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Louisiana Geo-Lagniappe: The Tuscaloosa Marine Shale and Smackover Brown Dense Plays – Where Does It Go From Here?

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I. ABSTRACT

Louisiana’s newest shale plays are the oil-rich Tuscaloosa Marine Shale and the Smackover Brown Dense. Their early exploration stages and possible development patterns are analyzed by: 1) review of publically-available current well data and known geological history; 2) synthesis with established knowledge of organic-rich rocks and hydrocarbon generation; and 3) comparison to ongoing more-developed liquids-rich shale plays, primarily the Eagle Ford Shale of south Texas. Initial exploration geologic concepts include defining the organic-rich sections, the oil and wet gas thermal windows, and the rock compositions which affect engineering methods (brittle vs. soft rocks). The Tuscaloosa Marine Shale drilling is occurring in two regions—the western up-dip area of Rapides and Vernon parishes, and the eastern down-dip area of the Florida parishes and southwestern Mississippi. Rock composition and thermal window variations are being documented from the two areas. Exploration in the Smackover Brown Dense is most intense along the southern Arkansas-north Louisiana state line area and eastward towards the Monroe Uplift. The Monroe Uplift area has the greatest complexity due to its multiple episodes of uplift and rock fracturing.

la·gniappe ˈlan-ˈyap, lan-ˈ  noun; broadly : something given or obtained gratuitously or by way of good measure

II. INTRODUCTION

This paper in an updated version of a similar paper presented February 2012 at the Ark-La-Tex Association of Professional
Landmen annual seminar. Its purpose is to discuss the emerging shale oil plays of Louisiana and the current publically-available data so as to reflect upon the plays’ status to date. To do so, the paper presents the following topics: a summary of national shale play development, an introduction to the geology and exploration concepts of shale oil plays, a discussion of the Eagle Ford Shale for “lessons learned” in shale oil plays, and lastly, a discussion of the Tuscaloosa Marine Shale and the Smackover Brown Dense plays.

A. National Stories Through Early 2012

Shale resource development due to horizontal well engineering is expanding across North America and the world (Fig. 1). Unconventional development of primarily fine-grain sedimentary rocks (“shale” term loosely used) and “tight sandstones” (Fig. 2) are yielding ever-increasing reserve potentials for both hydrocarbon gas and liquids. The dominance of horizontal over vertical well drilling in North America was evident by March of 2009, and by the week of February 23, 2012, the Baker Hughes rig count indicated that 59% of the U. S. drilling rigs were for horizontal trajectories (Baker Hughes, 2012; Meeham, 2011).
Figure 1. Shale plays of North America (Energy Information Agency, www.eia.gov). I have added the Smackover Brown Dense to their May 2011 map.
Figure 2. Schematic drawing of grain size distributions in nearshore to offshore environments. Sediment burial results in the common rock names shown. Fine-grain resource plays (oil and gas) occur in shales, limestones/chalks and chert (not shown).
Shale gas drilling began its decrease following the drop of natural gas prices relative to oil in 2009 (Fig. 3), a reflection of shale gas development success. Gas prices continued a slow fall in 2011, dropping 9% from 2010 at the Henry Hub, Erath, LA, to about $4 per MMBtu (million BTU). Natural gas prices fell to about $2.60 per MMBtu by mid-February 2012, a ten-year low (Fig. 3). Regionally, rigs in the Barnett Shale gas play peaked in October of 2010 while Haynesville Shale rig numbers peaked in July of 2010. In the first few months of 2011, the U. S. oil rig count caught up with the natural gas rig count, and by mid-February of 2012, 64% of U. S. rigs were drilling for oil (Baker Hughes, 2012; Energy Information Administration, 2011a, 2011b, 2012a; Spencer, 2011).

Shale liquids plays are the new focus in our country in addition to ongoing shale gas development. Both gas and oil production in the U. S. are now on the rise after a decades-long decrease in both (Energy Information Administration, 2012b). Our local gas shale, the Haynesville Shale, overtook the Barnett Shale in late 2010 and early 2011 to become the nation’s largest shale gas producer (Fig. 4) (Energy Information Administration, 2011c).

