

RECENT DEVELOPMENTS IN TEXAS AND UNITED STATES ENERGY LAW

I. INTRODUCTION	363
II. RECENT DEVELOPMENTS IN TEXAS ENERGY LAW	365
A. Texas Oil, Gas, and Energy Case Summaries	365
B. Changes in Wind Energy Law and Regulation in Texas	371
III. RECENT DEVELOPMENTS IN UNITED STATES ENERGY LAW	394
A. Federal Oil, Gas, and Energy Case Summaries	394
B. Master Limited Partnerships: At the Crossroads?	397
C. The Modernization of the Oil and Gas Disclosure and Reserves Rules of the Securities and Exchange Commission	421
D. Renewable Transportation Fuel: A Counterintuitive Windfall to the Oil Industry	428

I. INTRODUCTION

This section of *Recent Developments in Texas and United States Energy Law* consists of selected discussions and articles regarding recent case law, legislation, and regulations that affect the energy industry.¹ The first section, focusing on Texas, contains short summaries of recent Texas appellate court decisions and an article by Diana Liebmann discussing the implementation of Competitive Renewable Energy Zone (“CREZ”) legislation, which will increase wind power generation in Texas and facilitate its transmission to major markets. The second section focuses on national issues including summaries of several recent federal court decisions and three articles on issues of national significance for the energy industry. Philip Peacock discusses the formation, advantages, and disadvantages of the master limited partnership (“MLP”) structure that many oil and gas companies have adopted for certain assets, as well as some current challenges facing the MLP market. Jim Prince discusses recent changes by the Securities and Exchange Commission to the rules for reporting of oil and gas reserves estimates. Finally, Evan Turgeon makes a critical examination of the biofuels requirements in the

1. The content of the Recent Developments section is provided for general information purposes only. The case summaries and short articles may serve as a useful starting point in the legal research process but are not intended as a substitute for primary research of the laws of the jurisdictions discussed.

364 TEXAS JOURNAL OF OIL, GAS, AND ENERGY LAW [Vol. 4

government's Renewable Fuels Standards program and explores potential effects for the oil and gas industry.

II. RECENT DEVELOPMENTS IN TEXAS ENERGY LAW

A. *Texas Oil, Gas, and Energy Case Summaries*

1. Wagner & Brown, Ltd. v. Sheppard, No. 06-0845, 2008 WL 4958501 (Tex. Nov. 21, 2008).

Issue: Does termination of an oil and gas lease on land that is part of a pooling agreement terminate participation in the pooled unit?

This is the first case in which the Texas Supreme Court has addressed how a pool of producing properties is affected if a lease in that pool expires. The plaintiff, Sheppard, was a 1/8th mineral interest owner in a 62-acre tract in Ushur County. She had brought a declaratory judgment action against Wagner & Brown claiming that, when the lease on her tract had terminated, a signed pooling agreement that included her tract had also terminated. The trial court granted summary judgment for Sheppard, and the Texarkana Court of Appeals affirmed. The Texas Supreme Court, however, reversed and remanded.

Sheppard leased her mineral interests to C.W. Resources. In September 1996, C.W. Resources entered into a pooling agreement with Wagner & Brown and eight adjoining landowners. Soon afterward, two gas wells were completed and began producing. Both wells were physically located on Sheppard's tract but, pursuant to the pooling agreement, she had to share proceeds with the other tracts in proportion to acreage.

In September 2000 Wagner & Brown took over as operator of the pooled unit and discovered that Sheppard had not been paid royalties within 120 days of first gas sales, as required by a clause in her lease. The lease consequently terminated in 1997. The question for the court was thus whether termination of the lease also terminated Sheppard's participation in the pooled unit. In an 8-0 decision the court determined that it did not. If her participation terminated, Sheppard would be entitled to 1/8th of all of the production (less her share of costs of production and marketing) from the two wells since 1997, rather than 1/8th of only 51.3% of that production (the proportion her land bore to the total acreage of the pooling unit).

