Current Issues in Oil & Gas Shale Development

The 58th Mineral Law Institute

March 24, 2011

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LSU Law Center

Presented by

J. Lanier Yeates

Andrew M. Abrameit

GORDON ARATA MCCOLLAM DUPLANTIS & EAGAN, LLC
1980 Post Oak Boulevard, Suite 1800
Houston, Texas 77056

Telephone: (713) 333-5500
Telecopier: (713) 333-5501

www.gordonarata.com
Gordon Arata McCollam Duplantis & Eagan, LLC

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J. Lanier Yeates

Licensed to practice law in both Texas and Louisiana, J. Lanier Yeates has resided in Houston since completing his studies at Louisiana State University Law School in 1981. His practice includes representation of producers and other participants in the energy industry. Mr. Yeates is resident in the Houston office of Gordon Arata McCollam & Eagan, LLC and is a member of the firm.

Mr. Yeates currently teaches the law school course, "Essentials of Oil and Gas Shale Development," as a member of the Adjunct Faculty of the University of Houston Law Center. Mr. Yeates began teaching law school in the Fall semester of 1990 when he taught Louisiana Oil and Gas Law, as an adjunct faculty member of the University of Houston Law Center.

Since 1983, Mr. Yeates has served as both a member of the Advisory Council of the Louisiana Mineral Law Institute and its Chairman for multiple terms. He served as Vice-Chairman of several committees of the American Bar Association, including the Energy Policy Committee and the Oil & Natural Gas Exploration and Production Committee. Mr. Yeates served on the Technical Subcommittee of the AAPL-OCS Committee’s Deepwater Offshore Operating Agreement Model Form Subcommittee, which developed a deepwater offshore operating agreement that was adopted in 2000 by the AAPL as a model form.

Mr. Yeates has published numerous articles and other publications and has been a frequent speaker on subjects of importance to the energy industry. In 2004, he published his first novel, Bay of One Hundred Fires.

Appointed for two terms by Governor George W. Bush, Mr. Yeates served from 1998-2001, as Vice Chairman of the Spindletop Centennial Celebration Commission and that planned and celebrated the 100th anniversary of the discovery of the Lucas Gusher in the Spindletop Field.

Mr. Yeates currently serves as a member of the Board of Directors of the LSU Foundation, having served as its Chairman during 2007-2008. He currently serves as Chairman of Campanile Charities, Inc. Mr. Yeates is a past President of the LSU Law Alumni Association.

Among his professional memberships are the United States Supreme Court Bar Association, the State Bar of Texas, and the College of the State Bar of Texas, the Pro-Bono College of the State Bar of Texas, the Louisiana State Bar Association, the American Bar Association, the Houston Bar Association, and the American Law Institute.

He was graduated in December of 1977, with a B.S. from LSU, and, in 1981, from LSU Law School where he was Order of the Coif and served as Associate Editor of the
Louisiana Law Review. His fraternities include Phi Kappa Phi, Delta Sigma Pi, and Sigma Chi.

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1980 Post Oak Boulevard, Suite 1800
Houston, Texas 77056
Telephone: (713) 333-5500
Telecopier: (713) 333-5501
www.gordonarata.com
lyeates@gordonarata.com

Andrew M. Abrameit

Andrew Abrameit has a diverse practice involving transactions and litigation related to energy and real estate. Andrew participates in all phases of oil and gas acquisition due diligence, drafting of title opinions, oil and gas leasing, and the review of gas purchase agreements. With respect to real estate, Andrew represents owners, lenders, and investors in the acquisition, sale, development, and financing of commercial real estate projects. Andrew has advised clients on the purchase and sale of retail locations for O'Reilly Auto Parts, Arby's Restaurants, Family Dollar stores, auto dealerships, hotels, and dozens of ranches. His litigation experience has encompassed prosecuting and defending oil and gas royalty disputes, access easements, boundary disputes, joint operating agreements, mechanic's liens, construction defects, water rights, breaches of contract, and collection matters.

Andrew received his J.D. from the University of Texas School of Law in 2006. While attending law school in Austin, he served as a legislative aide for natural resource issues to Senator Ken Armbrister. In addition, Andrew served as the 2005-2006 Student Editor-in-Chief of the Texas Environmental Law Journal. Prior to law school, Andrew worked as a real estate loan officer for Capital Farm Credit. He graduated cum laude from Texas A&M University with a B.S. in Agricultural Economics in 2001. When he is not practicing law, Andrew enjoys ranching and hunting with his family and friends in his south Texas hometown of Goliad, Texas.

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Current Issues in Oil and Gas Shale Development

1. The Barnett Shale:

   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 further North and slight 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 show 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.\(^1\) 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.

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

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\(^1\) Exhibit 1 – EPA Emergency Order
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.

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 6, 2010</td>
<td>Landowner files complaint with RRC District Office. Field inspection performed, gas odor noted.</td>
</tr>
<tr>
<td>August 10, 2010</td>
<td>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.</td>
</tr>
<tr>
<td>August 11, 2010</td>
<td>RRC staff inspect the well property and collect water samples.</td>
</tr>
<tr>
<td>August 17, 2010</td>
<td>RRC staff return to the well property and re-sample the water well to address quality control issues with first samples.</td>
</tr>
<tr>
<td>August 26, 2010</td>
<td>RRC staff return to well property to meet landowner's consultant and collect gas samples.</td>
</tr>
<tr>
<td>August 27, 2010</td>
<td>RRC staff contacts Range and requests gas samples from Range’s production well.</td>
</tr>
<tr>
<td>September 2, 2010</td>
<td>Range Production Company samples gas from their Butler Unit No. 1-H well (bradenhead).</td>
</tr>
<tr>
<td>September 16, 2010</td>
<td>RRC contacts Range and requests additional gas samples to include bradenhead and production gas, and requests that Range pressure test their well.</td>
</tr>
<tr>
<td>September 20, 2010</td>
<td>Range collects samples of bradenhead and production gas.</td>
</tr>
<tr>
<td>October 13, 2010</td>
<td>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.</td>
</tr>
<tr>
<td>October 14, 2010</td>
<td>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.</td>
</tr>
<tr>
<td>October 25, 2010</td>
<td>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.</td>
</tr>
<tr>
<td>October 26, 2010</td>
<td>Range collects additional gas samples at the same time that the EPA collects gas and water samples.</td>
</tr>
<tr>
<td>November 23, 2010</td>
<td>EPA sends results of gas and water samples to RRC staff in Austin and requests attendance at a proposed meeting.</td>
</tr>
<tr>
<td>December 1, 2010</td>
<td>RRC staff call EPA to discuss sample results. Learns that the meeting has been postponed.</td>
</tr>
<tr>
<td>December 3, 2010</td>
<td>RRC receives letter from Range who agrees to take additional actions.</td>
</tr>
<tr>
<td>January 19 &amp; 20, 2011</td>
<td>RRC hearing on the matter – EPA elects not to participate</td>
</tr>
<tr>
<td>February 3, 2011</td>
<td>Range tendered final written statement with RRC requesting finding that its Gas Wells are not the source of contamination.</td>
</tr>
</tbody>
</table>

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.2

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-

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2 Exhibit 2 – EPA Federal Lawsuit against Range Resources
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.

2. Texas Haynesville

A. The Old Field has New Life. The geographical region of East Texas that overlays the Haynesville Shale (Nacogdoches, Harrison, Panola, Rusk, Shelby 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 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

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3 Exhibit 3 – Railroad Commission of Texas Update on Recycling of Fracture Water
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 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.

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4 Exhibit 4 – Railroad Commission of Texas Findings of Hearing Examiners in Oil and Gas Docket No. 06-0262000.

5 Exhibit 5 – Final Order of Railroad Commission of Texas in Oil and Gas Docket No. 06-0262000.
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 high porosities and pressures as you get deeper in the basin 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.

3. 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.

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7 Exhibit 7 – Plaintiff’s Original Petition, Gatti v. Commissioner, et al
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. Recission 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.

4. **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 Bakken 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 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 500,000 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 take affirmative action to acquire the “lapsed” interest. However, surface owners have been successful in suits to quiet title to

5. **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.

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8 Exhibit 8 – North Dakota Century Code 38-18.1
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 & Huntley 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.9

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6. **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 underlie 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.

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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 counties. Look for more and more operators to shift rigs and crews out of the Haynesville, which is exclusively dry gas, to the Eagle Ford Shale in 2011.

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

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10 Exhibit 10 - Texas Eagle Ford Shale field designations.
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.
Exhibit 1

EPA Emergency Order against Range Resources
ENVIRONMENTAL PROTECTION AGENCY
REGION VI

IN THE MATTER OF:
RANGE RESOURCES CORPORATION
and
RANGE PRODUCTION COMPANY
Respondents,

(Texas RRC Operator I.D. No. 691703)

Docket Number: SDWA-08-2011-1208

EMERGENCY ADMINISTRATIVE ORDER

Proceedings Under Section 1431(a) of the
Federal Safe Drinking Water Act, 42 U.S.C.
§ 300(i)(a).

STATUTORY AUTHORITY

The following findings are made and Order issued under the authority vested in the Administrator of the United States Environmental Protection Agency ("EPA") pursuant to the authority of Section 1431 of the Safe Drinking Water Act ("SDWA" or "Act"), 42 U.S.C. § 300(i).

EPA may issue such Orders upon receipt of information that contaminants are present in or are likely to enter an underground source of drinking water and may present an imminent and substantial endangerment to the health of persons, and EPA has determined that appropriate State and local authorities have not taken sufficient action to address the endangerment described herein and do not intend to take such action at this time, as described in Section 1431(a) of the Act, 42 U.S.C. § 300(i)(a).

The Administrator delegated the authority to issue this Order to the Regional Administrator of EPA Region 6, who further delegated such authority to the Director of the Compliance Assurance and Enforcement Division.

Federal law provides that violation of any terms of this Order may subject Respondents to a civil penalty of up to $16,500 per day of violation, assessed by an appropriate United States District Court, under SDWA § 1431(b), 42 U.S.C. §300(i)(b), as modified by the Debt Collection Improvement Act, 31 U.S.C. § 3701 and codified at 40 C.F.R. § 19.4.
FINDINGS OF FACT

1. Range Resources Corporation ("RRC") is a Fort Worth, Texas-based independent natural gas company engaged in the exploration, development and acquisition of primarily natural gas properties in the Southwestern and the Appalachian regions of the United States. RRC is a Delaware corporation with its common stock listed and traded on the New York Stock Exchange under the symbol "RRC."

2. Range Production Company ("RPC") is a wholly-owned subsidiary of Range Resources Corporation operating in the State of Texas.

3. At all times relevant to this Order, RRC and RPC (hereinafter "Respondents") owned or operated the natural gas production facilities (collectively, "Gas Wells") identified as the Butler Unit Well 1-H ("Butler Well") (permitted at Atwood, JB Survey, Abstract #802, Hood County, 660 feet from the N line and 986 feet from the SE line) and the Teal Unit Well 1-H ("Teal Well") (permitted at Atwood, JB Survey, Abstract #802, Hood County, 703 feet from NE line and 948 feet from SE line).


5. Respondents contracted for and directed the drilling of the Teal Well in March and April of 2009 and completed hydraulic fracture stimulation operations in April 2009. Gas production began from the Teal Well in August 2009.

6. The Trinity Aquifer exists under twenty Texas counties, including Parker and Hood counties where the Gas Wells and the private drinking water wells described below are located.

7. As set forth more fully below, two domestic drinking water wells ("Domestic Well 1" and "Domestic Well 2"), located near the Gas Wells and utilizing the Trinity Aquifer, have been shown to contain methane, benzene, toluene, ethane, propane, and hexane. Some of these contaminants are at levels that may endanger the health of persons.

8. Domestic Well 1 lies approximately 120 feet in horizontal distance to the east-northeast from the track of the horizontal section of the Butler Well bore.

9. Domestic Well 2 lies approximately 470 feet in horizontal distance to the southeast from the track of the horizontal section of the Butler Well bore.

10. Domestic Wells 1 and 2 provide drinking water to nine people including both adults and children.
11. The Gas Wells are the only gas production facilities within approximately 2,000 feet of Domestic Wells 1 and 2.

12. Domestic Well 1 (32.56342 latitude, -97.79144 longitude) was drilled in April 2005 and was immediately used for human consumption, building construction, and landscape irrigation.

13. Neither the consumer, nor the well drilling service, observed or reported that the water from Domestic Well 1 contained any noticeable natural gas at the time of its drilling.

14. In late December 2009, approximately four months after the Gas Wells began producing gas, the owner of Domestic Well 1 first noticed that the water had begun to effervesce.

15. On July 26, 2010, the down-hole pump in Domestic Well 1 began experiencing mechanical problems soon identified by a well service company as “gas locking.”

16. “Gas locking” is a condition sometimes encountered in a down-hole pump when dissolved gas is released from solution by the action of the pump and prevents the pump from moving water.

17. In addition, on July 26, 2010, the gas in Domestic Well 1 was determined to be flammable.

18. On August 8, 2010, the owner contracted for water samples to be taken from Domestic Well 1. The samples showed the presence of benzene (3.1 μg/L), toluene (2.0 μg/L), dissolved methane (7,810 μg/L) and dissolved ethane (7,580 μg/L).

19. On August 17, 2010, TRRC took water samples from Domestic Well 1 that showed the presence of benzene (6.84 μg/L) and toluene (6.12 μg/L).

20. The consumer and well owner removed Domestic Well 1 from service during the first week of September 2010 due to the rising gas content within the drinking water and concerns with water quality, indoor air quality and potential explosivity.

21. EPA took samples of the gas from Domestic Well 1 and the Butler Well production stream on October 26, 2010 to perform compositional analysis and isotopic fingerprinting.

22. Isotopic fingerprinting is a method for determining the ratio of different isotopes of a particular element in an investigated material. Understanding this ratio helps scientists know the source of the investigated material.

23. Methane is a molecule comprised of one carbon atom for every four hydrogen atoms. Its chemical formula is CH₄.
24. While the carbon atoms in methane may be chemically identical, they may have different numbers of neutrons and different atomic mass. Atoms of the same element with different atomic mass are known as isotopes.

25. The isotopic fingerprint analysis of methane obtained on October 26, 2010 from Domestic Well 1 (δ¹³C = -47.05, δD = -188.5) and the isotopic fingerprint analysis of commingled produced gas from the Butler and Teal Wells (δ¹³C = -46.60, δD = -183.9) indicates that both gases are thermogenic in origin and likely to be from the same source.

26. The term "thermogenic," when applied to a gas like methane, means that the gas formed through deep geologic processes involving pressure, heat and time. The term is used to distinguish such gas from biogenic gas, which is formed through biological processes.

27. The compositional analysis of the gas obtained on October 26, 2010 showed that both gases contain significant amounts of heavier hydrocarbon components and that the hydrocarbon portion of each gas contains the same components. The presence of these hydrocarbons further indicates the presence of gas in Domestic Well 1 is likely to be due to impacts from gas development and production activities in the area.

28. On October 26, 2010, EPA also collected samples of water from Domestic Well 1 that showed the presence of dissolved methane (22,100 µg/L), ethane (5,27 µg/L), propane (2,820 µg/L), benzene (4.55 µg/L), toluene (3.47 µg/L), and hexane (31.7 µg/L).

29. The chemicals found in Domestic Well 1 pose a variety of risks to the health of persons.

30. Methane poses a risk of explosion and fire. In large concentrations in air, it may pose a risk of asphyxiation. Natural methane, unlike treated methane, pumped to homes for cooking and heating, is odorless and colorless. Usually a minute amount of an odorant such as t-butyl mercaptan is added to natural gas used by consumers.

31. Benzene is a known human carcinogen. It can also cause anemia, neurological impairment and other adverse health impacts.

32. Hexane, propane, ethane and toluene may also cause adverse health impacts if inhaled or ingested.

33. On November 16, 2010, EPA advised the consumers of Domestic Well 1 to continue not using the water due to water quality and potential explosivity concerns.

34. Domestic Well 2 (32.56505 latitude, -97.79041 longitude) was drilled and completed in August 2002 and was immediately used for human consumption and landscape irrigation.

35. Neither the owner, nor the well drilling service company, observed or reported that the water from Domestic Well 2 contained any noticeable natural gas at that time.
36. In May 2010, the owner of Domestic Well 2 first noticed that the water had begun to effervesce.

37. On August 26, 2010, the consumer contracted for water samples to be taken from Domestic Well 2. The samples showed the presence of dissolved methane (10.9 µg/L), EPA sampled the water from Domestic Well 2 on October 26, 2010. Results from this sample showed the presence of dissolved methane (627 µg/L), ethane (38.5 µg/L), and propane (2.05 µg/L).

38. On November 23, 2010, EPA advised the consumers of Domestic Well 2 of the levels of natural gases in the water and that they may wish to cease using the water due to water quality and potential explosivity concerns.

39. EPA has consulted with the appropriate State of Texas and local authorities, including the Railroad Commission of Texas, the Texas Commission on Environmental Quality, and the Parker County fire marshal, regarding the presence of contaminants in the source of drinking water identified below and disclosed the potential endangerment to the health of persons.

40. The Railroad Commission of Texas ("TRRC") is the state agency with regulatory authority over oil and gas production activities and the potential endangerment discussed below. EPA has informed the TRRC of the endangerment and the proposed issuance of this Order. EPA has shared data and findings related to this matter with the TRRC and has consulted with the TRRC on the accuracy of the information upon which this Order is based. EPA has determined that the appropriate State and local authorities have not taken sufficient action to address the endangerment described herein and do not intend to take such action at this time.

41. The contaminants identified herein may present an imminent and substantial endangerment to the health of persons because methane in the levels found by EPA are potentially explosive or flammable, and benzene if ingested or inhaled could cause cancer, anemia, neurological impairment and other adverse health impacts.

CONCLUSIONS OF LAW

42. Benzene, methane, toluene, ethane and propane are "contaminants," as that term is defined in SDWA § 1401(6), 42 U.S.C. § 300f(6) and 40 C.F.R. § 141.2.

43. The Trinity Aquifer is an "underground source of drinking water," as that term is defined at 40 C.F.R. § 144.3.

44. The contaminants identified herein are present in the Trinity Aquifer.
Respondents are "person(s)," as defined by Section 1431(12) of the Act, 42 U.S.C. § 300f(12).

Respondents caused or contributed to the endangerment identified herein.

In accordance with SDWA § 1431(a), 42 U.S.C. § 300f(a), EPA has consulted with appropriate State and local authorities to confirm the correctness of the information on which this action is based.

EPA has determined that appropriate State and local authorities have not taken sufficient action to address the endangerment described herein and do not intend to take such action at this time.

EPA has determined that this action is necessary to protect the health of persons.

ORDER AND GENERAL PROVISIONS

Based on these findings and pursuant to the authority of Section 1431(a) of the Act, 42 U.S.C. § 300f(a), EPA Orders that Respondents take the following actions:

A) Within twenty-four (24) hours of receipt of this Order, Respondents shall notify EPA in writing whether they intend to comply with this Order.

B) Within forty-eight (48) hours of receipt of this Order, Respondents shall provide replacement potable water supplies for the consumers of water from Domestic Well 1 and Domestic Well 2.

C) Within (48) forty-eight hours of receipt of this Order, Respondents shall install explosivity meters, approved by EPA, in the dwellings served by Domestic Wells 1 and 2.