The nation’s gas and liquids reserves are growing due to the horizontal well development and associated fracturing (“fracing” is the older abbreviated term, not “fracking”). We have some developmental history of shale gas to assist in resource estimates, yet those numbers vary each year as we learn more. Early in 2012, the Energy Information Administration calculated the U. S. estimated unproved technically recoverable shale gas resource as 482 TCF (trillion cubic feet), a significant decrease from their estimate of 827 TCF in 2011. This decrease was primarily from revisions of the Marcellus Shale estimates (Energy Information Administration, 2012c). We have less data for shale oils, so any resource estimates are likely to be significantly updated these next few years. Some shale oil production estimates have been put forward recently. A Morgan Stanley research report estimated oil production from the known major U.S. shale plays will increase to about 1.9 million bbl/day by 2016, while Hart Energy Research estimated an oil production of about 2 million bbl/day by 2020 (Barnes, 2012; Weisenthal, 2011).
B. Shale Plays and Emerging Trends

Figure 1 is a May 2011 map illustrating major shale plays in North America. I have added the Smackover to the map as an emerging play. Some of the most prominent shale gas (dry) production is from the Haynesville, Barnett, Marcellus, Woodford, and Fayetteville plays (Fig. 4). Plays such as the Eagle Ford have both liquids and gas (wet and dry), but the liquids and wet gases are being actively developed due to oil and gas prices. Some of the most prominent shale oil/wet gas plays (in terms of both development and estimated resources) are the Bakken, Eagle Ford, Avalon and Bone Springs (Permian). Older oil plays in fine-grained rocks, primarily the Monterey Formation of California and the Austin Chalk of Texas and Louisiana, are also undergoing new developments with improved drilling technology. Other unconventional reservoirs, low-permeability (“tight”) coarser-grained rocks, are making headlines—the Granite Wash (sandstones) play in the Texas Panhandle and western Oklahoma is the largest of several stacked plays within that region. Even more-conventional higher-permeability rocks such as the Mississippi Lime (running along the Oklahoma and Kansas state line) are undergoing extensive reserves growth with horizontal drilling (Darbonne, 2012; Petzet and Dittrick, 2011; Warren and Nyveen, 2011).
Figure 3. Prices of crude oil and natural gas through late December 2011 (data from Energy Information Agency, www.eia.gov).

Figure 4. Production graph of major shale gas producers (Yeager, 2011, BHP Billiton presentation, www.bhpbilliton.com/home/investors/reports).
C. Louisiana Shale Production and Emerging Liquids Plays

The Haynesville Shale (Fig. 5) of northwestern Louisiana and east Texas is currently the largest shale gas producer in the nation. The high production numbers are a result of the intense drilling of the past few years, even though the rig numbers are now decreasing. This decrease is the effect of both decreasing gas prices and the fulfillment of lease obligations.

Figure 1 also shows some of the major new plays or emerging trends that are occurring. Two of those are in Louisiana—the Tuscaloosa Marine Shale and the Smackover Brown Dense. Both plays are shale liquids/wet gas plays, although they both have dry gas as well if one considers deeper (and currently uneconomical) burial depths.

The last section is focused upon these two newer Louisiana play regions and current activity as of late February 2012. But to help us understand the plays’ boundaries, potentials, and possible exploration patterns, I will review the general geological and geochemical concepts of shale liquids plays as they apply not only to Louisiana, but national and international plays. Our Louisiana examples represent most of the major geological concepts of U.S. shale plays.

III. THE ORIGIN OF SHALE OIL ROCKS

Current shale plays vary from oil to condensate/wet gas to dry gas deposits. These different hydrocarbon origins are a result of one or both of the following variables—1) the amount and geochemical type of organics in the fine-grained rock, and 2) the temperature history over geologic time that the fine-grained rock has been exposed to.

This discussion of new Louisiana shale plays focuses upon shale oil (liquids), thermally-mature oil that is within organic-rich fine-grain sedimentary rock. This differs from oil shale, an older term used to describe thermally-immature fine-grained sedimentary rock with abundant kerogen. The organics in oil shale have not been exposed to high-enough temperatures over geologic time to cook the organic material to oil and gas. The United States has large oil
shale reserves in the Green River Formation of the western U.S. The sediment must be somehow heated up, either after mining or in-situ (in place), to create an oily liquid. This is not cheap and environmentally is more challenging, so while pilot projects study recovery mechanisms, we still do not develop oil shale.

Shale oil, or thermally-mature oil which resides in a fine-grained sedimentary rock, is our emphasis here. It is a continuum with shale gas, or thermally-mature gas which is in a fine-grained sedimentary rock. Organic-rich fine-grained sedimentary rocks and related hydrocarbon generation have a long history of study, especially since the early 1970s and onward with sophisticated geochemical tools. They were (and are) studied because these rocks are the source rocks for hydrocarbons in conventional petroleum reservoirs.
Figure 5. Geologic column for Louisiana. Note that Paleozoic-age rocks occur below the Triassic-age rocks (modified from Li, 2006a).
The past several decades of source rock studies included the investigations of hydrocarbon generation, migration, and conventional reservoir trapping. Major understanding of fine-grained organic-rich sedimentary rocks and their hydrocarbon generation and migration developed in the 1960s through the 1980s, especially, with more refined works being published through the 1990s-2000s.

These source rocks, as they were/are called, are the same rocks that we now explore and develop as shale oil and shale gas plays. The major difference is that we look for optimum conditions where petroleum has formed within these organic-rich rocks and then develop these rocks (rather than consider migration and entrapment into other rocks).

