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Current Issues in Oil & Gas Shale Development

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A. This is where it all began.

The Barnett Shale, centered near Fort Worth, Texas, was the original laboratory for perfecting the extraction techniques of oil and gas shale. The initial operator in the Barnett Shale was Houston-based Mitchell Energy. The founder and owner of Mitchell Energy, Mr. George Mitchell, was a revolutionary pioneer with a curious mind. Known as determined tinkerer, from 1981 to 1989, Mitchell Energy completed most of the first sixty-three wells drilled in the Barnett. The first well completed in the Barnett was originally a deepening well to test the adjoining Viola Lime formation. By 1986, Mitchell Energy began massive hydraulic fracturing of the Barnett formation using 400,000 gallons of gel fracturing fluid and 1,200,000 pounds of sand and by 1989 began to drill on 160-acre units. Notably, none of the wells drilled from 1981 to 1989 were horizontal.

From 1990 to 1994, over 200 wells were drilled in the Barnett, including the first horizontal well in Wise County, which is the county to the immediate Northwest of Fort Worth (Tarrant County). Further, by 1994, 80-acre drilling density had begun, although horizontal drilling was still not yet the exclusive drilling method for the Barnett Shale. The first major breakthrough came in 1997, when Mitchell Energy performed the first slick water fracture stimulation using 800,000 gallons of water and 200,000 pounds of sand. This method made hydrocarbon recovery possible, and operators began to see Estimated Ultimate Recovery ("EUR") of wells at 1 Billion Cubic Feet ("BCF"), but the wells were costly and not supported by gas prices or infrastructure. Spot natural gas prices were hovering around $2.50 per thousand cubic feet ("MCF").

Finally, in 2001 the first commercially viable horizontal well was completed and by 2003 (the same year that Devon acquired Mitchell Energy), horizontal drilling was in full swing. Thereafter, operators began to use all cemented laterals and multistage fracturing jobs. Presently (2010-2011), operators are re-fracturing older horizontal wells and attempting to extract hydrocarbons from the "oily" window of the Barnett Shale, which is farther North and slightly West of the original "core" areas of Johnson and Tarrant Counties. The current production from the Barnett Shale is in excess of 5 BCF per day. Devon, Chesapeake and ExxonMobil/XTO produce 60% of the output, with over half of the production coming from Tarrant and Johnson Counties.
Furthermore, there are 16,000 wells currently in production in the play; prior to 2003, there were only 2,100 wells producing.

Like all shale plays, the Barnett has its own unique operational challenges. The most obvious challenge is that the play is located in a major metropolitan area. Being located in an urban area, even in a state friendly to oil and gas operators like Texas, creates problems. The initial problem linked to fracturing was that of karsting, or karst sinkholes forming. Karsting, or karsts, are natural sinkholes that form at the top of the Ellenburger formation due to the dissolution of the underlying limestone and dolomite rocks by acidic waters. However, karsting is naturally occurring in and near the Ellenburger formation and thus, while naturally occurring, may be exacerbated by hydraulic fracturing. An example of karsting collapse is shown below.

B. This is how it is ending up.

With horizontal drilling and the necessity of hydraulic fracturing of shale gas formations, claims of drinking water contamination have arisen. In August 2010, two families living near wells produced by Range Resources complained to the Environmental Protection Agency ("EPA") about "flammable and bubbling drinking water coming out of their tap." The EPA tested the water and determined that "extremely high levels" of natural gas were present in the water. The water wells are located in the Trinity Aquifer, which roughly underlies the twenty county area identified with Barnett Shale.

The EPA determined that the concentration of natural gas "posed and imminent and substantial risk of explosion or fire" and further identified other contaminants such as carcinogenic benzene. However, the EPA has yet to determine whether hydraulic fracturing itself caused the natural gas to be present in the drinking water. Similar to other Texas versus the EPA matters, the EPA sought to proceed against Range Resources after the EPA determined that the Texas Railroad Commissions ("TRRC") response to the alleged contamination was inadequate.

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1 Exhibits included with the original presentation have been omitted from the published version of the paper by the editor.
The TRRC began its investigation into the complaint on August 6, 2010, after receiving the initial complaint which involved natural gas around a 200-foot deep domestic water well. The two natural gas wells at issue are the Butler Unit No. 1 and the Teal Unit No. 1 located in Hood County, southwest of Fort Worth; however, the actual water wells at issue were located in Hood County, Texas, which is about fifty miles southwest of Fort Worth.