D) Within five (5) days of receipt of this Order, Respondents shall submit to EPA a survey listing and identifying the location description (latitude and longitude) of all private water wells within 3,000 feet of the Butler wellbore track and 5,000 feet of the Teal wellbore track and all of the Lake Country Acres (TX1110059) public water supply system wells. This submittal shall include a plan for EPA's approval, to sample those wells identified in Order to determine if any of those wells have been impacted. The plan shall include head space (air) and dissolved constituent (water) sampling. The head space sampling shall commence no later than five (5) days after submittal of the plan.
E) Within fourteen (14) days of receipt of this Order, Respondents shall submit to EPA, for approval, a plan to conduct soil gas surveys and indoor air concentration analyses of the properties and dwellings served by Domestic Wells 1 and 2.

F) Within sixty (60) days of receipt of this Order Respondents shall develop, and submit to EPA for approval, a plan to: 1) identify gas flow pathways to the Trinity Aquifer; 2) eliminate gas flow to the aquifer if possible, and 3) remediate areas of the aquifer that have been impacted.

51. Each submittal made pursuant to this Order shall be sent by U.S. mail or by certified mail, with receipt requested to the address below. Electronic submittals will also be accepted.

U.S. EPA, Region 6
Water Enforcement Branch
1445 Ross Ave., Suite 1200
Dallas, TX 75202
Attn: Chris Lister, (6EN-WR)
FAX: (214) 665-6672
Email: lister.chris@epa.gov

Railroad Commission of Texas
Site Remediation Section
William Travis Building
Austin, TX 78701
Attn: Peter Pope
Email: peter.pope@rrc.state.tx.us

52. Each submittal shall include reference to the docket number as shown on the first page of this Order.

53. All plans, reports, notices, or other documents submitted by Respondents pursuant to this Order, which make any representation concerning Respondents' compliance or noncompliance with any requirement of this Order, shall be accompanied by the following statement signed by a responsible corporate officer of the Respondents:

"I certify under the penalty of law that this document and all attachments were prepared by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel gathered and evaluated the information submitted. Based on my inquiry of any and all persons directly responsible for gathering and analyzing the information obtained, I certify that the information contained in or accompanying this submittal is to the best of my knowledge and belief true, accurate, and complete. As to those identified portion(s) of this submittal for which I cannot personally verify the accuracy, I certify that this submittal and all attachments were prepared in accordance with procedures designed
The certification shall also include the name, title, date and signature of the person or persons completing the certification.

Respondents shall submit to EPA and the State of Texas, at the addresses listed in Paragraph 53, the results of all sampling, tests, or other data generated pursuant to this Order by Respondents or their agents, consultants, or contractors.

If any event occurs which causes delay in the achievement of any requirement of this Order, Respondents shall have the burden of proving that the delay was caused by circumstances beyond the reasonable control of Respondents or any entity controlled by Respondents, including but not limited to their contractors and consultants, which could not have been overcome by due diligence. Respondents shall notify EPA verbally within 72 hours, and in writing within 7 days of the verbal notification, of the anticipated length and cause of the delay, the measures taken and/or to be taken to prevent or minimize the delay, and the timetable by which Respondents intend to implement these measures. If EPA agrees that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of the Respondents, the time for performance hereunder shall be extended for a period equal to the delay resulting from such circumstances. Respondents shall adopt all reasonable measures to avoid or minimize delay. Failure of Respondents to comply with the notice requirements of this paragraph shall constitute a waiver of Respondents' right to request an extension to meet the requirements of this Order.

Nothing in this Order shall be construed to limit or otherwise affect EPA's authority under any applicable law or regulation including but not limited to EPA's authority to conduct inspections, to seek access to property, to request the provision of information, or to bring a civil or criminal enforcement action under the Safe Drinking Water Act or other applicable statutes or regulations.
58. Respondents may assert a confidentiality claim covering all or part of any information submitted to EPA pursuant to this Order. Any assertion of confidentiality must be accompanied by information that satisfies the items listed in 40 C.F.R. § 2204(e)(4) or such claim shall be deemed waived. Information determined by EPA to be confidential shall be disclosed only to the extent permitted by 40 C.F.R. Part 2. If no such confidentiality claim accompanies the information when it is submitted to EPA, the information may be made available to the public by EPA without further notice to Respondents. EPA will not accept any confidentiality claim with regard to any physical or analytical data.

59. EPA, its contractors, employees, and representatives are authorized to enter and freely move about all property at Gas Wells pursuant to this Order for the purposes of, inter alia, interviewing facility personnel and contractors; inspecting records, operating logs, and contracts related to the facility; reviewing the progress of the Respondents in carrying out the terms of this Order; conducting such tests, sampling, or monitoring as EPA or its representatives deem necessary; using a camera, sound recording, or other documentary type equipment; and verifying the reports and data submitted to EPA by the Respondents. Respondents shall provide EPA and its representatives access to the facility at all reasonable times and to any other property to which access is required for implementation of this Order. Respondents shall permit such persons to inspect and copy all records, files, photographs, documents, and other writings, including all sampling and monitoring data, that pertain to work undertaken pursuant to this Order and that are within the possession or under the control of Respondents or their contractors or consultants.

60. This Order is effective upon receipt and will remain in effect until EPA provides notice of its termination. Notice will be given after the requirements of the Order have been satisfied.

61. This Order does not constitute a waiver, suspension, or modification of the requirements of the Act or implementing regulations, which remain in full force and effect. Issuance of this Order is not an election by EPA to forego any civil or criminal action otherwise available under the Act.

62. EPA expressly reserves all rights and defenses that it may have, including but not limited to the right to disapprove work performed by Respondents pursuant to this Order and to modify documents submitted by Respondents and require that Respondents implement those modifications. Nothing in this Order shall diminish, impair, or otherwise adversely affect the authority of EPA to enforce the provisions of this Order. This Order shall not be interpreted to relieve Respondents of their obligations to comply with any provision of the Act, its implementing regulations, or any other federal, state, or local law.
63. Failure to timely complete any requirement of this Order shall be deemed a violation of this Order, beginning on the first day that performance is scheduled to commence.

64. This Order shall not limit or otherwise preclude EPA from taking additional enforcement action, civil or criminal, pursuant to the SDWA, or any other available legal authority, should EPA determine that such action is appropriate. Issuance of this Order is not an election by EPA to forego any civil or criminal action otherwise authorized under the Act or other laws.

65. All actions required to be taken pursuant to this Order shall be undertaken in accordance with the requirements of all applicable local, State, and federal laws and regulations.

66. Respondents shall obtain or cause their representatives to obtain all permits and approvals necessary under such laws and regulations to perform work pursuant to this Order and shall submit timely applications and requests for any such permits and approvals. Failure to obtain any necessary permits or approvals shall not constitute grounds for an extension pursuant to Paragraph 56 of this Order.

67. This Order may be modified or amended by EPA to ensure protection of the health of persons. Such an amendment shall be in writing, shall have as its effective date the date on which it is received by Respondents, and shall be incorporated into this Order.

68. If any provision or authority of this Order, or the application of this Order to any party or circumstance, is held by any judicial or administrative authority to be invalid, the application of such provision(s) to other parties or circumstances and the remainder of the Order shall remain in force and shall not be affected thereby.

69. This Order shall be binding upon the Respondents cited herein and all their heirs, successors, and assignees. No change in ownership of the leases or properties shall alter the responsibility of the Respondents under this Order.

70. This Order constitutes final agency action for purposes of SDWA § 1448, 42 U.S.C. § 300j-7.
OPPORTUNITY TO CONFER WITH EPA

71. Respondents have the opportunity to confer informally with EPA concerning the terms and applicability of this Order. Respondents must contact Tucker Henson, Office of Regional Counsel, at (214) 665-2718 within seven (7) days of receipt of this Order to schedule such a conference. This conference is not an evidentiary hearing, does not constitute a proceeding to challenge the Order, and does not give Respondents a right to seek review of this Order. Any such conference with EPA will be held at the following location:

U.S. EPA, Region 6
Office of Regional Counsel (6RC-EW)
ATTN: Tucker Henson
1445 Ross Avenue, Suite 1200
Dallas, TX 75202.

12-7-10
Date

John Blevins
Director
Compliance Assurance and
Enforcement Division
Exhibit 2

EPA Federal Lawsuit against Range Resources
UNITED STATES DISTRICT COURT
NORTHERN DISTRICT OF TEXAS

UNITED STATES OF AMERICA,

Plaintiff,

v.

RANGE PRODUCTION COMPANY,
a Delaware Corporation; and
RANGE RESOURCES CORPORATION,
a Delaware Corporation,

Defendants.

Civ. A. No. _____________

COMPLAINT

The United States of America, by authority of the Attorney General of the United States
and through the undersigned attorneys, acting at the request of the Administrator of the United
States Environmental Protection Agency ("EPA"), files this Complaint and alleges as follows:

NATURE OF THE CASE

1. This is a civil action for injunctive relief and civil penalties pursuant to Section
1431(b) of the Safe Drinking Water Act ("SDWA" or "the Act"), 42 U.S.C. § 300i(b).

Specifically, this civil action seeks to (a) require defendants Range Production Company and
Range Resources Corporation (collectively, "Range" or "Defendants") to achieve and maintain
compliance with an Emergency Administrative Order issued by the EPA, pursuant to Section
1431 of the SDWA, 42 U.S.C. § 300i, on December 7, 2010 ("Emergency Order"); and (b)
obtain civil penalties to redress Range's continuing violations of the Emergency Order. A true
and correct copy of the Emergency Order, dated Dec. 7, 2010, is attached hereto as Exhibit A.
JURISDICTION AND VENUE

2. This Court has jurisdiction over the parties and the subject matter of this action under 28 U.S.C. §§ 1331, 1345, and 1355, as well as Section 1431 of the Act, 42 U.S.C. § 300i. This Court has personal jurisdiction over Defendants because Range is located in this district.

3. Venue is proper in this judicial district under 28 U.S.C. §§ 1391(b) and (c) and 1395(a), and Section 1431(b) of the Act, 42 U.S.C. § 300i(b), because the Defendants are located in this district and the events or omissions giving rise to this action occurred in this district.

PARTIES

4. Plaintiff is the United States of America, acting by the authority of the Attorney General and on behalf of the Administrator of the EPA.

5. Range Production Company and Range Resources Corporation (collectively “Range” or “Defendants”) are corporations organized under the laws of the State of Delaware and are registered to do business in Texas. Range is engaged in the exploration, development, and acquisition of gas-bearing properties, including some gas-bearing properties located adjacent to drinking water wells in Parker County and Hood County, Texas. Range Production Company and Range Resources Corporation may be served through their registered agent, David P. Poole, 100 Throckmorton Street, Ste. 1200, Fort Worth, Texas 76102.

STATUTORY AND REGULATORY FRAMEWORK

7. Pursuant to the authority under Section 1412 of the SDWA, 42 U.S.C. § 300g-1, EPA has promulgated National Primary Drinking Water Regulations ("NPDWRs") setting maximum contaminant levels for specified drinking water contaminants. The term "maximum contaminant level" is defined in Section 1401(3) of the SDWA, 42 U.S.C. § 300f(3), as the "maximum permissible level of a contaminant in water which is delivered to any user of a public water system."

8. Under Section 1413 of the SDWA, 42 U.S.C. § 300g-2, States may obtain primary responsibility for administering and enforcing federally-mandated standards, including the NPDWRs, provided that the State satisfy certain statutory requirements.

9. In the State of Texas, the Texas Commission on Environmental Quality ("TCEQ") has primary enforcement responsibility for the SDWA. 42 U.S.C. § 300g-2.

10. TCEQ and the Railroad Commission of Texas ("TRRC") have entered into a Memorandum of Understanding concerning the commissions' division of responsibility for matters which arise under overlapping jurisdictions of different statutes. See 16 T.A.C. § 3.30.

11. Even if a State has obtained primary responsibility for administering and enforcing EPA’s standards, EPA retains the authority to issue emergency administrative orders pursuant to the emergency powers provision of Section 1431(a) of the SDWA, 42 U.S.C. §300i(a).

12. Section 1431(a) of the SDWA, 42 U.S.C. § 300i(a) reads, in pertinent part:

   Notwithstanding any other provision of this subchapter, the Administrator, upon receipt of information that a contaminant which is present in or is likely to enter a public water system or an underground source of drinking water, . . . which may present an imminent and substantial endangerment to the health of persons, and that appropriate State and local authorities have not acted to
protect the health of such persons, may take such actions as he may
decnecessary in order to protect the health of such persons.

13. Pursuant to Section 1431 of the SDWA, 42 U.S.C. § 300i, the United States may
bring a civil judicial action to require compliance with an emergency administrative order issued
by the EPA, as well as to seek civil penalties for violations of such order.

14. Section 1431 of the SDWA, 42 U.S.C. §300i(b), provides that any person who
violates or fails or refuses to comply with an emergency administrative order issued by EPA may
be subject to a civil penalty of not more than $16,500 for each day in which such violation
occurs or failure to comply continues after January 12, 2009. See Debt Collection Improvement

BACKGROUND AND GENERAL ALLEGATIONS

15. Range is engaged in the production of natural gas from the Barnett Shale Formation,
located in and around the Fort Worth, Texas area.

16. By mid to late 2009, Range drilled and completed well stimulation operations at –
and began producing natural gas from – two gas extraction wells known as the Butler 1-H well
(“Butler Well”) and the Teal 1-H well (“Teal Well”) in the Newark East (Barnett Shale) Field.

17. The Butler and Teal Wells are located on a shared surface site and were identified by
TRRC as two gas wells that terminate within a 1/4 mile radius of a domestic drinking water well
(“Lipsky Well”). Both the Butler and Teal Wells consist of vertical wellbores, which extend for
more than 5,800 in depth before continuing in a generally horizontal direction for several more
thousand feet.

18. TRRC identified no other active gas wells within a ½ mile radius of the Lipsky Well.
19. Two domestic drinking water wells, the Hayley Well and the Lipsky Well, were drilled in 2002 and 2005, respectively. The Hayley Well is located approximately 470 feet in horizontal distance from the track of the lateral wellbore of the Butler Well; the Lipsky Well lies approximately 120 feet in horizontal distance from the track of the lateral wellbore of the Butler Well.

20. The drilling records prepared contemporaneously with the construction of the Hayley and Lipsky water supply wells do not indicate the presence of natural gas in the wells (including methane).

21. At some point in time between September 2009 and September 2010, the Hayley residence experienced a lack of water pressure from its water supply well.

22. From approximately mid 2005 through late 2009, the Lipskys used water from the Lipsky Well for residential and agricultural purposes, without noticing problems with water quality.

23. Recent water samples from the Hayley and Lipsky Wells reveal the presence of contamination, including methane. Additional analysis of the gas recovered from the Lipsky Well indicate that it is thermogenic natural gas, the kind formed by geologic processes deep within the earth.

24. The Hayley Well sample indicated the presence of methane, ethane, and propane, while the Lipsky Well sample indicated the presence of elevated levels of dissolved methane, ethane, propane, benzene, toluene, and hexane.

25. Beginning in or around August 2010 and continuing through December 7, 2010, EPA received and considered information, such as that noted above, as well as (but not limited
to) gas well drilling permit applications, plugging records, and other oil and gas well information recorded in documents of the Oil and Gas Division of the TRRC; water well location information from the Water Information Integration & Dissemination System of the Texas Water Development Board relating to residential and public water supply wells; well water laboratory test results; and other water and gas sampling analyses (including comparative gas analysis and isotopic fingerprinting analysis).

26. Upon the information before it, including but not limited to any actions taken by the appropriate State and local officials, EPA determined that the contaminants identified in the Emergency Order “may present an imminent and substantial endangerment to the health of persons because methane in the levels found by EPA are potentially explosive or flammable, and benzene if ingested or inhaled could cause cancer, anemia, neurological impairment and other adverse health impacts.” (See Emergency Order Para. 41).

27. On December 7, 2010, EPA memorialized its findings in an Emergency Administrative Order issued to Range under Section 1431 of the Safe Drinking Water Act, 42 U.S.C. § 300i(a), in which EPA determined expressly that the contamination in two domestic water wells that draw water from the Trinity Aquifer may present an imminent and substantial endangerment to the health of persons.

28. In the Emergency Order, EPA also found that appropriate State and local authorities, including TRRC, had not taken sufficient action to address the endangerment. (See Emergency Order Para. 40).

29. Based on findings in the Emergency Order and pursuant to Section 1431 of the SDWA, 42 U.S.C. § 300i, the Emergency Order requires Range to perform six Ordered
Provisions. (Emergency Order Paras. 50(A) through 50(F)).

30. Range disputes the validity of the Emergency Order. Range has explained it will not comply with a number of the directives of the Emergency Order, e.g., Paragraphs 50(D), (E), and (F).

**ALLEGED VIOLATIONS**

31. Range has and will violate a number of the requirements of the Emergency Order. As a result, the contaminants identified in the Emergency Order may pose an imminent and substantial endangerment to the health of persons. 42 U.S.C. § 300i.

32. Specifically, Range already has failed or has reported to EPA that Range will fail to comply with the following requirements of the Emergency Order:

(i) within five (5) days of receipt of the Emergency Order, submit to EPA a survey of all private water wells within 3,000 feet of the Butler and Teal wellbore tracks and all of Lake Country Acres’ public water supply system wells, together with a sampling plan for EPA’s approval to determine if any of the identified wells have been impacted (Emergency Order Para. 50(D));

(ii) within fourteen (14) days of receipt of the Emergency Order, submit to EPA for approval a plan to conduct soil gas surveys and indoor air concentration analyses for the properties and dwellings serviced by Domestic Wells 1 and 2 (Emergency Order Para. 50(E));

(iii) within sixty (60) days of receipt of the Emergency Order Range must develop and submit to EPA for approval a plan to

   (1) identify gas flow pathways to the Trinity Aquifer;
(2) eliminate gas flow to the aquifer, if possible; and
(3) remedy the areas of the aquifer that have been affected
(Emergency Order Para 50(F)).

FIRST CLAIM FOR RELIEF
(Injunctive Relief)

33. Paragraphs 1 through 32 are re-alleged and incorporated by reference as if fully set forth below.

34. Pursuant to Section 1431 of the SDWA, 42 U.S.C. § 300i, the United States seeks permanent injunctive relief to require Range to comply with Ordered Provisions 50(D), (E), and (F) of the Emergency Order.

35. To date, Range has not complied with these requirements of the Emergency Order. As a result, the contaminants identified in the Emergency Order, which are present in the underground source of drinking water, may pose an imminent and substantial endangerment to the health of persons, in violation of the SDWA. 42 U.S.C. § 300i.

36. Therefore, unless permanently enjoined, Range will continue to violate the Emergency Order.

SECOND CLAIM FOR RELIEF
(Civil Penalty)

37. Paragraphs 1 through 36 are re-alleged and incorporated by reference as if fully set forth below.

38. Range has violated the Emergency Order. Pursuant to Section 1431(b) of the SDWA, 42 U.S.C. § 300i(b), and the Debt Collection Improvement Act of 1996, Pub. L. No.
101-134, and 40 C.F.R. § 19.4 (Table), Range is liable for a civil penalty not to exceed $16,500 for each day of each violation.

**PRAYER FOR RELIEF**

WHEREFORE, the United States of America requests that this Court grant it relief as follows:

1. Direct Range to comply with the Emergency Order Paragraphs 50 (D), (E), and (F);
2. Enter judgment against Range and in favor of the United States for civil penalties up to the amount of $16,500 for each day of each such violation of Emergency Order Paragraphs 50 (D), (E), and (F); and
3. Grant the United States such further relief as is just and appropriate.