A. Rock Types and Variability

Petroleum source rocks have, by necessity, a higher-than-average organic content of different types (often 1% and higher). Where present, this higher organic content usually occurs in fine-grained sedimentary rocks dominated by clay (fine-grained sediment derived from erosion of land, “terrigenous”), carbonate (fine-grained biochemical sediment derived from organisms), biochemical silica, or a mixture (Fig. 2). Siliceous sediment (fine-grain quartz, chert or opal, commonly biochemical and/or chemical in origin) is often present in the mixture or may even dominate (the opal and chert of the Monterey Formation, California, is an example). Sediment accumulates in sedimentary environments, and fine-grain sediment is deposited in quiet (low-energy) environments.

Organic matter in this fine-grain sediment may be from one-cell plant and animal remains, algal/bacterial material, and/or land-derived terrestrial organic material (“woody” material).

The environment must preserve the organic matter from breakdown so that eventually an organic-rich sedimentary rock forms. This occurs by organic-matter accumulation in a low- to no-oxygen environment (anoxic). Additionally, rapid burial of the sediment to remove it from the sediment/water interface promotes organic matter preservation. These low-oxygen environments also do not have organisms digging through and scavenging the organic
matter. The reasons for anoxic conditions vary, but common depositional settings include deeper-water environments, saline environments, and restricted-circulation environments. Common resulting sedimentary rocks that will have high organics are “terrigenous” shales (like black shales), fine-grain carbonates, fine-grained silica/quartz rocks (opals, cherts), or compositional mixtures of these (Fig. 2). The term “mudrock” or “mudstone” is often used as a general catch-all phrase for fine-grain sedimentary rocks (not necessarily organic-rich). Most of the so-called “shale” plays are actually composed of these three major compositions, either as end-members or as mixtures. From a geologic perspective, the more generic term of “mudrock” is better than “shale” (a terrigenous-derived fine-grain rock) to describe the general rock nature of these plays. These “shales” (mudrocks) are dark from organic matter and often laminated (thinly-layered) due to the lack of burrowing organisms in the depositional environment.

B. Organic Type

Different sedimentary environments accumulate different types and amounts of organic matter in the sediment. Common sedimentary environments include the marine environment (common one-cell plants and animals, or plankton organic matter), lakes (algal/bacterial organic matter), and offshore from deltas (“woody” or terrestrial organic matter). The original organic material changes initially to an immature kerogen; with geologic burial and exposure to higher subsurface temperatures (thermal maturation), part of the kerogen converts to bitumen, which eventually forms hydrocarbons. As previously mentioned, the organic material type can vary in different sedimentary environments. Their origins are important, because the organic matter is geochemically distinct, and upon heating, will develop as different hydrocarbon types. In general, one-cell plankton and algal/bacterial matter result in oil generation upon the beginning of thermal maturation, but “woody” terrestrial material will result in more gas generation upon the beginning of thermal maturation.
C. Thermal Maturation Levels

Let’s focus on the “oily” type of organic matter and more “oily” source rocks or shale oil. Extensive study since the 1960s has been conducted on the thermal maturation of fine-grain rocks, and geochemists have recognized three basic “windows” of thermal maturity: the oil window, the wet gas (condensate) window, and the dry gas window (Fig. 6). As an organic-rich rock is buried deeper and deeper and goes through these higher thermal maturity levels, the rock will generate the hydrocarbon type (oil, wet gas, dry gas) in that specific window. The amount of generated hydrocarbons per given rock volume will depend on the organic type and richness for a given thermal history. Figure 7 illustrates the importance of burial history in petroleum generation. The diagram is simplified to assume the same thermal setting and organic rock geochemistry for all four (A, B, C, D) scenarios. Each line represents a different burial history through time of an oil-prone source rock. Pathways A and B are simple sediment burials to different depths, and they each end up at different thermal maturation levels. Pathway C is an example of sediment that gets buried in the basin, then undergoes a period of uplift, and then again is buried and eventually resides in the wet gas thermal window. Pathway D has the most complex geological history. It is eventually buried deep to a thermal maturation level of dry gas (that is, the organic matter is generating dry gas). At a later time, the area undergoes geologic uplift (“mountain-building”) and this layer is pushed upward to more shallow depths, eventually residing in the present-day oil window. If you now drill into this shale to produce it, what hydrocarbon would it produce? Probably gas, because this rock has been “cooked” at deeper depths.