The court, on principles of contract, held that lease termination did not terminate participation in the pooled unit because the lease and the unit agreement pooled certain "premises" and "lands," rather than just the leasehold interest.

While the court stated that "a lease is not necessarily required for pooling," it left open the possibility for pooling agreements to end upon

cancellation of a lease if such termination is explicitly included in the pooling agreement language.² The court also held that Wagner & Brown, based on principles of equity, may be able to recoup from Sheppard pre-termination lease expenses such as drilling costs, and the case was remanded to the trial court on this issue.

2. Sonat Exploration Co. v. Cudd Pressure Control, Inc., 271 S.W.3d 228 (Tex. 2008).

Issue: How is choice of law determined for a Master Service Agreement for oilfield services when not explicitly stipulated in the agreement?

Last November, the Texas Supreme Court decided this case highlighting the importance of carefully drafted choice of law provisions in Master Service Agreements (“MSAs”) between oil companies and oilfield service providers. Sonat Exploration signed an MSA with Cudd Pressure Control to govern oilfield services in at least four potential jurisdictions. The agreement contained a choice-of-law provision stipulating that maritime law would apply to offshore operations in navigable waters and that Texas law would apply to all operations on land in Texas and New Mexico. The MSA made no mention of what law would apply to operations in Louisiana.

In October 1998 an explosion at one of Sonat’s Louisiana wells killed seven workers, including four Cudd employees. Survivors of the workers sued Sonat and Cudd in Texas, and Sonat sought indemnity from Cudd.

Texas law and Louisiana law are in conflict regarding the validity of oilfield services indemnity clauses. Under Texas law, oilfield indemnity clauses will be valid if they are mutual and supported by liability insurance.³ Under Louisiana law, however, such clauses are not valid if the party seeking indemnity was negligent or strictly liable.⁴ Due to the conflict, a determination of what law applied to the Louisiana operations under the MSA became essential to determining whether Cudd owed Sonat indemnification.

The Texas Supreme Court began its analysis by applying § 188 of the Restatement (Second) of Conflict of Laws, which states, “an issue in contract [is] determined by the local law of the state which, with respect to that issue, has the most significant relationship to the transaction and the parties.”⁵ In determining this, the Restatement takes into account: the place of contracting; the place of negotiation; the place of performance;

2. Wagner & Brown v. Sheppard, No. 06-0845 2008, WL 4958501 (Tex. Nov. 21, 2008), at *3.

3. TEX. CIV. PRAC. & REM. CODE ANN. § 127.005 (Vernon 2005); Ken Petrol. Corp. v. Questor Drilling Corp., 24 S.W.3d 344, 346 (Tex. 2000).

4. See LA. REV. STAT. § 9:2780 (2005).

5. RESTATEMENT (SECOND) OF CONFLICT OF LAWS § 188(1) (1971).

the location of the subject matter; and the domicile, place of incorporation, and place of business of the parties.⁶

The court held that none of these factors were dispositive with regard to the MSA, however, because the agreement was negotiated by each company from its home state and contemplated work in many states, and both companies were Delaware corporations (but obviously never contemplated oilfield work there). While the Court of Appeals held that place of performance was dispositive, the Supreme Court noted that the Restatement explains that place of performance is only of “paramount importance” when the services called for by a contract are to be rendered in a single state.⁷

With its § 188 analysis yielding no result, the Supreme Court looked to § 6 of the Restatement, which states that protection of the justified expectations of the parties should be the most important factor to be considered in determining the applicable law.⁸ Following this rationale, the court surveyed other language in the MSA and held that the parties had intended Louisiana law to apply to the operations in Louisiana. It based this on the parties’ inclusion in the MSA of a clause stipulating that Sonat would be an additional insured under Cudd’s insurance policies for all work in Louisiana. The court reasoned that the “only explanation is that the parties expected their cross-indemnities might not be enforceable [in Louisiana],” which would only result if Louisiana law applied.⁹ While Sonat argued that the additional-insured provision was inserted simply as a belt-and-suspenders provision to make sure indemnity occurred, the court rejected this argument holding that “both belt and suspenders are unnecessary unless a person expects trouble with one of them.”¹⁰

After deciding that Louisiana law applied, the court remanded the case to the trial court to determine whether Sonat had been negligent in the explosion, which will determine whether its indemnity claim is ultimately void under Louisiana law. (In an additional holding not summarized here, the court ruled that although, in a prior agreement with Sonat, Cudd had waived its argument that Louisiana law should apply to its claim, this did not preclude Cudd from benefiting from a reversal of the judgment for Sonat after the issue was raised by Cudd’s liability insurer who intervened on appeal.)