Respectfully submitted,

JAMES T. JACKS
UNITED STATES ATTORNEY

/s/Katherine Savers McGovern

Dated: January 18, 2011

KATHERINE SAVERS MCGOVERN
Assistant United States Attorney
Texas State Bar No. 13638020
1100 Commerce Street, Suite 300
Dallas, TX 75242
(214) 659-8650 (tel)
(214) 767-2916 (fax)
katherine.mcgovern@usdoj.gov
IGNACIA S. MORENO
Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice

s/Keith T. Tashima

JEFFREY K. SANDS
Senior Attorney
Maryland State Bar No. 199412150130
KEITH T. TASHIMA
Trial Attorney
New York State Bar No. 3938701
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611 Ben Franklin Station
Washington, DC 20044-7611
(202) 514-3908 (Sands)
(202) 616-9643 (Tashima)
(202) 616-2427 (fax)
jeffrey.sands@usdoj.gov
keith.tashima@usdoj.gov

OF COUNSEL:

SCOTT McDONALD
Chief, Water Enforcement Branch
TUCKER HENSON
Assistant Regional Counsel, Water Enforcement Branch
Office of Regional Counsel
U.S. Environmental Protection Agency, Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202
(214) 665-2718 (McDonald)
(214) 665-8148 (Henson)
Exhibit 3

Railroad Commission of Texas Update on Recycling of Fracture Water
WATER USE IN THE BARNETT SHALE

Last Update: 1/24/11

Hydraulic Fracturing

The Newark East, Barnett Shale, Field is one of the most active drilling targets in the past decade. The initial development of the field was centered in southeast Wise County. Activity has expanded to the north in Montague County, to the east in Denton County and to the south in Tarrant County and now is present in 16 counties in North Texas.

The success of the Barnett Shale is in large part a result of the use of stimulation technology. While the volume of gas-in-place is large in the Barnett Shale (estimated to be over 27 trillion cubic feet), recovery of the gas is difficult because of the low permeability of the shale. The Barnett Shale must be stimulated – treated to increase permeability – in order for the field to be economic.

In order to be able to produce gas at volumes that are economical, reservoirs with low permeability must be treated. One method of treatment to increase permeability is fracture treatment or "fracing," which increases the available surface area by creating fractures that are "propped up" or held open by the propping agents in the frac fluid.

Hydraulic fracturing is used in the Barnett Shale. Hydraulic fracturing consists of pumping into the formation very large volumes of fresh water that generally has been treated with a friction reducer, biocides, scale inhibitor, and surfactants, and contains sand as the propping agent. The water treating fluid maximizes the horizontal length of the fracture while minimizing the vertical fracture height. The fractures, which are held open by the sand, result in increased surface area, which further results in increases in the desorption of the gas from the shale and increases in the mobility of the gas. The result is more efficient recovery of a larger volume of the gas-in-place.

In 1997, the first slick water frac (or light sand frac) was performed and found to be very successful in stimulating the Barnett Shale. Slick water fracturing of a vertical well completion can use over 1.2 million gallons (28,000 barrels) of water, while the fracturing of a horizontal well completion can use over 3.5 million gallons (over 83,000 barrels) of water. In addition, the wells may be re-fractured multiple times after producing for several years.

Water Use Estimates

Increasing water use due to growing population, drought, and Barnett Shale development has heightened concerns about water availability in North-Central Texas. In January of 2007, the Texas Water Development Board (TWDB) published a study of a 19-county area in North Texas that includes the Barnett Shale development area. This report, "Northern Trinity/Woodbine Aquifer Groundwater Availability Model, Assessment of Groundwater Use in the Northern Trinity Aquifer Due to Urban Growth and Barnett Shale Development," includes estimates of water used in Barnett Shale development. This report can be found at http://twdb.state.tx.us/RWPG/rrgmn_rpts/0604830413_BarnetShale.pdf.

The TWDB report states that approximately 89% of the total water supply for the region for all purposes (municipal, agricultural, electric power generation, industrial, and mining) is provided by surface water sources, while groundwater is used for the remainder of the total demand (about 140,000 acre-feet per year 1). The amount of water from all sources that is used for Barnett Shale development has been a relatively small (less than 1 percent), although growing, percentage of the total water use from all sources and for all purposes in the counties with Barnett Shale development.

The TWDB report estimates that, out of the total water used in 2005 for Barnett Shale development, approximately 60 percent was groundwater from the Trinity and Woodbins Aquifers. The report further estimates that groundwater used for Barnett Shale development accounted for approximately 3 percent of all groundwater used in the entire study area in 2005. However, the ratio of groundwater to surface water used in specific areas varies greatly. For example, groundwater provides as much as 88 percent of the total water supply for Cooke County. In general, groundwater provides for a greater percent of total supply in rural counties and a smaller proportion of total use in more urban counties. Therefore, increased groundwater use for any purpose will have a greater impact on rural areas in the study area.

The TWDB report makes predictions of future water needs for all purposes, including Barnett Shale development. The low estimate for Barnett Shale development predicts a decrease of about 2,000 acre-feet by the year 2025 and the high estimate predicts an increase from an estimated 7,200 acre-feet in 2005 to about 10,000 to 25,000 acre-feet per year by 2025, which corresponds to a estimated potential increase in groundwater used from 3% in 2005 to 7 to 13 percent in 2025. As with the development of any estimate of future conditions, the
TWDB and its contractors used educated assumptions to develop reasonable low and high estimates in light of the unpredictability of the natural gas market, which would drive future drilling activity in the area.

Recycling
Updated: 1/24/11

Recognizing the concerns with water use in the area, over the past few years several companies have applied for, and the Commission has approved, recycling projects in the Barnett Shale to reduce the amount of fresh water used in Barnett Shale development activities. While no authorizations have been issued to date, Commission staff anticipates water recycling projects will be explored in South Texas and East Texas, as a result of development in the Eagle Ford Shale and the Haynesville Shale, respectively.

The following authorizations have been issued by the Commission and are currently active:

- **Fountain Quail Water Management of Jacksboro uses a recycling process that allows reuse of approximately 80 percent of the returned fracture fluids processed through its commercial mobile recycling unit. When water injected to fracture formations returns to the surface, it becomes unusable due to its high salt content. This recycling process involves on-site distilling units that apply heat to separate the brine resulting from fracturing gas formations into a relatively small volume of concentrated brine that is disposed of in a disposal well and a large volume of distilled water that can be reused to fracture additional wells. Under this project, instead of hauling unusable return fracture fluids to a disposal well, the fracture flow-back fluid is stored in tanks on location and piped into treatment equipment. Natural gas produced on location is used to fire the distilling units that in turn boil the returned fracture fluid and produce distilled water. The distilled water can then be used to fracture treat another Barnett Shale well. Based on the success of Fountain Quail's pilot program, on October 30, 2006, the Commissioners authorized Fountain Quail on a permanent basis to treat fracture flow-back fluid. Fountain Quail was granted a 5-year authorization for its mobile recycling unit. As of October 2010, Fountain Quail has processed over 12.7 million barrels of returned fracture fluid to recover over 9.9 million barrels of reusable distilled water.**

- **Fountain Quail Water Management received authorization for a commercial stationary recycling facility in Parker County (RRC District 7B) in November 2009. The stationary facility will use the same technology as Fountain Quail’s mobile water recycling process. While the facility has yet to begin operations, Fountain Quail’s submitted plans indicate the stationary facility would initially be able to process 7,000 barrels per day of returned fracture fluid and an additional 7,000 barrels per day of produced water. The facility will be capable of processing 15,000 barrels per day of returned fracture fluid and an additional 15,000 barrels of produced water. Like Fountain Quail’s mobile recycling units, the stationary facility will allow for reuse of approximately 80 percent of the fluids it processes.**

- **The Barnett Shale Water Conservation Company received authorization from the Commission in March 2007 to dispose of produced water and drilling fluids in the City of Fort Worth’s wastewater system. The authorization to dispose of these waste streams is contingent upon The Barnett Shale Waster Conservation Company also receiving authorization from the Texas Commission on Environmental Quality and the City of Fort Worth. While The Barnett Shale Water Conservation Company does not reuse any of these fluids in oil and gas activities, treating produced water and drilling fluids in a municipal water treatment system rather than disposing of these fluids in a disposal well allows the water to remain in the hydrologic cycle.**

- **Brazos Bend Energy Services of Granbury, on behalf of Chesapeake Operating, Inc., received authorization to dispose of produced water and drilling fluids in the City of Fort Worth’s wastewater system in July 2009. The authorization to dispose of these waste streams is contingent upon Brazos Bend also receiving authorization from the Texas Commission on Environmental Quality and the City of Fort Worth. While Brazos Bend does not reuse any of these fluids in oil and gas activities, treating produced water and drilling fluids in a municipal water treatment system rather than disposing of these fluids in a disposal well allows the water to remain in the hydrologic cycle. As of June 2010, Brazos Bend Energy Services has introduced approximately 19,000 barrels of oil and gas wastewater into the City of Fort Worth’s wastewater system.**

- **Burlington Resources and Stroud Energy were authorized in 2003 and 2005, respectively, to reuse returned fracture fluids in the Barnett shale, without a permit, for reuse in future fracs or drilling new wells.**

The following water recycling pilot projects have been previously approved but are no longer being pursued:

- **DTE Gas Resources, Inc. was granted authority on April 18, 2006 to conduct a pilot project. The pilot project consisted of the storage, handling, treatment and reuse of returned fracture fluids at two Barnett Shale gas well drill sites in Tarrant and Jack Counties. The returned fracture fluids were treated with on-site separation and filtration. On November 13, 2007, DTE Gas Resources reported that the pilot project had ended. DTE reported that the project was found non-viable economically.**

- **Devon Energy Production Company, LP was granted authorization effective January 15, 2007, to perform a pilot project to store, handle, treat and reuse returned fracture fluids from five to ten Barnett Shale gas well drill sites. The returned fracture fluids were to be treated via on-site separation and filtration. On October 22, 2007, Devon reported that the pilot project had ended. Devon indicated that returned fracture fluids were brought into the system for treatment; however, no recycled water was reused to fracture additional wells. On July 15, 2008, Commissioners approved Devon’s request for authorization for another pilot project to treat and...**

[http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php](http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php)

3/1/2011
re-use returned fracture fluids and produced water from the Barnett Shale using equipment from a different manufacturer. However, Devon abandoned this pilot project in October 2008 as a result of having no success in producing reusable treated water.

\(^1\)One acre-foot (AF) is the amount of water to cover one acre with one foot of water and equals 325,851 gallons.
Exhibit 4

Railroad Commission of Texas Findings of Hearing Examiners in Oil and Gas Docket No. 06-0262000.
THE APPLICATION OF DEVON ENERGY PRODUCTION CO., LP FOR A NEW FIELD DISCOVERY AND TO ADOPT FIELD RULES FOR THE PROPOSED CARTHAGE (HAYNESVILLE) FIELD, PANOLA COUNTY, TEXAS

HEARD BY: Richard D. Atkins, P.E. - Technical Examiner
          Marshall F. Enquist - Legal Examiner

HEARING DATES: July 25 and September 1, 2009

APPEARANCES: REPRESENTING:

APPLICANT:

Brian R. Sullivan
Sandra Bush
Dale Greenfeather
Ben Wilson
Brad Hall
Douglas Dahmann
Daniel W. Higdon

Devon Energy Production Co., LP

INTERESTED PARTIES:

Ana Maria Marsland-Griffith
Frank A. Davis
Scott Crump

Georges Neale

Anadarko E & P Company, LP

El Paso E & P Company, LP

Energen Resources Corporation

Tanis Exploration, LLC

Bill G. Spencer

Chesapeake Operating, Inc.

Carroll Martin
Randall Davis
Richard Rhodes

EOG Resources, Inc.
OIL AND GAS DOCKET NO. 06-0262000

Carroll Martin
Darren Groce
Mickey Melton

R. Laey, Inc.

OBSERVERS:

David Gross
Rick Johnston

Mickey Olmstead
James M. Clark

XTO Energy, Inc.
Samson Lone Star, Llc.

Tim George
ExxonMobil Corporation

PROCEDURAL HISTORY

Application Filed: June 1, 2009
Notice of Hearing: June 8, 2009
Hearing Held: July 23, 2009
Re-convened Hearing Held: September 1, 2009
Transcript Received: September 10, 2009
Proposal for Decision Issued: November 6, 2009

EXAMINERS’ REPORT AND PROPOSAL FOR DECISION

STATEMENT OF THE CASE

Devon Energy Production Co., LP ("Devon") requests that a new field designation called the Carthage (Haynesville) Field be approved for its Hull Unit A Lease, Well No. 102 (API No. 42-355-36748), and include the entirety of Panola County. Devon also requests that the following permanent Field Rules be adopted for the new field:

1. Designation of the field as the correlative interval which includes both the Bossier and Haynesville Shales;

2. 330' lease line spacing and no between well spacing with special provisions for “take points” and an off-lease penetration point for horizontal wells with an included “box rule” stating that the as-dug location of a well will be considered in compliance with spacing rules if it falls within a rectangle of which two sides are parallel to the permitted drainhole and 50 feet on either side of the drainhole;
3. 640-acre gas proration units with 10% tolerance and optional 40-acre density;
4. Allocation based on 95% acres and 5% per well with AOF status;
5. Special provisions for stacked lateral wells;
6. An "allocation rule" for horizontal wells drilled and completed in more than one existing lease or pooled unit.

Based on evidence received at the hearing, the examiners reconvened the hearing to consider the consolidation of numerous other Haynesville/Bossier Shale fields into the Carthage (Haynesville) Field. There was no objection by any party to inclusion of the Shelbyville Deep (Haynesville), Center (Haynesville), Carthage, E. (Bossier), Waskom (Haynesville), Nacochiche Creek (Haynesville), Nacochiche Creek (Bossier), Bossierville (Bossier-Shale), Beckville (Haynesville) and Carthage, North (Bossier Shale) Fields into the Carthage (Haynesville Shale) Field. The examiners recommend that the nine Bossier and Haynesville Shale fields listed above be consolidated into the Carthage (Haynesville Shale) Field.

Commission staff reviewed the P-7 submitted for the new field and recommended that the field name be changed to Carthage (Haynesville Shale) Field. Staff felt that this would highlight the fact that this field is producing from a shale formation. Devon did not consider this to be an adverse recommendation.

The application was unprotested. The examiners recommend approval of the new field designation and Field Rules for the Carthage (Haynesville Shale) Field, with the exception of proposed Rule 8 ("allocation rule"); the included "box rule" in proposed Rule 2 and the calculation of additional acreage assignments pursuant to Statewide Rule 86 in proposed Rule 2. The examiners also recommend expansion of paragraph 1 of the proposed Rule 6 ("Stacked Lateral Rule") to include language ensuring each point of a stacked lateral drainhole is no further than 300 feet away horizontally from any point along any other horizontal drainhole of the same Stacked Lateral Well. In addition, the examiners recommend that for purposes of assigning additional acreage to a horizontal wellbore pursuant to Statewide Rule 86, any "no-pair" zones between the first and last take points in excess of 350 feet be excluded from the calculation of horizontal drainhole displacement. Finally, the examiners recommend adoption of 320-acre density with optional 20-acre units and that these rules be adopted on a temporary basis for review in eighteen months.

**DISCUSSION OF THE EVIDENCE**

Devon completed its Hull Unit A Lease, Well No. 102, in July 2008 with perforations in the Haynesville Shale between 10,629 feet and 11,024 feet. On initial test, the well produced at a maximum rate of 474 MCFGPD and 0.1 BCIPD and 38 BWPD.
Devon submitted a structure map, cross sections and two geological papers that show that the proposed Carthage (Haynesville Shale) Field produces from the Bossier and Haynesville Shale formations which extend from the State of Louisiana through several counties in East Texas, including all or portions of Harrison, Nacogdoches, Panola, Rusk and Shelby County. Devon does not consider the examiners recommendation that the Shelbyville Deep (Haynesville), Center (Haynesville), Carthage, E. (Bossier), Waskom (Haynesville), Naconiche Creek (Haynesville), Naconiche Creek (Bossier), Bossierville (Bossier Shale), Beckville (Haynesville) and Carthage, North (Bossier Shale) Fields be consolidated into the Carthage (Haynesville Shale) Field to be adverse.

Devon asserts that the Haynesville Shale formation has relatively uniform petrophysical properties and is homogeneous and isotropic over the length of any horizontal well drilled and completed in the field. Consequently, over the length of any given horizontal well, Devon opines that the amount of gas present in the rock and contributing to production into the wellbore is expected to be the same for one linear foot of rock as for any other linear foot of rock completed.

Devon requests that the entire correlative interval from 9,558 feet to 11,089 feet as shown on the log of the Devon Energy Production Co., LP - Hull Unit A Lease, Well No. 102 (API No. 42-365-39749), Panola County, Texas, be considered a single field known as the Carthage (Haynesville Shale) Field. This interval includes the entire Bossier and Haynesville Shales and is located stratigraphically between the base of the Cotton Valley and the top of the Lutban Salt formations.

Devon requests that the Carthage (Haynesville Shale) Field be classified as non-associated and that field rules similar to those that currently exist for shallower fields in the area be adopted for the new field. In addition, Devon requests adoption of some of the field rules that currently exist in the Newark, East (Barnett Shale) Field. Devon proposes field rules that provide for 330' lease line spacing and no between well spacing with special provisions for "take points" and an off-lease penetration point for horizontal wells. Devon also requests 640 acre gas proration units with 10% tolerance and optional 40 acre density. Devon feels that adopting a density rule similar to other shallower fields in the area will provide consistency in developing the Carthage (Haynesville Shale) Field and will allow greater flexibility in selecting future drilling locations.

Wells in the area covered by the proposed Carthage (Haynesville Shale) Field have been producing oil and gas since the 1930s and there are numerous oil and gas producing zones above the field. Over 11,000 wells have been drilled in Panola County. Well spacing of 330 feet is used in the State of Louisiana, located immediately to the east, and has already been adopted for the Waskom (Haynesville Shale) Field which will be included in the Carthage (Haynesville-Shale) Field.

The historic unit size for gas wells in the Haynesville trend is 640 acres and most of the acreage is held by production from existing units that are approximately 640 acres in size. Where field rules have been adopted for gas fields producing above the Carthage (Haynesville Shale) Field, 640 acres plus 10% tolerance has been the predominant
standard unit size; and most of the fields have adopted optional 40-acre density. In addition, the standard development unit size for Haynesville wells in the State of Louisiana is 640 acres and the density field rules for the Waskom (Haynesville-Shale) Field, proposed to be included in the Carthage (Haynesville-Shale) Field, are 640-acre units plus 10% tolerance with an optional 40-acre unit size.

Devon felt that the Haynesville Shale could not be commercially developed with vertical wells and that conventional drainage area calculations did not apply. Devon submitted decline curves for two horizontal wells located in Panola County and four horizontal wells located across the Texas state line in Louisiana. The two Panola County wells had limited production data of less than six months and the decline curve data indicated gas recovery between 4.0 and 6.0 BCFG. The four Louisiana wells also had limited production data of less than one year, but the decline curve data indicated gas recovery between 12.0 and 20.0 BCFG. Based on these gas recovery estimates, Devon believes that the fracture stimulated horizontal wells are impacting a drainage area of greater than 320 acres.

Operators are currently developing the field with horizontal wellbores. Devon requests that a field rule be adopted which includes language relevant to measurement of distances to lease lines for horizontal drainhole wells. Devon's proposed rule specifies that, for purposes of lease line spacing, the nearest "take point" in a horizontal well be used. This take point could be a perforation, if a horizontal well is cased and cemented, an external casing packer in a cased well, or any open-hole section in an uncased well. Similar rules have been adopted in other tight reservoirs, including the Barnett Shale, Cotton Valley, and Granite Wash Fields.

