressure) that influence production rates by affecting the in-place resource, the brittleness of the target unit and the hydrocarbon flow rate. By comparing the mapped distribution of these factors with well production data, limits associated with the highest production within this play can be defined.

Production data used for this study was sourced from Rystad NASWellCube (RYSTAD Energy, 2017). The first year's initial production (12-month IP) was used as the production metric. Maps of each of the four previously mentioned geological factors were created during the resource in-place evaluation.

Maturity

A regional maturity assessment was performed using the methodology outlined in Bromhead et al. (2017), accounting for variable uplift related to the Laramide Orogeny. This output was verified by comparing to known maturity information. Higher maturity is generally related to higher oil production rates, reflecting the reduction in fluid viscosity with increasing maturity and its impact upon flow rate, as predicted by Darcy's Law (Cander, 2012).

The Eagle Ford play spans a wide range of thermal maturity, from the early oil window in the north to the gas window in the south. This study demonstrates that production rates are sensitive to maturity, with the highest producing wells clustered in the area mapped as late oil-gas mature. Optimal production for oil is suggested to occur between 1-1.5 % Ro and for gas between 1.35-2%, where predominantly gas production is defined at gas-oil ratio (GOR) >8,000 scf/bbl.

Mineralogy

Shale mineralogy can have a significant effect on the geomechanical properties of the reservoir interval and, therefore, on its ability to be hydraulically fractured. In general, carbonate and silica are associated with increased brittleness, while clay and kerogen are associated with an increase in ductility (Slatt and Abousleiman, 2011).

The western and central sectors of the Eagle Ford play are typically carbonate dominated (>60 wt% calcite) with a minor clay and silica fraction (Clemons et al., 2016). For the eastern sector of the Eagle Ford play, close to the southeast plunging hinge of the San Marcos Arch, the proportion of clay content increases (>30 wt%) because of siliciclastic input distal to the Harris Delta system (Clarke et al., 2016). A steep decline in production is evident from west to east in the Eagle Ford play across the San Marcos Arch, likely related to the increased clay content (Figure 1). The arch acts as a structural barrier, isolating the western portion of the Eagle Ford play from the clastic input sourced by the Harris Delta.

Net Thickness

Net thickness is the total thickness of organic-rich facies within a shale play interval. For the Eagle Ford and Agua Nueva formations, net thickness was mapped using well log information and published isopach maps for the play. Net thickness is quite variable and ranges between 10-100 m across the Texan portion of the play (Hammes et al., 2016), with higher values within tectonically controlled depressions in the Comanche Platform, such as the Maverick Basin and the Karnes Trough.

Across the Eagle Ford play, oil production (GOR < 8,000 scf/bbl) generally increases with net thickness. Net thickness of > 40 m appears to be optimum for oil production, which is in agreement with the study of Clarke et al. (2016). Optimal thickness for gas production appears to be > 20 m, while there is no evident relationship between net thickness and production above this threshold. However, this trend could potentially be obscured by other variables (e.g., pressure).

Reservoir Pressure

Reservoir pressure was mapped using the relationship between depth and pressure for the Comanche Platform and verified by comparing published maps. Higher pressure is related to higher production, as predicted by Darcy's Law of fluid flow (Cander, 2012).

Reservoir pressure increases from north to south in the Eagle Ford play, primarily as a function of depth, and ranges between 3,000-11,000 psi across the extent of the play (Cander, 2012). It has been demonstrated that high reservoir pressure (> 8,000 psi) is optimum for oil production, while high gas production can be achieved at slightly lower pressure, with > 4,500 psi considered to be optimum.

Assessment Results

This assessment shows a geological control on production sweet spots within the Eagle Ford play based on the four parameters of maturity, mineralogy, net thickness and reservoir pressure. Using the geological information, optimal oil and gas production limits have been defined for each of these parameters (Table 1).

The limits defined in Table 1 were tested to investigate how well they reproduce known high production trends within the Eagle Ford play. The spatial overlap of the four parameters (defined in Table 1) with the screened Eagle Ford play extent was calculated to define the geological sweet spots. All production data from Rystad NASwell Cube (RYSTAD Energy, 2017) was graded from high to low, and quintile ranks of 1 (top 20% of wells) to 5 (bottom 20% of wells) were assigned. These wells were then plotted spatially and compared to the predicted geological sweet spots. Within the geological sweet spots, 71% of the producing wells are in the first and second quintile, compared to only 26% outside (Figure 4). This implies a strong spatial relationship between the modelled geological sweet spots and the proven production sweet spots, demonstrating that by understanding the geological controls alone, there is an increased likelihood of drilling high performing unconventional wells.