8/6/2010  
Landowner files complaint with RRC District Office. Field inspection performed, gas odor noted.

8/10/2010  
RRC staff inspect the Range Butler Unit No. 1-H and Teal Unit No. 1-H production wells nearest the well property. 30 pounds pressure observed on bradenhead of Butler Unit No. 1-H

8/11/2010  
RRC staff inspect the well property and collect water samples.

8/17/2010  
RRC staff return to the well property and re-sample the water well to address quality control issues with first samples.

8/26/2010  
RRC staff return to well property to meet landowner’s consultant and collect gas samples.

8/27/2010  
RRC staff contacts Range and requests gas samples from Range’s production well.

9/2/2010  
Range Production Company samples gas from their Butler Unit No. 1-H well (bradenhead).

9/16/2010  
RRC contacts Range and requests additional gas samples to include bradenhead and production gas, and requests that Range pressure test their well.

9/20/2010  
Range collects samples of bradenhead and production gas.

10/13/2010  
RRC staff contacts local water well driller to discuss the occurrence of natural gas in water wells drilled in the area. RRC staff requests documentation.

10/14/2010  
Range performs pressure test of production casing from a point just below the top of cement to the surface. The well
holds 845 pounds per square inch (psi), and no leaks were observed.

10/25/2010 RRC staff contact Range and request additional samples of gas from the Butler Unit No. 1-H to include gas lift, bradenhead and production gas.

10/26/2010 Range collects additional gas samples at the same time that the EPA collects gas and water samples.

11/23/2010 EPA sends results of gas and water samples to RRC staff in Austin and requests attendance at a proposed meeting.

12/1/2010 RRC staff call EPA to discuss sample results. Learns that the meeting has been postponed.

12/3/2010 RRC receives letter from Range who agrees to take additional actions.

1/19-20/2011 RRC hearing on the matter – EPA elects not to participate

2/3/2011 Range tendered final written statement with RRC requesting finding that its Gas Wells are not the source of contamination.

Essentially, the EPA emergency order and directives are tracking the RRC investigation. On January 25, 2011, Range deposed John Blevins, director of enforcement for the Dallas regional office of the EPA. Range is in the process of testing the water wells as per the EPA Order. As of March 1, 2011, the RRC has not issued a proposal for decision. As you can see, a time period of about eight years elapsed from the time of full-scale drilling to significant EPA enforcement actions. The industry will use the Range case as a benchmark to watch the EPA’s timeline in other developing shales. Further, Range has appealed the EPA order to the 5th Circuit and the EPA has filed suit in Federal District Court in Dallas to enforce the order.

C. Speaking of Water in the Barnett Shale: Shall We Recycle?

A typical Barnett Shale well slick water fracturing job requires roughly 3.5 million gallons of water (83,000 barrels, of which a barrel typically costs fifty to seventy-five cents). The flow-back water, which now contains salts and other chemicals, is captured in open-pits and then transported for off-site down-hole disposal. Devon Energy, the leading producer in the Barnett Shale, is also leading the way in water recycling in the Fort Worth Basin.

In 2005, Devon began working in partnership with Fountain Quail Water Management LLC, a subsidiary of Aqua-Pure Ventures to utilize Fountain Quail’s NOMAD units. The NOMAD Units are on-site vapor distillation units that apply heat to separate brine from water used to fracture the gas formations. On October 30, 2006, Fountain Quail obtained a permit to treat fracture flow-back water. The method has worked so well that as of March 2008 ninety to one-hundred percent of the flow-back water recovered was being recycled. The estimated costs to recycle a barrel of frac water is $4.43 per barrel, which includes the transfer and disposal of 20% of the fracturing fluid that cannot be
recycled, which is higher, on a per barrel basis than an estimated $2.00 to $2.50 per barrel for traditional injection well disposal.

II. Texas Haynesville

A. The Old Field has New Life.

The geographical region of East Texas that overlies the Haynesville Shale (Nacogdoches, Harrison, Panola, Rusk, Shebly and Angelina Counties) are home to various mature fields and formations, such as the Cotton Valley and Travis Peak Formations. Indeed, 11,000 wells have been drilled in Panola County alone. The original field rules adopted for the Cotton Valley fields provided that only one well could be drilled per 640 acres. Thereafter, field rules were eventually amended to allow Cotton Valley density as small as 40-acre units. However, the majority of Cotton Valley units include 704 acres per well, following the standard voluntary pooling clause in most leases that allow for a 640-acre pool, with tolerance of 10%. Further, a vast number of Cotton Valley wells are still producing, thereby holding production on 704 acre units.