The proposed rule would allow operators to drill horizontal wells with penetration points, as defined by Rule 86, at distances closer than 330 feet to a lease line, as long as no take-point is closer than 330 feet to any lease line. Horizontal drainhole length on a lease is then maximized, resulting in additional recovery of gas. For purposes of assignment of additional acreage pursuant to Rule 86, it is proposed that the distance between the first and last take-point in a horizontal well be used. In addition, Devon proposes a fifty (50) foot "box rule" for horizontal drainhole wells that would allow drainholes to deviate 50 feet from their permitted track without the necessity of obtaining a statewide Rule 37 exception.

In some cases, it is beneficial to penetrate the reservoir off lease, while still having "take points" no closer to lease lines than allowed under the field rules. Devon requests that field rules for the subject field provide for off-lease penetration points. Statewide Rule 86 requires that the penetration point of a horizontal drainhole be on the lease. In this field, a well generally requires 500-600 feet of horizontal displacement to make the 90 degree turn from vertical to horizontal. If the penetration point is required to be on the lease, then the first point of production would be about 600 feet from the lease line. The proposed rules will allow approximately 250 feet of additional producing drainhole, resulting in the recovery of 316 MMCFG to 437 MMCFG of additional gas reserves. Similar rules
allowing offsite penetration points have been adopted in other fields, after notice to the mineral owners of the off-lease tract on which the penetration point is to be located and if no protest is received.

Devon also requests that spacing rules for the field be adopted to accommodate the drilling of stacked horizontal lateral wells. The gross thickness of the Bossier and Haynesville shale interval is over 2,000 feet. Devon believes that several separate laterals may be necessary to effectively develop the reservoir with horizontal wells. Similar stacked lateral rules have already been adopted in Granite Wash and Cotton Valley Fields, as well as in the Newark, East (Barnett Shale) Field. The rule would allow stacked horizontal laterals within the Bossier and Haynesville correlatives interval that are drilled from different wellbores to be considered a single well for regulatory purposes. It is proposed that a stacked lateral be defined to be multiple horizontal drainholes which are drilled (1) from different surface locations on the same lease unit no more than 200 feet from each other at the surface.

Devon requests that a two factor allocation formula based on 95% acres and 5% per well be adopted for the field. Devon also requests that the allocation formula be suspended, as there is a 100% market for all gas produced and that the filing of P-45’s and plats not be required.

Due to the shape of the existing 840 acre units in the field area, Devon argues that many horizontal wells will not be drilled. Devon proposes an “allocation rule” to be placed in the field rules, which will allow drilling wells across unit boundaries and allocating the production from those wells to the separate units on a per foot pro rata basis for royalty payment purposes. Devon supplied a plat in its Exhibit No. 35 demonstrating how acreage would be taken from each of three fictional units and assigned to an “allocation well” (see Attachment 1). In the supplied example, Devon proposes to take 10 acres from the Dell Unit, 22 acres from the Jones Gas Unit and 48 acres from the Smith Lease, thereby creating an 80 acre unit for the Smith-Dell-Jones Allocation Well No. 1H.

Devon proposes to drill across units and submit forms to the Commission similar to those used in the Newark East (Barnett Shale) Field for Production Sharing Agreement wells. The wells drilled across unit boundaries would not respect the proposed 330 foot lease line spacing rule, but the operators of each unit with a boundary crossed would grant waivers to each other. Devon proposes that the field rule for the proposed Carthage (Haynesville Shale) Field include an “allocation rule” which states:

"Operators shall be permitted to drill and complete horizontal wells that traverse one or more units and/or leases as long as that operator has a lease or other mineral ownership right to produce from each such unit or lease. If such a well is not already subject to an agreement regarding the allocation of proceeds (commonly referred to as a Production Sharing Agreement), then the following allocation formula will be presumed to constitute a fair and reasonable allocation of production from a well in this field: an allocation of
production to each of the units and/or leases traversed by and completed in the horizontal well based on the percent of such horizontal well from first take point to last take point that lies under each unit or lease.

Devon argues that the Railroad Commission has the authority to include its proposed "allocation rule" in a field rule and refers to the provisions in Texas Natural Resources Code §§88.001(3); 88.011(a)(1); 88.115; 85.053, 85.054; 85.055, 85.059; 85.046(3);(6);(7);(11); 85.042; 85.201; 85.202(3);(7);(8); 85.203; 86.012(5);(13); 86.041; 86.042(1);(4); 86.081; 86.083; 86.084; 86.085; 86.086; 86.087; 86.089; and 86.099 as support for its proposition.

It is Devon's assertion that a problem is created by the existing pooled units in the Haynesville trend which have been in place since the 1930s through 1950s and held by production from fields shallower than the proposed Carthage (Haynesville Shale) Field. The existing units were developed before the advent of horizontal drilling and are not optimally shaped for horizontal drilling. It is Devon's position that the field can only be economically developed by drilling and completing horizontal wells approximately 5,000 feet long. Devon also believes that, due to regional stresses, the wells must be oriented 10 degrees west of north. (See Attachment II)

Devon looks east to Louisiana and notes the square 640-acre sections available for development as opposed to the less uniform property lines in East Texas. Louisiana uses the township and section method of surveying, at least in the portion of the state adjacent to Pandale County, resulting in neat rows of 640 acre sections. This is convenient for the type of development Devon envisions and it is also convenient to Devon that Louisiana is a compulsory pooling state. A square 640-acre drilling unit can be obtained by application to the Louisiana Office of Conservation. Texas, on the other hand, uses a metes and bounds hybrid surveying system based partially on old Spanish land grants and partially on township and section method. This gives rise to oddly-shaped tracts which in turn give rise to less uniform tracts and units. Unlike Louisiana, Texas is not a compulsory pooling state, except in very limited circumstances under the Mineral Interest Pooling Act (Texas Natural Resources Code, Chapter 102).

Devon states that it is not possible to unpool and repost the existing Texas units without the royalty owners' consent and complains that the number of owners has multiplied due to the passage of time and inheritance of interests. Devon has argued that for many of the old units, hundreds of owners would need to sign off on any effort to repost (VI, p. 54, l. 2-5). Devon argues that, due to the high number of interest owners and the fact that many cannot be located, it is not feasible to amend the old leases to allow the type of pooling suitable for horizontal well technology. Devon also argues that it is not feasible to obtain the signatures of enough interest owners to enter into a Production Sharing Agreement. Devon believes the only way to develop these old units effectively is to drill horizontally from one unit across the unit boundary and into another unit. Devon proposes its "allocation rule" as the means of doing so. Devon asserts that if its proposed plan is not approved, "...the Haynesville will just not be developed." (Transcript, July 28, 2006, V. 1,
EXAMINERS' OPINION

The examiners recommend that most, but not all, of the field rules proposed by Devon be approved as temporary field rules. Designation of the field as the correlative interval that includes both the Bossier and Haynesville Shales, 330 foot leaseline spacing with no between-well spacing and a provision for an off-lease penetration point should be approved.

Devon has requested permanent field rules prescribing standard units of 640 acres with optional 40 acre units. Devon presented very little evidence directly from wells in the proposed field. The evidence for the proposed "standard" density of 640 acres is particularly tenuous. The standard unit size is supposed to indicate the acreage that a typical vertical well in the specific field at issue can effectively drain. The Commission's informal guide to oil and gas practice and procedure provides,

At field rule hearings where density provisions are requested, reservoir pressure and production performance data are presented to indicate whether the wells are capable of draining the requested proration unit size. The supporting data for a density request should include pressure interference testing or material balance calculations based on production history or a pressure decline versus production curve.

Texes Oil & Gas - Discussions of Law, Practice and Procedure, p. 5 (Railroad Commission of Texas)

No such data was submitted by Devon. In fact, Devon candidly admitted that vertical wells could not be economically produced from the proposed field which indicates extremely small drainage areas for vertical wells. In addition, the information Devon put on at the hearing regarding its planned development of the field, 640 acre existing units were typically shown with four or more proposed horizontal wellbores. This indicates that Devon believes the drainage area for horizontal wells will be 160 acres or less per well. Of the nine fields proposed to be consolidated into the new Carthage (Haynesville Shale) Field, there are two fields with prescribed 640 acre density. However, those fields both have optional 40 acre units. The other seven fields to be consolidated into the proposed Carthage (Haynesville Shale) Field are all governed by 40 acre standard density. The examiners do not find the Louisiana orders submitted by Devon persuasive with regard to drainage areas. First and foremost, those orders obviously involve wells that are not located in the proposed field area in Texas. In addition, neither the standard employed nor the evidence relied on regarding drainage area were shown.

The examiners recognize that shale fields are different from more traditional reservoirs and that size and effectiveness of fracture stimulation are more important than
the more traditional methods of determining the productivity and drainage area of a well. However, Devon also did not put on any evidence of typical fracture size or other data to support the 640 acre density it proposes. Devon's own development plans showing multiple horizontal wellbores on 640 acre units indicate that it believes multiple wells are necessary to adequately develop 640 acre units.

The examiners recommend adoption of 320 acre density with optional 20 acre units. This recommended density is identical to the rules governing the Newark, East (Barnett Shale) Field, the only shale field in Texas which has been significantly developed. This recommendation is also consistent with the 330 foot lease line spacing proposed by Devon for the field. Under Commission rules, lease line spacing of 330 feet is generally associated with optional 20 acre units, not 40 acre units. See Statewide Rule 28(b)(2)(A).

Permanent rules are established for a field only where there is sufficient evidence to determine the drainage abilities of wells in the field. See Texas Oil & Gas Discussions of Law, Practice and Procedure, p. 3 (Railroad Commission of Texas). Based on the extremely limited evidence regarding wells within the proposed field, the examiners recommend that the Commission adopt field rules on a temporary basis to be reviewed in eighteen months.

The examiners recommend adoption of Devon's two-factor allocation formula based on 95% acres and 5% per well with AOI status. The examiners also recommend approval of the proposed Rule 6 ("Stacked Lateral Rule") after expansion of paragraph 1 to include language ensuring each point of a stacked lateral drainhole is no farther than 300 feet away horizontally from any point along any other horizontal drainhole of the same 'Stacked Lateral Well.' The additional language would make the Carthage (Haynesville Shale) Field Stacked Lateral Rule identical to the one currently in place for the Newark, East (Barnett Shale) Field. Devon does not object to this and states the missing language was inadvertently left out of its proposed rule when the application was made.

There has been no objection to the examiners' proposal that the field be named the Carthage (Haynesville Shale) Field and that it consist of a consolidation of the Shelbyville Deep (Haynesville), Center (Haynesville), Carthage, E. (Bossier), Waskom (Haynesville), Nacociche Creek (Haynesville), Nacociche Creek (Bossier), Bossierville (Bossier Shale), Beckville (Haynesville) and Carthage, North (Bossier Shale) Fields in Harrison, Nacogdoches, Panola, Rusk, and Shelby Counties.

The examiners do not recommend approval of Devon's proposed Rule 8 ("allocation rule") or the included "box rule" in proposed Rule 2 and recommend revisions to the proposed rule for the calculation of additional horizontal well acreage assignments in proposed Rule 2.

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1 The Toyah, NW (Shale) Field, the only other shale field in the state with more than a negligible number of wells also is governed by 320 acre standard units.
Proposed Rule 8 "Allocation Rule"

Devon proposes that the field rule for the proposed Carthage (Haynesville Shale) Field include an "allocation rule" which states:

"Operators shall be permitted to drill and complete horizontal wells that traverse one or more units and/or leases as long as that operator has a lease or other mineral ownership right to produce from each such unit or lease. If such a well is not already subject to an agreement regarding the allocation of proceeds (commonly referred to as a Production Sharing Agreement), then the following allocation formula will be presumed to constitute a fair and reasonable allocation of production from a well in this field: an allocation of production to each of the units and/or leases traversed by and completed in the horizontal well based on the percent of said horizontal well from first take point to last take point that lies under each unit or lease."

This proposed "allocation rule" exceeds the boundaries of normal field rule provisions. No similar field rule has ever been adopted. "Field rules are special rules that modify the Railroad Commission's well spacing, density, prorationing and casing requirements for designated fields to deal with differences in reservoir conditions. See 2 Smith & Weaver, supra, § 10.2; Robert E. Hardwicke, Oil Well Spacing Regulations and Protection of Property Rights in Texas, 31 Tex. L. Rev. 103 (1952)." Footnote 5 in Browning Oil Co. Inc. v. Luecke, 36 S.W.3d 625, 633 (Tex. App. - Austin, 2000, writ denied). The proposed rule does not address well spacing, density, or prorationing but, instead, addresses lease interpretation and royalty apportionment issues.

Devon's proposed "allocation rule" allocates production between units as opposed to allocation of gas allowable to individual wells. In the quote above from the Luecke case, prorationing refers to allocation. Devon has already proposed an allocation formula based on 95% acres and 5% per well. The examiners have recommended approval of the 95/5 rule, thus the true allocation formula issue is already resolved.

The "allocation rule" proposed by Devon does not allocate authorized production among different wells in the field. Instead, the proposed rule purports to authorize drilling across unit and/or lease lines without the agreement of any royalty or working interest owners. In addition, the proposed rule would direct, by Railroad Commission rule, how production and thus royalty payments could reasonably be divided among different royalty owners.

The first sentence of the proposed "allocation rule" states: "Operators shall be permitted to drill and complete horizontal wells that traverse one or more units and/or leases as long as that operator has a lease or other mineral ownership right to produce from each such unit or lease." This sentence, in a field rule, would purport to give operators Commission-granted authority to override lease or unit provisions (such as limitations on unit size or other anti-dilution clauses) that would otherwise prohibit the drilling of such a well. "It is thought to be fundamental that the rules and regulations of the Railroad Commission cannot have the result of effecting a change or transference of

The language in Jones v. Killingsworth stating that the orders of the Commission cannot compel pooling agreements that the parties themselves do not agree on is subject to the limited exception of the Mineral Interest Pooling Act ("MIPA"). Devon is not seeking to invoke the MIPA in this proceeding.

The restrictive-lease terms that would be affected by the proposed allocation rule are those that have led to the presently existing 640-acre units. Leases introduced into evidence by Devon commonly contain a grant of pooling authority subject to the following restriction or substantially similar:

"Each such drilling or production unit shall not exceed 40 acres plus an acreage tolerance not to exceed ten percent (10%) of 40 acres, when drilled for the purpose of drilling for or producing oil therefrom and 640 acres, plus an acreage tolerance not to exceed ten percent (10%) of 640 acres, when drilled for the purpose of drilling for or producing gas, distillate or condensate."


Devon argues that the Railroad Commission is authorized to adopt its proposed "allocation rule" under the provisions of Texas Natural Resources Code §§ 88.001(3); 88.011(a)(1); 88.115; 85.053, 85.054; 85.055, 85.056; 85.046(3), (6), (7), & (11); 85.042; 85.201; 85.202(3)(7), & (8); 85.203; 86.012(5)(9)(13); 86.041; 86.042(1), (4), (7), & (9); 86.081; 86.083; 86.084; 86.085; 86.086; 86.087; 86.088; and 86.089. A review of these statutes indicates they give the Commission broad powers to prevent waste and confiscation in its role as a conservation agency, and to require accurate measurement of produced hydrocarbons to meet reporting requirements. The examiners find nothing in the referenced statutes that grant the Commission the authority to override lease provisions or determine property rights, such as the proper apportionment of royalties.

The Commission does not have power to determine title to land or property rights, it is invested with broad powers to determine where, whether wells may be drilled, and how much oil or gas may be produced. But it does not have authority to determine the ownership of oil or gas, or how the proceeds from the sale of oil or gas should be apportioned among people who contend that it was, or is, actually being produced from beneath their land. Railroad Commission of Texas v. City of Austin, 524 S.W.2d 262, 267-
The Railroad Commission has no authority to interpret leases and determine that they authorize the drilling of a well as contemplated in the first sentence of the proposed "allocation rule". The effect of Devon's proposed language would essentially be the authorization of a 0% sign-up Production Sharing Agreement, contrary to the Commission's current policy of requiring at least a 65% sign-up for a Production Sharing Agreement. Devon's proposal amounts to compulsory pooling by-field rule.

Although Devon may argue that it is not pooling portions of existing units, this is, in fact, what it is doing. In the hypothetical example provided by Devon, it proposes to take acreage from each of three units (10 acres from the Dell Unit, 22 acres from the Jones Gas Unit and 48 acres from the Smith Lease) and combine them into 80 acres for the drilling of a horizontal well. "Pooling occurs when tracts from two or more leases are combined for the purpose of drilling a single well." 1 Smith & Weaver, Texas Law of Oil and Gas, §4.8. That is precisely what Devon proposes - combining multiple tracts for purposes of drilling a horizontal well. Devon has admitted that it does not have pooling authority.

Examiner: The proposed form you have shown us, the allocation of well tract description, which is somewhat like a P-12, is different in that it does not make any representation that you have pooling authority. I suppose that is because of the lease problems.

Attorney for Devon: And that is also true of the production sharing agreement description form. It intentionally does not make that representation because it wouldn't be true.

Transcript, Re-opened Hearing, September 1, 2009, p. 41, lines 11-20, (Emphasis added).

"A lessee's authority to pool is derived solely from the terms of the lease; a lessee has no power to pool absent express authority." Browning Oil Co., Inc. v. Luecke, 38 S.W.3d 625, 634 (Tex. App. - Austin, 2000, pet. denied). See also Southeastern Pipe Line Co. v. Tichacek, 997 S.W.2d 166, 170 (Tex. 1999); Jones v. Killingsworth, 403 S.W.2d 325, 328 (Tex. 1965).

As support for its proposed "allocation rule", Devon relies heavily on the opinion letter from its retained expert, Professor Ernest Smith (see Attachment III, consisting of Devon's Request for Opinion and Professor Smith's Reply), and the court's opinion in Browning Oil Co., Inc. v. Luecke, 38 S.W.3d 625 (Tex. App. - Austin, pet. denied). Curiously, neither directly addresses Railroad Commission rules or provides any substantial support for Devon's position.

In his opinion letter, Professor Smith responded to very specific questions based on a specified hypothetical situation involving drilling a horizontal well across existing units designated as A, B and C. Interestingly, although Professor Smith was asked whether Devon was authorized to drill a horizontal well across the boundaries of the three existing
units, he declined to answer the question. Instead, Professor Smith chose to break the question into two parts and answer whether such drilling would "constitute an actionable trespass." Professor Smith opined, "The answer...is susceptible to reasonable disagreement, but my considered response to it is No, i.e. that Devon will not commit an actionable trespass by drilling [the hypothesized horizontal well]." This is clearly not an unequivocal opinion that Devon has the legal authority to drill as it proposes even under its carefully constructed hypothetical.

Similarly, in response to the question of whether a production sharing agreement is necessary, Professor Smith responded: "Without a production sharing agreement, a lessee that drills a horizontal well such as the one proposed unquestionably exposes itself to litigation by the royalty owners in the various units; however, uncertainty over how production should be allocated does not override a lessee's right to drill." (Smith Opinion, pp. 7-8). Again, this is hardly an unequivocal statement of support.