6. *Id.* at § 188(2).

7. *Sonat Exploration Co. v. Cudd Pressure Control, Inc.*, 271 S.W.3d 228, 234 (Tex. 2008).

8. RESTATEMENT (SECOND) OF CONFLICT OF LAWS §§ 188 cmt. B, 6(2)(d)-(e).

9. *Sonat Exploration Co.*, 271 S.W.3d at 235.

10. *Id.*

3. *Blackmon v. XTO Energy, Inc.*, 276 S.W.3d 600 (Tex. App.—Waco 2008, no pet.).

Issue: Is a gas well that is shut in pending new processing improvements capable of producing in paying quantities?

The plaintiffs, the Blackmons, filed a declaratory judgment action against XTO Energy alleging that an oil and gas lease between the two parties had expired because the well was shut in. After making a distinction between “paying quality” and “paying quantity,” the court held that the lease had not terminated because the well was still capable of producing in paying quantities while shut in and granted XTO’s motion for summary judgment.

The Blackmons’ predecessors-in-interest had leased two tracts of land to Wessely Energy Corporation (XTO’s predecessor-in-interest) in January 1983. One of the tracts was pooled with other lands leased by Wessely to form the Biggs #1 Well. Production from the Biggs #1 held the lease past its primary term, but production ceased in April 1997 when the company purchasing the gas refused to continue purchasing because the production’s carbon dioxide levels exceeded those stipulated in the purchase agreement. No royalty payments were made to the Blackmons’ predecessors-in-interest while the well was shut in. In September 1998 Wessely installed an amine processing unit in order to remove the excess carbon dioxide, and production resumed.

The Blackmons argued that that the lease terminated because the well was “not capable of producing in paying quantities” from April 1997 to September 1998 while the well was shut in. They pointed to the standard from *Anadarko Petroleum v. Thompson*, under which “a well ‘capable of producing in paying quantities’ means a well that will produce in paying quantities if the well is turned ‘on,’ and it begins flowing, without additional equipment or repair.”¹¹ The Blackmons contended that the Biggs #1 well did not meet this standard because it was not capable of producing marketable gas under the contract until “additional equipment,” namely the amine processing unit, was installed.

The court, however, said that “the focus is on whether the well is capable of producing gas in a marketable quantity, not a marketable quality.”¹² The amine unit affected only quality, so, even in its absence, the well might be capable of producing a marketable quantity of gas.

The court noted that the *Anadarko* standard requires that the potential production from turning on the well be profitable: “There must be facilities located near enough to the well that it would be economically

11. *Anadarko Petrol. Corp. v. Thompson*, 94 S.W.3d 550, 558 (Tex. 2002).

12. *Blackmon v. XTO Energy*, 276 S.W.3d 600, 603 (Tex. App.—Waco 2008, no pet.).

feasible to establish a connection so that production could be marketed at a profit,” and “income from the sale of the gas must exceed production and marketing costs.”¹³ The court found that the Biggs #1, which was connected to a pipeline and capable of producing a high volume of gas at the wellhead, met these criteria. Any post-production equipment installed “to refine the raw product to marketable form” was not considered in the test from Anadarko.¹⁴

The court thus held that the Biggs #1 was capable of producing in paying quantities even while it was shut in and affirmed the trial court’s order of summary judgment for the defendants. (In a section of the case not summarized here, the court rejected the Blackmons’ second claim that failure to pay shut-in royalties should result in termination of the lease. It held that the lease’s shut-in royalty clause was a covenant and that suit for money damages, not lease termination, was the proper means of enforcement.)

