# Geologic Models and Evaluation of Undiscovered Conventional and Continuous Oil and Gas Resources—Upper Cretaceous Austin Chalk, U.S. Gulf Coast

Scientific Investigations Report 2012–5159

**U.S. Department of the Interior**
**U.S. Geological Survey**

**Front Cover.** Photos taken by Krystal Pearson, U.S. Geological Survey, near the old Sprinkle Road bridge on Little Walnut Creek, Travis County, Texas.

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# Geologic Models and Evaluation of Undiscovered Conventional and Continuous Oil and Gas Resources—Upper Cretaceous Austin Chalk, U.S. Gulf Coast

By Krystal Pearson

## Abstract

The Upper Cretaceous Austin Chalk forms a low-permeability, onshore Gulf of Mexico reservoir that produces oil and gas from major fractures oriented parallel to the underlying Lower Cretaceous shelf edge. Horizontal drilling links these fracture systems to create an interconnected network that drains the reservoir.

Field and well locations along the production trend are controlled by fracture networks. Highly fractured chalk is present along both regional and local fault zones. Fractures are also genetically linked to movement of the underlying Jurassic Louann Salt with tensile fractures forming downdip of salt-related structures creating the most effective reservoirs. Undiscovered accumulations should also be associated with structure-controlled fracture systems because much of the Austin that overlies the Lower Cretaceous shelf edge remains unexplored.

The Upper Cretaceous Eagle Ford Shale is the primary source rock for Austin Chalk hydrocarbons. This transgressive marine shale varies in thickness and lithology across the study area and contains both oil- and gas-prone kerogen. The Eagle Ford began generating oil and gas in the early Miocene, and vertical migration through fractures was sufficient to charge the Austin reservoirs.

## Introduction

The U.S. Geological Survey (USGS) completed a geologic assessment of the undiscovered, technically recoverable oil and gas resources in the Austin Chalk and Tokio and Eutaw Formations of the U.S. Gulf Coast region (Pearson and others, 2011). The assessment was based on the geologic elements and petroleum processes used to define a total petroleum system (TPS), which in this study is the Upper Jurassic-Cretaceous-Tertiary Composite TPS (fig. 1), and includes petroleum source rocks (source-rock maturation and petroleum generation and migration), reservoir and seal rocks (sequence stratigraphy and petrophysical properties), and petroleum traps (trap formation, timing, and seals).

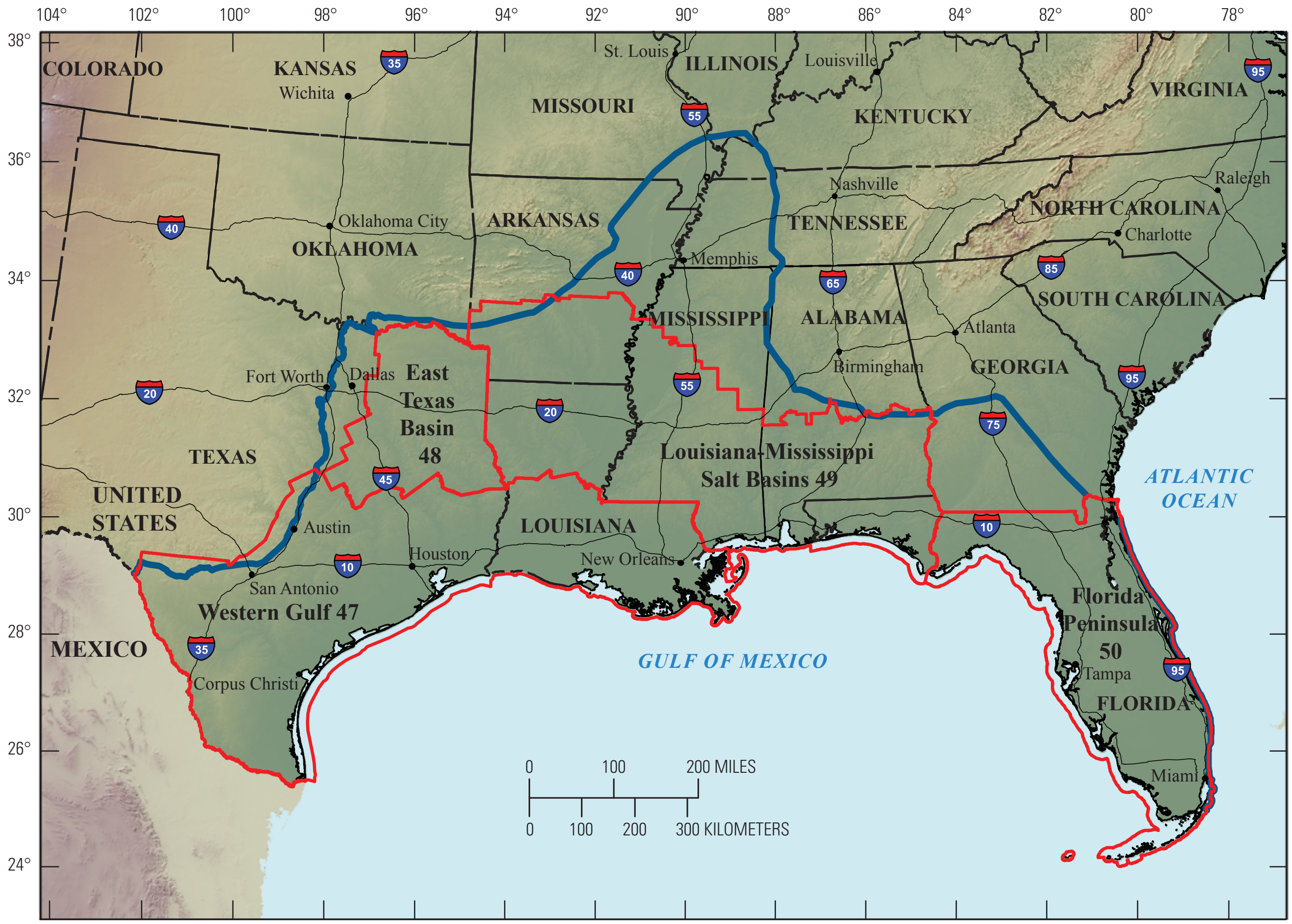
Separate assessment units (AU) are defined to evaluate the potential in regions with differing geologic conditions or different production profiles. These evaluations permit resource prediction in both conventional and continuous AUs. Geologic factors such as trap type and local geology, as well as exploration trends, are used to predict these totals (Pearson and others, 2011).

Using this petroleum-system framework, the USGS defined four AUs within the Upper Jurassic-Cretaceous-Tertiary Composite TPS: Austin-Tokio-Eutaw Updip Oil and Gas AU, Austin-Eutaw Middip Oil and Gas AU, Austin Downdip Gas AU, and Austin Pearsall-Giddings Area Oil AU (fig. 2) (Pearson and others, 2011).

The study area of this assessment spans a wide region that includes parts of Texas, Louisiana, Arkansas, Mississippi, Alabama, and Florida (figs. 1 and 2). Its extent is broadly defined by the bounding fault zones to the north and east, the U.S.-Mexico border to the west, and the extent of State waters to the south in the Gulf of Mexico.

The Upper Cretaceous Austin Chalk (fig. 3) is a historically well-known onshore oil and gas play that extends across south-central Texas into southern Louisiana. Production data plotted from IHS Energy Group (2009a) indicate that hydrocarbon production trends within the formation are subparallel to the underlying Lower Cretaceous shelf edge (fig. 2). Recent drilling has expanded this traditional reservoir belt farther east into Louisiana as well as downdip of the Lower Cretaceous shelf edge.

The Austin Chalk is classified as a biomicrite, according to Folk (1959), composed primarily of coccoliths (Dawson and others, 1995). This low-permeability, low-porosity rock requires large, connected fracture systems to store and produce hydrocarbons. Most of the large fractures parallel regional strike with few dip-oriented fractures. This single dominant joint set requires the presence of many smaller, intersecting local fractures to maintain fluid flow in the reservoir. The clay component of the formation also affects fracture intensity and connectivity. Although termed a chalk, marls are prevalent, alternating with chalk layers to form a heterogeneous package.




**Fgure 1.** Map for the Gulf Coast region showing the Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System (TPS). TPS boundary is shown in blue. Province boundaries are shown in red; numbers refer to a U.S. Geological Survey coding system.

Individual fractures within the chalk layers may terminate at marl layers that are one-tenth the thickness of the chalk (Haymond, 1991) contributing to the complex and disconnected nature of these fracture systems.

Early drilling within the Austin Chalk focused on simple, vertical wells that drained oil and gas from the local fracture systems near the well. In the 1970s, hydraulic fracturing of the reservoir was initiated, which enhanced and connected these fracture systems to ultimately create a larger drainage area. A second advance in oil and gas production arrived in 1984, with the advent of horizontal drilling. First utilized in Pearsall and Giddings fields (fig. 4) to produce oil and gas from the Austin, this new technique allowed for the drainage of multiple vertical fracture systems, thus enhancing the ultimate recovery from a single well from three to five times that of a comparable vertical well (Haymond, 1991).

## Geologic Setting and Stratigraphy

The Upper Cretaceous (Coniacian to Campanian) Austin Chalk is known by different names in the literature across the study area, such as the Austin Chalk Formation or the Austin Chalk Group (fig. 3). The name Austin Chalk will be used to reference the unit in this paper. The Austin Chalk was deposited during a world-wide sea-level highstand (Vail and others, 1977) (fig. 3). Across what is now Texas, carbonate deposition occurred in a shallow-marine setting, in paleowater depths that ranged from 30 ft or less to more than 300 ft, indicating that deposition was below normal wave base on the inner to middle shelf as well as in much deeper water (Dravis, 1979). Paleowater depths likely deepened to the south and east, basinward of the Lower Cretaceous shelf edge (fig. 2). Trace fossil

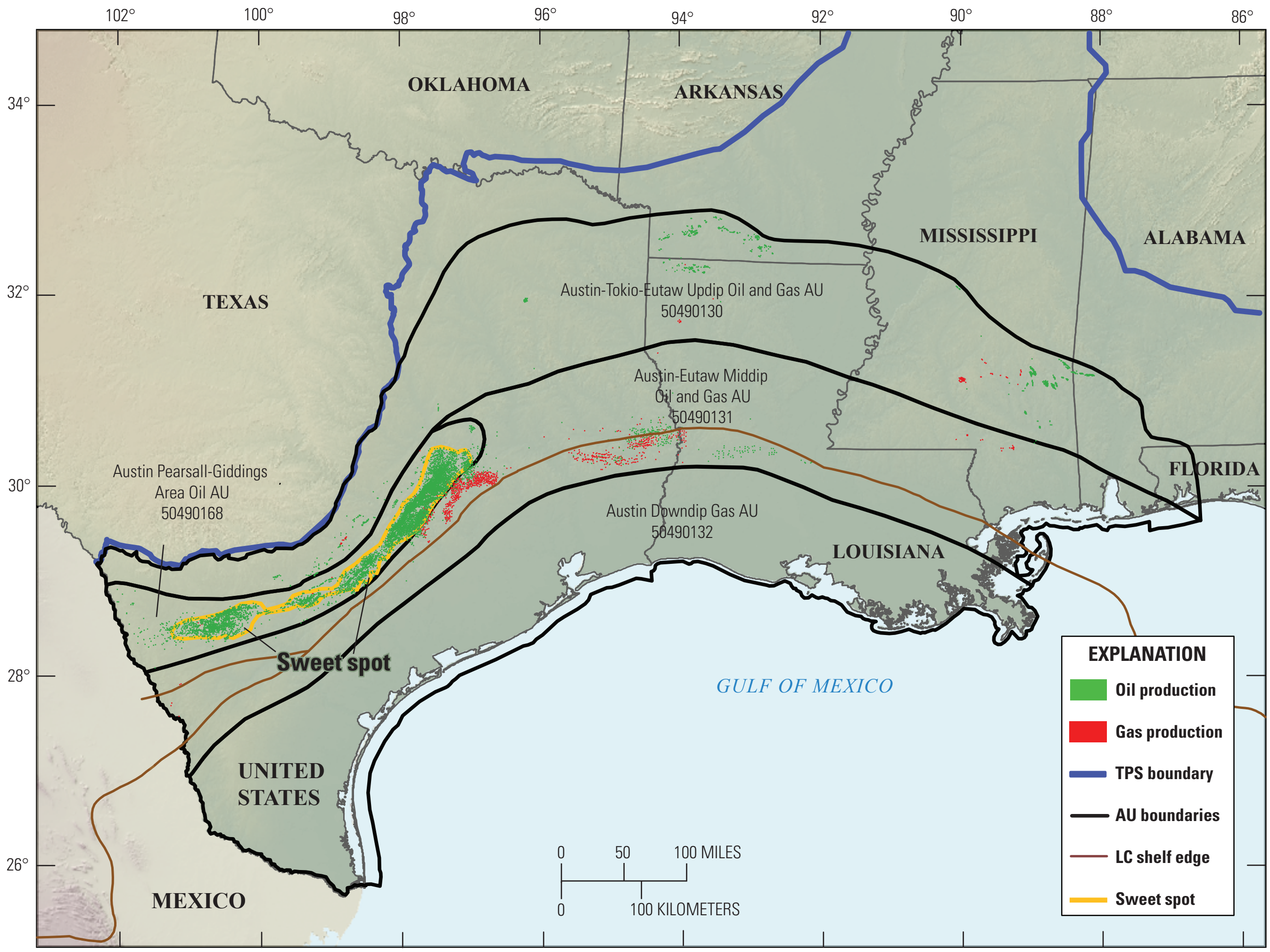



**Figure 2.** Location map showing assessment unit (AU) areas within Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System (TPS); numbers refer to a U.S. Geological Survey coding system. AU boundaries are shown in bold black. Location of Austin Chalk oil and gas production (IHS Energy Group, 2009a), shown in green and red, respectively, are plotted on the basis of quarter-mile area cells. Sweet spot (where production is, or is expected to be, elevated compared to the surrounding area) is outlined in gold inside the Austin Pearsall-Giddings Area Oil AU. Lower Cretaceous (LC) shelf edge after Martin (1980) and Ewing and Lopez (1991).

assemblages indicate normal marine salinity with deposition in an open marine environment. Dominant trace fossils include *Planolites, Thallassinoides,* and *Chondrites* (Dawson and Reaser, 1990).