These traditional pooling designations pooled all depths under the unit, which now happens to include the highly productive Haynesville Shale. Operationally, these traditional units might not be situated ideally for horizontal drilling into the Haynesville. Further, from time to time, an operator would seek to drill across unit lines (but below the existing productive formation) to maximize lateral contact and encounter the Haynesville Formation. The issue generated significant discussion in the summer of 2009.

B. Devon Seeks Special Field Rules.

Beginning in June 2009, Devon Energy Production Co., LP ("Devon") sought to alleviate some of the operational issues posed from the prohibition against drilling across unit lines. Devon sought a new field designation called the Carthage (Haynesville) Field based on the completion data for Devon’s Hull Unit A Lease, Well No. 102 (API No. 42-365-36749) in Panola County, Texas, which is on the Texas/Louisiana state line. Devon’s primary assertion was that the entire Haynesville Shale formation has relatively uniform petrophysical properties and is essentially a homogeneous reservoir over the entire length of the lateral of a horizontal well completed in the field. Thus, Devon claimed that the amount of gas present in the rock contributing to production in wellbore is expected to be the same for one linear foot of rock as any other linear foot of rock completed. The interval for the Hull Unit includes the entire Bossier and Haynesville Shales and is located between the base of the Cotton Valley and the top of the Louann Salt Formations.

Devon’s proposed field rules sought 330-foot lease line spacing, no spacing requirement between wells, and forty acre density to allow for
consistency in developing the formation and greater flexibility in selecting drilling locations. Notably, just across the state line in Louisiana, 330-feet spacing is used in the Haynesville. However, the major difference in Texas and Louisiana, in this scenario, is the availability of compulsory pooled units in Louisiana.

Given the metes and bounds descriptions and non-uniform nature of property ownership in East Texas, drilling units are not nice neat sections as in Louisiana. Further complicating matters is the manner in which royalties should be allocated amongst the owners of the mineral estate. In short, as any landman who has worked in East Texas will tell you, mineral title in East Texas is as complicated as it gets anywhere in United States. Therefore, attempting to locate landowners to obtain lease amendments, production sharing units or amended pooling declarations necessary to allow for the drilling across unit lines can be nearly impossible.

Essentially, Devon sought to enact a field rule that would endorse its desires to amend the terms of the lease agreements with the mineral owners, authorize it to combine the tracts and direct that the mineral owners be paid in a manner different than what is provided in the existing lease agreements. The Railroad Commission hearing examiners declined to accept the portion of Devon’s proposed rule that called for a formulaic allocation of royalties for each tract included in the new “joint unit.” However, the hearing examiners did recommend that the Railroad Commission adopt leasing line spacing that mirrors that which is in place just across the Sabine River in Louisiana on a two-year, temporary basis. In summary, Devon scored a partial victory and talked of appealing the portion of the ruling that did not adopt its proposed royalty allocation formula; however, the appeal never materialized.

C. Meet the Shelby Trough.

A wise farmer once told me “Nothing cures high prices, like high prices.” Of course he was referring to supply responses to increased prices, which eventually drive equilibrium into commodity prices. As the industry has seen, with the advances in shale gas production, the market is flooded with natural gas, thereby depressing prices. The Haynesville Shale in Texas (and to a greater extent Louisiana) has obviously contributed to this abundance of natural gas.

The Shelby Trough is a southwest extension of the core Haynesville Shale trend in DeSoto Parish, Louisiana and extending into Shelby, San Augustine, Nacogdoches and Angelina Counties, Texas. The Trough experiences some variability and improves as the play extends into Nacogdoches and Angelina Counties due to higher porosity and pressures as you get deeper in the basin. Some discoveries have been unreal, with initial production (IP) rates in excess of 30,000 Mcf/day. Look for operators to shift their Haynesville focus to the Shelby Trough.
acreage, where lease retention pressure is lower and production rates are so high, that drilling makes sense even at today’s low gas prices. The figure below shows the general area of the Haynesville Shale as it trends from southwest to northeast from Texas to Louisiana.