4. XTO Energy Inc. v. Smith Production Inc., No. 14-07-00069-CV, 2009 WL 442003 (Tex. App.—Houston [14th Dist.] Feb. 24, 2009, pet. filed).

Issue: Can parties to a Joint Operating Agreement change their elections to not participate in the drilling of new wells?

In August 2004 XTO Energy closed an asset purchase agreement with Chevron whereby it became a non-operating working-interest owner under a Joint Operating Agreement (“JOA”) to work a prospect called the Bloomberg Lease. Smith Production was the operator in the JOA.

In June 2004, before XTO had succeeded Chevron’s interest in the lease, Smith gave written notices of a proposal to drill four more wells on the lease to all of the non-operating interest owners. On June 17, 2004, Chevron notified Smith that it did not wish to participate. At this time elections to participate had been made by all other interest owners. On June 24, 2004, Chevron sent a letter to Smith indicating that the previous letter had been sent in error and informed Smith that it wished to participate.

The parties used a JOA based on an American Association of Petroleum Landmen template, which stated that after receiving notice of another JOA party’s intent to drill, parties “shall have thirty days after receipt of the notice within which to notify the party wishing to do the work whether they elect to participate in the cost of the proposed

13. *Id.*

14. *Id.*

operation.”¹⁵ Chevron’s second communication, indicating that it intended to take part in the drilling, came within thirty days of Smith giving notification of intent to drill. Smith responded, however, that Chevron could not revoke its previous election, and, upon XTO succeeding in Chevron’s interest, Smith applied the non-consent provision to XTO. In December 2004 XTO filed suit for breach of contract alleging that Smith had breached by not accepting Chevron’s notifications that it wished to change its election to participate in the wells.

As a matter of apparent national first impression, the Houston Fourteenth Court of Appeals ruled that—absent explicit language to the contrary—a party to a JOA does not have the ability to change an election not to participate in proposed drilling after it has given notice of its election to the proposing party. The court stated that “once a receiving party timely gives notice of its election regarding the drilling operation by properly replying within the thirty days, the Notice Period has expired as to that party.”¹⁶

The court rejected XTO’s argument that a party is entitled to change its election within thirty days after receipt of notice, provided that the other parties have not materially changed their positions in reliance on the initial election. The court said allowing such an interpretation would “introduce uncertainty as to whether each party is a Consenting Party or a Non-Consenting Party” because it would allow non-consenting parties to become consenting parties as long as they did so during the 30-day notice period.¹⁷

The court left open the possibility for parties to draft JOAs that include a mechanism allowing parties to change erroneous elections. This would apparently require alteration of the model form, however.

(In an additional section of the case not summarized here, the court considered certain evidence of custom and trade usage from an industry expert that XTO had submitted. The court ruled that XTO had not sufficiently proven that the evidence was custom and trade usage, and it was not taken into consideration in the court’s construction of the agreement.)

15. AM. ASS’N OF PETROL. LANDMEN, MODEL FORM OPERATING AGREEMENT 610-1982 (1982).

16. XTO Energy v. Smith Production, No. 14-07-00069-CV, 2009 WL 442003, at *5 (Tex. App.—Houston [14th Dist.] Feb. 24, 2009, pet. filed).

17. *Id.* at *6.

B. CHANGES IN WIND ENERGY LAW AND REGULATION IN TEXAS

DIANA M. LIEBMANN*

I. BRIEF HISTORY OF THE CREZ PROCESS	374
II. LEGAL STANDARDS FOR TRANSMISSION	376
III. CONTESTED CASE TO DESIGNATE CREZS AND TRANSMISSION FOR CREZS	377
IV. THE TSP SELECTION RULEMAKING AND TSP SELECTION DOCKET.....	379
V. DISPATCH PRIORITY.....	380
VI. NEXT STEPS.....	381

Texas not only leads the nation in wind energy generation but also has set a course toward expanding the amount of wind generation in the state to take advantage of this abundant natural energy source. Renewable energy has competed favorably with non-renewable generation resources over the past several years, as fuel costs for non-renewable generation have multiplied. Recently, the demand for power and fuel has ebbed with the downturn of the economic cycle. Given the expected timing of wind-related statutory and regulatory changes, however, much of Texas's new wind generation will be coming on-line between 2012 and 2014, long after the economic cycle has shifted.