The widespread chalk deposition across the carbonate shelf shows only gradual lateral facies changes with few major facies recognized in Texas (Scholle, 1977). In parts of the East Texas Basin, northern Louisiana, southern Arkansas, and southern Alabama, however, sandstone sourced from fluvial systems to the north in the Mississippi Embayment is the dominant facies. The sandy facies equivalents in eastern Texas, Louisiana, and western Alabama are the Tokio and Eutaw Formations (Salvador and Quezada Muñeton, 1991) (fig. 3). These formations grade basinward into carbonate partial time-equivalent units, specifically the lower parts of the Austin Chalk and the Selma Group (Clark, 1995; Liu, 2005). The study area includes the regions with Austin Chalk deposition as well as its clastic equivalents to the east.

The Austin Chalk ranges in thickness from 150 to 800 ft and has many named members. In a broader and more regionally applicable sense, however, it has been divided into three main units: the lower chalk, the middle marl, and the upper chalk (fig. 3). The upper and lower chalks contain less clay and are therefore better reservoirs because they are more brittle, leading to higher fracture density (Hovorka and Nance, 1994).

Hovorka and Nance (1994) described the three main Austin units in detail. The lower chalk consists of a number of lithofacies, including alternating chalk and marl, with the chalk intervals having a greater thickness than the intervening

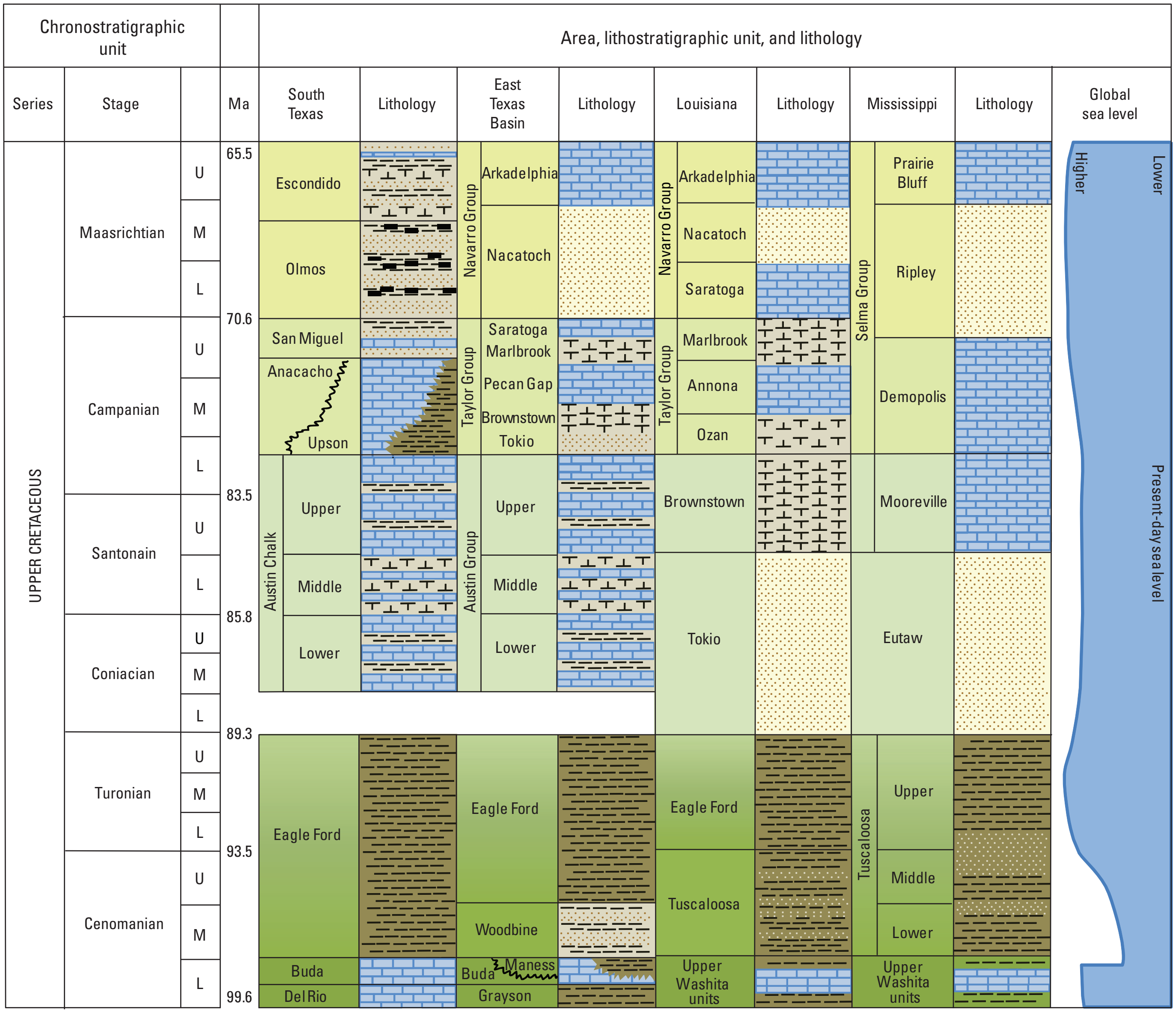



**Figure 3.** Stratigraphic column for Upper Cretaceous rocks in the study area (modified from Vail and others, 1977; Wooten and Dunaway, 1977; Dawson and Reaser, 1990; Wescott and Hood, 1994; Mancini and others, 2006a,b). Reservoir rocks: Austin Chalk and Tokio and Eutaw Formations. Source rocks: Eagle Ford Shale and Smackover Formation (not shown). Seal rocks: Anacacho, Upson, Brownstown, and Mooreville Formations and Taylor Group. Global sea-level curve shows a prominent sea-level rise during the Cenomanian. U=upper, M=middle and L=lower.

marls. Hovorka and Nance (1994) suggested that these alternations are transgressive in nature. Also present are chalks with thin, dark, and locally laminated marls that contain as much as 3.5-percent total organic carbon (TOC) as well as disseminated pyrite, indicating dysaerobic depositional conditions. Transgressive marls deposited under normal oxygen levels, as well as marly chalks that grade into chalks, are interpreted as highstand deposits in the lower chalk (Hovorka and Nance, 1994).

The middle marl contains a zone of alternating and cyclic burrowed chalk and light-colored marl. This unit has much higher clay content and, as such, most of the layers should be termed “chalk-marl” or “marl” rather than “chalk.” Authigenic clay that formed as an alteration product of volcanic ash is also present. This unit is interpreted as initially regressive, with the younger strata deposited during a transgression (Hovorka and Nance, 1994).

In the upper chalk, the cyclicity of chalks and marls becomes less regular and defined. There is a marked increase in winnowed packstone units toward the top of the unit. The entire member is interpreted as a highstand deposit, with decreased water depths basinward of the shoreline and falling

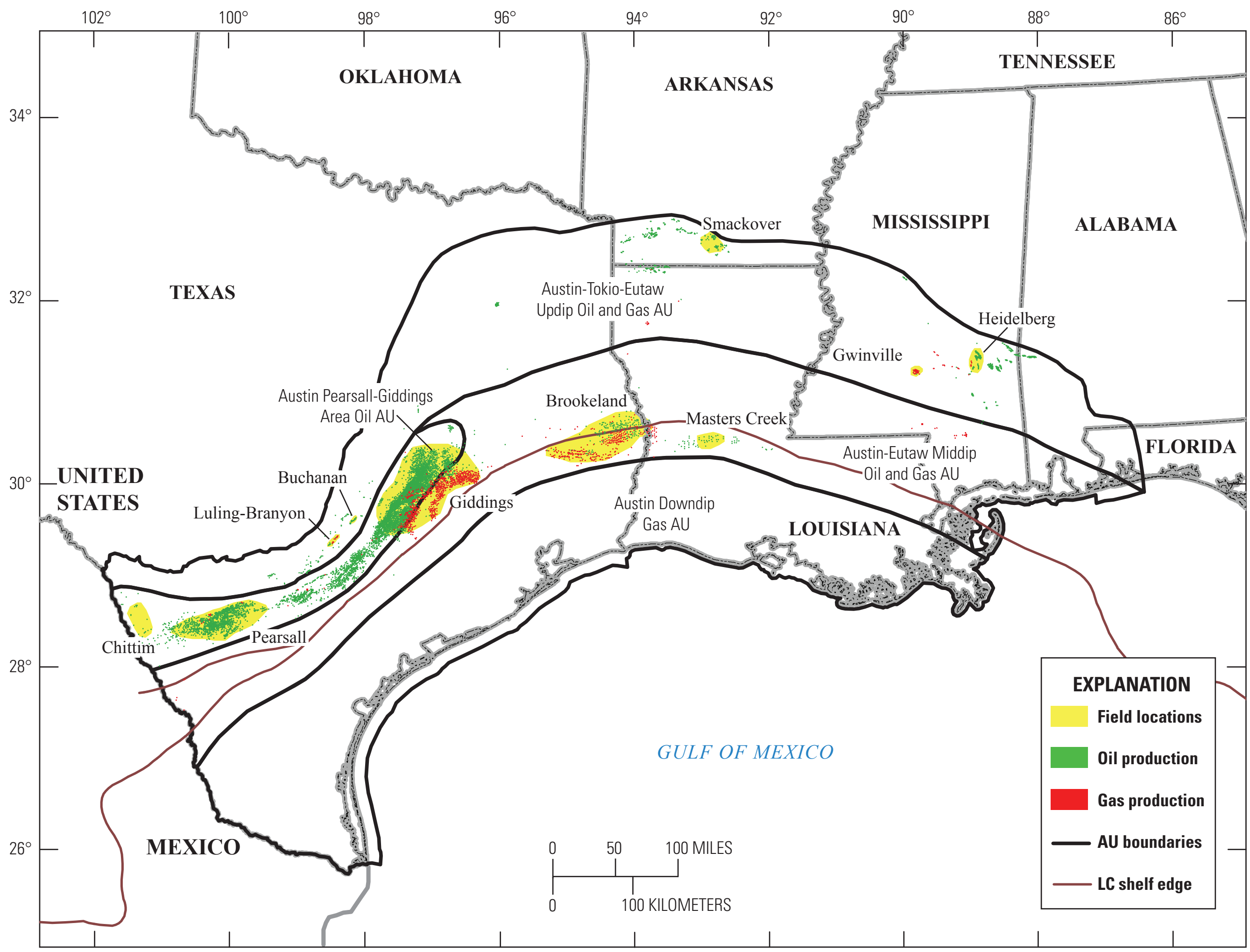



**Figure 4.** Location map showing assessment units (AUs) and major Austin Chalk fields (yellow). Location of Austin Chalk oil and gas production (IHS Energy Group, 2009a) shown in green and red, respectively, are plotted on the basis of quarter-mile area cells. Lower Cretaceous (LC) shelf edge after Martin (1980) and Ewing and Lopez (1991).

sea level (Hovorka and Nance, 1994). A diverse faunal assemblage indicates normal marine conditions. The top surface of the Austin Chalk is locally a bored hardground that is generally interpreted as the common by-product of sediment bypass (Hovorka and Nance, 1994).

Updip Austin strata, as described by Dawson and others (1995), were deposited in shallow water, above storm wave base during normal marine conditions. These light-colored, organic-poor chalks are similar to other “shelf-sea” or “onshore” chalks of Cretaceous age and were likely deposited in shallow water. Regionally, these are described as “progradational highstand deposits” (Vail and others, 1977). As these chalks were deposited in shallow marine water, they are heavily bioturbated.

Downdip Austin strata are much darker than the updip strata because of a deeper water depositional environment and increases in clay and pyrite contents. These are termed “far offshore” chalks and exhibit little bioturbation. Microstylolites and clay seams are common. Breccia horizons are apparent and are interpreted to indicate shallow water deposits that were transported downslope (Dawson and others, 1995).

Sediments deposited farthest from the shoreline are referred to as deep downdip strata (Dawson and others, 1995). These have been interpreted as basinal marine deposits that accumulated in paleowater depths greater than 300 ft (Dravis, 1979) or outer ramp and slope deposits (Dawson and others, 1995). A scarcity of skeletal debris, the presence of pyrite, and the absence of bioturbation all indicate these strata were deposited under oxygen-deficient conditions, although alternations of lighter colored chalks with darker colored marls indicate that oxygen levels varied. In addition, the rock is not completely devoid of trace fossils, which indicates that complete anoxia was not established.

Clark (1995) described the depositional environments, diagenesis, and porosity of the Tokio Formation (fig. 3). This unit comprises sublitharenitic to litharenitic sandstone with lithics sourced from volcanism in Alabama and Louisiana. The unit includes sandstone and shale sequences with friable well-sorted sandstones, mudstones, conglomeratic sandstones, and thin discontinuous coals. Although the Tokio is divided into four zones (RA, S3, S2 and S1), the 100-ft-thick basal RA zone, which is dominantly sandstone, forms the best reservoir unit in the formation.

The Tokio Formation is 210 ft thick in Haynesville field in northern Louisiana. Depositional environments across the study area include distributary channels (overlying the Eagle Ford Shale or Group), prodelta, transgressive marine settings, shallow marine bars, shoreface to barrier or beach complexes, and marsh or tidal flats and channels. Bioturbation, storm deposits, soft-sediment deformation, rip-up clasts, volcanic clasts, and glauconite are all present (Clark, 1995).

Permeability of the Tokio ranges from under 1 millidarcy (mD) to more than 3 darcies, but chlorite rims and clay cements appear to have caused a general reduction in permeability (Clark, 1995). Total porosity ranges from 20 to 32 percent, with averages of 26 percent in volcaniclastic sandstones and 30 percent in quartzose sandstones. Secondary porosity was created from dissolution of plagioclase and calcite and pitting or etching of quartz grains. Early burial diagenesis cements caused reduced porosities and permeabilities and may have inhibited compaction (Clark, 1995).

The Eutaw Formation (fig. 3) reaches thicknesses of 350 to 400 ft in western and central Alabama where it lies on the eastern edge of the study area. It was deposited during a marine transgression and comprises two members: (1) the lower, unnamed member that contains micaceous, glauconitic crossbedded sand with silty clay and carbonaceous clay and (2) the upper, Tombigbee Sand Member that includes massive, glauconitic, micaceous, silty sandstone (Liu, 2005). The Tombigbee Member grades downdip into chalk and marl beds of the Selma Group, and the lower member grades into glauconitic sands and carbonaceous shales. The Eutaw Formation accumulated in nearshore- and marginal-marine environments, such as isolated barrier islands and lagoons with tidal deltas and tidal inlets.