III. Louisiana Haynesville

A. “Haynesville Mineral Leases”

In Civil Action No. 09-0579, Sullivan v. Chesapeake Louisiana, L.P., the Plaintiff (Sullivan) sought to declare his “Haynesville Mineral Lease” invalid due to insufficient consideration paid for the per acre bonus. Plaintiff leased his mineral rights to Chesapeake for $350 per acre and a 25% royalty. However, Plaintiff later asserted that the true market value for his 16.880 acres was $700 to $900 per acre. Plaintiff brought his claim in state court, which was then removed to federal court. However, the Plaintiff successfully obtained a remand of the case to state court, because the federal court trial judge concluded that the amount in controversy did not exceed $75,000.

B. Gatti v. Commissioner.

Landowners from North Louisiana sued the Commissioner of Conservation and twenty-two Haynesville operators in the 19th Judicial District Court for East Baton Rouge Parish. The landowners sought to have the court certify a class action, consisting of approximately 50,000 mineral owners, essentially challenging the formation of alternate unit wells in approximately 42 Haynesville Fields and seeking damages as a result of the alleged failure of the operators to present evidence to the Commissioner, as purportedly required by the initial orders establishing the Haynesville Units, after drilling of the initial unit wells for each unit.

C. Most Favored Nations clause.

Stephenson v. Petrohawk Properties, L.P., 37 So.3d 1145 (La. App. 2nd Cir. 2010). On April 15, 2008, Petrohawk paid the Stephensons a
lease bonus of $4,250 per acre, for a total payment of $680,000 (on 160 acres). Each of the Stephenson leases contained a “most favored nations” clause (hereafter the “MFNC”) which stated:

Lessee agrees that, if at any time during the first twelve (12) months of this lease, Lessee acquires directly (or indirectly through Lessee’s agents, Affiliates, parent or Subsidiaries), a lease (“Third Party Lease”) affecting land(s) or mineral rights located, in whole or in part, within two miles of the perimeter of any boundary line of any of the land(s) covered by this lease (the “Geographic Area”), and in consideration of said Third Party Lease, Lessee pays a lease or signing bonus greater than $4,250.00 per acre, then Lessee shall immediately pay to Lessor an amount equal to the difference between the more favorable bonus in the Third Party Lease and $4,250.00 per acre. Notwithstanding the foregoing, the following leases shall not be considered a Third Party Lease for purposes of this provision: (a) a lease obtained from any state, city, parish, or federal governmental entity or from any school board or levee board or district; and (b) a lease covering a tract of land of less than 20 acres; provided, however, that a lease that is one (1) of two (2) or more leases obtained from a single lessor or owner which leases cover tracts of 20 acres or more in the aggregate located in whole or in part within the Geographic Areas, which leases cover tracts of 20 acres or more in the aggregate located in whole or in part within the Geographic Area, shall be a Third Party Lease for purposes of this provision.

Petrohawk: apparently acquired a lease within the Geographic Area shortly after the execution of the Stephenson leases for $6,500 per acre and paid the Stephensons an additional $1,040,000 for the difference based on the first triggering of the MFNC. Thereafter, on July 9, 2008, Petrohawk entered into an oil and gas lease with the Frierson interests on non-contiguous tracts covering 4,000 surface acres, including an undivided 1/14th interest in a 7.37-acre tract located within the Geographic Area covered by the Stephenson leases. Petrohawk paid a bonus of $18,500 per acre for the Frierson lease. Notably, only the 7.37 acre tract was within the Geographic Area covered by the Stephenson leases. Nonetheless, Stephenson demanded an additional $12,000 per acre multiplied by 160 acres ($1,920,000). The base amount for the Stephenson lease was now $6,500, thus the demand was for the difference between $18,500 and $6,500. Petrohawk refused and litigation ensued.

The trial court granted the lessor’s summary judgment motion and ordered Petrohawk to pay the lessor an additional $1,920,000 in additional bonus, plus interest, plus attorney’s fees. On appeal,
Petrohawk argued ambiguity in the MFNC, but was unsuccessful and the appellate court upheld summary judgment in favor the landowner.