Implications for the Agua Nueva

This assessment defines a series of cut-off values for optimal production within the Eagle Ford play (Table 1). Applying these to mapped variability in maturity, mineralogy, thickness and reservoir pressure within the Agua Nueva play can help locate potential production sweet spots.

Much of the Agua Nueva Formation is within optimal levels of maturity for unconventional oil and gas production. Following trends noted within the Eagle Ford play, mineralogy and thickness are also likely to be optimal behind the Sligo/Cupido Margin. However, throughout the Agua Nueva Formation, reservoir pressure is below optimal thresholds defined for oil production. Lower reservoir pressure in the Agua Nueva can be explained by looking at the Eagle Ford play. For the western-most portion of the Eagle Ford, pressure is lower than at an equivalent depth in the primary oil production sweet spots (Cander, 2012) because of Laramide exhumation causing a loss of overpressure (Gherabati et al., 2016). As a result, reservoir pressure in the Eagle Ford play is suboptimal for oil production in the western portion of the play. The eastern margin of Mexico has also experienced high magnitudes of Laramide exhumation (Ewing, 2003); therefore, it is likely that reservoir pressure within the Agua Nueva Formation will be lower than the optimal range for oil production because of loss of overpressure.

When considering reservoir pressure, production rates for oil in Mexico are unlikely to reach those observed within the production sweet spots in the central sector of the Eagle Ford play, despite the high in-place resource. However, for gas production, optimal reservoir pressure conditions are considered to be lower than those for oil (Table 1). The modeled reservoir pressure values for the Agua Nueva Formation suggest that optimal conditions continue into Mexico. A potential gas production sweet spot in the Agua Nueva play is mapped in the northwestern Burgos Basin near the border with Texas. This is the direct western extension of the proven Eagle Ford gas sweet spot.

Conclusions

This study demonstrates that the prospectivity of the Eagle Ford Group is controlled not only by resource in-place but also by multiple other geological parameters that can be related to production rates. Within the emerging Agua Nueva play, high resource in-place has been mapped in the northwest Burgos and Sabinas basins behind the Sligo Margin. There is the potential for gas production sweet spots in a limited portion of this area within the northwestern Burgos Basin; however, reservoir pressure appears to be generally too low for high oil production rates. For the Tuscaloosa play, the predominance of clay is likely to have a detrimental effect on the producibility of the resource. In-place resource is generally lower than the Eagle Ford, and the systems are not comparable.

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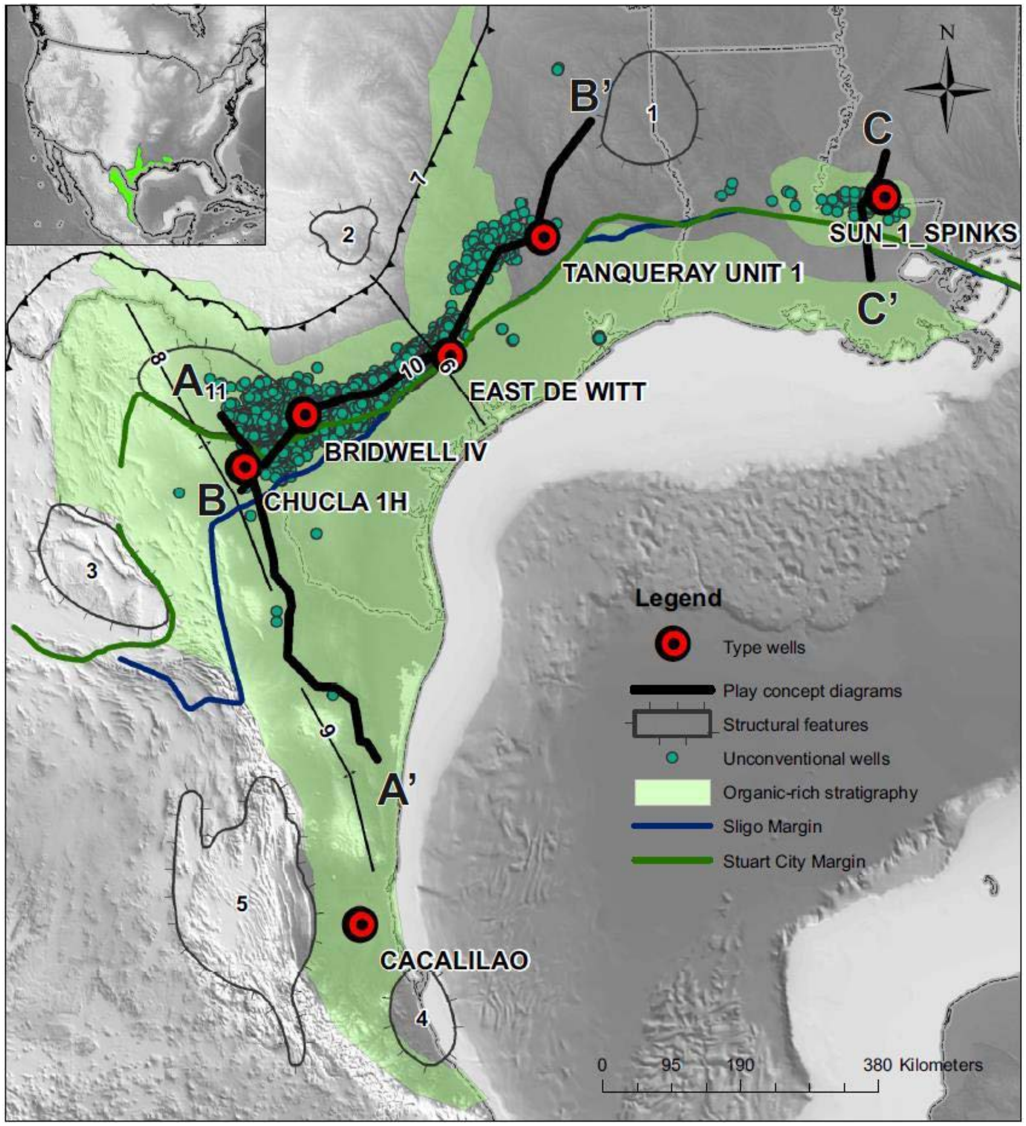