The subsurface depths to these different windows vary in a geologic setting or basin, depending on the type of oil-prone organic matter, the temperatures (gradients or heat flow) during sediment burial, and the geologic time that the sediment/rock spends at these various temperatures. For a given similar geologic area, regional burial history, and certain organic matter type, the depth to each window does not vary too much (but it can move ± 1000 feet from a local average depth). We are very interested in what these
Figure 6. Diagram illustrating the different thermal maturation windows and hydrocarbons generated (modified from Tissot and Welte, 1984).
Figure 7. Burial history examples of four (A, B, C, D) different oily source rocks.
depths are once we have identified an organic rock of interest. There are both direct measurements of rock thermal maturation levels and indirect ways to calculate this thermal maturity if we understand the geological history and conditions. Needless to say, many articles and books have been written on source rocks and hydrocarbon generation over the decades, and I reference a few which also contain significant reference lists as well (Jones, 1981; Tissot and Welte, 1984; Hunt, 1996; Dembicki, 2009).

The bottom line is this—in the “old days” we reconstructed the geologic history of a potential source rock to understand its composition, distribution and its geologic timing of generation and migration so as to prioritize regions where these hydrocarbons may have migrated to and been trapped. Now we want to understand these source rocks so as to develop them as shale oil and gas plays. We still want to know where the higher-quality organic-rich rocks are, the rock volumes, what are the depths of the different thermal maturation windows, and where the (oil-prone) organic-rich rocks lie within the thermal maturation window of interest.

Modern mudstone research (shale plays) focuses upon geophysical exploration tools to better identify plays of interest, characteristics which affect the rock’s ability to respond to various fracing completion practices, and rock properties which ultimately control the amount of potential reserves. The latter “micro-scale” rock characteristics include, but are not limited to: microfractures, pore types, distribution and types of constituents (organics, clays, carbonate, silica), and water, gas and oil saturation and distribution. Engineering research and development encompasses this work so as to constantly improve on horizontal well drilling, fracing, completion, and production techniques.

D. The Geologic Setting

The concept of the “geologic setting” is quite broad and includes the entire history of a sedimentary formation, from deposition through its burial history to its ultimate resting place (and acquired geologic characteristics). The depositional environment imparts the rock’s sedimentary characteristics. The basin’s geological setting(s) will strongly affect the rock’s burial, thermal, geochemical and geomechanical history.
All of our current shale plays are best understood by characteristics derived from their geologic setting(s). While Louisiana’s rolling hills and flat plains give a surface impression of subsurface geologic simplicity, it is not true. We actually have some interesting variability in our geologic settings, and I hope to demonstrate this in discussing our two emerging plays—the Tuscaloosa Marine Shale and the Smackover Brown Dense.

IV. LOUISIANA SHALE PLAYS

I will first summarize the Haynesville/Bossier shale plays that have been undergoing drilling/development since 2007. Then, I will use the Eagle Ford play of Texas to demonstrate shale oil plays and apply this to the equivalent Tuscaloosa Marine Shale of Louisiana. Lastly, I will discuss our most diverse geological setting of Louisiana shale plays in northern Louisiana and southern Arkansas.

A. Haynesville/Bossier Shale Gas

The Haynesville Formation (which includes the Haynesville Shale) and overlying Bossier Shale (Formation) continue to be drilled and developed as shale gas (dry) plays (Fig. 8). The newer play extensions are in the East Texas area. Depths to the top of the Haynesville Shale play range from 10,500-13,500 ft. Typical wells are 11,000 to 12,500 ft vertical depth with horizontal laterals of 4,000 to 5,500 ft. Typical horizontal completions usually consist of 10 to 15 fracture stages. As previously mentioned, the Haynesville shale play is the largest shale gas producer in the country at this time. The shale’s production currently makes up about 60% of Louisiana’s gas production. It is a high-temperature, high-pressure (HTHP) play, unlike the other major gas shale producers at this time (Cohen, 2011; Kaiser and Yu, 2011).

The Haynesville Shale and the overlying Bossier Shale represent two different geological formations (as defined by established sedimentary geological principles), but are treated as one unit or “formation” in state regulatory orders (Barrett, 2010). The formations are both Jurassic-age sequences (Fig. 5). The stacked plays overlie the Sabine Uplift. The Haynesville Shale varies in its composition, and its most dominant mineral components are clay, quartz, and carbonates. The origin of the quartz (as well as clay and feldspar) is related to terrigenous material eroded from the land, although some quartz is probably chemical/biochemical as well. Organic content varies from less than 1% to over 6% (Buller and Dix, 2009; Hammes and others, 2011). The mineralogical makeup plus the minor wet gas production in the Haynesville Shale suggest that most organics have a “woody” gas-prone geochemical nature in addition to the high thermal maturity levels.
B. LA Emerging Plays—Lessons Learned from the Eagle Ford Shale of Texas

The Cretaceous-age Eagle Ford Shale and its equivalents occur throughout the Gulf Coast region (Fig. 9). Its burial history is mainly one of subsidence, similar to curves A and B of Figure 7 (but not its southwestern extension). The Eagle Ford Shale was the source rock for oils of the famous 1930s East Texas Field, the largest field in the U. S. until the discovery of the Prudhoe Bay Field. Now the Eagle Ford is being developed successfully as a shale oil/gas condensate play. Horizontal drilling and leasing is occurring in the different thermal maturity windows. Figure 10 illustrates the different thermal windows as mapped on the top of the Eagle Ford Shale. The shale dips to the south-southeast, so as we move in this direction, the deeper Eagle Ford occurs in higher thermal settings.