Perhaps most interesting is the response to the question, "...would an allocation based on the percent of the wellbore within each tract between the first and last takepoint represent a fair and reasonable allocation to each tract?" Professor Smith states:

The method of allocation described above would appear to be both fair and reasonable. If supported by appropriate geological studies. ... It should be noted, however, that even though it is fair and reasonable, this method of accounting can be attacked on the ground that it fails to comply with the ruling in Browning v. Luecke. Each of the three units is the equivalent of each of plaintiffs tracts in Browning. It can thus be argued that the case requires Devon to establish the amount of gas that is actually produced from each specific unit and allocate that amount to each unit in making payments to the royalty owners in that unit. (Smith Opinion, pages 10-11)

Again, in spite of the carefully worded question and hypothetical facts, Professor Smith is unable to conclude that the proposed procedure is unambiguously authorized. Perhaps most pertinent to the issues before the Commission is the fact that Devon's request for an opinion from Professor Smith does not mention that either its proposal to drill across unit boundaries or its proposal for allocation of production are contemplated for inclusion in a field rule. No question was asked and no opinion is given by Professor Smith regarding the legality or advisability of inserting Devon's proposals into a Commission field rule. Professor Smith's opinion is written in terms of what Devon, on its own, may or may not be entitled to do under Texas law and the possible consequences. Professor Smith does not indicate any endorsement of Devon's proposals being placed in a field rule.

Browning Oil Co. v. Luecke provides even less support for Devon's proposed rule. In that case, Browning Oil Co., as Devon proposes here, ignored the terms of its leases and drilled a horizontal well across multiple tracts it operated. Luecke, one of the mineral owners, sued. The Luecke court noted the need to restrain operators while not discouraging the use of new technology. "Moreover, in considering public policy, we must attempt to balance two competing interests. First, we recognize that Lessees should not
be allowed to ignore anti-dilution provisions and exceed their pooling authority with impunity. A reasonably prudent operator may conclude that horizontal drilling in the Austin Chalk formation will benefit the lessor, and the operator may correctly opine that reasonable prudence dictates the drilling of a horizontal well that exceeds the authority granted under the applicable lease. Nevertheless, rather than ignore the written lease, the prudent operator must seek to negotiate a solution mutually beneficial to both the lessee and the lessor or else forego drilling.\(^4\) Luecke, 38 S.W.3d 625, 646-7 (Tex. App. - Austin, 2000, writ denied) (emphasis added). Far from upholding the operator’s actions, the court found Browning had breached its leases and remanded the case for a determination of damages.

Devon is not the owner of the minerals under the various tracts it operates in the area of the proposed Carthage (Haynesville/Shahe) Field. It is the lessee and its rights are controlled by the terms of the leases it took from the owners of the minerals. Devon itself acknowledges that those lease terms do not authorize it to pool the tracts as it desires. Devon is seeking a Commission field rule that would endorse its desires to effectively amend the terms of its agreements with the mineral owners, authorize it to combine the tracts and direct that the mineral owners be paid in a manner different than is provided in the lease contracts. Such a field rule would be unprecedented in Commission practice and would far exceed the Commission’s statutory authority. (see Railroad Commission v. City of Austin, 524 S.W.2d 262, 267-268 (Tex. 1975). The Commission’s own website, under “Frequently Asked Questions,” states, “The Railroad Commission does not have jurisdiction over leases, pipeline easements or royalty payments.”

Devon is not without alternatives. First, it could negotiate amendments to the leases with the mineral owners. Devon claims this would be burdensome. Undoubtedly, it would be more burdensome than ignoring the lease terms it previously agreed to and drilling and paying royalties as it proposes without obtaining the agreement of any of the mineral owners whose rights are being affected. However, inconvenience or burden is not a legally permissible reason for ignoring property rights. Further, Devon clearly overstates the difficulty involved. These are currently active leases and units on which Devon is (presumably) paying royalties monthly to the mineral owners. The mineral owners currently receiving monthly checks are the very property owners Devon must negotiate lease amendments with.

As another alternative, Devon has the option under current Commission practice to enter into production sharing agreements. Production Sharing Agreements (PSAs) have the advantage that the Commission only requires agreement of 65% of mineral owners rather than the 100% that may be required for lease amendment.

Devon’s proposed Rule 8 addresses lease interpretation, property rights, and royalty apportionment issues over which the Commission does not have jurisdiction. The examiners recommend that the Commission not approve the proposed Rule 8 “allocation rule.”
Box Rule:

Devon proposes an unusual "box rule" providing that a properly permitted horizontal drainhole will be considered to be in compliance with spacing rules if the as-drilled location falls within two sides of a rectangle whose sides are parallel to the permitted drainhole and 50 feet on either side of the drainhole. Devon notes that a box rule has been approved in the Brookeland (Austin Chalk 8800) Field. VI, p. 78, l. 16-17:

The proposed rule would authorize an operator drilling a well along the lease line to deviate 50 feet closer to an offset than the stated regular distance of 330 feet without notifying the offset or obtaining a Rule 37 exception. Devon asserts that this "box" rule would allow operators to avoid having to seek "unnecessary" Rule 37 exceptions. Why Devon considers Rule 37 exceptions for any and all encroachments of 50 feet or less as unnecessary is not clear. As proposed, the rule would allow an operator to permit a horizontal well running parallel to its lease line 330 feet from an offset operator or unleased mineral owner. Because the well would be permitted at a regular location, no notice to offsets would be required. The operator could then drill the well with an actual location parallel to the lease line but only 250 feet from the offsetting tract along its entire length from penetration point to terminus. Under the proposed rule, the wellbore would be within the "box" and no Rule 37 exception (or notice to the offset being encroached on) would be required. In practical effect, the box rule changes the lease line spacing to 250 feet from offset tracts rather than the 330 feet spacing distance expressly stated in the rule. No evidence was presented to support 250 feet lease line spacing.

Although a handful of fields in the state have a so-called "box rule," those instances are significantly different than the circumstances presented in this field. First, in the few existing instances where a box rule has been adopted, the regular spacing distance is 1200 feet or more and the authorized deviation box is 10% of the spacing distance. In this instance, the regular spacing distance is only 330 feet and the proposed authorized deviation is nearly 15% of the regular distance. Under the proposed rule the regular distance is less than a third of the regular distance in the only other fields in which a box rule has been adopted. However, the proposed deviation is proportionately even greater (15% versus 10%). More importantly, none of the few fields that currently have a box rule have rules dictating that spacing be determined by where the wellbore is open to the formation. In other words, in those fields there is no way to "cure" a minor deviation from the permitted wellbore path.

2 Of the more than 50,000 fields in the state, the examiners are only aware of three that have a "box rule" and all are in the Austin Chalk formation. The Brookeland (Austin Chalk 8800) Field has prescribed leaseline spacing of 1500 feet and a box rule authorizing 150 foot deviations. The Magnolia Springs (Austin Chalk) Field and Double A-Well, N (Austin Chalk) Field both have 1200 foot leaseline spacing and a box rule authorizing 120-foot deviations.
Under the recommended Carthage (Haynesville Shale) Field rules, the need for a Rule 37 exception is determined by take points. An operator that inadvertently drills closer than allowed by its permit and the field rules to an offset can cure the problem (and, in Devon's parlance, avoid an unnecessary Rule 37 exception application) by simply not perforating that portion of the wellbore that encroaches on an offset. Further, the Commission has long recognized that it is not practically possible to drill a perfectly straight hole and, even under existing rules and procedures, a Rule 37 exception is not required where an operator has attempted in good faith to drill the well as permitted when minor deviations (usually understood to be less than 10%) from the permitted path have occurred. This existing policy requires an operator to have made a good faith attempt to comply with its permit and, unlike the proposed rule, does not grant an absolute right to deviate from the wellbore track that was permitted.

**Acreage Assignment under Statewide Rule 56**

With regard to additional acreage assignment under Rule 56 based on the length of the horizontal wellbore, the examiners agree with Devon that generally the length of the wellbore should be measured from first to last take point (rather than penetration point to terminus) as proposed by Devon. However, experience in the Newark, East (Barnett Shale) Field has shown that operators frequently permit horizontal wells with long interim unperforated intervals (usually to avoid having to prove the right to a Rule 37 exception as to an unleased or partially unleased tract). These unperforated intervals are frequently hundreds of feet, and sometimes thousands of feet in length, and clearly do not contribute to production. These non-contributing intervals should not be counted for purposes of determining the amount of additional acreage that can be added to a standard proration unit. Accordingly, the examiners recommend that the proposed rule authorizing additional acreage for horizontal wells based on wellbore length be amended to exclude any interim unperforated portions of a wellbore that are more than 330 feet in length.

**FINDINGS OF FACT**

1. Notice of this hearing was given to all persons entitled to notice and no protests were received.

2. Devon completed its Hull Unit A Lease, Well No. 102, in July 2008 with perforations in the Haynesville Shale between 10,529 feet and 11,024 feet. On initial test, the well produced at a maximum rate of 474 MCFGPD and 0.1 BCPD and 36 BWPD.

3. The Hull Unit A Lease, Well No. 102 is entitled to a new field designation.

   a. A structure map, cross sections and several geological articles show that the Carthage (Haynesville Shale) Field produces from the Bossier and Haynesville Shale formations which extend from the State of Louisiana through several counties in East Texas, including all or portions of Harrison,
Nacogdoches, Panola, Rusk and Shelby Counties.

b. The Haynesville Shale formation has relatively uniform petrophysical properties. The field can only be economically developed by drilling and completing horizontal wells.

c. The Haynesville Shale formation is similar throughout East Texas and should be governed by one set of field rules.

d. The Shelbyville Deep (Haynesville), Center (Haynesville), Carthage, E. (Bossier), Wasken (Haynesville), Nacochiche Creek (Haynesville), Nacochiche Creek (Bossier), Bossierville (Bossier Shale), Beckville (Haynesville) and Carthage, North (Bossier Shale) Fields should be consolidated into the Carthage (Haynesville Shale) Field.

4. The correlative interval from 9,568 feet to 11,089 feet as shown on the log of the Devon Energy Production Co., LP - Hull Unit A, Lease, Well No. 102 (API No. 42-385-36749), Panola County, Texas, should be considered a single field known as the Carthage (Haynesville Shale) Field. This interval includes the entire Bossier and Haynesville Shales and is located stratigraphically between the base of the Cotton Valley and the top of the Louann Salt formations.

5. Field Rules that provide for 330' lease line spacing and no between well spacing with special provisions for "lake points" and an off-lease penetration point for horizontal wells will provide consistency in developing the field and will allow greater flexibility in selecting future drilling locations.

6. Well spacing of 330 feet from lease lines is used to space wells in the State of Louisiana, located immediately to the east, and has already been adopted for the Carthage, N. (Bossier Shale) Field which will be consolidated into the Carthage (Haynesville Shale) Field.

7. Devon did not present sufficient evidence to demonstrate that a density of 640 acres with optional 40 acre density should be adopted on a permanent basis in the proposed Carthage (Haynesville Shale) Field. A density of 320 acres with optional 20 acre units should be adopted on a temporary basis.

a. The only shale field in Texas that has been significantly developed is the Newark, East (Barnett Shale) Field. The Newark, East (Barnett Shale) Field is governed by 320 acre standard units with optional 20 acre units.

b. The Toyah, NW (Shale) Field is governed by 320 acre standard units.

c. The proposed 640 acre density for the Carthage (Haynesville Shale) Field
is not based on evidence of actual drainage areas, but simply mimics the
density rules in effect for the shallower, non-shale fields in the area.

d. Devon's own development plans show multiple horizontal wellbores on 640
acre units indicating that multiple wells are necessary to adequately develop
640 acre units.

e. Based on limited gas recovery estimates from six wells, Devon only opines
that fracture stimulated horizontal wells are impacting a drainage area of
greater than 320 acres.

f. Of the nine fields proposed to be consolidated in the Carthage (Haynesville
Shale) Field, two have prescribed 640 acre density with optional 40 acre
units. The other seven fields to be consolidated are governed by 40 acre
standard density.

g. Lease line spacing of 330 feet is associated with 20 acre units.

8. A spacing rule which utilizes "take-points" in a horizontal well for the determination
of distances to lease lines will prevent waste and will not harm cumulative rights.

a. The Bossier and Haynesville are shale formations and are not commercially
productive unless fracture-stimulated.

b. A take-point in a horizontal well in this field may be a perforation, if a
horizontal well is cased and cemented, an external casing packer in a cased
well, or any open-hole section in an uncased portion of the wellbore.

c. Adoption of the proposed rule would allow operators to drill horizontal wells
with penetration points, as defined by Rule 86, at distances closer than 330
feet to a lease line, as long as no take-point is closer than 330 feet to any
lease line.

d. Adoption of the proposed rule will allow the horizontal drainhole length on a
lease to be maximized.

9. For purposes of assignment of additional acreage pursuant to Rule 86, the distance
between the first and last take-point in a horizontal well should be used.
Unperforated intervals between the first and last take points of a horizontal well do
not contribute to the production of the well. Unperforated intervals greater than 330
feet should be excluded as wellbore length for purposes of assignment of additional
acreage to a horizontal well pursuant to Statewide Rule 86.

10. Allowing off-lease penetration points will result in maximum producing drainhole
length, thereby increasing ultimate recovery from horizontal drainhole wells. The proposed rules will allow an additional approximately 250 feet of producing drainhole, resulting in the recovery of 316 MMCF to 437 MMCF of additional gas reserves. To protect correlative rights, prior notice and opportunity to object should be given to the mineral owners of offsite surface locations.

11. The proposed "stacked lateral" rule, as revised, will allow stacked horizontal laterals within the Bossier and Haynesville shale correlatives interval that are drilled from different wellbores to be considered a single well for regulatory purposes and facilitate additional recovery of gas.

12. Allocation based on 95% acres and 5% per well will protect correlative rights.

13. Continued suspension of the allocation formula is appropriate, as there is a 100% market for all the gas produced. Elimination of the requirement to file P-15's and plats when the field has 100% AOF status will eliminate unnecessary paperwork.

14. Devon's proposed Rule 8, the "allocation rule," purports to allow drilling of horizontal wells across unit and/or lease boundaries without the agreement of any royalty or working-interest owners under the authority of a Railroad Commission field rule.

15. Devon's proposed "allocation rule" purports to apportion production and thus royalty payments between units and/or leases under the authority of a Railroad Commission field rule.

16. Compliance with existing lease terms will not cause the physical waste of oil or gas. Existing gas within the proposed field that is not recovered now will remain in place in the formation and will be recovered when an operator negotiates amended lease terms, enters into a production-sharing agreement, or negotiates new leases.

17. The "box rule" proposed by Devon would authorize an operator drilling a horizontal well along a leaseline to deviate 50 feet closer to an offset than the stated regular leaseline spacing distance of 350 feet without notifying the offset or obtaining a Statewide Rule 37 exception.

18. The proposed "box rule" would effectively reduce the lease line spacing rule for the Carthage (Haynesville Shale) Field to 280 feet.

19. No drainage calculations or other geological evidence was submitted to support 280-foot lease line spacing.

20. The proposed box rule is not necessary to allow operators reasonable minor deviations from the wellbore track that has been permitted.
21. With regard to optional additional acreage assignment under Statewide Rule 85 based on the length of a horizontal wellbore, generally the length of the wellbore should be measured from first take point to last take point.

   a. Operators frequently permit horizontal wellbores with long unperforated intervals, usually to avoid the need for a Statewide Rule 37 exception hearing due to an unleased or partially unleased tract.

   b. Unperforated intervals do not contribute to production from the wellbore and should not be counted as wellbore length for purposes of assigning additional acreage to a horizontal well pursuant to Statewide Rule 85.

22. Devon’s proposed rule language authorizing additional acreage for horizontal wells based on wellbore length should be amended to exclude any unperforated portions of a wellbore that are more than 330 feet in length.

CONCLUSIONS OF LAW

1. Proper notice of this hearing was issued.

2. All things have been accomplished or have occurred to give the Commission jurisdiction in this matter.

3. Approval of the requested new field designation and adoption of field rules prescribing 330 foot lease line spacing, no minimum between well spacing, and standard density of 820 acres with optional 20 acre units will prevent waste, protect correlative rights and promote the orderly development of the field.

4. Consolidation of the Shelbyville Deep (Haynesville), Center (Haynesville), Carthage, E. (Bossier), Wasken (Haynesville), Naconiche Creek (Haynesville), Naconiche Creek (Bossier), Bossierville (Bossier Shale), Beckville (Haynesville) and Carthage, North (Bossier Shale) Fields into the Carthage (Haynesville Shale) Field will prevent waste, foster conservation, and protect correlative rights.

5. The Railroad Commission has no authority to extend or modify the terms of a lease by its acts or orders.

6. The Railroad Commission has no authority to determine the ownership of oil or gas or how the proceeds from the sale of oil or gas should be apportioned.

8. The Railroad Commission has no jurisdiction to adopt the proposed allocation rule and adopting the rule is not necessary to prevent waste and could harm correlative rights.

9. Sufficient evidence of well performance and drainage areas within the proposed field area does not exist to warrant permanent field rules for its proposed Carthage (Haynesville Shale) Field.

10. The proposed "box rule" will not prevent waste and will harm correlative rights.

11. No-perf zones 330 feet or longer do not contribute to the production from a well and should be excluded from the calculation of additional assignment of acreage to a horizontal wellbore pursuant to Statewide Rule 86.

**RECOMMENDATION**

Based on the above findings of fact and conclusions of law, the examiners recommend that the Commission approve the new field designation and Field Rules for the Carthage (Haynesville Shale) Field prescribing 330 foot lease line spacing, no minimum between-well spacing, and standard density of 320 acres with optional 20 acre units, with the exception of the "allocation rule" and the "box rule". The examiners also recommend that temporary rules be assigned to the Carthage (Haynesville Shale) Field. In addition, the examiners recommend that no-perf zones be excluded from the calculation of additional acreage assigned to horizontal wellbores in the Carthage (Haynesville Shale) Field. Finally, the examiners recommend that the nine subject Bossier and Haynesville Shale fields be consolidated into the Carthage (Haynesville Shale) Field.

Respectfully submitted,

Richard D. Atkins, P.E.  
Technical Examiner

Marshall F. Enquist  
Legal Examiner
Exhibit 5

Final Order of Railroad Commission of Texas in Oil and Gas Docket No. 06-0262000.
RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL
HEARINGS SECTION

OIL AND GAS DOCKET
NO. 06-0262000

IN THE CARTHAGE (HAYNESVILLE SHALE) FIELD, HARRISON, NACOGDOCHES, PANOLA, RUSK AND SHELBY COUNTIES, TEXAS

FINAL ORDER
APPROVING THE APPLICATION OF DEVON ENERGY PRODUCTION CO., LP FOR A NEW FIELD DESIGNATION AND ADOPTING TEMPORARY FIELD RULES FOR THE CARTHAGE (HAYNESVILLE SHALE) FIELD AND CONSOLIDATING VARIOUS BOSSIER AND HAYNESVILLE SHALE FIELDS INTO THE CARTHAGE (HAYNESVILLE SHALE) FIELD HARRISON, NACOGDOCHES, PANOLA, RUSK AND SHELBY COUNTIES, TEXAS

The Commission finds that after statutory notice in the above-numbered docket heard on July 28 and September 1, 2009, the presiding examiner has made and filed a report and recommendation containing findings of fact and conclusions of law, for which service was not required; that the proposed application is in compliance with all statutory requirements; and that this proceeding was duly submitted to the Railroad Commission of Texas at conference held in its offices in Austin, Texas.

The Commission, after review and due consideration of the examiners' report and proposal for decision, the findings of fact and conclusions of law contained therein, and any exceptions and replies thereto, hereby adopts as its own Findings of Fact Nos. 1 through 22, with the exception of Nos. 7, 9, 20, 21 and 22, and Conclusions of Law Nos. 1 through 11, with the exception of Nos. 3, 10 and 11, and incorporates said findings of fact and conclusions of law as if fully set out and separately stated herein. The Commission adopts the following substitute Findings of Fact and Conclusions of Law:

Substitute Findings of Fact:

7. Devon did not present sufficient evidence to demonstrate that a density of 640 acres with optional 40 acre density should be adopted on a permanent basis in the proposed Carthage (Haynesville Shale) Field. A density of 640 acres with optional 40 acre units should be adopted on a temporary basis.