# Reservoir Properties

The Austin Chalk is a low-porosity, low-permeability carbonate with a dual pore system. It has a micro-porous matrix with micropores ranging in size from 5 to 7 microns (Dawson and others, 1995) and a moderately interconnected fracture system. Matrix porosity commonly ranges from 3 to 10 percent (Dawson and others, 1995) and generally decreases with depth (Dravis, 1979). Permeability also decreases with depth, and it is typically near 0.5 mD and locally around 0.1 mD (Dawson and others, 1995). Because of such low porosity and especially low permeability, production must rely heavily on fracture porosity and permeability. Water saturations are generally high, from 45 to 80 percent, and residual oil saturations range from 10 to 50 percent (Dawson and others, 1995).

Tectonic fracturing within the Austin increases local permeabilities to over 2 darcies (Dawson and others, 1995). Fracture density and connectivity are highly variable, however, depending on proximity to faults (fig. 5), mineralogical variations (such as an increase in clay content), bed thickness, and the distribution of post-fracture cements. Fracture densities of more than 20 microfractures per foot have been observed in core (Snyder and Craft, 1977).

Near-vertical fractures are abundant in the area of study with widths of 0.1 mm to 4 mm (Dawson and others, 1995). Bleeding oil or oil staining is common along fractures, which indicates that fracture networks provide migration pathways for hydrocarbons. Two or three generations of intersecting fractures are generally present with the earliest tending to be partially or completely cemented with calcite. A second orthogonal set typically remains uncemented, and a third set consists of "gash fractures" that are associated with stylolite development (Dawson and others, 1995).

Most fractures in the Austin Chalk were created in response to the downwarping of the Gulf Coast basin, paired with associated faults and localized uplifts (fig. 5) that tend to parallel regional strike of rock units. Where associated with major faulting, fractures tend to be concentrated on downthrown fault blocks and within grabens (Dawson and others, 1995). This creates a fracture network that typically communicates in a strike direction rather than in a dip orientation leading to variable gas-oil ratios at the updip and downdip limits of production.

As noted earlier, lithologic variation, specifically increases in marl or clay content, directly affects fracture density and connectivity. The upper and lower chalks contain more abundant and larger fractures than the middle marl (fig. 3). Fractures can terminate at a marl or shale bed that is much thinner than the adjacent chalk layer (Haymond, 1991). Therefore, thin alternating layers of chalk and marl likely have minimal communication. In addition, vertical, parallel fractures have moderately large spacing and generally few intersections (Wiltschko and others, 1991), which leads to reservoir compartmentalization.

Diagenetic processes can greatly influence the reservoir properties of the chalk. The Austin Chalk underwent considerable physical compaction that reduced primary porosity by 60 to 80 percent (Grabowski, 1981). Solution compaction also occurred in the unit producing stylolites, microstylolites, and concentrations of insoluble material such as clays and organic carbon (Grabowski, 1981).

Dawson and others (1995) described the Austin Chalk as an "argillaceous, compacted, foraminiferal biomicrite" where the micrite matrix is composed of coccolith fragments. The conversion of aragonite and high-magnesium calcite to the more stable low-magnesium calcite occurred post-deposition (Scholle, 1977). Additional calcite emplacement probably contributed to some porosity loss. Maximum burial depth affects degree of physical compaction and remains the main

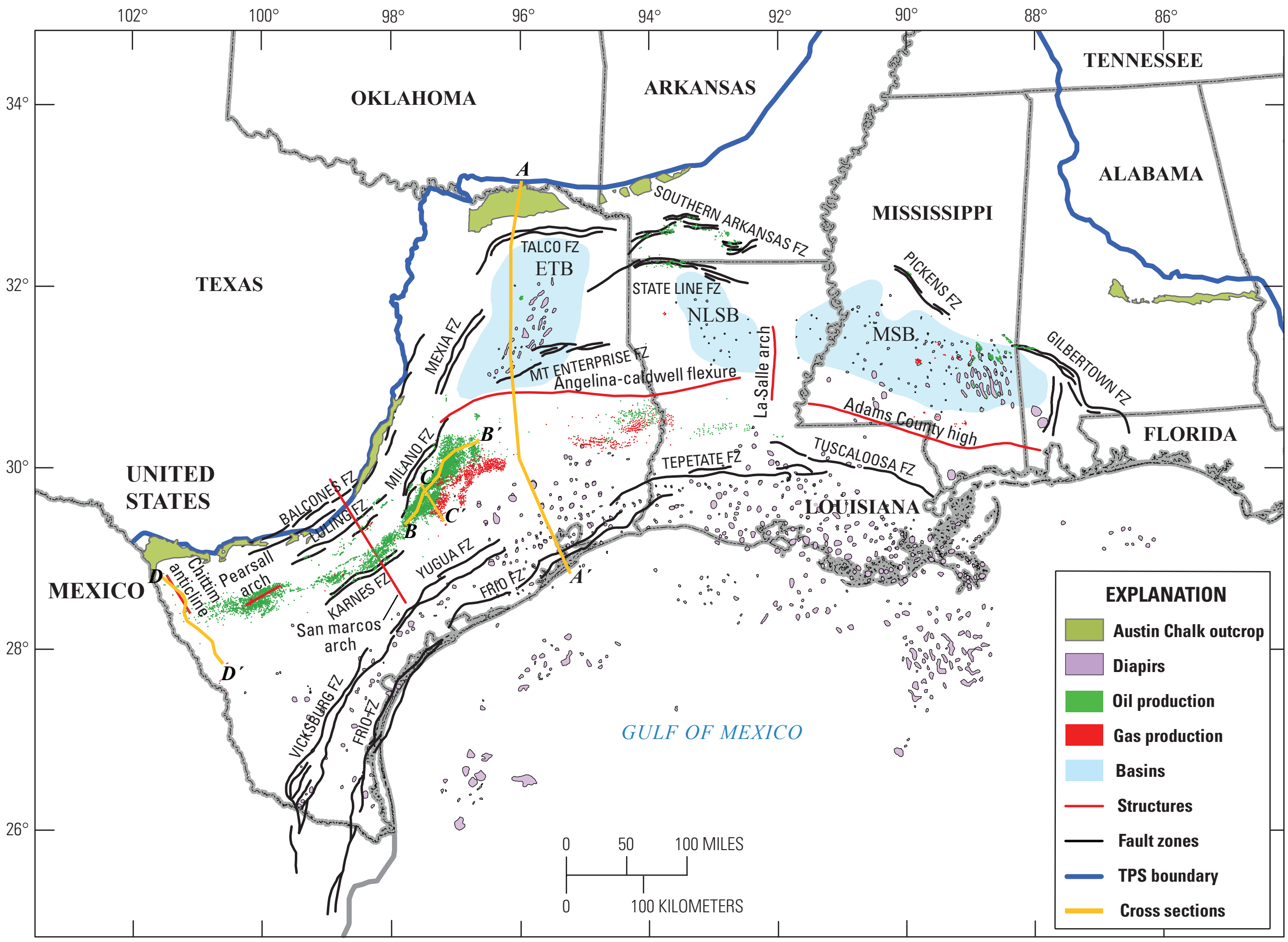



**Figure 5.** Major geological components of the study area, including the Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System (TPS) boundary, fault zones (FZ) and other structural features, Austin Chalk outcrops, and locations of cross sections. Locations of Austin Chalk oil and gas production (IHS Energy Group, 2009a), shown in green and red, respectively, are plotted on the basis of quarter-mile area cells. ETB = East Texas Basin, NLSB = North Louisiana Salt Basin, MSB = Mississippi Salt Basin. Structural features modified from Martin (1980) and Ewing and Lopez (1991). Austin outcrop modified from Schruben and others (1998) and King and Beikman (1974a,b).

factor that controlled porosity loss or preservation (Dawson and others, 1995).

## Source Rocks and Thermal Maturity

The Upper Cretaceous (Cenomanian to Turonian) Eagle Ford Shale (fig. 3) is known by different names in the literature across the study area, such as the Eagle Ford Formation or the Eagle Ford Group (fig. 3). The name Eagle Ford Shale, or simply Eagle Ford, will be used to reference the unit in this report. It is a mixed siliciclastic-carbonate unit that was deposited during a 2nd order eustatic transgression that contains superimposed, higher frequency 3rd order cycles (Dawson, 2000). Thickness varies over the region ranging from just 35 ft over the San Marcos arch of central Texas (fig. 5) to as much as 1,400 ft in the southern part of the East Texas Basin (fig. 5). As sea levels rose 60 to 100 ft, marine shales and carbonates were deposited south of the clastic fluvial systems in the northern part of the study area (Dawson, 2000). A major depocenter for the Eagle Ford Shale is centered in northeastern Texas (fig. 4). These terrigenous strata grade into marine deposits downdip and carbonate content increases (Dawson, 2000). As such, this creates a source rock with variable lithology and hydrocarbon generation potential. Dawson (2000) divided the Eagle Ford into two stratigraphic units. The lower, overall transgressive unit, consists of laminated shales that exhibit minor bioturbation. Transgressive and condensed strata of this unit were deposited in a poorly oxygenated marine setting below storm wave base. Few faunal species are recognized, and these lower shales tend to be oil-prone. An upper regressive unit contains high-frequency cycles of shale, limestone, and carbonaceous quartzose siltstone. These strata were deposited in a higher energy, more oxygenated setting above storm wave base. A more diverse faunal assemblage is present, and the unit tends to be gas-prone.

Dawson (2000) recognized and described six microfacies in the Eagle Ford. These include bituminous claystones and shales, pyritic fissile shales, phosphatic shales, bentonitic shales, fossiliferous shales, and silty shales. The primary microfacies acting as source rocks are bituminous claystones and shales, as well as phosphatic shales. Bituminous claystones and shales were deposited in a restricted, distal-marine, oxygen-depleted environment and are interpreted as transgressive deposits (Dawson, 2000). TOC is approximately 5 weight percent and pyrite is locally present. These strata lack bioturbation, fossils, and diagnostic sedimentary structures. Dawson (2000) proposed that the phosphatic shales (also known as "condensed shales") were deposited below wave base in an oxygen-depleted environment. These shales show a large abundance yet low diversity of planktonic fossils, as well as a low abundance of benthic fossils. TOC is approximately 2 to 4 weight percent, pyrite and glauconite contents are elevated, and bioturbation is sparse.

Robison (1997) examined the source rock potential and characteristics of the Eagle Ford. Based on percentages of oil-prone kerogen (fluorescent amorphinite plus exinite), the strata are of source rock quality in eastern Texas. Most samples contain a mixture of hydrogen-enriched Type II kerogen and hydrogen-poor Type III kerogen making the Eagle Ford prone to both oil and gas production. TOC ranges from 1 to almost 10 weight percent. Plotting TOC content versus sulfur content, Robison (1997) suggested a normal marine depositional setting for the formation, as opposed to an oxygen-depleted environment as interpreted by Dawson (2000).

A map of distribution of oils typed as Cretaceous (mostly Turonian) across the study area by Hood and others (2002; shown here as fig. 6) shows that oil produced from the historic Austin Chalk trend is likely sourced from the Eagle Ford because it is low sulfur marine in type and Turonian in age. Turonian source rocks in Louisiana and Mississippi may actually be in the Tuscaloosa Group (fig. 3) because these strata are a partial time-equivalent of the Eagle Ford.

In general, the Eagle Ford possesses good to excellent source rock characteristics and probably generated large quantities of hydrocarbons in its present-day oil-generation window location (fig. 7), as well as where it was previously within the oil window. The most productive intervals are transgressive, consisting of a condensed interval of marine shales that were deposited in oxygen-depleted environments. Kerogen type is dominantly oil-prone, and source rock quality varies both laterally and vertically.

Robison (1997) and others considered the Austin Chalk to be at least partially self-sourcing. Grabowski (1981) examined the source rock potential of the formation and reported that TOC was as much as 3.5 weight percent with higher values in deeper and more distal samples. Far updip chalks contain little organic carbon. Amorphous and sapropelic Austin oils contain Type II kerogen, produced from planktonic and algal organic matter. Grabowski (1981) placed the onset of petroleum generation at a burial depth around 5,000 ft based on an increase in extractability of hydrocarbons from samples below this depth. Similarly, where those hydrocarbons decrease, the onset of gas generation occurs at approximately 9,000 ft. API gravities for the Austin range from less than 20 degrees to more than 60 degrees. Grabowski (1981) attributed API gravity variation to the extent of hydrocarbon migration, with higher API gravities indicating increased migration distances. On the other hand, oils with API gravities less than 30 degrees may have undergone biodegradation, as they tend to be present in shallow wells.

In addition to the Eagle Ford, other rocks may be source rocks for the Austin Chalk in the study area. The Jurassic (Oxfordian) Smackover Formation was deposited over much of the eastern portion of the study area and varies in lithology and sulfur content (fig. 8). Geochemical oil-typing of oil samples from Louisiana and Mississippi indicate that the Smackover Formation is likely the primary source rock (Hood and others, 2002). This source rock, like those in the western portion of the study area, contains both Type I and Type II kerogen, implying contribution from both algal and some terrigenous material (Sassen, 1990).

Burial history plots were constructed for two wells that produce oil from the Austin Chalk (figs. 9 and 10). Input parameters including formation tops, lithology, organic carbon content (percent), paleowater depth, sediment-water interface temperature, paleoheat flow, vitrinite reflectance, temperature, and erosion were used to create the models. The first well (fig. 9) is located in Giddings field (fig. 7) where the Eagle Ford is the dominant source rock. Here, the Austin is approximately 570 ft thick with a formation top depth at 6,730 ft. The Eagle Ford is 300 ft thick and lies just beneath the Austin. Using Woodford kinetics (low sulfur) for this modeling, the top and base of the oil window were estimated using vitrinite reflectance ($R_o$) values of 0.6 percent and 1.3 percent, respectively. The Eagle Ford is currently within the oil window (fig. 9); the Eagle Ford in this area began generating oil approximately 10 million years ago (Ma), and the top of the formation entered the oil window approximately 4 Ma. The top of the Eagle Ford at present has a $R_o$ value of 0.61 percent, indicating that the upper portion of the formation has only been generating oil for a short time (approximately 4 million years).

A second study well (fig. 10) is located within Brookeland field (fig. 7) and was also modeled using the same input parameters, source rock, kinetics, and $R_o$ values for estimating the oil window. Here, the Austin is approximately 470 ft thick with a formation top depth of 11,300 ft. Figure 10 shows that at present the Eagle Ford is within the oil window with a $R_o$ value of 1.03 percent, and it began generating oil approximately 37 Ma. The Eagle Ford is much thinner in the Brookeland area than in Giddings field with a thickness of only 60 ft. Therefore, $R_o$ values are given as a formation average, as opposed to the top of the formation, as in the previous well.