D. Rescission of Lease based on Fraud, Mistake or Error in State Court.

*Cascio v. Twin Cities Development, LLC, 48 So. 3d 341 (La. App. 2nd Cir. 2010).* Lessor entered into an oil and gas lease on April 15, 2008, with Twin Cities Development (“Twin Cities”), which was acting as an undisclosed agent for Chesapeake Louisiana, L.P. Plaintiff alleged that when it entered into the lease, it did not know of the existence of the Haynesville Shale below the leased lands (a 76-acre tract in Bossier Parish). In October 2008, Plaintiff brought suit to rescind the lease based on error concerning the object of the contract. Twin Cities moved for partial summary judgment to enforce the terms of the lease. The trial court granted summary judgment holding that an error as to the existence of a mineral deposit is not an error as to a cause “without which the obligation would not have been incurred” under La. C.C. art. 1949 and further the error is not an error as to a substantial quality which would vitiate consent under La. C.C. art. 1950. The appellate upheld the grant of partial summary judgment in favor of Twin Cities reasoning that mineral exploration is inherently uncertain and therefore not a finite fact that can be the basis of a mistake.

*Adams v. JPD Energy, Inc., 46 So. 3d 751 (La. App. 2nd Cir. 2010).* Plaintiff (Adams) entered into an oil and gas lease with JPD Energy on February 22, 2008, in which the lease contained a traditional 1/8th royalty clause and no depth limitation. Plaintiff alleged that prior to the execution of the lease, he and a representative of Defendant verbally agreed to a 25% royalty and a depth limitation, but that the executed version of the lease did not include these terms. Defendant alleged that that a 25% royalty had never been offered to the Plaintiff, but conceded that the 1/8th royalty clause was incorrect. Nonetheless, Defendant argued that the parties had agreed on 20% royalty clause, some surface protections but no depth limitations.

Plaintiff brought suit to rescind the mineral lease on the grounds of fraud, error and failure of cause. The trial court granted Plaintiff’s cross-motion for summary judgment and entered an order rendering the lease “null, void and cancelled” because there was no meeting of the minds as to the amount of royalties to be paid. The appellate court agreed and affirmed the judgment rescinding the lease.

E. Denial of 12(b) (6) Motion in Federal Court.

*Johnson Special Trust v. El Paso E & P Co., 2010 WL 3076193 (W.D. La. 2010).* Plaintiff owned land burdened by a 1950 lease producing in the Bethany/Longstreet field that provided for a 1/8 royalty and that contained no depth limitation. Starting in 2009, Plaintiff began receiving offers to lease for Haynesville development on the Plaintiff’s
1,230 acre tract in Desoto Parish offering a 25% royalty and per acre bonus of $10,000. Plaintiff sought to rescind or reform the lease to exclude the Haynesville formation. Defendant moved to dismiss the case "failure to state claim under which relief can be granted" under Federal Rule of Civil Procedure 12(b) (6). The trial court denied the Defendant's 12(b) (6) motion holding that Plaintiff's allegations of ambiguity in the lease were sufficient to state a claim for relief that was plausible on its face.

IV. Bakken Shale
North Dakota, Montana, Saskatchewan Province, Canada.
A. We're not sitting on moose pasture anymore.

The Bakken Shale, located within the Williston Basin has clearly been a game changer for North Dakota, part of Montana and now Saskatchewan Province, Canada. The Baaken is currently forecasted to produce 15% of the United States oil supply by the year 2015. By comparison, the largest producing basin in the United States, the Permian Basin, presently represents 18% of the annual production of the United States. Total oil shale reserves in the entire United States are estimated to be over 1.5 Trillion barrels of oil, over five times the known reserves of Saudi Arabia.

The U.S. Geological Survey ("USGS") estimates that roughly 3.65 Billion barrels of oil, associated natural gas of 1,848 billion cubic feet of gas and natural gas liquids of 148 million barrels are technically recoverable from the Bakken. The cumulative production from the Bakken since its first production in 1953 through 2008 was 135 million barrels of oil.

B. Bakken Express.

On December 31, 2009, EOG Resources announced that its first train shipment of crude produced from the Bakken departed EOG's rail facility in Stanley, North Dakota for the approximate four-day trip to Stroud, Oklahoma, where it will be transported to market via a 17-mile pipeline to a terminal in Cushing, Oklahoma. BNSF Railway is the rail carrier and the train has a maximum capacity of 60,000 gross barrels of oil per train. EOG is the second largest producer in the Bakken with approximately 5,000,000 net acres under lease.