![Depositional and paleogeographic setting, Eagle Ford and Tuscaloosa Marine Shale plays](image)

*Figure 9. Depositional and paleogeographic setting, Eagle Ford and Tuscaloosa Marine Shale plays (modified from Indigo Minerals, 2011.)*
Figure 10. Map of the thermal window on the Eagle Ford Shale structure map. I have highlighted the depth contours to the top of the Shale. Away from the Maverick Basin (to the southwest), the top of the Shale enters the wet gas window at 11,000’ – 13,000’ (Chesapeake investor presentation, October 2010, www.chk.com).

Development has been rapid in the past three years—the Eagle Ford and the Bakken Shale (North Dakota) are two of the largest shale oil plays at this time. Drilling continues to define “sweet spots” of enhanced performance (Toon, 2012). Operators began openly discussing by 2010 that the “oily” window usually is normally-pressured, has steeper declines, and lower recoveries. Yet, economics are still good and worth pursuing. In general, the rich/wet gas (condensate) window is over-pressured, has higher recoveries and the better economics.

The operators learned that the region of “peak oil” to “wet gas” generation is a good area to focus upon. The boundary of the mapped transition from oil to wet gas on these maps appears to vary from 11,000 ft to 13,000 ft (Figure 10) as one moves northeastward away from the Maverick Basin (an uplifted area with a different geological history). Oil gravity is one indicator of thermal maturity, and gravity numbers increase with increasing thermal maturity. In general, Eagle Ford areas producing liquid
gravities of 50° to 60° are indicative of the wet gas/condensate areas. These data, oil gravity numbers, are publically available and are a useful indicator of what “thermal window” a (shale) well is producing from.

What is “peak oil,” and why is the peak oil to wet gas window important? Peak oil is when the organic material is at its “thermal best,” and there is maximum conversion of organic matter to liquid oil. Back in the 1970s to early 1980s, studies on well-known source rocks like the Bakken Shale (another hot area today) suggested to researchers that “peak oil” generation was when the newly-formed oil was in a continuous migration from thermal-generation-induced microfractures into any tectonic or structural (other geologic) fractures within the source rock. Also, the wet gas generation creates more internal pressure (since gas is less dense). This “over”-pressuring adds to the improved recovery of the hydraulic fracturing we conduct today.

Shale production performance is also improving due to defining localized areas of improved geologic conditions (rock fracturing, composition) and improved engineering practices. Improved engineering practices in the U. S. shale plays include longer lateral lengths, increased frac stages, improved proppant types and volumes, and better completion fluid types.

C. LA Emerging Plays—The Tuscaloosa Marine Shale

The Eagle Ford Shale and the underlying more-sandy Woodbine Formation of Texas are time-equivalent (to a major extent) to the Tuscaloosa Formation of Louisiana (Fig. 5 and 9). The Tuscaloosa is divided into three units from top to bottom: the Upper Tuscaloosa, the Tuscaloosa Marine Shale (TMS), and the Lower Tuscaloosa.

There is some terminology confusion that is occurring as operators move exploratory attempts from the successful Eagle Ford play in Texas to the Tuscaloosa Marine Shale. At this time, operators active in the Vernon and Rapides area are using the term “Louisiana Eagle Ford” in these up-dip areas as compared to the TMS term in down-dip areas of the Florida Parishes-SW Mississippi region. They are the same formation (a
“lithostratigraphic” unit as defined by conventional geologic concepts). The formation thins northward, and it overlies different formations from downdip to updip, but those are not controlling factors in how one names formations or stratigraphic units. A further note of confusion—be aware that previous workers in the 1960s did not use the term “Eagle Ford” in Louisiana as an equal to the Tuscaloosa Formation, but considered the Eagle Ford as younger (lying above) the Tuscaloosa Formation.

The most extensive publically available reviews of the TMS play to date are John and others (1997; 2005), Amelia Resources’ website and blog (Amelia Resources, 2012), and the recently released presentation by Indigo Minerals LLC (Indigo Minerals, 2011) of their wells in the Vernon-Rapides updip area.