The Competitive Renewable Energy Zone ("CREZ") legislation—passed by the Texas Legislature in 2005—recognizes the value of wind generation by implementing a renewable portfolio standard, which requires that installed wind generation reach certain levels through 2015.¹⁸ Given the current number of wind projects already underway, Texas may surpass the 2015 level by 2010. At the time of this article's drafting a new legislative session had just begun, which may impact the work that the Public Utility Commission of Texas ("PUCT" or "Commission") is doing in developing and implementing regulations to meet the legislature's objectives. As a result, it is possible that new

* Diana Liebmann is a Partner in the Energy and Power Practice Group of Haynes and Boone, LLP. Ms. Liebmann represents clients in regulatory matters before the Public Utility Commission of Texas, the Federal Energy Regulatory Commission, the Electric Reliability Council of Texas, the Southwest Power Pool, and in various state commission proceedings. Ms. Liebmann represents clients in corporate and transactional matters, including project development, and in drafting and negotiating power purchase agreements for both long-term and short-term sales including the sale of renewable energy credits.

18. TEX. UTIL. CODE ANN. § 39.904 (Vernon 1998 & Supp. 2007) (codifying the Public Utility Regulatory Act).

statutory provisions and regulations relating to CREZ generation or CREZ transmission will be implemented.

In November 2007 the PUCT released its Interim Order on Competitive Renewable Energy Zones.¹⁹ The Interim Order designated five zones as CREZs. The Commission requested that the Electric Reliability Council of Texas (“ERCOT”) develop transmission plans to provide transfer capacity at multiple levels of wind generation. In April 2008 ERCOT released the CREZ Transmission Optimization Study to identify the key transmission infrastructure.²⁰ In August of 2008 the PUCT issued a Final Order designating CREZs and adopting a transmission plan, and it issued its Order on Rehearing in October of 2008 providing additional clarification as to the CREZ developers.

The Commission’s Final Order results in large transmission build-outs to accommodate tens of thousands of megawatts (“MW”) of new wind generation in Texas. Construction of this transmission will be the largest coordinated transmission build-out that ERCOT has undertaken. This new CREZ-related transmission will enable wind generation from wind rich areas of Texas to access the more densely populated areas in the ERCOT market, resulting in fuel cost savings and lower overall costs for generation. As a result, the CREZ process is not only about new wind generation but is also about readying ERCOT’s transmission infrastructure to support this new generation and benefiting the market and end-consumers by diversifying the generation portfolio. The substantial additions of wind generation will result in Texas consumers enjoying energy-cost savings that are projected to outweigh the cost of building this new transmission within the first 17 months of the wind generation being on-line.²¹

The Public Utility Regulatory Act (“PURA”) charges the PUCT with implementing statutory requirements to increase wind generation and to provide transmission for certain competitive renewable energy generation.²² The PUCT has made decisions that, following the completion of multiple additional Commission proceedings, will result in the construction of transmission to serve 12,000 MW of new wind generation and provide needed transmission to more than 6,000 MW of

19. See Pub. Util. Comm’n of Tex., *Interim Order on Reconsideration*, Docket No. 33672 (Nov. 11, 2007) [hereinafter *Interim Order*].

20. See Pub. Util. Comm’n of Tex., *ERCOT’s CREZ Transmission Optimization Study*, Docket No. 33672, at 10 (Nov. 6, 2007).

21. See ELEC. RELIABILITY COUNCIL OF TEX., ANALYSIS OF TRANSMISSION ALTERNATIVES FOR COMPETITIVE RENEWABLE ENERGY ZONES IN TEXAS 46 (2006), available at http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf; see also Pub. Util. Comm’n of Tex., *Rebuttal Testimony of Brendan Kirby*, Docket No. 33672, at 16 (Nov. 6, 2007).