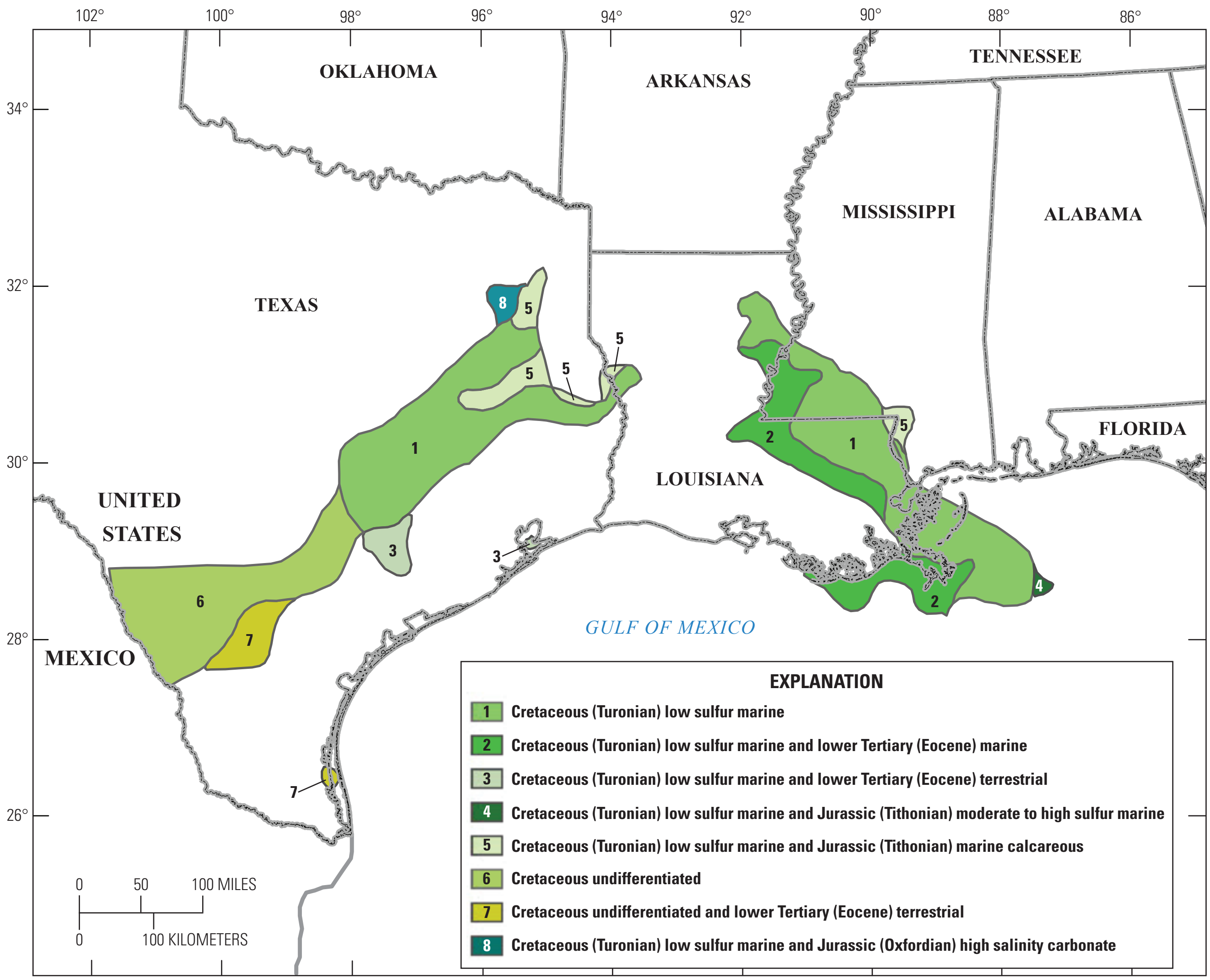



**Figure 6.** Distribution of oils that have been typed as Cretaceous age across the study area (modified from Hood and others, 2002). Subtypes coded by color and number.

# Traps, Migration, and Timing

Well and production data from IHS Energy Group (2009a, b) and field data from NRG Associates (2007) were analyzed to assess the trap types and production trends associated with the Austin Chalk and Tokio and Eutaw Formations. Numerous trap types exist in the Austin Chalk play with many fields exhibiting a combination of trap types. Cross section *A-A*' (fig. 11) provides a display of the various trap types across the region. Reservoirs in the updip region of the play are commonly sealed by normal fault traps with hydrocarbons accumulating on the downthrown side of faults. These faults, largely the Balcones, Luling, and Mexia-Talco fault zones in Texas, and the Pickens, Gilbertown, and Southern Arkansas fault zones farther to the east, are in long, en-echelon systems that are subparallel to the Austin outcrop belt (fig. 5). Because of the en-echelon nature of these faults, oil fields appear somewhat separated in map view, and a single field rarely extends beyond the end of a given fault segment. Well and production data (IHS Energy Group, 2009a, b) indicate that most of these faults have been explored, and the potential for undiscovered hydrocarbons is low for this trap style in the updip portion of the play area.

The low-porosity, low-permeability character of the reservoir itself provides another common trap type. Unconnected intergranular porosity provides much of the storage capacity of Austin Chalk reservoirs with the unfractured rock matrix itself serving as both top and lateral seals. The USGS defines these reservoirs as continuous because they tend to be regional in extent, exhibit diffuse boundaries and low permeabilities, and lack obvious seals, traps, and hydrocarbon-water contacts (Schmoker, 1999). These are in contrast to conventional

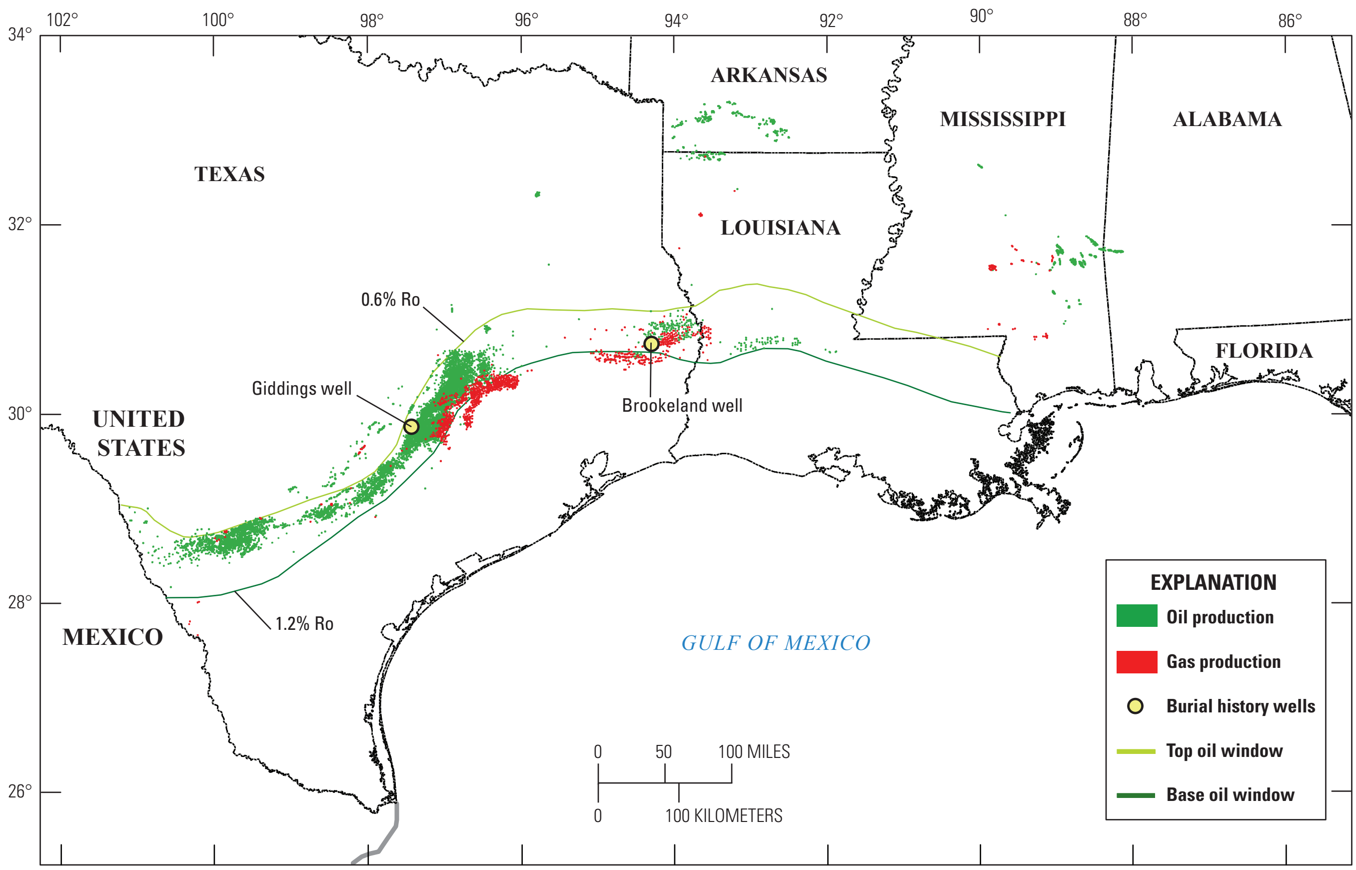



**Figure 7.** Map showing Austin Chalk production and top ($R_o$=0.6 percent) and base ($R_o$=1.2 percent) of the oil window for the Eagle Ford Shale (J. Pitman, written commun., 2010). Location of Austin Chalk oil and gas production (IHS Energy Group, 2009a), shown in green and red, respectively, are plotted on the basis of quarter-mile area cells. $R_o$ = vitrinite reflectance.

reservoirs in which traditional hydrocarbon traps, such as faults, structures, and stratigraphic pinch outs, are present. Conventional reservoirs are also defined by the USGS as having well-delineated hydrocarbon-water contacts and typically display high matrix permeabilities (Schmoker, 1999). A modest portion of the study area likely contains continuous reservoirs. This region, including Pearsall, Giddings, and several smaller fields in between, most likely includes multiple trap types where broad structures and low-permeability rocks both contribute to the accumulation of oil and gas.

Other trap types across the study area include anticlines, rollover anticlines, stratigraphic pinch outs through facies change, and growth faults. Structural traps such as anticlines tend to be associated with the movement of the Jurassic Louann Salt and are concentrated in the East Texas Basin, the North Louisiana Salt Basin, and the Mississippi Salt Basin (fig. 5).

Fractures associated with fault zones in the region likely coincided with movement along those faults during the Oligocene and early Miocene (Dawson and others, 1995). The Eagle Ford Shale entered the oil window sometime in the early Miocene (Dawson and others, 1995), and thermal maturity models (figs. 9 and 10) indicate it is still generating oil and gas (fig. 7). This is critical because this time frame postdates the creation of fractures allowing for the emplacement of oil and gas into these systems immediately after generation (fig. 12). The Austin Chalk itself probably entered the oil window sometime during the Miocene, which is an important component if the Austin possesses the other necessary qualities to be self-sourcing (that is, sufficient TOC). Hydrocarbon generation and migration in the Smackover Formation began in the Early Cretaceous and has continued to the present (Mancini and others, 2003). Salt movement likely began in the Late Jurassic, soon after deposition, and continued through the Paleogene in the onshore Gulf Coast creating salt-related structures (fig. 5) and fractures. This salt movement allowed oil and gas to migrate into these salt-related traps.

Vertical migration pathways are required to charge the Austin Chalk reservoirs. The Eagle Ford lies directly beneath the Austin allowing for hydrocarbons to migrate upward though localized fracture networks. Hydrocarbons in rocks that are updip and continuous with those in the oil window probably followed bed-parallel routes (Dawson and others, 1995) through either the Eagle Ford or the Austin itself.

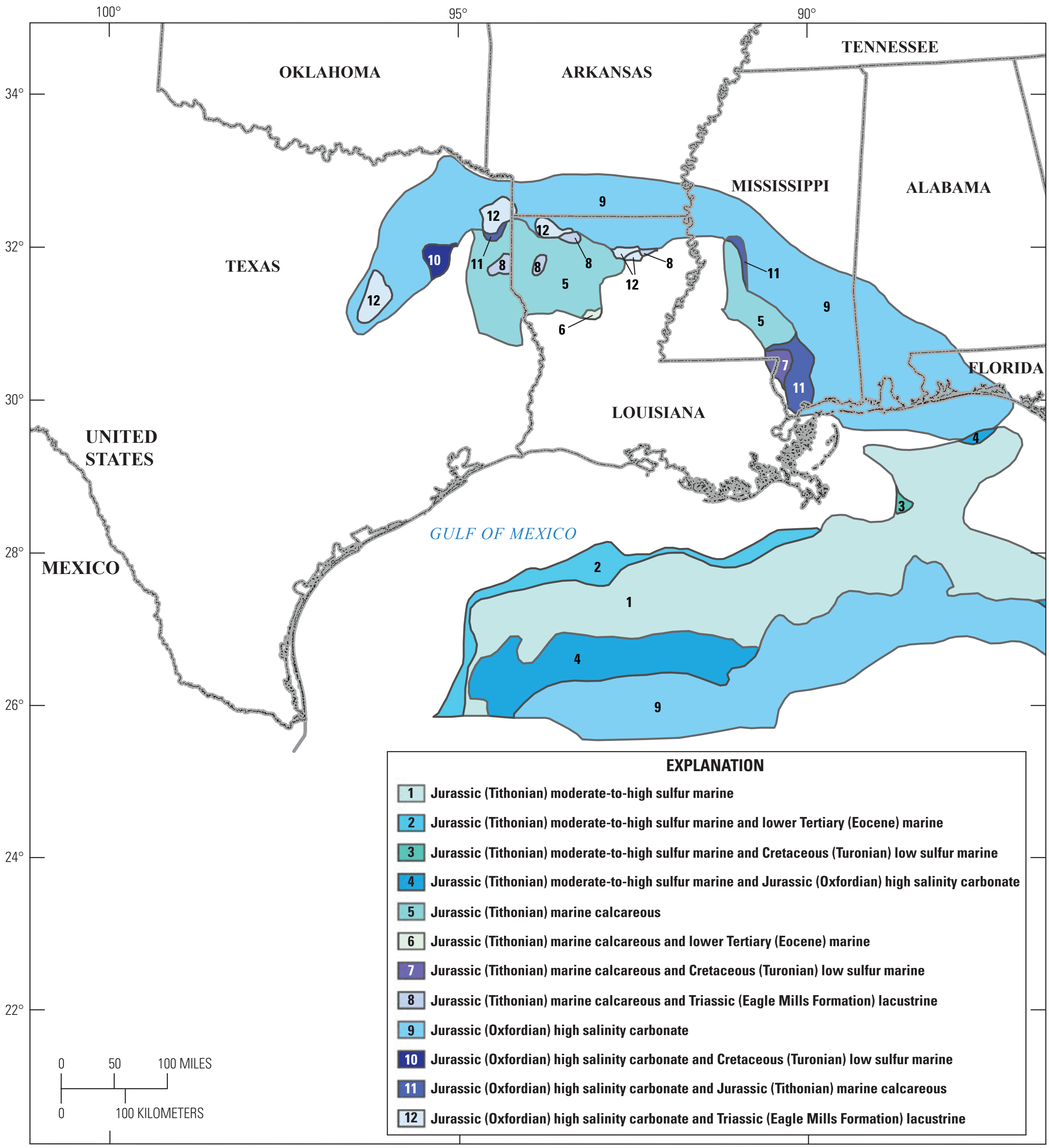



**Figure 8.** Distribution of oils that have been typed as Jurassic age across the study area (modified from Hood and others, 2002). Subtypes coded by color and number. The main contributor to Jurassic-sourced oils produced from the Austin Chalk is likely the Oxfordian high salinity carbonate (subtype 9) because it is generally spatially associated with Austin Chalk production in the region.