Figure 1. Gulf Coast study area highlighting unconventional well locations (Dyer, 2017; RYSTAD Energy, 2017), type wells, play concept diagram locations and maximum depositional extent of Cenomanian-Turonian organic-rich stratigraphy. Structural elements highlighted are (1) Sabine Uplift, (2) Llano Uplift, (3) Coahuila Block, (4) Tuxpan Platform, (5) Valles-San Luis Potosi Platform, (6) San Marcos Arch, (7) Marathon-Ouchita Tectonic Trend, (8) Burro-Salida Arch, (9) Tamaulipas Arch, (10) Karnes Trough, and (11) Maverick Basin (after Goldhammer and Johnson, 2001; Denne et al., 2016).

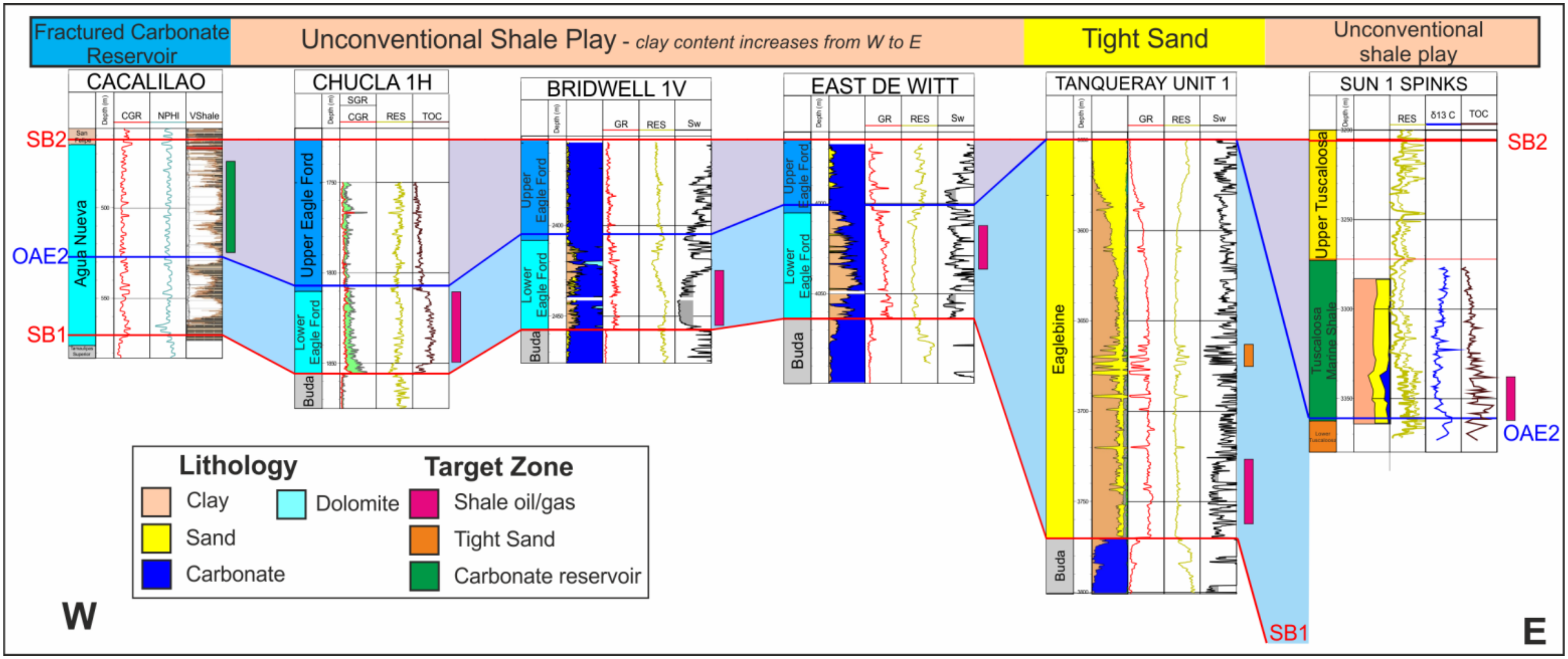

Figure 2. Well correlation panel through the studied resource interval, illustrating how the stratigraphic character