22. TEX. UTIL. CODE ANN § 39.904(g).

existing or “base case” generation. This article will discuss the decisions made by the Commission to date and the additional regulatory proceedings and decisions necessary to reliably achieve both growth in wind generation development and the expanded transmission capacity this new generation will require.

Only two of the necessary proceedings have actually been finalized. The first proceeding established a rule, PUCT Substantive Rule 25.174 (the “CREZ Rule”), to implement CREZ-related amendments to the Utilities Code that were adopted in Senate Bill 20 of the 2005 legislative session. The CREZ Rule provides the road map for the designation of CREZs and the procedural process for subsequent dockets. Following the adoption of the CREZ Rule, a contested case was initiated to select the Competitive Renewable Energy Zones, as required by the rule. The Final Order was issued in that proceeding on October 7, 2008, but Texas Industrial Energy Consumers appealed the decision in the Travis County District Court.²³ As such, that decision is not yet final.

The second finalized proceeding requires the transmission to be “cost-effective and beneficial to consumers” in accordance with PURA § 39.904. In the rulemaking initiated to interpret this requirement, adopted as PUCT Substantive Rule 25.216 (“TSP Selection Rulemaking”), the Commission determined that competition among transmission service providers (“TSPs”) would be most “cost-effective and beneficial.”²⁴ The TSP Selection Rulemaking required that each TSP submit a CREZ Transmission Plan Proposal that includes the CREZ facilities the TSP seeks to build.²⁵ In submitting its proposal to the PUCT, a TSP must include very detailed information, though not in accordance with any specific format. The rule requires the information to be submitted to include: (1) the process by which the TSP will prepare its Certificate of Convenience and Necessity (“CCN”); (2) descriptions of the actual facilities including types of towers to be used; (3) right of way widths; (4) discussion of the capability and experience of the interested TSP that would enable it to comply with PUCT and ERCOT rules and regulations; (5) a discussion of business practices; (6) prior violations by the interested TSP; and (7) the estimated costs in current dollars for the engineering, procurement, and construction.²⁶ Another key requirement for a TSP is

23. *Tex. Indus. Energy Consumers v. Pub. Util. Comm’n of Tex.*, No. D-1-GN-08-004631 (419th Dist. Ct., Travis County, Tex. filed Dec. 22, 2008).

24. *See* 16 TEX. ADMIN. CODE § 25.216(d) (2009) (Pub. Util. Comm’n of Tex., Selection of Transmission Service Providers).

25. *Id.* § 25.216(c)-(d).

26. *Id.* § 25.216(e).

the demonstration of the financial capability to own, operate, and maintain transmission facilities in the ERCOT market.²⁷

The TSP Selection Rulemaking was completed on May 22, 2008, and the rule was not appealed. Following completion of the TSP Selection Rulemaking, the Commission initiated a contested case to implement the rule and select the TSPs in accordance with the rule. That case, PUCT Docket No. 35665 (the “TSP Selection Docket”), has not yet concluded.

Before construction of transmission can begin, several dockets will have to be initiated and completed. The contested case to determine TSP Selection must be finalized. A Final Order was issued in Docket No. 35665 on March 30, 2009, and the Order on Rehearing was adopted on May 8, 2009, but it is expected that additional motions for rehearing and appeals will be filed. Each selected TSP must file a CCN case to receive authorization from the PUCT in order to own and operate designated transmission lines. The Lower Colorado River Authority has already filed the first CCN application in Docket No. 36686, but many more will follow. The rulemaking relating to the dispatch of CREZ generation on these new CREZ transmission lines must also be completed, and, finally, the contested case designating which wind generators are entitled to dispatch priority must be completed.