9. For purposes of assignment of additional acreage pursuant to Rule 86, the distance between the first and last take-point in a horizontal well should be used.

20. The proposed box rule will allow operators reasonable minor deviations from the wellbore track that has been permitted.
OIL AND GAS DOCKET NO. 06-0262000

Substitute Conclusions of Law:

3. Approval of the requested new field designation and adoption of temporary field rules prescribing 330 foot lease line spacing, no minimum between well spacing, and standard density of 640 acres with optional 40 acre units will prevent waste, protect correlative rights and promote the orderly development of the field.

10. The proposed "box rule" will prevent waste and protect correlative rights.

Therefore, it is ORDERED by the Railroad Commission of Texas that the application of Devon Energy Production Co., LP for a new field designation for its Hull Unit A Lease, Well No. 102, is hereby approved. The new field shall be known as the Carthage (Haynesville Shale) Field (RRC Field No. 16032300), Harrison, Nacogdoches, Panola, Rusk and Shelby Counties, Texas.

It is further ORDERED that the following Field Rules are hereby adopted for the Carthage (Haynesville Shale) Field, Harrison, Nacogdoches, Panola, Rusk and Shelby Counties, Texas:

RULE 1: The entire correlative interval from 9,568 feet to 11,089 feet as shown on the log of the Devon Energy Production Co., LP - Hull Unit A Lease, Well No. 102 (API No. 42-365-36749), Panola County, Texas, shall be designated as a single reservoir for proration purposes and be designated as the Carthage (Haynesville Shale) Field.

RULE 2: No well for gas shall hereafter be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line, or subdivision line. There is no between well spacing limitation. The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well, and the above spacing rule and the other rules to follow are for the purpose of permitting only one well to each drilling and proration unit. Provided however, that the Commission will grant exceptions to permit drilling within shorter distances and drilling more wells than herein prescribed whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to these rules is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions of said rules are incorporated herein by reference.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Provided, however, that for purposes of spacing for horizontal wells, the following shall apply:

a. A take point in a horizontal drainhole well is any point along a horizontal drainhole where oil and/or gas can be produced into the wellbore from the
reservoir/field interval. The first take point may be at a different location than the penetration point and the last take point may be at a location different than the terminus point.

b. All take points in a horizontal drainhole well shall be a minimum of THREE HUNDRED THIRTY (330) feet from any property line, lease line, or subdivision line. A permit or an amended permit is required for all take points closer to the property line, lease line, or subdivision line than the lease line spacing distance, including any perforations added in the vertical portion or the curve of a horizontal drainhole well.

A properly permitted horizontal drainhole will be considered to be in compliance with the spacing rules set forth herein if the as-drilled location falls within a rectangle established as follows:

a. Two sides of the rectangle are parallel to the permitted drainhole and 50 feet on either side of the drainhole;

b. The other two sides of the rectangle are perpendicular to the sides described in (a) above, with one of those sides passing through the first take point and the other side passing through the last take point.

Any point of a horizontal drainhole outside of the described rectangle must conform to the permitted distance of the nearest property line, lease line or subdivision line measured perpendicular from the wellbore.

In addition to the penetration point and the terminus of the wellbore required to be identified on the drilling permit application (Form W-1H) and plat, the first and last take points must also be identified on the drilling permit application (remarks section) and plat. Operators shall file an as-drilled plat showing the path, penetration point, terminus and the first and last take points of all drainholes in horizontal wells, regardless of allocation formula.

For any well permitted in this field, the penetration point need not be located on the same lease, pooled unit or unitized tract on which the well is permitted and may be located on an Offsite Tract. When the penetration point is located on such Offsite Tract, the applicant for such a drilling permit must give 21 days notice by certified mail, return receipt requested to the mineral owners of the Offsite Tract. For the purposes of this rule, the mineral owners of the Offsite Tract are (1) the designated operator; (2) all lessees of record for the Offsite Tract where there is no designated operator; and (3) all owners of unleased mineral interests where there is no designated operator or lessee. In providing such notice, applicant must provide the mineral owners of the Offsite Tract with a plat clearly depicting the projected path of the entire wellbore. In the event the applicant is unable, after due diligence, to locate the whereabouts of any person to whom notice is required by this rule, the applicant must publish notice of this application pursuant to the Commission's Rules of Practice and Procedure. If any mineral owner of the Offsite Tract objects to the location of the penetration point, the applicant may request a hearing to demonstrate the
necessity of the location of the penetration point of the well to prevent waste or to protect correlative rights. Notice of Offsite Tract penetration is not required if (a) written waivers of objection are received from all mineral owners of the Offsite Tract; or, (b) the applicant is the only mineral owner of the Offsite Tract. To mitigate the potential for well collisions, applicant shall promptly provide copies of any directional surveys to the parties entitled to notice under this section, upon request.

RULE 3: The acreage assigned to an individual gas well shall be known as a proration unit. The standard drilling and proration units are established hereby to be SIX HUNDRED FORTY (640) acres. No proration unit shall consist of more than SIX HUNDRED FORTY (640) acres; provided that, tolerance acreage of ten (10) percent shall be allowed for each standard proration unit so that an amount not to exceed a maximum of SEVEN HUNDRED FOUR (704) acres may be assigned. Each proration unit containing less than SIX HUNDRED FORTY (640) acres shall be a fractional proration unit. All proration units shall consist of continuous and contiguous acreage which can reasonably be considered to be productive of gas. No double assignment of acreage will be allowed.

An operator, at his option, shall be permitted to form optional drilling and proration units of FORTY (40) acres. A proportional acreage allowable credit will be given for a well on a fractional proration unit. There is no maximum diagonal limitation in this field.

For the determination of acreage credit in this field, operators shall file for each well in this field a Form P-15 Statement of Productivity of Acreage Assigned to Proration Units. On that form or an attachment thereto, the operator shall list the number of acres that are being assigned to each well on the lease or unit for proration purposes. When the allocation formula in this field is suspended, operators in this field shall not be required to file plats with the Form P-15. When the allocation formula is in effect in this field, operators shall be required to file, along with the Form P-15, a plat of the lease, unit or property; provided that such plat shall not be required to show individual proration units. Provided further, that if the acreage assigned to any well has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled. Operators in this field are exempt from the requirements of Rule 86(f)(4) entitled Proration Unit Plat; however operators must, for each horizontal drainhole, file a plat showing the as-drilled path, penetration point, terminus and, if applicable, perforations or external casing packer, for that horizontal drainhole and, for wells treated as stacked laterals, operators must file the plats required by paragraph number 6 of Rule 5. All plats referred to in this paragraph may be either a surveyor’s plat or a certified plat, at the operator’s option.

For the purpose of assigning additional acreage to a horizontal well pursuant to Rule 86, the distance from the first take point to the last take point in the horizontal drainhole shall be used in such determination, in lieu of the distance from penetration point to terminus.
RULE 4: For oil and gas wells, Stacked Lateral Wells within the correlative interval for the field that are drilled from different wellbores may be considered a single well for regulatory purposes, as provided below:

1. A horizontal drainhole well qualifies as a Stacked Lateral Well under the following conditions:
   a) There are two or more horizontal drainhole wells on the same lease or pooled unit within the correlative interval for the field;
   b) Horizontal drainholes are drilled from at least 2 different surface locations on the same lease or pooled unit;
   c) There shall be no more than 250 feet between the surface locations of horizontal drainholes qualifying as a Stacked Lateral Well.
   d) Each point of a Stacked Lateral Well’s horizontal drainhole shall be no more than 300 feet in a horizontal direction from any point along any other horizontal drainhole of that same Stacked Lateral Well. This distance is measured perpendicular to the orientation of the horizontal drainhole and can be illustrated by the projection of each horizontal drainhole in the Stacked Lateral Well into a common horizontal plane as seen on a location plat; and
   e) There shall be no maximum or minimum distance limitations between horizontal drainholes of a Stacked Lateral Well in a vertical direction.

2. A Stacked Lateral Well, including all surface locations and horizontal drainholes comprising such Stacked Lateral Well, shall be considered as a single well for density and allowable purposes.

3. Each surface location of a Stacked Lateral Well must be permitted separately and assigned an API number. In permitting a Stacked Lateral Well, the operator shall identify each surface location of such well with the designation "SL" in the well’s lease name and also describe the well as a Stacked Lateral Well in the "Remarks" of the Form W-1 drilling permit application. The operator shall also identify on the plat any other existing, or applied for, horizontal drainholes comprising the Stacked Lateral Well being permitted.

4. To be a regular location, each horizontal drainhole of a Stacked Lateral Well must comply with (i) the field’s minimum spacing distance as to any lease, pooled unit or property line, and (ii) the field’s minimum between well spacing distance as to any different well, including all horizontal drainholes of any other Stacked Lateral Well, on the same lease or pooled unit in the field. Operators may seek exceptions to Rules 37 and 38 for Stacked Lateral Wells in accordance with the Commission’s rules, or any applicable rule for this field.

5. Operators shall file separate completion forms for each surface location of the Stacked Lateral Well. Operators shall also file a certified as-drilled location plat for each surface location of a Stacked Lateral Well showing each horizontal
drainhole from that surface location, confirming the well’s qualification as a Stacked Lateral Well and showing the maximum distances in a horizontal direction between each horizontal drainhole of the Stacked Lateral Well.

6. In addition to the completion forms for each surface location of a Stacked Lateral Well, the operator must file a separate Form G-1 or Form W-2 for record purposes only for the Commission’s Proration Department to build a fictitious “Record Well” for the Stacked Lateral Well. This Record Well will be identified with the words “SL Record” included in the lease name. This Record Well will be assigned an API number and Gas Well ID or Oil lease number and listed on the proration schedule with an allowable if applicable.

7. In addition to the Record Well, each surface location of a Stacked Lateral Well will be listed on the proration schedule, but no allowable shall be assigned for an individual surface location. Each surface location of a Stacked Lateral Well shall be required to have a separate G-10 or W-10 test and the sum of all horizontal drainhole test rates shall be reported as the test rate for the Record Well.

8. Operators shall report all production from horizontal drainholes included as a Stacked Lateral Well on Form PR to the Record Well. Production reported for a Record Well is the total production from the horizontal drainholes comprising the Stacked Lateral Well. Operators shall measure the production from each surface location of a Stacked Lateral Well. Operators may measure full well stream with the measurement adjusted for the allocation of condensate based on the gas to liquid ratio established by the most recent G-10 well test rate for that surface location. The gas and condensate production will be identified by individual API number and recorded and reported on the “Supplementary Attachment to Form PR”.

9. If the field’s 100% AOF status should be removed, the Commission’s Proration Department shall assign a single gas allowable to each Record Well classified as a gas well. The Commission’s Proration Department shall also assign a single oil allowable to each Record Well classified as an oil well. The assigned allowable may be produced from any one or all of the horizontal drainholes comprising the Stacked Lateral Well.

10. Operators shall file an individual Form W-3A Notice of Intention to Plug and Abandon and Form W-3 Well Plugging Report for each horizontal drainhole comprising the Stacked Lateral Well as required by Commission rules.

11. An operator may not file Form P-4 to transfer an individual surface location of a Stacked Lateral Well to another operator. P-4’s filed to change the operator will only be accepted for the Record Well if accompanied by a separate P-4 for each surface location of the Stacked Lateral Well.
RULE 5: The daily allowable production of gas from individual wells completed in the subject field shall be determined by allocating the allowable production, after deductions have been made for wells which are incapable of producing their gas allowables, among the individual wells in the following manner:

FIVE percent (5%) of the field's total allowable shall be allocated equally among all the individual proratable wells producing from the field.

NINETY FIVE percent (95%) of the total field allowable shall be allocated among the individual wells in the proportion that the acreage assigned such well for allowable purposes bears to the summation of the acreage with respect to all proratable wells producing from this field.

It is further ORDERED by the Railroad Commission of Texas that the application of Devon Energy Production Co., LP for suspension of the allocation formula in the Carthage (Haynesville Shale) Field is approved. The allocation formula may be reinstated administratively if the market demand for gas in the Carthage (Haynesville Shale) Field drops below 100% of deliverability. If the market demand for gas in the Carthage (Haynesville Shale) Field drops below 100% of deliverability while the allocation formula is suspended, the operator shall immediately notify the Commission and the allocation formula shall be immediately reinstated.

It is further ORDERED that a hearing will be held on or before January 1, 2012, to consider whether these Field Rules should be made permanent, modified or rescinded.

It is further ORDERED by the Railroad Commission of Texas that the following fields are consolidated into the Carthage (Haynesville Shale) Field (RRC Field No. 16032 300), Harrison, Nacogdoches, Panola, Rusk and Shelby Counties, Texas:

<table>
<thead>
<tr>
<th>FIELD NAME</th>
<th>FIELD NUMBER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shelbyville Deep (Haynesville)</td>
<td>82907 500</td>
</tr>
<tr>
<td>Center (Haynesville)</td>
<td>16897 300</td>
</tr>
<tr>
<td>Carthage, E. (Bossier)</td>
<td>16033 500</td>
</tr>
<tr>
<td>Waskom (Haynesville)</td>
<td>95369 280</td>
</tr>
<tr>
<td>Naconiche Creek (Haynesville)</td>
<td>64300 280</td>
</tr>
<tr>
<td>Naconiche Creek (Bossier)</td>
<td>64300 100</td>
</tr>
<tr>
<td>Bossierville (Bossier Shale)</td>
<td>10758 500</td>
</tr>
<tr>
<td>Beckville (Haynesville)</td>
<td>06448 600</td>
</tr>
<tr>
<td>Carthage, North (Bossier Shale)</td>
<td>16034 200</td>
</tr>
</tbody>
</table>

Wells in the subject fields shall be transferred into the Carthage (Haynesville Shale) Field without requiring new drilling permits.
Each exception to the examiners' proposal for decision not expressly granted herein is overruled. All requested findings of fact and conclusions of law which are not expressly adopted herein are denied. All pending motions and requests for relief not previously granted or granted herein are denied.

This order will not be final and effective until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the Commission. Pursuant to TEX. GOV'T CODE §2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the parties are notified of the order.

Done this 15th day of December, 2009.

RAILROAD COMMISSION OF TEXAS

Chairman Victor G. Carrillo

Commissioner Elizabeth A. Jones

Commissioner Michael L. Williams

[Signature]
Exhibit 6

MEMORANDUM RULING

Before the Court is a Motion to Remand to State Court for Lack of Jurisdiction filed by Plaintiff, Richard Sullivan, Jr. [Doc. #20]. Defendant, Chesapeake Louisiana, L.P., opposes this motion. [Doc. #24]. For the reasons assigned herein, Plaintiff’s motion is hereby GRANTED.

Plaintiff filed suit in the First Judicial District Court, Caddo Parish, Louisiana, on March 13, 2009. Plaintiff’s suit seeks both damages under the Louisiana Blue Sky law as well as declaratory relief to cancel the mineral lease at issue. [Doc. #1, Ex. 1]. Defendant filed a Notice of Removal on April 6, 2009. [Doc. #1].

Plaintiff moves to remand the case, arguing that this Court lacks subject matter jurisdiction because the amount in controversy is less than $75,000. [Doc. #20]. Plaintiff seeks to rescind the mineral lease under two theories: (1) the bonus payment in the amount of $5,908.00 was untimely paid, and (2) Defendant failed to provide Plaintiff certain information in violation of Louisiana’s Blue Sky law, codified at La. R.S. 51: 701 et seq. [Doc. #1]. Plaintiff leased the mineral rights to his 16.880 acres for a lease bonus of $350 per acre, plus 1/4 royalty on future production. [Doc. #1]. Plaintiff asserts that the true market value of the lease bonus was $700 to $900, or for a total of $15,192.00. [Doc. #20]. Plaintiff argues that $15,192.00 is “woefully short of the amount in controversy sufficient for federal jurisdiction.” Id.
Defendant counters that the amount in controversy easily exceeds $75,000 because the lease in question allowed for the exploration and development of oil and gas. [Doc. #24]. Specifically, Defendant argues that the total value of the lease incorporates the total amount of rights conveyed, including the value of the recoverable minerals from the property during the duration of the lease. *Id.*

Federal Courts have limited subject matter jurisdiction and must be authorized by law to hear a certain suit. In diversity cases, jurisdiction is limited to actions where the amount in controversy exceeds $75,000, and the suit is between parties of different states. *See* 28 U.S.C. 1332(a)(1). The party removing the case to Federal Court bears the burden of showing that jurisdiction exists. *See* De Aguilar v. Boeing Co., 47 F.3d 1404, 1408 (5th Cir. 1995). Ambiguities are construed against removal. *See* Manguno v. Prudential Prop. & Cas. Ins. Co., 276 F.3d 720, 723 (5th Cir. 2002). The Court must first examine the Complaint to determine whether it is “facially apparent” that the claims exceed the jurisdictional amount. *See* St. Paul Reinsurance Co., Ltd. v. Greenburg, 134 F.3d 1250 (5th Cir. 1998). When the amount is not “facially apparent” the Court may rely on “summary judgment-type” evidence to ascertain the amount in controversy. *Id.* When a party is seeking declaratory relief, such as in this case, the amount in controversy “is not measured by the mere amount of the potential monetary judgment, but by the value of the object of the litigation.” *Hunt v. Washington State Apple Advertising*, 432 U.S. 333, 347 (1977).

At issue is whether the value of the lease is merely the right of possession, or whether it also includes the value of minerals which remain undisturbed on the property. Federal Courts have taken into account the value of undisturbed minerals in determining the value of a mineral lease, and thus, the jurisdictional amount. *See Northup Properties, Inc., v. Chesapeake Appalachia, LLC*, 567 F.3d
767 (6th Cir. 2009); Ladner v. Tauren Exploration, Inc., 2009 WL 196021 (W.D. La. 2009). The Court agrees with Defendant that the jurisdictional amount in this case includes the value of the undisturbed minerals. However, the value of the minerals which may or may not exist under the acreage in question is not "facially apparent" to the Court.

The Court could look to summary judgment-type evidence to determine the amount in controversy if such evidence had been submitted. In both Northup Properties and Ladner, the Court relied on affidavits provided by the removing party to determine the jurisdictional amount. For example, in Ladner the Court relied on the affidavits of two petroleum engineers who determined the value of the natural gas capable of being produced from the acreage at issue. Ladner at *2. In this case, Defendant did not provide affidavits or similar summary judgment-type evidence for the Court to rely upon to determine the amount in controversy. See St. Paul, 134 F.3d 1250.

Defendant provides two exhibits for the Court to consider. The exhibits consist of press releases found on the websites of Petrohawk Energy Corp. and Exco Resources, Inc., which reference wells drilled in connection with the Haynesville Shale play as well as production rates. [Doc. #24, Exs. 1 and 2]. Unauthenticated press releases by themselves are similar to newspaper articles, and are considered inadmissible hearsay. See Roberts v. City of Shreveport, 397 F.3d 287, 295 (5th Cir. 2005). Thus, the two exhibits in question cannot be relied upon by the Court to establish an estimated value of the undisturbed minerals for the lease in question.

Defendant concedes that it cannot be certain of the potential reserves located underneath the leased acreage. [Doc. #24 at 4]. Defendant cites Savoy v. Tidewater Oil Co., 218 F.Supp. 607 (D.C. La. 1963), arguing that the jurisdictional amount may be satisfied even though there is no evidence of the value. Tidewater is distinguishable because in that case there was a history of royalty
payments, which combined with the amount of damages claimed clearly established an amount that exceeded the jurisdictional requirement. There is no such evidence in this case.