of the play changes across onshore Gulf of Mexico. (Refer to well locations in Figure 1) (Bowman, 2015; Lu et al., 2015; Sandoval, 2016; CNH, 2017).

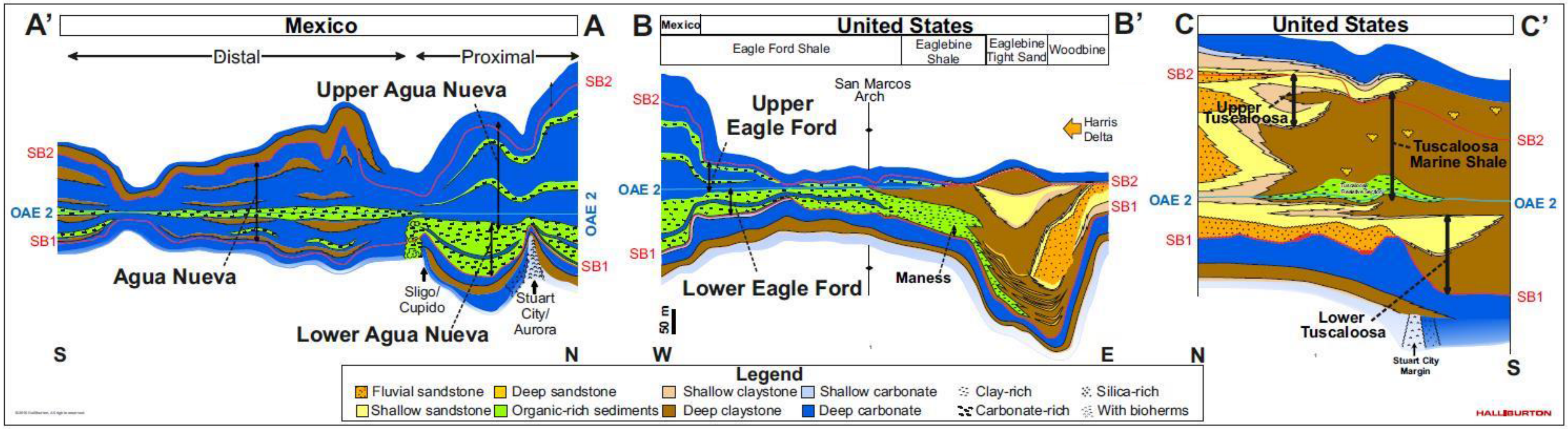

Figure 3. Play concept diagrams for the Agua Nueva (A'-A), Eagle Ford (B-B'), and Tuscaloosa (C-C') plays, illustrating the stratigraphic architecture and lithological variability within the resource interval. (Panel location in Figure 1).

	Oil	Gas
Maturity	1.0-1.5 Ro%	1.4-2.0 Ro%
Mineralogy	Carbonate-rich (clay <30%)	Carbonate-rich (clay <30%)
Net thickness	>40m	>40m
Reservoir pressure	>8,000psi	>4,500psi

Table 1. Geological factors for optimal production from the Eagle Ford play. Oil wells have been defined as those with a GOR of <8,000 scf/bbl.