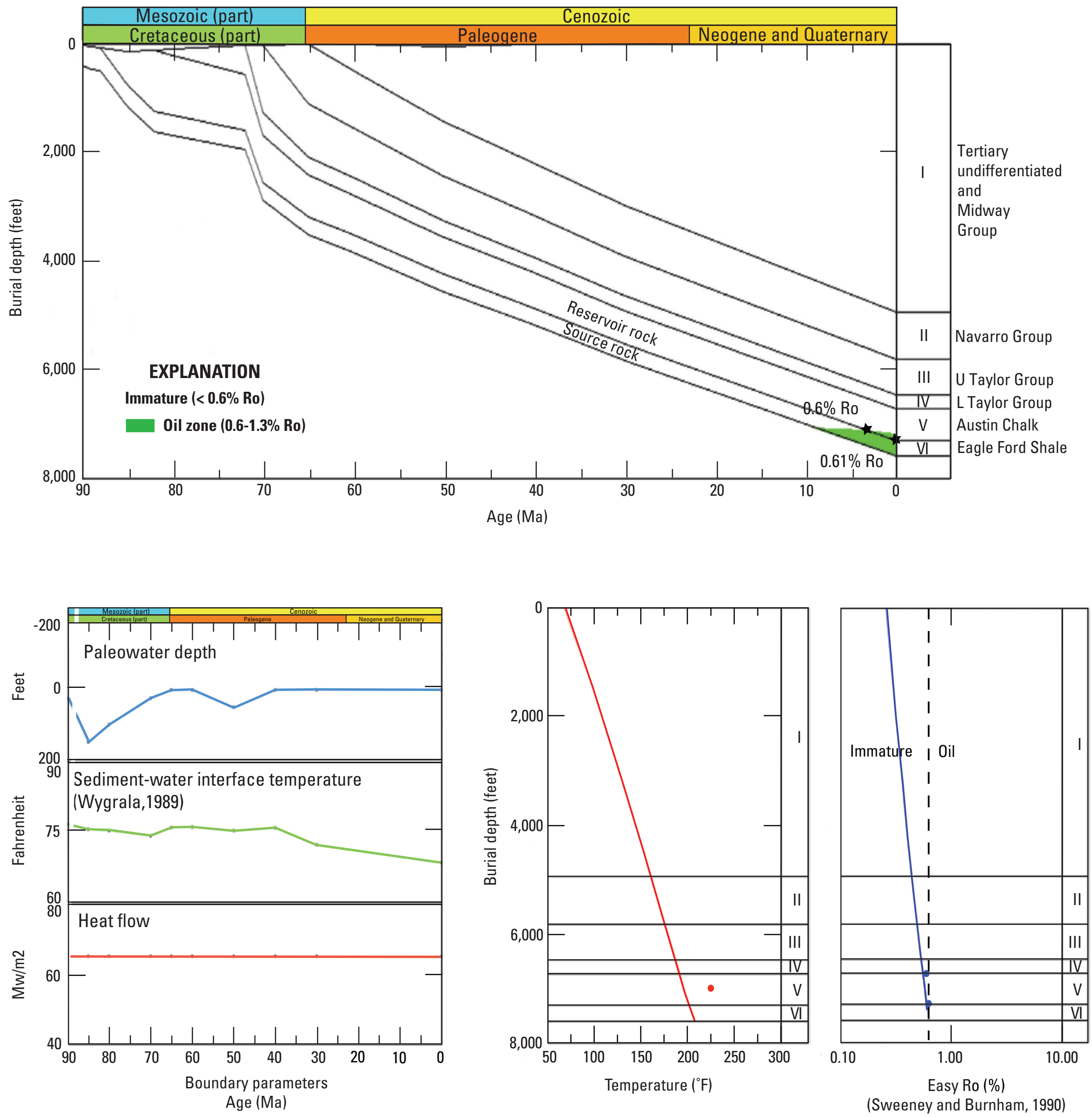



**Figure 9.** Burial history diagram for Giddings field. Stars indicate locations at the top of the Eagle Ford Shale where vitrinite reflectance ($R_o$) values were calculated. Roman numerals designate stratigraphic units that are equivalent in all plots. Note the top of the Eagle Ford entered the oil window approximately 4 million years ago (Ma) and currently has a $R_o$ value of 0.61 percent. Data from IHS Energy Group (2009a,b). Input parameters from Wygrala (1989) and Sweeney and Burnham (1990). mW/m² = megawatts per square meter.

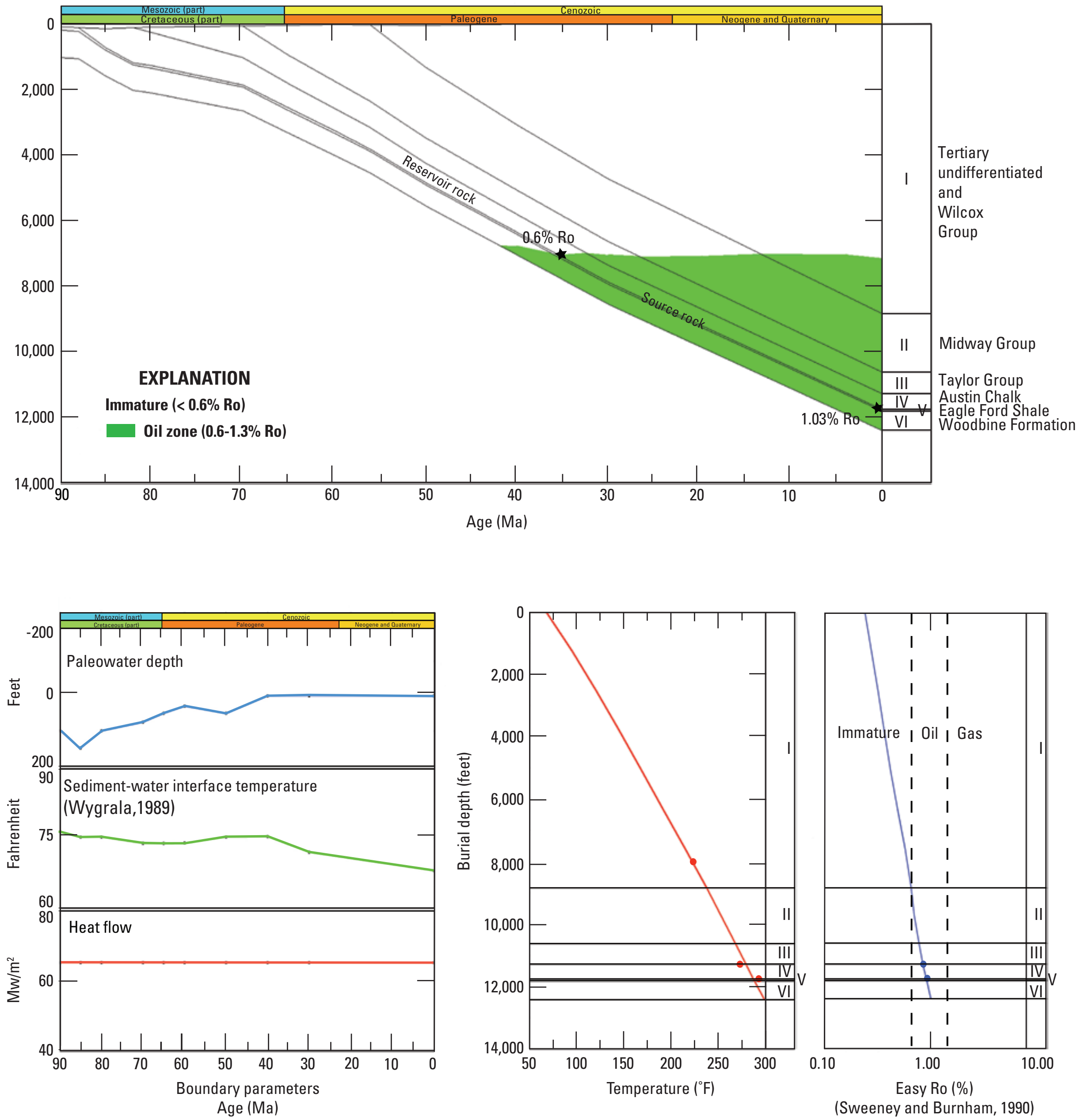



**Figure 10.** Burial history diagram for Brookeland field. Stars indicate locations where $R_o$ values were calculated (approximately in the middle of the formation). Roman numerals designate stratigraphic units that are equivalent in all plots. Note the Eagle Ford Shale entered the oil window approximately 37 million years ago (Ma) and currently has a $R_o$ value of 1.03 percent. Data from IHS Energy Group (2009a,b). Input parameters from Wygrala (1989) and Sweeney and Burnham (1990). mW/m² = megawatts per square meter.

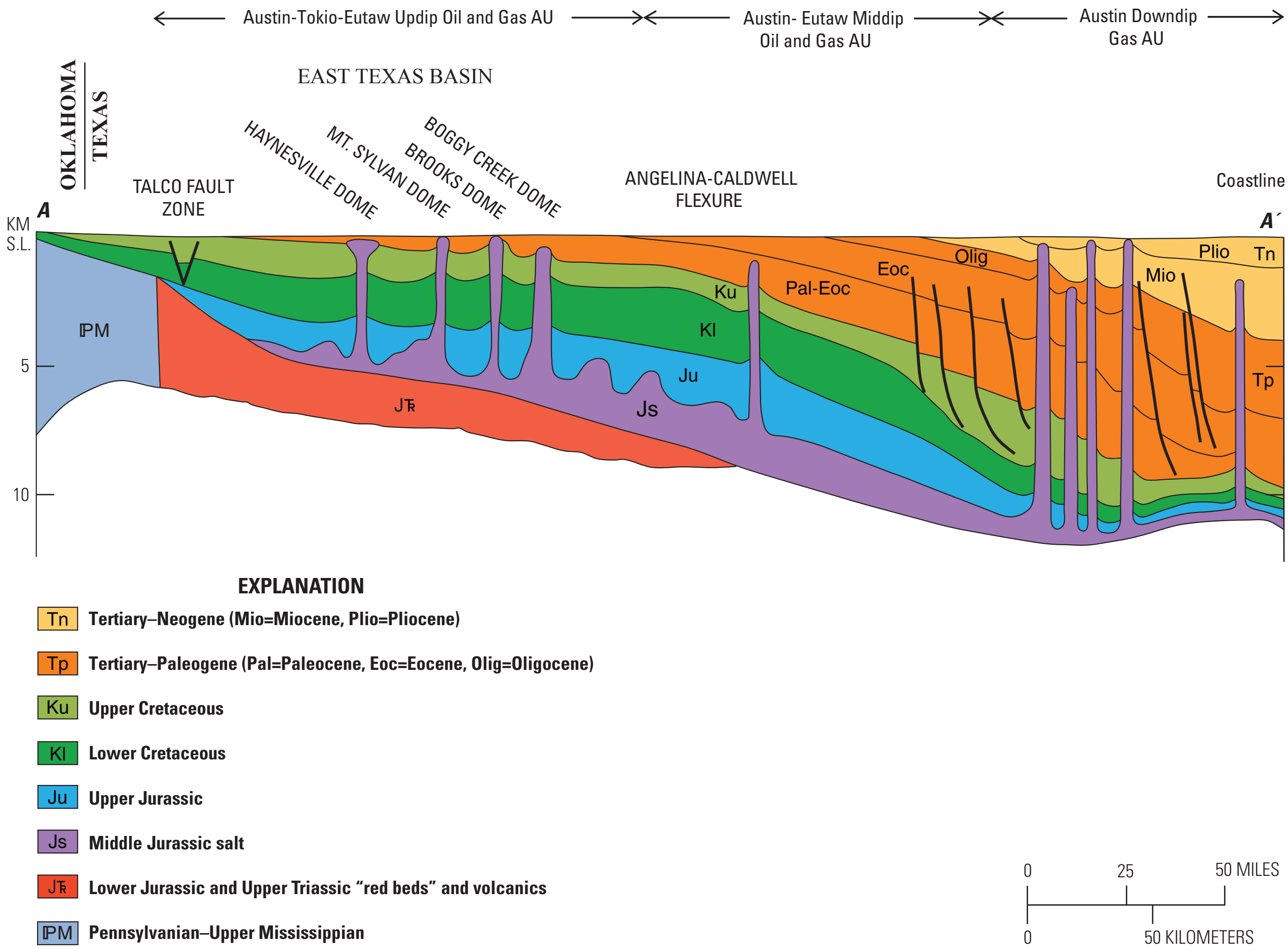



**Figure 11.** Cross section *A-A*' (located in fig. 5) showing major stratigraphic units and structural features (modified from Salvador, 1991). The Austin Chalk falls within the Upper Cretaceous (Ku) shown in light green. Line of section spans from the Oklahoma-Texas border to the Texas coastline. Oil migration has likely occurred in the Austin Chalk and sourced from the Eagle Ford Shale downdip. Note the various trap types shown; accumulations may have formed near salt structures or faults zones such as the Talco. Vertical scale in kilometers (km) from original plate; vertical exaggeration is 10 times. S.L., sea level; AU, assessment unit.