While the Court agrees with Defendant that the value of the lease includes the undisturbed minerals, the quantum is not facially apparent to the Court and no summary judgment-type evidence is available for the Court to consider.

Accordingly, the Court finds that Defendant has not met the burden of showing that jurisdiction exists. See De Aguilar, 47 F.3d at 1408. Plaintiff’s Motion to Remand [Doc. #20] is hereby GRANTED.

THUS DONE AND SIGNED, this 5th day of November, 2009.

DONALD E. WALTER
UNITED STATES DISTRICT JUDGE
Exhibit 7

Plaintiff's Original Petition

*Gatti v. Commissioner*
ROBERT H. GATTI, SR., MARCIA JEAN
WESTBROOK GATTI, RANDA DURHAM,
CAVE FAMILY TRUST, REPRESENTED
BY ITS TRUSTEE, STEPHANIE F. CAVE,
ROBERT H. GATTI, JR. AND JENNIFER
TURNER GATTI

VS.

THE STATE OF LOUISIANA THROUGH
THE DEPARTMENT OF CONSERVATION,
JAMES H. WELCH, CHESAPEAKE
OPERATING, INC., J-W OPERATING,
ENCANA OIL & GAS (USA), INC., EXCO
OPERATING, LP, JAG OPERATING, LLC,
CONOCO PHILLIPS COMPANY, PETRO
HAWK OPERATING COMPANY, SWEEP
LP, COMSTOCK OIL & GAS—LOUISIANA
LLC, EOG RESOURCES, QUESTAR
EXPLORATION & PRODUCTION COMPANY,
FOREST OIL PERMIAN CORPORATION,
BEUSA ENERGY, INC., ARK-LA-TEX
ENERGY, LLC, EL PASO E&P COMPANY, LP,
GOODRICH PETROLEUM COMPANY, LLC,
XTO ENERGY, INC., and CORONADO
ENERGY E&P COMPANY, LLC,

******************************************************************************

PETITION FOR DECLARATORY JUDGMENT AND FOR DAMAGES-
CLASS ACTION

******************************************************************************

The petition of Robert H. Gatti, Sr., Marcia Jean Westbrook Gatti, Randa
Durham, Cave Family Trust, represented by trustee, Stephanie F. Cave, Robert H. Gatti,
Jr., and Jennifer Turner Gatti, all residents of the State of Louisiana, respectfully
represents that:

1. 

Made defendants herein are:

   A. The State of Louisiana through the Office of Conservation, James H. Welch,
      Commissioner of Conservation with his principal office situated in the Parish of East
      Baton Rouge, State of Louisiana; and
   B. Chesapeake Operating, Inc., a business corporation organized under the laws of the
      State of Oklahoma that is qualified to do and doing business in the State of Louisiana,
      with a principal business establishment in Louisiana at 5615 Corporate Blvd., Suite 400
      B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for
service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

C. J-W OPERATING, a business corporation organized under the laws of the State of Texas that is qualified to do and doing business in the State of Louisiana with a principal business establishment at 2601 Stonewall-Frierson Road, Frierson, Louisiana in the Parish of Caddo, and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

D. ENCANA OIL & GAS (USA), INC. a business corporation organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

E. EXCO OPERATING, LP, a limited partnership organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

F. JAG OPERATING, LLC, a Louisiana Limited Liability Company, organized under the laws of the State of Louisiana that is qualified to do and doing business in the State of Louisiana with a principal business establishment in the Parish of Caddo at 416 Travis Street Suite 910, Shreveport, Louisiana 71101 with its agent for service of process, Jack D. Farnham, Jr. 416 Travis Street Suite 910, Shreveport, Louisiana 71101; and

G. CONOCO PHILLIPS COMPANY, a business corporation organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana at 320 Somerulos Street, Baton Rouge, Louisiana 70802-6129 in the Parish of East Baton Rouge and its agent for service of process being United States Corporation Company, 320 Somerulos Street,
H. PETROHAWK OPERATING COMPANY, a business corporation organized under the laws of the State of Texas that is qualified to do and doing business in the State of Louisiana with a principal business establishment in the Parish of St. Tammany at 1011 N. Causeway Blvd., Suite 3, Mandeville, Louisiana 70471 and its agent for service of process being National Registered Agents, Inc., 1011 N. Causeway Blvd., Suite 3, Mandeville, Louisiana 70471; and

I. SWEPI LP, a business corporation organized under the laws of the State of Texas that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

J. COMSTOCK OIL & GAS–LOUISIANA LLC, a Louisiana Limited Liability Company, organized under the laws of the State of Louisiana that is qualified to do and doing business in the State of Louisiana with a principal business establishment in the Parish of Bienville at 2318 Myrtle Street, Arcadia, Louisiana 71001 and its agent for service of process being National Registered Agents, Inc., 1011 N. Causeway Blvd., Suite 3, Mandeville, Louisiana 70471; and

K. EOG RESOURCES, a business corporation organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in the Parish of East Baton Rouge at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

L. QUESTAR EXPLORATION & PRODUCTION COMPANY, a Louisiana Limited Liability Company, organized under the laws of the State of Louisiana that is qualified to do and doing business in the State of Louisiana with a principal business establishment in the Parish of East Baton Rouge at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for
service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

M. FOREST OIL PERMIAN CORPORATION, a business corporation organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana in the Parish of East Baton Rouge at 320 Somerolos Street, Baton Rouge, Louisiana 70802-6129 in the Parish of East Baton Rouge and its agent for service of process being United States Corporation Company, 320 Somerolos Street, Baton Rouge, Louisiana 70802-6129; and

N. BEUSA ENERGY, INC., a business corporation organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana in the Parish of East Baton Rouge at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

O. ARK-LA-TEX ENERGY, LLC, a Louisiana Limited Company, organized under the laws of the State of Louisiana that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana in the Parish of Caddo at 415 Texas Street, Ste 210, Shreveport, Louisiana 71101 and its agent for service of process being Bobby D. Mathews, 812 Brook Hollow Dr. Shreveport, Louisiana 71105; and

P. EL PASO E&P COMPANY, LP, a foreign Limited Partnership, organized under the laws of the State of Delaware that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana in the Parish of East Baton Rouge at 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808 and its agent for service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B, Baton Rouge, Louisiana 70808; and

Q. GOODRICH PETROLEUM COMPANY, LLC, a Louisiana Limited Company, organized under the laws of the State of Louisiana that is qualified to do and doing business in the State of Louisiana with a principal business establishment in Louisiana in the Parish of Caddo at 533 Texas Street, Ste 1375, Shreveport, Louisiana 71101 and
its agent for service of process being C T Corporation System, 5615 Corporate Blvd.,
Suite 400 B, Baton Rouge, Louisiana 70808; and
R. XTO ENERGY, INC., a business corporation organized under the laws of the
State of Delaware that is qualified to do and doing business in the State of Louisiana
with a principal business establishment in the Parish of East Baton Rouge that is
qualified to do and doing business in the State of Louisiana with a principal business
establishment in Louisiana at 320 Somerulus Street, Baton Rouge, Louisiana 70802-
6129 in the Parish of East Baton Rouge and its agent for service of process being United
States Corporation Company, 320 Semerulus Street, Baton Rouge, Louisiana 70802-
6129; and
S. CORONADO ENERGY E&P COMPANY, LLC, a foreign Limited Liability
Company, organized under the laws of the State of Delaware that is qualified to do and
doing business in the State of Louisiana with a principal business establishment in
Louisiana in the Parish of East Baton Rouge at 5615 Corporate Blvd., Suite 400 B,
Baton Rouge, Louisiana 70808 in the Parish of East Baton Rouge and its agent for
service of process being C T Corporation System, 5615 Corporate Blvd., Suite 400 B,
Baton Rouge, Louisiana 70808.

2.
The named Plaintiffs and others similarly situated are persons who are owners of
mineral rights (other than mineral leasesholds) in Fields in the Haynesville Zone as
recognized by the Commissioner, hereinafter referred to as the “Plaintiff Class”, who
have sustained damages as hereinafter set forth. The Fields are shown on the attached
Exhibit “A”.

3.
The Plaintiff Class is entitled to a declaratory judgment and a judgment for damages
as hereinafter set forth.

4.
The named Plaintiff brings this class action on behalf of themselves and all
others similarly situated. Although damages sustained by individual members of the
Plaintiff Class may vary in amount, the nature of the causes of loss depend on differing
circumstances that indicate the Plaintiff Class should be divided into subclasses as
hereinafter set forth. The named Plaintiffs shall fully and adequately protect the interests
of the other members of the Plaintiff Class. There are approximately 50,000 members of
the Plaintiff Class such that the class members are too numerous to be named
individually and to individually appear in these proceedings.

5.

The Plaintiff Class is entitled to class action treatment under L.A.C.C.P. art.
591, et seq., on behalf of all lessee and other interested owners who sustained damages
as the result of Defendants' respective individual failure, while serving as unit operator
of one or more units in the Fields under appointment by the Commissioner, to provide
the Commissioner with geological, engineering and other appropriate information
indicating a required change or revision of unit boundaries, in violation of express orders
of the Commissioner and the legal duties incumbent on unit operators.

6.

The common issue to be certified herein is the legal effect of the failure of
Defendants to protect the mineral rights of members of the Plaintiff Class in the Fields.

7.

There is a well defined community of interest in questions of law and the facts
affecting both the named plaintiffs and the parties to be represented, hereinafter referred
to as "Represented Parties". The claims or defenses of the Represented Parties are
typical of the claims or defenses applicable to the entire class. The questions of law and
facts applicable to the entire class predominate over questions which may affect
individual members rights to recover for the causes of action set forth herein.

8.

The named Plaintiffs will fairly and adequately represent and protect the
interests of the Represented Parties and have no interests which are antagonistic to the
Represented Parties. The named Plaintiffs are represented by experienced and capable
counsel who have previously litigated numerous class action cases and/or mineral law
cases.
9.

The Plaintiff Class can be defined objectively in terms of ascertainable criteria, such that the court may determine the constituency of the class for purposes of the conclusiveness of any judgment that may be rendered in this case.

10.

The prosecution by individual class members would create a serious risk of inconsistency or varying adjudications which may prejudicially affect the claims of other class members in subsequent litigation. The prosecution of individual actions presents a risk that adjudications respecting individual claimants would be entirely dispositive of the interests of class members not parties to the litigation or would otherwise substantially impair or impede the ability of class members to protect their interests. The class action is a superior procedural device for this litigation because the primary objective of the class action, the economies of time, efforts and expense, would be achieved.

11.

While the presence of natural gas in shale formations has long been known, the low porosity and permeability of shale as compared to sand formations have precluded economic development of shale until improvements in technology in recent years, principally "fracturing" operations and horizontal well bores have greatly increased porosity and permeability, providing sufficient quantity and flow rates for profitable natural gas operations.

12.

On information and belief, the first well completed in the Haynesville Zone, the SRLT 29-1 on March 22, 2007 was vertically drilled by defendant Chesapeake Operating, Inc. in the Johnson Branch Field, Section 29, Township 15 North, Range 13 West, Caddo Parish, and was named the unit well, for the subsequently formed 640 acre HA RA SUA. established by Office of Conservation Order No. 994-D, effective July 10, 2007, with Chesapeake Operating, Inc., designated as unit operator. The well was completed with tests of only 231,000 cubic feet of gas per day, no condensate, and had a flowing tube pressure of 125 pounds on a 48/64" choke.
13.

Due to the low porosity and permeability of the shale, the vertically drilled SRLT 29-1 was able to drain gas from only a small area around the borehole and the remainder of the gas in the Haynesville Zone remained locked in as it had been for millions of years, totally beyond the reach of the SRLT 29-1 well. Consequently, if a unit were not limited in size to accord with the true drainage area of the unit well, the Plaintiff Class members owning mineral rights within the true drainage area of the unit well faced an enormous dilution of their share of unit well production. For example, if the true drainage area of the SRLT 29-1 is 20 acres and the unit had been reduced in size accordingly, the mineral owners in the revised unit would have received their fair and equitable share of unit production of 1/20th per mineral acre owned. With no revision of the unit, however, the same owners would receive only 1/640th per mineral acre owned, a reduction of 32 times what they should have received.

14.

La. R.S. 30: 9 B. provides that a drilling unit, as contemplated herein, means the maximum area which may be efficiently and economically drained by one well. The legislature foresaw the possibility of inequitable allocation of unit production in some situations due to inadequate advance data, and included the following among the powers and authority granted the Commissioner in La. R.S. 30: 4 C. (13): "to regulate the spacing of wells and establish drilling units, including temporary or tentative spacing rules and drilling units in new fields". Upon successful completion of the historical SRLT 29-1 well, the duty of Chesapeake Operating, Inc. was to apply for a unit boundary to accord with that data was clear and well recognized in the industry and the Department of Conservation.

15.

However, instead of applying for a unit limited to the small drainage area of the SRLT 29-1 well, in fulfillment of its duty as unit operator, Chesapeake Operating, Inc. at that same hearing established by Office of Conservation Order No. 994-D, effective July 10, 2007 applied for a permit to drill an "alternate unit well", the SRLT 29-2 Alt., thus seeking a clearly forbidden two-well unit. The Commissioner granted the requested
permit for the horizontally drilled SRLT 29-2 as a second well for the HA RA SUA a further compounding the illegals and resulting inequities and damages to Plaintiff Class members in the HA RA SUA. Chesapeake Operating, Inc., again applied to the Commissioner for a third well, drilled horizontal, the SRLT 29-3 Alt. at a hearing established by Office of Conservation Order No. 994-D-4, effective July 15, 2008. The testimony offered in support of the third well was that the proposed well was necessary to efficiently and economically drain a "portion" of the Haynesville Zone underlying this unit which could not be drained by the two existing wells in the unit. The permit was granted thus exceeding once more the explicit limited statutory authority mandating one-well units. On information and belief production from all three wells is distributed to all mineral owners in the unit on a unit acreage basis of 640 acres.

16.

The term "alternate unit well" used as a descriptive term for the additional unit wells permitted in the Haynesville Zone refer to a practice in existence for many years whereby wells were permitted to be drilled to previously unitized sands for reasons and under circumstances totally irrelevant and inapplicable to state units, regardless of whether such "alternate unit wells" were legally authorized when originally permitted as a euphemism in unique situations.

17.

A step in the right direction was taken however, when the Commissioner included in effectuation of the Commissioner's unitization authority, the following provision in Order No. 994-D, effective, July 10, 2007 as part of the Johnson Branch Field series of Orders:

("When there is obtained additional geological, engineering or other appropriate information which would indicate a required change or revision of the unit boundary as adopted herein, or which would indicate a required change or revision of other provisions of this Order, the party or parties in possession of such additional information shall petition the Commissioner of Conservation for a public hearing for the purpose of considering appropriate changes.") emphasis supplied.

The same or similar provisions are included in many other Orders of the Commissioner of Conservation for the Fields.

18.

On information and belief, Plaintiffs aver that contrary to Orders of the
Commissioner requiring submission of information warranting revision of units to meet statutory standards, no unit operator has complied with and all continue not to comply with such Orders, causing damage to class members.

19.

Further, defendant operators were well aware at all relevant times that horizontal shale wells drained a somewhat cylindrically shaped limited portion of the shale reservoir underlying a surface area of approximately 80 acres extending out from the drill site, and that approximately eight wells, not one, would be required to drain the 640 acres prescribed in the original unit order. Nevertheless, despite the enormous damage sustained from the resulting inequities, operators continued to apply for and the Commissioner continued to order 640 acre units in clear violation of the statutory standard, and no revision of the units have occurred to meet the statutory requirement of a one-well unit nor have they been ordered or applied for and natural gas production from the Fields continues to be distributed according to the 640 acre drilling units.

20.

Properly administered, the statutory one-well unit provides for a fair and equitable share of production based on the surface area underlain by the productive portion of the reservoir, and in the case of the Fields no harm would be done if the units were revised upon completion of the unit well to fit the approximately 80 acre cylindrical area overlying the "fracked" portion of the shale formation.

21.

As a result of the actions described above different circumstances caused different damages to class members and class members should be divided into sub-classes sharing the same type of damage, as hereinafter set forth:

(1) Sub-Class A: Lessor class members owning mineral rights within the drainage area of a well drilled in the productive area of a Haynesville Zone 640-acre unit whose share of production would be substantially greater had the unit been legally established or timely revised.
(2) Sub-Class B: Class members owning mineral rights to lands outside the drainage area had there been a legally established or timely revised cylindrically shaped unit yet within the purported 640-acre unit, whose title is clouded by the apparent maintenance of a lease otherwise expired, in whole or in part that precluding the member from realizing the market value of the member's lease rights.

Separate judgments should be entered in favor of each class member against the responsible defendant operators of the units in the amount of damage sustained by the class member in the respective units as aforesaid.

22.

In addition to a judgment awarding damages to plaintiff class members, named plaintiffs desire and seek a declaratory judgment as follows:

(1) That only a few exceptions exist to the statutory requirement that a drilling unit is the maximum area which may be efficiently and economically drained by one well. The first exception is Act 441 of 1960, La. R.S. 30:5(C) regarding secondary recovery operations in poolwide units, where a certain percentage of interested parties agree to a poolwide unit allowing for the drilling of more than one well. The second exception is Act 1094 of 1999, La. R.S. 30:5.1 regarding deep wells where the geologic top is encountered in the initial well for the pool at a depth in excess of 15,000 feet true vertical depth. Under those circumstances the Commissioner can establish a single unit served by one or more wells. The third exception is Act 892 of 2004, La. R.S. 30:5.2 where to encourage the development of coal seam natural gas the Commissioner of Conservation was authorized to establish a single unit to be served by one or more wells for a coal seam natural gas producing area. Therefore, except for the above statutory exceptions no authority or power is prescribed by law for the Commissioner to establish a unit having an area in excess of the area drainable by one well and the purported creation of a unit having an area in excess of the area drainable by one well is null and void.

(2) That "alternate unit wells" having the meaning and effect attributed by the Commissioner in the Haynesville Shale are not authorized by statute and absent the grant of authority by the legislature are beyond the legal authority of the Commissioner.
and violate the specific provisions of La. R. S. 30: 9 B.

In view of the foregoing and in the interest of due process, the State of Louisiana, through the Commissioner of Conservation should be and is made a party defendant herein to respond to plaintiffs' prayer for declaratory judgment.

24.

WHEREFORE Plaintiffs pray that:

1. That after due proceedings this action be certified as a class action pursuant to the provision of LA C.C.P. art. 591, et seq., in the respects alleged hereinabove, for the purposes of determining the common issues of liability for damages and the basis for assessment of damages, if any.

2. That upon certification of the class action, the Court call for the formulation of a suitable management plan pursuant to LA C.C.P. art. 593.

3. That after due proceedings had that there be judgment herein in favor of the Plaintiffs Class and against the defendants, Chesapeake Louisiana, L.P., Chesapeake Operating Inc., J-W Operating, Encana Oil & Gas (USA), Inc., Exco Operating, LP, JAG Operating, LLC, ConocoPhillips Company, Petrohawk Operating Company, SWEFI LP, Comstock Oil & Gas–Louisiana LLC, BOG Resources, Questar Exploration & Production Company, Forest Oil Permian Corporation, Beusa Energy, Inc., Ark-La-Tex Energy, LLC, El Paso E&P Company, LP, Goodrich Petroleum Company, LLC, XTO Energy, Inc., and Coronado Energy E&P Company, LLC. for all compensatory damages as are reasonable in the premises, plus legal interest from the date of judicial demand until paid, for all costs of this action and for all other just and equitable relief permitted by law.