C. North Dakota Version of Prescription and Interruption of Prescription.

North Dakota’s "dormant mineral act," N.D.C.C. 38-18.1, allows a surface owner to acquire and abandoned mineral interest where the interest has not been used, as defined by the code, for a period of twenty years. Unlike Louisiana, the North Dakota dormant mineral act requires that the claimant affirmative action to acquire the "lapsed" interest. However, surface owners have been successful in suits to quiet title to

V. Marcellus Shale.

A. Going Back to Where it all Began.

The Marcellus Shale has reignited the oil and gas industry in the very state where oil drilling first began. Edwin Drake drilled the world’s first oil well in Titusville, Pennsylvania, which struck oil on August 27, 1859. Pennsylvania is again the center of attention, but this time due to the huge shale formation called the Marcellus Shale. The Marcellus Shale is named for the town of Marcellus, New York, which is southwest of Syracuse. The Marcellus technically covers six states, but nearly 75% of the play underlies Pennsylvania at a depth of 7,000 to 9,000 feet. Because of the attractive location to the populations centers of the Northeast, drilling permits have risen significantly in the Marcellus. In 2007, only 99 permits were issued, compared to over 2,000 permits in 2010 and from January to August 2010, 950 wells were drilled in Pennsylvania alone.

B. Capital Deployment.

Capital investments, especially from foreign capital, together with mergers and acquisitions in the Marcellus, have been staggering.

1. Royal Dutch Shell Plc. On May 28, 2010, Shell announced that it would acquire nearly all of the shares of closely held East Resources, Inc. for $4.7 billion cash. Shell now controls nearly 700,000 acres of Marcellus acreage, generally centered around Tioga County, Pennsylvania.

2. EXCO Resources. In May 2010, Dallas-based EXCO Resources announced that it formed a joint venture with BG Group Plc (British Gas) on a 50/50 basis that included cash consideration of $800 million, together with a commitment to fund a $150 million drilling program for 186,000 net acres of Marcellus acreage.

3. Chesapeake. In May 2010, Chesapeake announced that the state-owned oil company for Singapore, Temasek Holdings Pte had invested $500 million and China’s Hopu Investment Management Co. had invested $100 million in the company for a share of Chesapeake’s Appalachia operations.

4. Gastar Exploration, Ltd. In September 2010, Gastar announced it had entered into a joint venture to sell 21.43% of the company’s Marcellus assets for $70 million to Atinum Marcellus I, LLC, an affiliate of Atinum Partners Co., Ltd. from South Korea. The transaction covered approximately 34,200 net acres and some existing shallow production.
5. **Rex Energy.** In September 2010, Rex Energy entered into a joint venture with Japan’s Sumitomo Corp. valued at $140 million for the development of 12,900 net acres of Marcellus acreage.

6. **Carrizo Oil and Gas.** In August 2010, Carrizo Oil and Gas sold a 60% in Carrizo’s Marcellus assets to India-based Reliance Industries for $392 million, of which $342 million was cash consideration.

7. **Chevron.** In November 2010, Chevron announced that it was acquiring Atlas Energy for $4.3 billion, which included cash of $3.2 billion and assumption of debt valued at $1.1 billion. At the time of announcement, Atlas held 486,000 net acres in the Marcellus. However, the transaction also covered 623,000 acres in the Utica Shale (which generally adjacent to the Marcellus) and 100,000 acres in the Collingwood/Utica Shale in Michigan.

C. **Tough “Environment” for Operations.**

The northeast is not known to be the most operator-friendly climate and is full of entities with regulatory power. In Pennsylvania alone, there are 2,566 “municipalities” that all can adopt zoning ordinances and subdivision and land development ordinances (“SALDOs”). See Pennsylvania Municipalities Planning Code (“MPC”), 53 P.S. § 10101, et seq. Further, in Pennsylvania there are 4,678 “local governments” which includes counties, cities, township and boroughs. In addition, the Delaware River Basin Commission (“DRBC”) and Susquehanna River Basin Commission (“SRBC”) exert significant influence over drilling in their respective basins. Fortunately for operators, the DRBC and SRBC do not have jurisdiction over the “core” Marcellus areas.