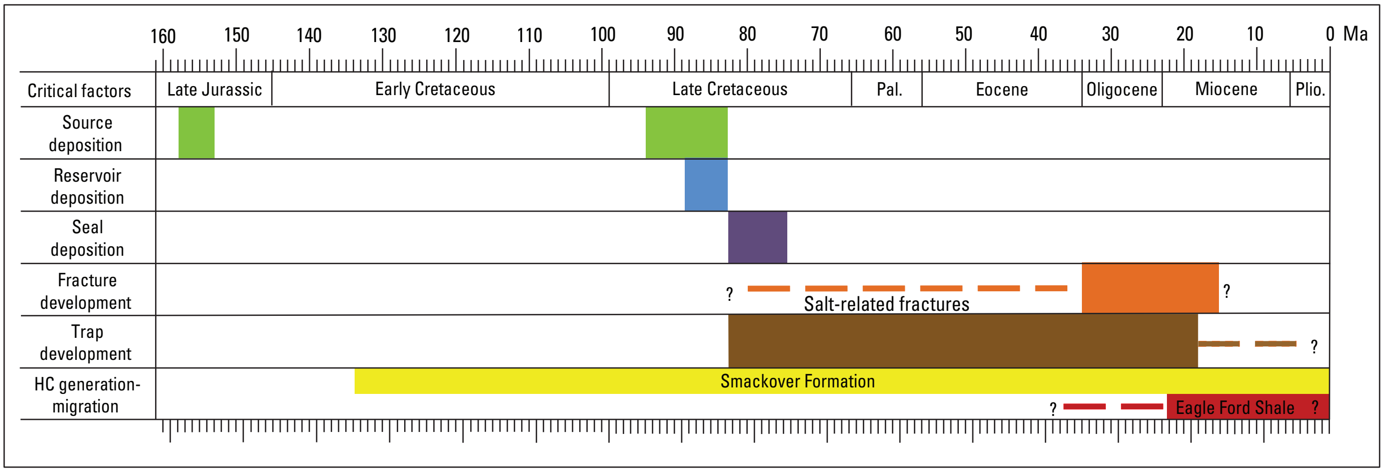



**Figure 12.** Events chart for the Austin Chalk Petroleum System (modified from Dawson and others, 1995; Zimmerman, 1997; Mancini and others, 2003). Source rocks include Smackover Formation, Austin Chalk, and Eagle Ford Shale. Salt-related fractures (from salt movement) formed sometime after emplacement of the Louann Salt during the Jurassic. Hydrocarbon (HC) generation and migration is likely still occurring in the Eagle Ford Shale (see figs. 9 and 10) and also in the Smackover Formation. Pal., Paleocene; Plio., Pliocene; Ma, million years ago.

However, hydrocarbons sourced from the Jurassic Smackover Formation require complex pathways to charge the reservoirs, such as upward migration along salt structures, vertical movement through nonsealing faults, or slow migration through intervening formations. Any hydrocarbons that are self-sourced require short migration pathways into nearby traps unless fractures enhance the production of a continuous play, in which case conventional traps are not essential.

# Assessment Unit Definition and Assessment Methodology

## Austin-Tokio-Eutaw Updip Oil and Gas Assessment Unit (50490130)

### AU Description

The Austin-Tokio-Eutaw Updip Oil and Gas Assessment Unit (AU) (fig. 2) is a conventional AU in which fields produce from traditional types of traps. As noted above, oil and gas production is associated with sealing faults and salt structures. Major fields in this play include Buchanan and Luling-Branyon in Texas, Smackover in Arkansas, and Heidelberg and Gwinville in Mississippi (fig. 4).

The northern boundary of this AU is defined by the updip extent of the reservoir rock in the western portion of the AU. Farther north, the Talco and Pickens fault zones (fig. 5) delineate the edge of the AU because it is unlikely that hydrocarbons have migrated updip of these sealing fault zones. Between fault zones in the eastern portion of the AU, the northern boundary is located along the approximate extent of Smackover source rocks in the subsurface (Hood and others, 2002). The western boundary lies on the U.S.-Mexico border. The southern extent is just south of the Luling and Mt. Enterprise fault zones and north of the Milano fault zone. It is also north of larger regional structures, such as the Angelina-Caldwell flexure, La Salle arch, and Adams County high (fig. 5).

In the western portion of this AU, the major source rock is the Eagle Ford with possible minor self-sourcing from the Austin. Where the Eagle Ford is immature, as is the case in most of the western region, oil has migrated updip from areas where the source is within the oil window (fig. 7). In the eastern portion of the AU, where the Eagle Ford is not of source rock quality, the Smackover likely is the source for most of the oil and gas with a small amount probably derived from the Austin itself (Hood and others, 2002).

Reservoir characteristics of the Austin in this AU vary from west to east, coinciding with a facies change from dominantly chalks of the Austin to sandstones of the Tokio and Eutaw Formations. Porosity type changes from fracture porosity in the west to dominantly matrix porosity in the sandstones to the east. Porosity is lower in the chalk facies and generally higher in the sandstones. Permeability follows a similar pattern with very low values common to the west and much higher permeabilities to the east (NRG Associates, 2007).

Trap styles across the AU vary from fracturing and growth faults in the western part of the AU to normal faults, anticlines, and facies changes in the salt basins of the eastern part. Drive type also varies, although solution gas drive is the most common, particularly in anticlinal traps. There is water drive in about one-third of reservoirs in this AU, most commonly associated with normal and growth faults. Traps and drive mechanisms such as these indicate conventional accumulations because they generally have oil-water contacts.

The Austin-Tokio-Eutaw Updip Oil and Gas AU is dominated by regional fault zones (fig. 5) and small anticlines associated with salt basins; few large-scale anticlinal-type structures exist in this AU. Because the traps tend to be small, undiscovered fields are expected to have low resource volumes as well. New fields may be discovered along undrilled fault segments and salt structures. Grabens between sealing fault segments may also have potential for future discoveries because they provide another means for trapping hydrocarbons.

## Geological Analysis of Assessment Unit Probability

The AU probability represents the likelihood that at least one undiscovered field of minimum size or larger exists in the AU. Assessment unit probability is the product of the probabilities (out of 1.0) of charge, rocks, and timing and preservation. The likelihood that this AU contains at least one accumulation greater than the minimum field size of 50 million barrels of oil equivalent (MMBOE) is estimated to be 100 percent based on the following interpretation of petroleum system elements.

### Charge (1.0)

The large number of known and produced accumulations in the AU indicates that a sufficient charge is present, and furthermore, the Eagle Ford and Smackover are prolific source rocks in the region. Although the Eagle Ford oil window (fig. 7) lies south of the AU, numerous pathways exist for oil and gas to charge the reservoir.

### Rocks (1.0)

Austin Chalk and Tokio and Eutaw sandstone reservoirs are proven to have sufficient reservoir quality to host and produce oil and gas. The strata cover the entire AU with thicknesses that range from 150 ft to as much as 1,200 ft. Reservoir quality varies, however, with reservoirs in some regions having higher shale content and lower fracture connectivity and density.

### Timing and Preservation (1.0)

Timing of geologic events for this AU indicates that fractures associated with fault zones probably coincided with movement along those faults during the Oligocene and early Miocene (Dawson and others, 1995). This predates when the Eagle Ford entered the oil window, in the early Miocene (fig. 12), which allows for the emplacement of oil and gas in the reservoir immediately after generation. In the eastern part of the AU, salt created the majority of traps, and salt movement likely began in the Late Jurassic. This allows for Smackover oil and gas, which began generation in the Early Cretaceous (Mancini and others, 2003), to migrate into these traps after they formed.

### Number of Undiscovered Accumulations

Numbers of undiscovered oil and gas accumulations that exceed minimum size were predicted using the number of discovered accumulations, the number of wildcat wells, and drilling density (dry holes plus producing wells). There are 41 discovered oil accumulations larger than minimum size in this AU, which means that a mode of 15 would indicate that approximately 75 percent of oil accumulations have been discovered. As this is a fairly mature oil play, a minimum of one accumulation was chosen. In addition, less than 10 wildcat wells were drilled in the last 20 years, which is somewhat indicative of a decrease in exploration interest. A predicted maximum of 30 accumulations would indicate that only 58 percent of oil accumulations have been found. Future discoveries are expected to be associated with small salt structures and along undrilled fault segments; this would yield small production totals.

There are only six discovered gas accumulations larger than minimum size in this AU, and a mode of five accumulations would indicate that only 55 percent of all gas accumulations have been found, and that there is more potential for undiscovered gas accumulations in the AU than oil. This is partly because the potential for undrilled structures is higher in the portion of the AU that tends to be gas-prone, notwithstanding the fact that only one field has been discovered in the last 30 years. Like minimum oil accumulations, the minimum for gas accumulations was set at one. The maximum number of gas accumulations was placed at 15, indicating that only 29 percent of gas accumulations have been found. As with oil accumulations, undiscovered gas accumulations would likely be related to small salt structures and along undrilled fault segments.

### Sizes of Undiscovered Accumulations

Grown sizes of accumulations were assessed based on the distribution and trends through time of historical field sizes. Only two oil fields were discovered in the last 25 years; both totaled 1 million barrels of oil (MMBO) or less, so the median grown size of undiscovered oil accumulation was set at 1 MMBO. The minimum size was placed at 0.5 MMBO because this is the USGS minimum assessment convention. Only one field discovered in the last 40 years has yielded more than 10 MMBO, so the maximum grown oil size was estimated at 10 MMBO.

The median for grown gas was estimated to be 6 billion cubic feet (BCF), which correlates to a median of 1 MMBO that was estimated for oil because the volume equivalence is roughly 6:1. This indicates that expected sizes of oil and gas accumulations are approximately equal. This median is twice the size of the minimum size of 3 BCF, which is the set grown size for gas accumulations according to USGS assessment convention. Only two fields have been discovered that exceed 40 BCF, and the most recent discovery only yielded 15 BCF. Considering these facts, the maximum grown gas size was placed at 40 BCF, which is about one-third less than if the 6:1 ratio was applied to the maximum grown oil size of 10 MMBO; this would yield approximately 60 BCF.

## Austin Pearsall-Giddings Area Oil Assessment Unit (50490168)

### AU Description

The Austin Pearsall-Giddings Area Oil and Gas AU (fig. 2) is a continuous AU in which the chalk produces oil and gas in a continuous reservoir and where traditional trap styles such as anticlines and faults are not essential for the accumulation and production of oil and gas. A number of local structures in the AU, similar to those associated with Giddings field (figs. 13 and 14), are likely to enhance production. A continuous classification is common for reservoirs like the Austin because the extremely low matrix porosity and permeability of the chalk provide a means for trapping oil and gas. Where significant numbers of interconnected fracture systems exist, commonly associated with normal faults and structures, a “sweet spot” exists in the continuous AU. This sweet spot defines the region where production is, or is expected to be, elevated compared to the surrounding area. This AU includes Pearsall and Giddings fields, as well as the band of production between the fields.

The northern boundary is defined by the southern boundary of the Austin-Tokio-Eutaw Updip Oil and Gas AU (fig. 2), where the Luling fault zone terminates (fig. 5). The western boundary lies on the U.S.-Mexico border, and the eastern boundary encompasses wells located on the east side of Giddings field (fig. 4). The southern boundary lies just south of Pearsall field, continues eastward, south of the main Austin production belt, and eventually extends through Giddings field. The location of the boundary in Giddings field coincides with the transition from oil- to gas-dominated reservoirs (fig. 4).

The Eagle Ford is thought to source the Austin in this part of the study area, and almost the entire AU lies above the Eagle Ford oil window in map view (fig. 7). This AU also produces moderate amounts of gas that likely migrated updip from the deeper Eagle Ford or Austin (figs. 13 and 14). (Note: The oil-over-gas pattern in Giddings field suggests that the reservoir is continuous and lacks a hydrocarbon-water contact.)

Fracture porosity makes up almost all of the porosity of the unit, and permeability ranges from very low to much higher values. Solution gas drive is dominant (NRG Associates, 2007), and traps are generally anticlines and interconnected fracture sets.

Although additional sweet spots may exist in the area, such as continued expansion of Chittim and Pearsall fields (figs. 4 and 15), future discoveries are difficult to predict.

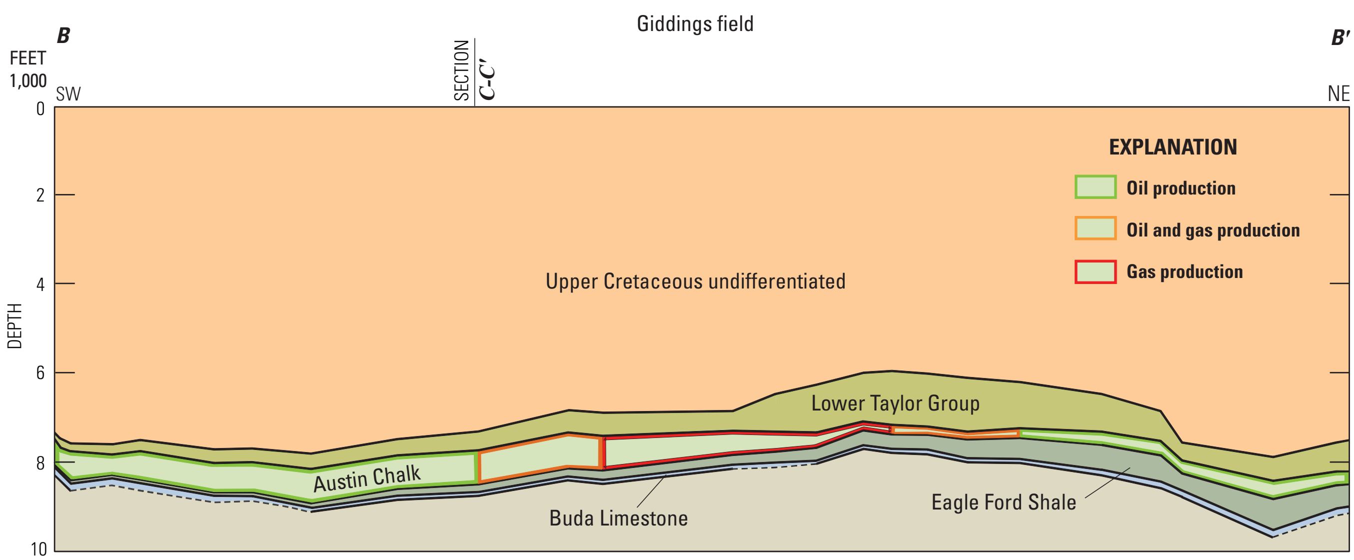



**Figure 13.** Cross section *B-B′* (located on fig. 5) showing stratigraphic units and oil and gas production in Giddings field. Note intersection point with cross section *C-C′* (fig. 14). Giddings field may be a broad structure where oil and gas have accumulated. Note that gas is dominant near the center of the cross section. Cross section is approximately 100 miles long. Vertical exaggeration is 20 times. Dashed lines indicate approximate formation boundaries where formation tops were absent from the data. Cross section created using data from IHS Energy Group (2009a, b).