The mapped TMS trend runs east-west across central Louisiana and into Mississippi (Figs. 9 and 11). The geologic setting indicates why the TMS varies in its terrigenous clay content from east (higher clays near the ancestral Mississippi River, softer rocks) to west (less clay, more brittle). Recent work by the Louisiana Geological Survey and the LSU Basin Research Institute (John and others, 1997, 2005) gathered the previous geological and engineering observations of unpublished workers and additionally studied the TMS.
Figure 11. Status (mid-February 2012) of well activity in the Tuscaloosa Marine Shale. Contours lines represent the base of the Shale. Note the encircled area to the east, outlining the region where the Shale has a higher-resistivity electric log characteristic.

The three labeled wells are plotted in Figure 12 and discussed in the text (modified from Amelia Resources, 2012).
They estimated that the Shale might contain a “potential reserve” of about 7 billion barrels of oil. This number is not a strict “reserve” estimate with well-defined boundaries on recoverability, but an early estimate of potential oil resources.

The TMS is fractured and over-pressured, and live oil is commonly present in the fractures. The abrupt electric-log resistivity increases (eastern area of Fig. 11) are believed due to active petroleum generation, a characteristic common to other source rocks. A few old vertical wells initially documented oil production from this shale. The reported organic content ranges from about 0.5 to about 4% total organic carbon.

The recent (2-17-2012) scout report of Amelia Resources (2012) list four horizontal producing wells and one vertical producing well (2 to 324 BOPD, 7 to 154 MCFD; oil gravities of 42° to 45° at vertical depths of about 11,200 to 13,750 ft). These numbers illustrate the early exploratory stage that the TMS is in. Figure 11 shows wells drilled as of mid-February 2012. Note the three labeled wells—the Weyerhaeuser 73H #1 and the Beech Grove Land Co. 68H #1 to the east, and the Bentley Lumber 34H #1. The wells to the east are located in the more-explored high-resistivity area, the area known to produce oil in older vertical shale wells. The Bentley Lumber well is of interest in understanding potential shale production in lower-resistivity areas. Figure 12 illustrates some of the initial production (IP) numbers and hydrocarbon characteristics from these two areas. As expected, IP numbers increase with increased lateral lengths and frac stages.
Figure 12. Graph of the three wells labeled in Fig. 11. Note that increased lateral lengths and frac stage numbers are generally associated with larger initial production. I have labeled each well with the oil gravity and true vertical depths (modified from Amelia Resources, 2012).

Note the oil gravity numbers in Figure 12—the Bentley Lumber 34H #1 oil gravity is 45° and produced from a depth of about 11,200 ft. Similar oil gravity values occur in the eastern wells, but the depth is greater, up to 13,700 ft. These data are an indication that regional depth variations occur to the different thermal maturation windows. The updip TMS areas to the west have shallower thermal windows as compared to the west, perhaps 2000 ft more shallow. This is most likely due to a history of higher subsurface temperatures in the western region and differences in burial history between the two regions.

The Lower Tuscaloosa sand is a conventional reservoir in southeast Louisiana and Mississippi, producing oil at more shallow subsurface depths and gas in deeper areas. The shift from oil into wet gas in the Lower Tuscaloosa fields occurs at about 14,500 ft. Oil fields are common around 10,000 ft, and dry gas occurs at depths of 20,000 ft. (Although these are conventional reservoirs where petroleum is trapped, not generated, this speaks to the depths of the thermal maturation windows. It reflects the...
thermal stability and conversion depths of oil to wet gas and then to dry gas. Recent thermal maturation work by Burke (2011) in the deep Tuscaloosa trend suggests that the thermal maturation boundaries in the eastern TMS play area may lie at about 13,500-14,500 ft (oil to wet gas) and 16,500+ ft (wet gas to dry gas).

D. LA Emerging Plays—The Smackover Brown Dense

The Smackover Formation is an Upper Jurassic (Fig. 5) carbonate section that occurs from south Texas through panhandle Florida, and the upper Smackover section is a prolific conventional reservoir throughout these states. Workers over the decades have separated the formation into informal “upper” and “lower” sections as well as “upper,” “middle” and “lower” sections. I will follow an upper, middle, and lower informal nomenclature. The conventional reservoir’s hydrocarbon source rock is from the lower (and in some areas, possibly middle) Smackover section, and the same source rock is the hydrocarbon origin for other Jurassic and Cretaceous conventional reservoirs. The term “Brown Dense” for the lower Smackover is related to its early descriptions in Arkansas, where the lower section included a dense and brown limestone (plus other variations in color, density and composition). The brown and dense nature often is described for the middle Smackover in northern Louisiana, while the lower Smackover is more often a dark gray color (Imlay, 1949). Thus, the “Brown Dense” term should be understood as an informal name that people most often use for a lower Smackover section, but it has no meaning as to color or compositional variations (which are prolific in the regional Smackover of Arkansas and Louisiana).