4. That the rights of the Plaintiff Class to establish their entitlement to compensatory damages, and the amounts thereof, be reserved for determination in their individual actions to be pursued in accordance with procedures and standards for the subclasses of class members defined hereinabove.

5. That a declaratory judgment be entered as follows:

(A.) That only a few exceptions exist to the statutory requirement that a drilling
unit is the maximum area which may be efficiently and economically drained by
one well. The first exception is Act 441 of 1960, La. R.S. 30:5(C) regarding
secondary recovery operations in poolwide units, where a certain percentage of
interested parties agree to a poolwide unit allowing for the drilling of more than
one well. The second exception is Act 1994 of 1999, La. R.S. 30:5.1 regarding
deep wells where the geologic top is encountered in the initial well in excess of
15,000 feet true vertical depth. The Commissioner under those circumstances can
establish a single unit served by one or more wells. The third exception is Act
892 of 2004, La. R.S. 30:5.2 where to encourage the development of coal seam
natural gas the Commissioner of Conservation was authorized to establish a
single unit to be served by one or more wells for a coal seam natural gas
producing area. Therefore, except for the above statutory exceptions no authority
or power is prescribed by law for the Commissioner to establish a unit having an
area in excess of the area drainable by one well and the creation of a unit having
an area in excess of the area drainable by one well is null and void.

(B.) That "alternate unit wells" having the meaning and effect attributed by the
Commissioner are not authorized by statute, nor granted to him by the legislature,
and absent the grant of authority by the legislature are beyond the legal authority
of the Commissioner and violate the specific provisions of La. R. S. 30: 9 B.

RESPECTFULLY SUBMITTED:

FAYARD & HONEYCUTT, APC

CALVIN C. FAYARD, JR. #5486
D. BLAYNE HONEYCUTT #81264
WANDA J. EDWARDS #27448
519 Florida Avenue SW
Denham Springs, LA 70726
Telephone: (225) 664-4193
Facsimile: (225) 664-6925
Email: calvin@fayardlaw.com

LAW OFFICES OF RUDOLPH ESTESS, JR.
Los Angeles Bar # 17948
Attorney at Law
517 Tents Place
Baton Rouge, Louisiana 70817
Telephone: (225) 757-0696
Facsimile: (225) 758-5853
CAVE LAW FIRM

By

ROBERT G. CAVÉ # 4073
MICHAEL L. CAVÉ #26002
Attorney at Law
3000 Plaza Tower Drive
Baton Rouge, Louisiana 70816
Telephone: (225) 292-3194

CHARLES G. TUTT
La., Bar # 12865
Attorney at Law
920 Pinesmont Road, Suite 308
Shreveport, Louisiana 71106
Telephone: (318) 868-6633

RYAN B. GATH
La., Bar # 26646
Attorney at Law
1661 Benton Road
Bossier City, Louisiana 71111
Telephone: (318) 752-1012

SIMON, PERAGINE, SMITH & REDFERN, LLP

By

ROBERT L. REDFERN # 5498
30th Floor
1100 Poydras Street
New Orleans, Louisiana 70163-3000
Telephone: (504) 569-2030
Facsimile: (504) 569-2999

SERVICE INFORMATION:

State of Louisiana through the Office of Conservation
James H. Welch, Commissioner of Conservation
617 North Third Street
Baton Rouge, Louisiana 70802

Chesapeake Operating Inc.
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

J-W OPERATING
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

ENCANA OIL & GAS (USA), INC.
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808
EXCO OPERATING, LP
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

JAG OPERATING, LLC
through its agent for service of process
Jack D. Ferriharn, Jr.
416 Travis Street Suite 910
Shreveport, Louisiana 71101

CONOCO PHILLIPS COMPANY
through its agent for service of process
United States Corporation Company
320 Sombrulos Street
Baton Rouge, Louisiana 70802-6129

Petrohawk Operating Company
through its agent for service of process
National Registered Agents, Inc.
1011 N. Causeway Blvd., Suite 3
Mandeville, Louisiana 70471

SWEPI LP
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

Comstock Oil & Gas Louisiana LLC
through its agent for service of process
National Registered Agents, Inc.
1011 N. Causeway Blvd., Suite 3
Mandeville, Louisiana 70471

EOG Resources
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

Questar Exploration & Production Company
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

Forest Oil Permian Corporation
through its agent for service of process
United States Corporation Company
320 Sombrulos Street
Baton Rouge, Louisiana 70802-6129

Beusa Energy, Inc.
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

Ark-La-Tex Energy, LLC
through its agent for service of process
Bobby D. Matthews
812 Brook Hollow Dr.
Shreveport, Louisiana 71105

El Paso E&P Company, LP
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808
GOODRICH PETROLEUM COMPANY, LLC
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808

XTO ENERGY, INC.
through its agent for service of process
United States Corporation Company
320 Somerulosa Street
Baton Rouge, Louisiana 70802-6129

CORONADO ENERGY E&P COMPANY, LLC
through its agent for service of process
C T Corporation System
5615 Corporate Blvd., Suite 400 B
Baton Rouge, Louisiana 70808.
<table>
<thead>
<tr>
<th>All the Fields in the Bayouville Group</th>
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<tbody>
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<td>Situated in Louisiana</td>
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| ALABAMA BEND                          |
| BAYOU SAN MIGUEL                      |
| BELLE BOWER                           |
| BELLEVUE                              |
| BENSEN                               |
| BETHANY LONGSTREET                   |
| BRACKY BRANCH                         |
| CADDY PINE ISLAND                    |
| CASPIANA                             |
| CEDAR GROVE                           |
| CONVERSE                             |
| DIXIE                                |
| ELM GROVE                             |
| GRAND CANE                            |
| GRAND CANE, NORTH                     |
| GREENWOOD-WASKOM                      |
| HAUGHTON                             |
| HOLLY                                |
| JOHNSON BRANCH                       |
| KING HILL                            |
| KINGSTON                             |
| LAKE BISTINEAU                       |
| LOGANSPORT                           |
| LONGWOOD                             |
| MANSFIELD                            |
| MARTIN                               |
| METCALF                              |
| PLEASANT HILL                        |
| RED CHUTE BAYOU                      |
| RED RIVER-BULL BAYOU                 |
| SENTELL                              |
| SHREVEPORT                           |
| SLIGO                                |
| SPIDER                               |
| SWAN LAKE                            |
| TEN MILE BAYOU                       |
| THORN LAKE                           |
| TRENTO                               |
| WILDCAT-NO LA SHREVEPORT DIST        |
| WOODARDVILLE                         |
| AShEland FIELD                       |
Exhibit 8

North Dakota "Dormant Mineral Act"

North Dakota Century Code 38-18.1
CHAPTER 38-18.1
TERMINATION OF MINERAL INTEREST

38-18.1-01. Mineral interest defined. In this chapter, unless context or subject matter otherwise requires, "mineral interest" includes any interest in oil, gas, coal, clay, gravel, uranium, and all other minerals of any kind and nature, whether created by grant, assignment, reservation, or otherwise owned by a person other than the owner of the surface estate.

38-18.1-02. Statement of claims - Recording - Reversion. Any mineral interest is, if unused for a period of twenty years immediately preceding the first publication of the notice required by section 38-18.1-06, deemed to be abandoned, unless a statement of claim is recorded in accordance with section 38-18.1-04. Title to the abandoned mineral interest vests in the owner or owners of the surface estate in the land in or under which the mineral interest is located on the date of abandonment. The owner of the surface estate in the land in or under which the mineral interest is located on the date of abandonment may record a statement of succession in interest indicating that the owner has succeeded to ownership of the minerals under this chapter.

38-18.1-03. When mineral interest deemed to be used.

1. A mineral interest is deemed to be used when:
   a. There are any minerals produced under that interest.
   b. Operations are being conducted thereon for injection, withdrawal, storage, or disposal of water, gas, or other fluid substances.
   c. In the case of solid minerals, there is production from a common vein or seam by the owners of such mineral interest.
   d. The mineral interest on any tract is subject to a lease, mortgage, assignment, or conveyance of the mineral interest recorded in the office of the recorder in the county in which the mineral interest is located.
   e. The mineral interest on any tract is subject to an order or an agreement to pool or unitize, recorded in the office of the recorder in the county in which the mineral interest is located.
   f. Taxes are paid on the mineral interest by the owner or the owner's agent.
   g. A proper statement of claim is recorded as provided by section 38-18.1-04.

2. The payment of royalties, bonus payments, or any other payment to a named or unnamed interest-bearing account, trust account, escrow account, or any similar type of account on behalf of a person who cannot be located does not satisfy the requirements of this section and the mineral interest is not deemed to be used for purposes of this section. Interest on such account must be credited to the account and may not be used for any other purpose. A named or unnamed interest-bearing account, trust account, escrow account, or any similar type of account that has been in existence for three years is deemed to be abandoned property and must be treated as abandoned property under chapter 47-30.1. A lease given by a trustee remains valid.

38-18.1-04. Statement of claim - Recording - Time. The statement of claim provided for in section 38-18.1-02 must:

1. Be recorded by the owner of the mineral interest or the owner's representative prior to the end of the twenty-year period set forth in section 38-18.1-02. A joint tenant,
but not a tenant in common, may record a claim on behalf of oneself and other joint tenants.

2. Contain the name and address of the owner of the mineral interest, and a legal description of the land on, or under which, the mineral interest is located as well as the type of mineral interest involved.

3. Be recorded in the office of the recorder in the county in which the mineral interest is located.

The mineral interest is deemed to be in use at the date of recording, if the recording is made within the time provided by this section. A statement of claim filed after July 31, 2009, by a person other than the owner of record of the mineral interest is not effective to preserve a mineral interest unless accompanied by a reference to the name of the record owner under whom the owner of the mineral interest claims.

38-18.1-05. Failure to record the statement of claim. Failure to record the statement of claim within the time period provided in section 38-18.1-04 will not cause a mineral interest to be extinguished if:

1. The owner of record of the mineral interest satisfies either one of the following requirements within sixty days after first publication of the notice provided for in section 38-18.1-06:
   
a. Files with the county recorder a statement of claim as required in section 38-18.1-04; or
   
b. Files with the county recorder documentation that at least one of the activities under subsection 1 of section 38-18.1-03 took place during the twenty-year period immediately preceding the first publication of notice.

2. A person other than the owner of record of the mineral interest files with the county recorder within sixty days after first publication of the notice provided for in section 38-18.1-06 an affidavit under oath or a declaration under oath which includes an explanation of the factual and legal basis for the person's assertion of title to the mineral interest. This explanation must be accompanied by documentation supporting the assertion or an explanation why documentation is unavailable.


1. The owner or owners of the surface estate in the land in or under which the mineral interest is located intending to succeed to the ownership of a mineral interest upon its lapse shall give notice of the lapse of the mineral interest by publication.

2. The publication provided for in subsection 1 must be made once each week for three weeks in the official county newspaper of the county in which the mineral interest is located; however, if the address of the mineral interest owner is shown of record or can be determined upon reasonable inquiry as defined in subsection 6, notice must also be made by mailing a copy of the notice to the owner of the mineral interest within ten days after the last publication is made.

3. The notice must state:
   
a. The name of the record owner of the mineral interest;
   
b. A description of the land on which the mineral interest involved is located; and
   
c. The name of the owner or owners of the surface estate in the land in or under which the mineral interest is located giving the notice.
4. A copy of the notice and an affidavit of service of the notice must be recorded in the office of the recorder of the county in which the mineral interest is located and constitutes prima facie evidence in any legal proceedings that such notice has been given.

5. The owner or owners of the surface estate in the land in or under which the mineral interest is located who succeeds to the ownership of a mineral interest upon its lapse under this chapter is entitled to record a statement of succession in interest indicating that that owner or owners of the surface estate in the land in or under which the mineral interest is located has succeeded to the ownership of the mineral interest.

6. To constitute a reasonable inquiry as provided in subsection 2, the owner or owners of the surface estate or the owner's authorized agent must conduct a search of:
   
a. The county recorder's records for the existence of any uses as defined in section 38-18.1-03 by the owner of the mineral interest;
   
b. The clerk of court's records for the existence of any judgments, liens, or probate records which identify the owner of the mineral interest;
   
c. The social security death index for the last-known residence of the owner of the mineral interest, if deceased; and
   
d. One or more public internet databases to locate or identify the owner of the mineral interest or any known heirs of the owner. The owner or owners of the surface estate are not required to conduct internet searches on private fee internet databases.

38-18.1-06.1. Perfecting title in surface owner.

1. Upon completion of the procedure provided in section 38-18.1-06, the owner or owners of the surface estate may maintain an action in district court in the county in which the minerals are located and obtain a judgment in quiet title in the owner or owners of the surface estate. This action must be brought in the same manner and is subject to the same procedure as an action to quiet title pursuant to chapter 32-17.

2. In an action brought under this section, the owner or owners of the surface estate shall submit evidence to the district court establishing that all procedures required by this chapter were properly completed and that a reasonable inquiry as defined by subsection 6 of section 38-18.1-06 was conducted. If the district court finds that the surface owner has complied with all procedures of the chapter and has conducted a reasonable inquiry, the district court shall issue its findings of fact, conclusions of law, and enter judgment perfecting title to the mineral interest in the owner or owners of the surface estate.

3. A judgment obtained by the owner or owners of the surface estate in compliance with this section is deemed conclusive except for fraud, misrepresentation, or other misconduct.

4. A mineral lessee that obtains a lease from the owner of the surface estate, which owner has obtained a judgment to minerals pursuant to this section, is deemed a bona fide purchaser and its lease remains effective in the event the judgment is subsequently vacated for any reason. Further, the lessee is not liable to any third party for lease bonus, royalties, or any other proceeds paid to the surface owner under the lease before the judgment being vacated.
5. Absent fraud or misrepresentation, the owner or owners of the surface estate which obtain a judgment under this section and lease minerals to a lessee are entitled to retain all lease bonus, royalties, or any other proceeds paid to the surface owner under the lease before the judgment being vacated.

38-18.1-07. Waiver prohibited. The provisions of this chapter may not be waived at any time prior to the expiration of the twenty-year period provided in section 38-18.1-02.

38-18.1-08. Applicability. This chapter does not apply to any mineral interest owned by any governmental body or agency thereof and this chapter is both prospective and retrospective in its application.
Exhibit 9

December 16, 2010 Wall Street Journal Editorial Regarding New York State's Drilling Permit Moratorium on Marcellus Shale Permits
The Madness of New York

A tale of two states on exploiting the boom in shale natural gas.

New York State urgently needs more jobs and new tax revenue, so naturally its political class has decided to reject one of the best economic opportunities in decades. And people wonder why Albany is bankrupt.

Governor David Paterson made headlines last weekend when he vetoed legislation that barred natural gas exploration in the Empire State. He then undercut his own pro-investment message with an executive order that is almost as restrictive. Imagine California, 1848, closing its border to gold miners.

The U.S. is in the early stages of what can only be described as a Shalé Gas Rush. About a decade ago the drilling industry made a technological breakthrough in attempting to tap into the Barnett Shale formation in north central Texas. America was suddenly able to extract, cost-effectively, huge amounts of natural gas from tightly packed shale rocks.

That has opened up vast new exploration possibilities, including the 65 million-acre Marcellus Shale formation, which extends from Ohio and West Virginia up through Pennsylvania and upstate New York. A recent Penn State study estimates that Marcellus is the second largest natural gas field in the world. The study notes that Pennsylvania had $4.5 billion in Marcellus-related investment in 2009, generating nearly $400 million in state and local tax revenue and 44,000 jobs.

And New York? Once a manufacturing powerhouse, the upstate economy has withered under global competition and the taxes and mandates that flow out of corrupt, liberal, government union-dominated Albany. The region has lost 90,000 manufacturing jobs since 2001.

The drilling industry could compensate with new jobs in construction, trucking, engineering and a variety of attendant services. The industry also pays royalties and leases land from landowners, who pay taxes and buy goods. A July study by the American Petroleum Institute estimates production in the Marcellus could provide $15 billion in economic output and $2 billion in state tax revenue over nine years.

Instead, New York has imposed a de facto drilling moratorium because of dubious environmental fears. Shale drilling relies on hydraulic fracturing, the process of blasting a solution that is 99% water and sand (less than 1% chemicals) into rock to...
release gas deposits. Fracking has been commercially viable since 1949 and is responsible for 30% of domestic oil and gas production.

The recent advances in shale gas have come from combining fracking with "horizontal" drilling, which permits wells to move laterally under the surface. Horizontal fracking lets the industry get much more energy out of one well. The industry uses steel casing and cement to prevent fracturing fluid from polluting wells and underground reservoirs.

The Environmental Protection Agency and the Ground Water Protection Council, a nonprofit made up of state regulatory agencies, have published studies concluding that fracking is safe. While energy exploration is never risk-free, the Ground Water Council hasn't found a single documented case of fracking having polluted local ground water.

That hasn't stopped New York's powerful green lobby from predicting disaster, and three years ago the state's Department of Environmental Conservation obliged by announcing it would rewrite all regulations, stopping new permits in the meantime. The legislature went further and outlawed even vertical fracking.

Mr. Paterson vetoed this, but his executive order backs the agency ban on horizontal fracking—the real future of the industry—until the new regulations are issued, which he insists should not happen for at least six months. The agency issued draft regulations a year ago that are so onerous they would guarantee that drillers go elsewhere.

Contrast that with Pennsylvania, which has for the most part welcomed the drilling industry. Between July 2009 and June 2010, Pennsylvania's 632 Marcellus wells released 180 billion cubic feet of gas, doubling state production. The Keystone State has used this development to attract more investment in company headquarters, training facilities and service sites—brick-and-mortar capital lost to the Empire State.

It is also positioning itself to lure new manufacturing on the promise of cheap natural gas. Bowing to liberal pressure, Pennsylvania Governor Ed Rendell issued a moratorium earlier this year on drilling permits on state land, though the drilling boom on private land continues. Both Pennsylvania and Canada are looking to lock in gas contracts with businesses in New York, which is one of the country's largest users of natural gas.

Political elites in Albany and New York City live off Wall Street and other service industries, and they think of upstate New York as an environmental museum: a nice place to visit on the weekend but they wouldn't want to develop the resources there. No wonder the once great Empire State can't pay its bills and keeps losing taxpayers to places that want their citizens to prosper.
Exhibit 10

Field Designations within the Eagle Ford Shale
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<th>井号</th>
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<th>日期</th>
<th>冲程数 (ft)</th>
<th>产能 (bbl/day)</th>
<th>注水量 (bbl/day)</th>
<th>反射系数（%）</th>
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</table>

**注:**
* 多个计数器表示该领域被整合到Briscoe Ranch (Eagleford) - Docket No. 01-026783
* 该字段表示将领域分割到Eagleville (Eagleford-1)或Briscoe Ranch (Eagleford) - Docket Nos. 01-0266450和01-0266677
* 该领域分割到了Sugarhouse (Huffhines Chalk)或Sugarhouse (Eagle Ford) - Docket No. 02-0284837
* 该领域分割到了Hawkeye (Eagleford Shale) - Docket No. 01-0263788

![](image)

**注意:**
* 基于额外评估，已经确定该领域的分割是该领域分割到Hawkeye (Eagleford Shale) - Docket No. 01-0263788

**注释:**
* 所有关于Schedule的信息都已经更新为2012年11月14日

**数据范围:**
* 2014年1月1日到2014年11月30日

**总和:**
* 2,505,076 3,267,036 84,238,478 4,665,505