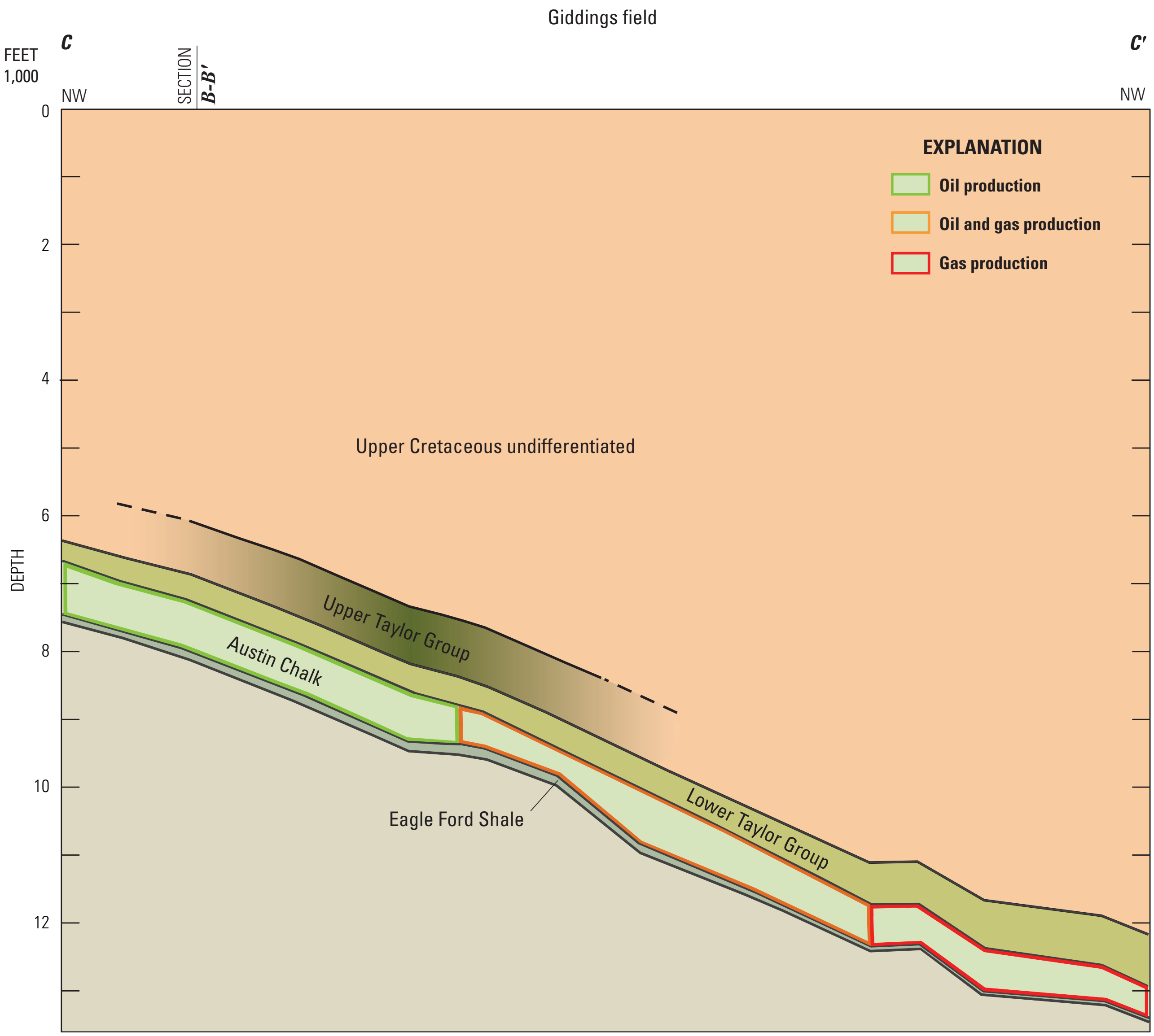



**Figure 14.** Cross section *C-C′* (location in fig. 5) showing stratigraphic units and oil and gas production in Giddings field. Note intersection point with cross section *B-B′*. Oil and gas likely migrated updip from the Eagle Ford Shale, as oil and gas are present updip of their respective windows. The upper part of the Taylor Group is shown terminated to the northwest and southwest because it was not present on well logs. Cross section is approximately 35 miles long. Vertical exaggeration is 10 times. Cross section created using data from IHS Energy Group (2009a, b).

Small structures and faults may exist outside of the sweet spot leading to an expanded area of production. Should the remainder of the AU yield few viable trapping mechanisms, or have poor fracture permeability, future production would be limited to infill drilling of the established sweet spot.

## Geological Analysis of Assessment Unit Probability

The likelihood that this AU contains at least one untested cell with a minimum total recovery of 0.002 MMBOE is estimated to be 100 percent based on the following interpretation of petroleum system elements.

### Charge (1.0)

Field size and well density of Giddings and Pearsall fields (fig. 4) indicate that a sufficient charge is present. In addition, the Eagle Ford is the dominant source rock, and the Eagle Ford lies within the oil window for a majority of the AU (fig. 7).

### Rocks (1.0)

The Austin Chalk has proven to be a viable reservoir rock in this AU. Although matrix permeability can be quite low, faults and structures create fractures that enhance the reservoir quality of the chalk (fig. 5). The Austin Chalk ranges in thickness from about 200 ft to as much as 1,000 ft. The Eagle Ford is currently within the oil window in Giddings field (fig. 9); the Eagle Ford in this area began generating oil approximately 10 Ma, and the top of the formation entered the oil window approximately 4 Ma. Fracturing in the Austin Chalk began in Late Cretaceous, and the subsequent generation of oil allows for the emplacement of oil into fractured Austin Chalk reservoirs.

### Total Assessment Unit Area (Acres)

Mode acreage was calculated using GIS that was based on AU boundaries. Maximum and minimum acreage are equal to approximately ±5 percent of the mode. As this is a symmetrical distribution, the calculated mean equals the mode.

### Area per Cell of Untested Cells Having Potential for Additions to Reserves (Acres)

Using horizontal well spacing (no vertical wells), the maximum number of existing wells per square mile was estimated to be four, which yields an area per cell of 160 acres. Allowing for the possibility of one additional well per cell in some cells (a total of five wells) would yield an area per cell of 128 acres; thus, 140 acres was used for the mode. As some cells only contain one or two wells, 240 acres was used for the maximum. In cells where wells with shorter laterals exist, there is the potential for up to six or seven wells. This would yield a minimum of approximately 100 acres. The uncertainty maximum and minimum means were calculated using the calculated mean ±20 percent.

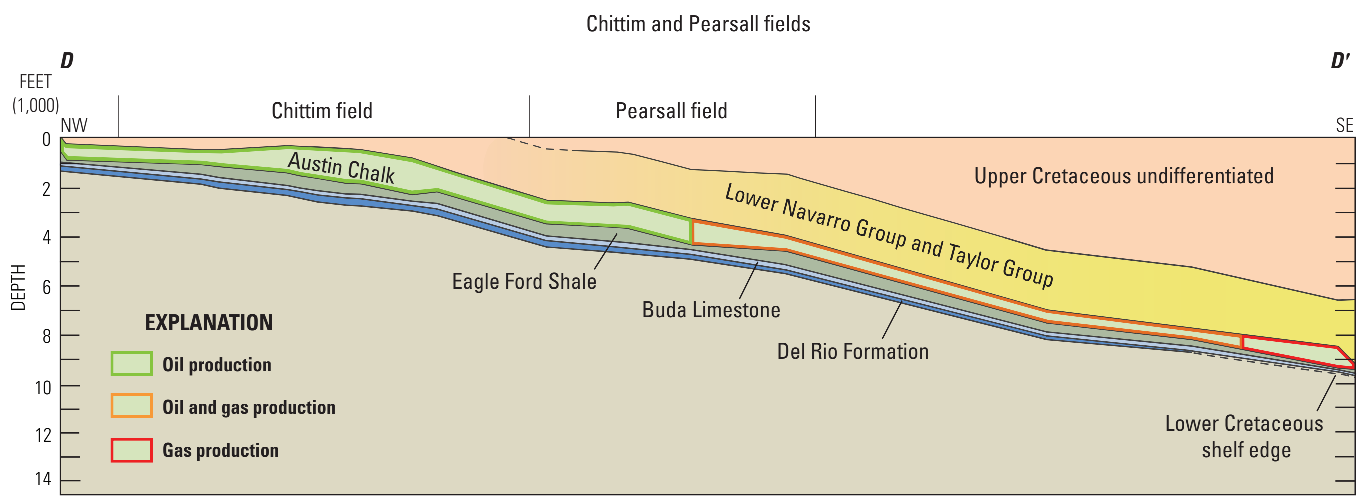



**Figure 15.** Cross section *D-D′* (located in fig. 5) showing stratigraphic units and oil and gas production in Chittim and Pearsall fields. Most of the Pearsall-Giddings Area Assessment Unit lies within the oil window, so little updip migration of oil is required to charge Austin Chalk reservoirs, though updip gas migration has likely occurred. The lower part of Navarro Group-Taylor Group interval is shown terminated to the northwest because formation tops were not present in well logs. Cross section is approximately 85 miles long. Vertical exaggeration is 10 times. Cross section created using data from IHS Energy Group (2009a, b).

### Percentage of Total Assessment Unit Area Untested

Mode was calculated using the number of tested cells (8,267) multiplied by an area per cell of 140 acres and dividing by the mode number of areas (7,649,000). Minimum and maximum are calculated in the same fashion using the uncertainty of mean minimum and maximum areas per cell of 130 and 190 acres, respectively. This yields minimum and maximum untested areas within 1 percent of the numbers shown below. As the distribution is essentially symmetrical, the calculated mean equals the mode.

### Number of Untested Cells with Potential for Additions to Reserves (Percent)

Using the mode untested area of 83 percent (above), the tested area (that is, the area drilled) was estimated to be 17 percent. Under the assumption that the majority of the tested area lies within the sweet spot, the percentage of area within the sweet spot that is tested was calculated. The sweet spot makes up 35 percent of the total area of the AU, so subtracting 17 percent (the tested area) from this number yields approximately 18 percent, which represents the untested area of the sweet spot. Dividing the untested area of the sweet spot (18 percent) by the untested area of the entire AU (83 percent), gives the percentage of untested area for the AU that lies within the sweet spot, which is approximately 20 percent. Multiplying this by the predicted maximum future success ratio of 80 percent yields a minimum percentage of untested cells with potential for additions to reserves of approximately 16 percent. This assumes that future drilling will be limited to infill drilling within the sweet spot. If future drilling expands outside the sweet spot, additional cells will have potential for additions to reserves; thus, the mode was estimated to be 30 percent, approximately twice the minimum. The maximum percentage can be estimated by supposing that large portions of the area outside the sweet spot will yield additional reserves. A maximum area of 75 percent was estimated. The calculated mean was determined using the minimum, mode, and maximum.

### Total Recovery per Cell (MMBO)

Total recovery per cell was estimated using estimated ultimate recovery (EUR) graphs that were broken down into the first, second, and third third of all horizontal producing wells in the AU that started production after 1996 and have production totals greater than minimum recovery. The third third shows a mean recovery per cell of approximately 0.035 MMBO, and the second third shows a mean recovery per cell of approximately 0.1 MMBO. As future wells should have recoveries closer to that of the third third, a median total recovery per cell of 0.04 MMBO was assigned. A minimum of 0.002 MMBO was used because this is the stated minimum total recovery per cell. Using the third thirds EUR graph, the cells with the largest total recoveries in the AU produce approximately 0.5 MMBO, so this number was used for the maximum total recovery per cell. The calculated mean was calculated using the minimum, median, and maximum.

### Success Ratios (Percent)

Historic success ratios were calculated based on the number of cells exceeding minimum recovery of 0.002 MMBOE (6,419) divided by the number of cells tested (8,267), which yields a success ratio of 78 percent. Success ratios for inside and outside the sweet spot were calculated in the same fashion yielding values of 81 percent for inside the sweet spot and 31 percent outside of it. Using these numbers, future success ratio was calculated. If future drilling is limited to inside the sweet spot, then the success ratio would approximate that of the historic success ratio of the sweet spot. Therefore, a maximum success ratio of 80 percent was assigned. Assuming that future drilling will be slightly more successful than the past due to improved completion practices and some of the future drilling will occur inside the sweet spot, a minimum of 40 percent was assigned, which is slightly higher than the historic success ratio outside of the sweet spot (31 percent). As this gives a symmetrical distribution, the calculated mean equals the mode.

# Austin-Eutaw Middip Oil and Gas Assessment Unit (50490131)

## AU Description

The Austin-Eutaw Middip Oil and Gas AU lies directly south of the central and eastern parts of the Austin-Tokio-Eutaw Updip Oil and Gas AU, and to the southwest it lies south of the Austin Pearsall-Giddings Area Oil AU (fig. 2). This AU is primarily defined by a production belt that lies along and north of the Lower Cretaceous shelf edge (fig. 4). The northern boundary is just south of the Mt. Enterprise fault zone and to the north of larger regional structures, such as the Angelina-Caldwell flexure, La Salle arch, and Adams County high (fig. 5). It extends west to the U.S.-Mexico border and to the east to the State waters of Louisiana, Mississippi, Alabama, and Florida. The southern boundary is placed at the inferred extent of fractures associated with the Lower Cretaceous shelf edge.

Major fields in this AU include Masters Creek, Brookeland, and the southern portion of Giddings (fig. 4). Fields associated with the shelf edge make up nearly all of the discovered accumulations (fig. 4). The draping of the Austin Chalk over the shelf edge may contribute to an increase in fracture density and connectivity, leading to increased production. Faulting within this AU may also contribute to accumulations.

As with the other AUs containing Austin Chalk throughout Texas and western Louisiana, the Eagle Ford Shale is the primary source rock. In addition, preliminary thermal maturity models indicate that the Eagle Ford is in the oil window in central and eastern parts of the AU (fig. 7) (J. Pitman, written commun., 2010). The Eagle Ford in the western portion is probably still generating gas. Major gas fields sit within the oil window, however, indicating probable updip migration of gas through the Austin Chalk or Eagle Ford (Dawson and others, 1995).

Reservoir characteristics differ from the Austin-Tokio-Eutaw Updip Oil AU with good porosities and generally low permeabilities. There is both fracture and matrix porosity (NRG Associates, 2007).

Fractures provide the most common traps with anticlines and rollover anticlines providing the remainder. Water drive is the most common drive type and is present in Masters Creek field (Swift Energy Company, 2000) and possibly in some of its neighboring shelf-edge fields.