The Smackover Brown Dense play is most active in southern Arkansas and northern Louisiana (Fig. 13). Moving from Arkansas southward into Louisiana, or eastward along the state line, the Smackover Formation can contain more shales and some sands, and the limestone can contain more terrigenous clays (Figure 14). The section
thickens overall to the south, and the thicker lower section is suspected to contain more organics. Extensive work exists on the Smackover as a source rock, including its composition, thermal
Figure 13. Counties and parishes most active in well drilling, permitting, and leasing for the Smackover Brown Dense, 2010 through early 2012.

Figure 14. Paleogeographic setting for the Jurassic-age Smackover Formation. Much of the uplift activity in the Monroe Uplift area occurred after Smackover deposition. Some faulting occurred during deposition, but much also
occurred after Smackover deposition. The two circles are wells drilled into Paleozoic rocks; the triangle is the area of shallow Smackover leasing (see text). Note terrigenous clastics to the east.
maturity, and geochemistry (Sassen, 1990; Li, 2006b; and these authors’ references). While there is always a “lower” Smackover in any section, the lower Smackover is not created equal! The most organic-rich Smackover is downdip to the more shallow sections and its updip pinch-out. The thicker the overall Smackover Formation, the thicker the lower “basinal” Smackover usually becomes. Also, since the reservoirs of the Ark-La-Tex Smackover are usually in the upper Smackover section, rarely has there been core or sampling of the middle and lower Smackover. This is probably the reason that total organic carbon content published for our area Smackover is only given at a maximum of less than 2%. The enormous Smackover reserves of our conventional reservoirs indicate an important downdip source rock. In the Mississippi Salt Basin, lower Smackover total organic content has been reported over 8%.

Exploration in the Brown Dense play is in the early stages of continued leasing, vertical and horizontal well drilling. The past year saw increased activity in defining the play’s potential, but limited data are publically available concerning recent Brown Dense rock measurements. However, the areas of activity in a somewhat-known geological setting probably reflect the basic exploration concepts. Figure 14 illustrates the counties and parishes that are most active in terms of drilling and leasing within the general geologic setting. Defining both the lithologic and organic (liquid- or gas-prone) variability of the Brown Dense, and the variations in thermal maturity (that is, what hydrocarbon products are stable), are of utmost importance.

1. **Current Exploration Trends.** Figure 15 is a map of the top of the Smackover Formation with several current wells/permits of interest. I have posted the estimated true vertical depths (TVDs) of these wells to speculate concerning thermal maturity levels at given burial depths. Several wells in south Arkansas are at vertical depths of about 9000 ft to 9500 ft. One well in Claiborne Parish has a vertical depth of around 11,000 ft, while some vertical test...
wells in the East Haynesville Field have TVDs up to 12,500 ft. Note that wells eastward towards the Monroe Uplift are more shallow, as the Smackover has been uplifted and occurs at more-shallow depths. Four wells permitted near the West Carroll/East Carroll parish lines (see triangle symbol, Fig. 14) have estimated TVDs of 7000 ft and are expected to drill below the Smackover Formation.

At what depths might one expect the oil to wet gas transition (an important location for optimum production)? These depth observations are worth considering:

1) In the **North Louisiana Salt Basin** (Fig. 14), the zone of the “late mature oil” zone (which is about peak oil into wet gas based on their provided data), is modeled (calculated) as commonly occurring at depths of 10,000 ft to over 15,000 ft (Li, 2006b). The data suggest that the depths of peak oil into wet gas are in the 11,000 ft to 13,000 ft range. These generated (calculated) profiles are only indicators, but are useful data for exploration of a shale’s thermal windows.

2) Sassen (1990) compiled a plot of depth vs. crude oil gravity in upper Smackover reservoirs from Mississippi to East Texas. In Figure 16, I have used his data from East
Figure 15. Depth map to the top of the Smackover Formation (base map from Southwestern Energy, investor presentation, January 2012, www.swn.com/investors). The “Brown Dense” is in the lower Smackover. I have placed the estimated TVD of recent wells/permits to illustrate the depth to Brown Dense targets. Wells 2 and 3 of Fig. 16 occur in the area labeled “AIX Energy wells,” and well 1 occurs northward in Columbia County (1-15 Roberson).
Figure 16. Plot of oil gravity vs. depth; data from Sassen (1990) and from recent (2012) Smackover wells (the areas of the three wells are shown on Fig. 15). Well 1 is Southwestern Energy’s Roberson #1-15H (horizontal), IP information of 103 bbls/oil/day, 200 MCF and 35-36° gravity at a vertical depth of 9369 ft. Well 2 is a vertical Upper Smackover test in the East Haynesville Field, AIX Energy’s Hardin #1, 46° gravity oil from 10,430-10,520 ft. Well 3 is a vertical Brown Dense test also from the East Haynesville Field, AIX Energy’s Garrett #1, 58° gravity oil from 11,442-11,475 ft. The drawn lines represent lowermost thermal stability for oils, based on the two data sets. This plot suggests that away from the Monroe Uplift, the depth range of about 10,800 ft to 11,500 ft is of interest as the oil to wet gas transition.
Texas and North Louisiana to estimate a thermal stability depth for the change from oil to wet gas (using 50º oil gravity). Similar to the Tuscaloosa discussion, these represent migrated oils trapped in conventional reservoirs, but the lowermost line on the graph can be used as a measure of regional thermal stability (values above that line probably represent migrated oil into more shallow reservoirs). If I consider a value of 50º gravity, the graph suggests that this thermal stability exists at depths of about 11,300 ft. I have also plotted recent (2012) available data from vertical Smackover wells in the East Haynesville Field, Claiborne Parish, LA, and recently released information on Southwestern Energy’s horizontal well in Columbia County, AR. These more-local data suggest that our current region of Brown Dense exploration, away from the Monroe Uplift, has a slightly shallower thermal stability line for the state line region than indicated by the regional data of Sassen (1990).