With respect to municipalities, the Oil and Gas Act (the “Act”), 58 P.S. § 101, et seq., expressly preempts local regulation of oil and gas production:

The Act supersedes all local ordinances that attempt to regulate matters addressed by the Act. Ordinances cannot “contain provisions which impose conditions, requirements or limitations on the same features of oil and gas well operations regulated by this act or that accomplish the same purposes as set forth in this act. 58 P.S. § 601.602

However, preemption only extends to local ordinances, but not the Pennsylvania Department of Environmental Protection (“Pa DEP”). Furthermore, because of local opposition to drilling, preemption is an often litigated topic:

*Huntley et al. v. Borough Council of the Borough of Oakmont*, 964 A.2d 855, (Pa. 2009). The Supreme Court of Pennsylvania held that a borough’s zoning ordinance which permitted mineral extraction by conditional use in residential area was *not* preempted by the Act when applied to the drilling of a natural gas well.
Range Resources – Appalachia, LLC v. Salem Township, 964 A.2d 869 (Pa. 2009). The Supreme Court of Pennsylvania held that portions of a township’s SALDO that required township permits for drilling related activities and otherwise regulated the operations of oil and gas wells within the township were preempted by the Act.

Range Resources – Appalachia, LLC v. Blaine Township, 649 F.Supp.2d 412 (W.D. Pa. 2009). The U.S. District Court for the Western District of Pennsylvania applied § 602 of the Act to invalidate the township’s “Disclosure Ordinance”, which allowed the township to deny an oil and gas operators the right to do business within the township due to a “history of consistent violations with the law.”

Other states in the Marcellus have divergent views of oil and gas development. West Virginia has welcomed the industry with open arms, but has recently passed certain requirements regarding the use of protective synthetic liners in pits and impoundments for holding waste water generated due to fracturing. In 2010, Ohio, where the Marcellus is considered to be very prolific in the eastern part of the state, the assembly passed direct regulations defining and regulating “well stimulation” and “brine and other wastes”. Ohio Rev. Stat. Ann. §§ 1509.10, et seq. (2010). Last, but not least, on August 5, 2010, the New York State Legislature passed a moratorium on issuing drilling permits in the Marcellus Shale. However, Governor Patterson vetoed the moratorium only to issue an equally restrictive executive order.

VI. Eagle Ford Shale.

A. The Best Crossbred Animal on the Ranch is a Hereford Cow and Oil Well.

The Eagle Ford Shale, like the Haynesville Shale, is named after a town that does not actually overlie the play. The town of Eagle Ford, Texas is near Dallas; however, the Eagle Ford Shale play spans a 300 mile area extended from Laredo in a northeasterly direction to East Texas. The play generally follows the Austin Chalk trend along the Texas Gulf Coast. The formation is typically encountered at depths of 10,000 to 12,000 feet and operators have completed successful laterals of up to 7,000 feet.

The geographic region is almost exclusively rural, with the western portion of the play being very sparsely populated. In fact, La Salle County, where the play was discovered in 2008, has a population of approximately 5,500 people. Thus, this dusty ranchland, and the ranchers who own it, should have plenty of reasons to build new fences, stock tanks and cattle pens.
B. The Three Window Play.

As drilling has progressed in the Eagle Ford, three somewhat distinct plays have developed — dry gas window, wet gas window and the oil window. The dry gas window is generally identified with the southern and western portions of the play, where initial production rates have been near 7.6 Mmcf/d, using a ten stage fracturing process. However, as the trend moves northeasterly, the play begins to produce more natural gas liquids (“NGLs”) and condensate. NGLs typically sell for 50% of the price of a barrel of oil and condensate sells for the same price as oil; therefore, wells that produce high amounts of NGLs and condensate can be dramatically more profitable than wells that simply produce dry gas.

Oil is found to varying degrees throughout the play, but is primarily produced in the north-central part of the play in De Witt and Gonzales Counties. Because of the variability within the play, the Railroad Commission of Texas has designated twenty fields in twenty-four Texas
C. Water Sources for Fracturing.

The water needed to complete hydraulic fracturing in the Eagle Ford Shale is typically provided from groundwater. In Texas, water is not considered to be a mineral and is owned by the surface owner. Water for fracturing typically sells for fifty to seventy-five cents per barrel (42 gallons). The majority of the counties within the play regulate groundwater withdrawal through the regulations of a local (county by county) groundwater conservation district ("GCD"). The GCDs generally have rules that allow a landowner to produce and export up to one-acre foot of ground water per surface acre owned. The completion of an Eagle Ford well requires approximately fifteen acre-feet of water (an acre-foot is 325,851 gallons). Thus, the water costs for one well are roughly $87,000. The Texas Supreme Court is also currently considering the issue of groundwater ownership in place, and the outcome of that decision will likely have significant impacts on the marketability of groundwater in Texas. Cause No. 08-0964, Edwards Aquifer Authority and the State of Texas v. Burrell Day and Joel McDaniel.