Because this AU is dominated by large fracture systems that are associated with the Lower Cretaceous shelf edge, undiscovered accumulations are predicted to be larger than those in the Austin-Tokio-Eutaw Updip AU where existing fields are associated with local faults and salt structures. Potential for undiscovered accumulations is moderate to excellent with future discoveries likely to be made in belts both updip and downdip of the shelf edge and extending both east and west of known accumulations.

## Geological Analysis of Assessment Unit Probability

The likelihood that this AU contains at least one accumulation greater than the minimum field size of 50 MMBOE is estimated to be 100 percent based on the following interpretation of petroleum system elements.

### Charge (1.0)

The large number of known and produced accumulations in the AU indicates that a sufficient charge is present. The Eagle Ford and Smackover are prolific source rocks in the region (figs. 6 and 8), with the former likely the most dominant, and both have sourced many accumulations. The Eagle Ford oil window lies in the southern portion of the AU, and many pathways exist for oil and gas to migrate updip into reservoirs in the northern part of the AU (fig. 2).

### Rocks (1.0)

Austin Chalk and Eutaw sandstone reservoirs have proven to have sufficient reservoir quality to host and produce oil and gas. The strata cover the entire AU with thicknesses that range from 150 to 1,000 ft. Reservoir quality varies, however, with some regions having higher shale content and lower fracture connectivity and density.

### Timing and Preservation (1.0)

Fractures associated with the Lower Cretaceous shelf edge may have developed soon after Late Cretaceous deposition. This predates the time when the Eagle Ford entered the oil window, in the early Miocene (fig. 12), which allows for the emplacement of oil and gas in the reservoir immediately after generation. In the eastern part of the AU, salt created the majority of traps, and salt movement likely began in the Late Jurassic. This would allow for Smackover oil and gas, which began generation in the Early Cretaceous (Mancini and others, 2003), to migrate into these traps after they formed.

### Number of Undiscovered Accumulations

Numbers of undiscovered oil and gas accumulations that exceed minimum size were assessed using number of discovered accumulations, number of wildcat wells, and drilling density (dry holes and producing wells). There are 14 discovered oil accumulations larger than the minimum size in this AU, which means that a mode of 10 accumulations would indicate that approximately 58 percent of oil accumulations have been discovered. A minimum of one accumulation was chosen because of moderate geologic uncertainty, such as number of existing undrilled structures. Approximately 25 wildcat wells have been drilled in the last 20 years, which may suggest the play has potential. A maximum of 40 accumulations would indicate that only 26 percent of oil accumulations have been discovered, which also suggests this AU could have more potential for accumulations than the Austin-Tokio-Eutaw Updip Oil and Gas AU. In this AU, undiscovered accumulations could probably be associated with small salt structures and in fracture networks associated with the Lower Cretaceous shelf edge; this could yield small (salt structures) to moderate (shelf edge) production totals.

There are only 8 discovered gas accumulations in this AU, and a mode of 15 indicates that only 35 percent of all gas accumulations have been discovered and that there is more potential for undiscovered gas accumulations than oil. This is because the highest potential for accumulations is highest along the shelf edge that should be mostly gas-prone. This is also supported by the fact that a number of accumulations discovered in the last 20 years are along the shelf edge. Like minimum oil accumulations, the minimum for gas accumulations was set at one. The maximum number of gas accumulations was placed at 60, indicating that only 12 percent of gas accumulations have been discovered. Most undiscovered accumulations are expected to be near the shelf edge, in or near the Eagle Ford gas window. As with oil accumulations, undiscovered gas accumulations could also be in relation to small salt structures in the eastern portion of the AU.

### Sizes of Undiscovered Accumulations

Grown sizes of accumulations were predicted based on the distribution and trends with time of historical field sizes. Of the ten oil fields discovered in the last 20 years, most totaled between 1 and 20 MMBO; however, the median grown size of undiscovered oil accumulations was set at 1.5 MMBO because the larger fields have probably already been discovered. The minimum size was placed at 0.5 MMBO, per USGS convention. Only one field discovered in the last 20 years has yielded more than 20 MMBO, but the maximum grown oil size was estimated at 50 MMBO suggesting that one accumulation may exist that is larger than everything found except for Giddings field, which yields approximately 600 MMBO.

The median for grown gas was estimated to be 9 BCF, which correlates to a median of 1.5 MMBO that was estimated for oil, as the volume equivalence for gas to oil is roughly 6:1. This indicates that expected sizes of oil and gas accumulations are approximately equal. This median is three times the size of the minimum size of 3 BCF, which is the set grown size for gas accumulations, per USGS convention. Only two fields exceed 100 BCF, and the most recent discovery yielded almost 80 BCF. The maximum grown gas size was placed at 700 BCF, which suggests that the largest accumulation is yet to be discovered.

## Austin Downdip Gas Assessment Unit (50490132)

### AU Description

The Austin Downdip Gas AU lies directly south of the Austin-Eutaw Middip AU (fig. 2). Its northern boundary is at the inferred downdip extent of fractures that are associated with the Lower Cretaceous shelf edge. The western and eastern boundaries are defined by the U.S.-Mexico border and the State waters of Louisiana, respectively. The downdip extent is defined by the State waters of Texas.

Currently, there is no known Austin Chalk production in this AU; as such, estimating production, trap type, and field size and distribution is speculative. Faults and fault zones are prominent, existing just south of the shelf edge downdip toward the Gulf of Mexico (fig. 5). Given certain geologic conditions, such as fault timing and oil and gas migration, these faults could trap and yield large undiscovered accumulations. Any Eagle Ford-sourced accumulations will likely be gas because the entire AU lies south of the downdip extent of the Eagle Ford oil window (J. Pitman, written commun., 2010). Traps are expected to include normal faults and salt-related anticlines.

Undiscovered accumulations probably exist along undrilled growth faults and salt-related structures. As these trap types mimic those of the Austin-Tokio-Eutaw Updip Oil and Gas AU, one can expect field size and distribution to be somewhat similar, though less of this region has been explored. Therefore, the potential for undiscovered accumulations is considered to be moderate to high with small to moderate field sizes expected. If larger structures exist, such as those in the Austin-Eutaw Middip Oil and Gas AU, one could then expect correspondingly larger field sizes.

### Geological Analysis of Assessment Unit Probability

The likelihood that this AU contains at least one accumulation greater than the minimum field size of 50 MMBOE is estimated to be 100 percent based on the following interpretation of petroleum system elements.

#### Charge (1.0)

The large number of known and produced accumulations in the Austin-Eutaw Middip Oil and Gas AU indicates that a sufficient charge is present in the region. The Eagle Ford has sourced many oil and gas accumulations updip of the Austin Downdip Gas AU. However, as the oil window also sits mostly updip, accumulations should be dominantly gas.

#### Rocks (1.0)

Austin Chalk reservoirs have proven to have sufficient reservoir quality to produce oil and gas. The strata cover the entire AU with thicknesses that likely range from 150 to 800 ft. However, as the Austin Chalk within the AU is essentially untested, reservoir quality is uncertain.

#### Timing and Preservation (1.0)

Normal faults associated with the movement and evacuation of the Louann Salt began moving shortly after salt deposition in the Late Jurassic and movement continued through the time of Wilcox Formation deposition (early Eocene). These faults in places detach in the Louann Salt and could provide traps for oil and gas. This fault movement predates when the Eagle Ford entered the oil window, in the early Miocene (fig. 12), which allows for the emplacement of oil and gas in the reservoir immediately after generation. In the central and eastern parts of the AU, salt structures (figs. 5 and 11) and their associated fractures and faults create the majority of traps. This also allows for the charging of the reservoir with oil and mostly gas of Eagle Ford origin.

#### Number of Undiscovered Accumulations

The number of undiscovered oil and gas accumulations that exceed minimum size were assessed using the Austin-Eutaw Middip Oil and Gas AU as an analog. There are 14 discovered oil accumulations in that AU, and a mode of 10 undiscovered accumulations was predicted. A mode of two accumulations was predicted for the Austin Downdip Gas AU, as oil accumulations should be rare because of the location of the base of the oil window. A minimum of one accumulation was chosen for this AU because of considerable geologic uncertainty largely owing to a lack of data. A maximum of 40 accumulations was assessed for the Austin-Eutaw Middip Oil and Gas AU, and a maximum of 10 accumulations was assessed for the Austin Downdip Gas AU, again due to the updip oil window for the most part. In this AU, undiscovered accumulations would probably be found along sealing normal faults and along salt-related structures.

There are only 8 discovered gas accumulations in the Austin-Eutaw Middip Oil and Gas AU, and a mode of 15 accumulations was chosen for that AU. For the Austin Downdip Gas AU, a mode of 50 accumulations was set because much of this region remains unexplored. Like minimum oil accumulations, the minimum for gas accumulations was set at one because of geologic uncertainty. The maximum number of gas accumulations was placed at 60 in the Austin-Eutaw Middip Oil and Gas AU; a maximum of 200 accumulations was chosen for the Austin Downdip Gas AU indicating that it has great potential for gas accumulations. As with oil accumulations, undiscovered gas accumulations would be related to normal faults and small salt structures.

### Sizes of Undiscovered Accumulations

Grown sizes of accumulations were predicted based on the distribution and trends of time of historical field sizes for the Austin-Tokio-Eutaw Updip Oil and Gas AU, which was used as an analog. Forty-one oil fields have been discovered in that AU, and only four totaled more than 40 MMBO. Therefore, the maximum accumulation size for the Austin Downdip Gas AU was set at 40 MMBO. The minimum size was placed at 0.5 MMBO, and the median was set at 2 MMBO, which is double that of the Austin-Tokio-Eutaw Oil and Gas AU. This is because the Austin Downdip Gas AU is virtually unexplored, whereas the larger fields have already been discovered in the Austin-Tokio-Eutaw Updip Oil and Gas AU, so its mode drops to 1 MMBO.

The median for grown gas was estimated to be 12 BCF, which correlates to a median of 2 MMBO that was estimated for oil because the volume equivalence for gas to oil is roughly 6:1. This indicates that expected sizes of oil and gas accumulations are approximately equal. This median is four times the size of the minimum size of 3 BCF, which is the set grown size for gas accumulations, per USGS convention. Only two fields in the Austin-Tokio-Eutaw Oil and Gas AU exceed 100 BCF, but the most recent discovery yielded about 15 BCF. The maximum grown gas size was placed at 240 BCF, which also shows a 6:1 ratio with an oil size prediction of 40 MMBO.

## Results

The USGS assessed undiscovered, technically recoverable oil and gas resources in the four AUs in the Upper Jurassic-Cretaceous-Tertiary Composite TPS (fig. 2) (Pearson and others, 2011). For conventional resources, means were estimated at (1) 20 million barrels of oil (MMBO), 53 billion cubic feet of gas (BCFG), and approximately 1 million barrels of natural gas liquids (MMBNGL) for the Austin-Tokio-Eutaw Updip Oil and Gas AU; (2) 45 MMBO, 677 BCFG, and 66 MMBNGL for the Austin-Eutaw Middip Oil and Gas AU; and (3) 13 MMBO, 1.6 trillion cubic feet of gas (TCFG), and 190 MMBNGL for the Austin Downdip Gas AU. The combined conventional resource mean totals for the Austin Chalk are 78 MMBO, 2.3 TCFG, and 257 MMBNGL. For continuous resources, the USGS estimated means of 879 MMBO, 1.3 TCFG, and 106 MMBNGL for the Austin Pearsall-Giddings Area Oil AU (Pearson and others, 2011).

## Summary

The Upper Cretaceous Austin Chalk is a low-porosity, low-permeability reservoir with a dual pore system that relies mainly on interconnected fracture networks for production. Horizontal drilling enhances these networks to produce oil and gas. The Tokio and Eutaw Formations of Arkansas, Mississippi, Louisiana, and Florida are partial age equivalents of the Austin Chalk and represent a facies change from an environment of chalk deposition in the west to a sandier, more clastic-rich sedimentary environment in the east.

The downwarping of the Gulf Coast basin during the Oligocene and early Miocene created large strike-parallel fracture systems in association with faulting and localized arching over uplifts. Movement of the Jurassic Louann Salt also contributed to fracture genesis where fractures form in association with salt-related structures. General proximity to faults and fracture-creating structures is critical when analyzing the region’s oil and gas production as well as predicting undiscovered accumulations.

The Eagle Ford Shale is the principal source rock for Austin Chalk hydrocarbons and is included in the Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System. This marine shale contains dominantly oil-prone kerogen and is thermally mature across much of the study area. Source rock quality can be inconsistent throughout the region, and some reservoirs may contain Jurassic-sourced hydrocarbons.

Generation of hydrocarbons from the Eagle Ford probably started sometime in the early Miocene. Migration of oil and gas into the Austin requires only direct upward migration. Hydrocarbons that migrated updip likely followed bed-parallel routes moving through either the Eagle Ford or the Austin Chalk. Hydrocarbons from other sources, such as the Smackover, require much more complex migration routes, such as along non-sealing faults associated with salt structures. Fracture generation predates the generation and migration of oil and gas allowing for the movement of hydrocarbons into reservoirs.

There are several trap styles in the Austin Chalk and Tokio and Eutaw Formations. Trapping mechanisms strongly control accumulation size and distribution where smaller localized traps such as fault segments and small salt-related structures lead to smaller, more distinct conventional accumulations. Large-scale fracture networks lead to continuous accumulations, and structures, such as broad anticlines, improve the production potential of continuous reservoirs.

The USGS conducted an assessment of undiscovered resources in the Austin Chalk for the onshore portion and State waters of the Gulf Coast region (Pearson and others, 2011). The study area was divided into four assessment units (fig. 2) that include Austin Chalk and the Tokio and Eutaw Formations (fig. 3). Assessment units were designated based on local geology, trap type, production trends, cumulative production, estimated ultimate recoveries, reservoir characteristics, and whether a region produces oil and gas in conventional or continuous reservoirs.

Based on these criteria, undiscovered accumulations were assessed (Pearson and others, 2011). Undiscovered resources in the updip region of the study area are expected to have low resource volumes with few new field discoveries. The middip region probably has low to moderate potential for undiscovered hydrocarbons because much of the shelf edge area remains unexplored. Field sizes are expected to be moderate with the potential for many new field discoveries. In the downdip portion of the study area, the potential for undiscovered gas accumulations is moderate to high with small to moderate field sizes expected. The Pearsall-Giddings region (figs. 13 through 15) was assessed as a continuous accumulation. Future production may expand outside the sweet spot if additional fractures exist or may be limited to infill drilling if good fracture permeability does not exist outside this sweet spot. Overall, this AU has moderate to high potential.

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