3) The move from Claiborne Parish (the previous observations) to Morehouse Parish, West Carroll and East Carroll parishes is a different ballgame. The Smackover is shallower in the Monroe Uplift area, and its thermal maturity reflects its once-deeper burial depths.

2. The Monroe Uplift. One trend in activity is towards northeast Louisiana, the broad region known as the Monroe Uplift (Fig. 14). The Monroe Uplift has a complex history of different uplift times centered in different areas of the uplift region. Exploration targets in the uplift area will be of interest, as here the Smackover is actually at a more shallow depth than its maximum burial (see Fig. 7, consider burial pathways C and D, but not necessarily the thermal maturation levels). The depth to a given thermal maturation will be shallower as compared to the drilled Brown Dense to the west. Also, the Smackover Formation will vary due to its closer proximity to the ancestral Mississippi Delta and associated land-derived (terrigenous) material. Limited well data suggest terrigenous (clay) influx may not affect the lower Smackover as much as the middle and upper Smackover sections, though.

Several recent papers address the thermal maturity of the Smackover Formation in our south Arkansas—North Louisiana area, although they are from the perspective of the source rock
generating oil, which migrates to conventional reservoirs (Sassen, 1990; Barnaby, 2006; Li, 2006b). The authors present limited data from the Monroe Uplift region, and my best (informed) guess after reviewing such data is that thermal windows in the complex uplift region may be on the order of 2,000+ feet higher as compared to the west (Claiborne Parish, as example). The Monroe Uplift variability probably resulted in different thermal maturity levels versus depth, depending on where one is within the Uplift area. Some areas of the Uplift were buried just into the oil window, while other areas may have been buried into a wet gas window prior to being uplifted.

The rocks in the Monroe Uplift region are described as commonly fractured (Zimmerman, 1992). The complex structural history has resulted in closely spaced fault systems. These faults and associated fractures may serve to improve production as described for the oil window of the Eagle Ford Shale, Texas. There, some operators have been able to develop “sweet spots” of production within the oil window by focusing on similar parallel fault systems and associated fractures (Toon, 2012). Igneous intrusions into the Smackover is described throughout the Uplift area (Imlay, 1949; Zimmerman, 1992), but the descriptions of rock heating and alteration are local in nature and will probably not affect the Brown Dense. Lastly, sometimes in uplift areas, the oil can be locally altered by intruding groundwater and result in a degraded heavy oil (there is reported heavy oil in the Upper Smackover in at least one area). Heavy oil can also occur due to oil generation and migration variations (Hunt, 1996).

V. IS THAT ALL THERE IS?

No. Studies of Louisiana source rocks have pointed to other sections that have probably generated hydrocarbons. Sassen (1990) and other workers have described source rocks in the Tertiary shales of southern Louisiana, primarily the Wilcox Formation (Fig. 5). The Wilcox shales will require deeper drilling, possibly like potentially deeper drilling of the TMS of eastern Louisiana. Additionally, high organic contents have not been reported, similar to the “problem” of the Smackover Brown Dense.
An additional possibility lies in north Louisiana as well. We forget that there are sedimentary rocks below the Smackover Formation (Fig. 5). There have been little data to strengthen the possibility of Triassic-age Eagle Mills equivalent organic-rich rocks, but such rocks are known to exist in Triassic-age rift valleys elsewhere in our country. However, it may be the much older Paleozoic shales that are worth watching for in northeast Louisiana drilling (these rocks did not even make it into Fig. 5). Two wells in this region have drilled into Paleozoic rocks (see Fig. 14, two circles on Monroe uplift). The wells encountered dark shales below the Triassic-age Eagle Mills (Morehouse Formation; Imlay, 1949). These rocks, likely gas-prone due to burial and uplift, may be encountered in some of the exploratory wells around the Monroe Uplift.

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