I. BRIEF HISTORY OF THE CREZ PROCESS

The amount of wind energy developed in Texas has surpassed that of all other areas of the country for roughly two years. However, although Texas’s wind energy portfolio is rapidly growing, it faces a substantial hurdle commonly called the “chicken and egg” conundrum. Wind generation can be sited quickly but the transmission capacity required to accommodate that wind generation takes substantially longer to build. As a result, developers recognize that if they build wind facilities, they may not have adequate access to transmission for some period of time. Transmission construction can take years to complete, so this period can be very lengthy. The decision to build wind generation facilities thus depends in part on available transmission infrastructure. Similarly, transmission infrastructure is not upgraded unless and until there is enough generation sited to require upgrades. Consequently, the conundrum arises: transmission upgrades cannot be made until wind generation is sited, and wind generation cannot be sited because there is a lack of transmission infrastructure.

One of the reasons Texas has become a leader in wind development is the passage of legislation instituting a Renewable Portfolio Standard and

27. *Id.*

setting forth a plan to overcome this “chicken and egg” situation. Without a national Renewable Portfolio Standard, decisions have been left to the states as to the amount of renewable energy to be built. In 1999 the Texas Legislature enacted PURA § 39.904, which mandated a target for renewable energy generating capacity. By adding § 39.904(g) in 2005 as part of the Senate Bill 20 Amendments, the Legislature asked the Commission to identify where the best wind resources in Texas are located, to designate these areas as CREZ zones, and to make sure that enough transmission is built to move the CREZ wind power from those areas to market.²⁸ At the same time, the Legislature sought to ensure that the transmission built to serve this new wind generation would be constructed in the most cost-effective and beneficial manner for Texas consumers.

The Senate Bill 20 Amendments became effective in 2005, and the CREZ process did not begin in earnest until January of 2006. The Commission opened a rulemaking proceeding to determine how best to accomplish the objectives of the Legislature—especially given the modified legal standards in PURA § 39.904—and to expedite the regulatory process associated with the construction of transmission for wind generation.

It is important to note that during this time, and continuing today, wind generators have sited generation along transmission lines that could not accommodate the large influx of generation. As a result there have been massive curtailments of wind generation at significant cost to impacted wind generators unable to sell their power while it is curtailed. Another consequence of this curtailment was that this generation could not reach load centers, and market prices did not reflect the benefits of this no-fuel cost generation. This will continue to be the case for thousands of MW of wind generation in Texas until the CREZ transmission is energized. Ultimately, the Commission adopted the CREZ Rule on December 15, 2006, in PUCT Docket No. 31852 as the road map to the development of wind generation in Texas and to the provision of transmission service to Texas’s excellent wind resources.²⁹

PURA § 39.904 also places corresponding burdens on wind developers, who will only have access to CREZ transmission if they make a financial commitment to build wind generation in a CREZ.³⁰ It is important to note that other “non-wind” generators in ERCOT are not required to make any similar type of financial commitment. CREZ wind

28. TEX. UTIL. CODE ANN. § 39.904 (Vernon 1998 & Supp. 2007).

29. 16 TEX. ADMIN. CODE § 25.174 (2009) (Pub. Util. Comm’n of Tex., Competitive Renewable Energy Zones).

30. TEX. UTIL. CODE ANN. § 39.904.

developers have been asked to provide this financial commitment because the transmission is being built to serve their generation. Their financial commitment ensures sufficient wind generation will be built and ready to interconnect upon the new transmission's completion. Under PURA § 39.904(g), the financial commitment is a required consideration in selecting a CREZ for designation. Significantly, the access to or use of CREZ transmission by CREZ developers has yet to be determined and is the subject of the Dispatch Priority rulemaking in Project No. 34577, which is currently in process at the PUCT.

II. LEGAL STANDARDS FOR TRANSMISSION

The traditional legal standard for recovery of transmission costs through electric utility rates ultimately charged to consumers is that the transmission be demonstrated to be "used and useful".³¹ That is, the transmission must be constructed, operational, and able to deliver electric power to market prior to the Commission approving the utility's recovery of transmission investment through rates.

The Commission is charged with granting or denying a transmission service provider the right to construct transmission pursuant to the CCN process established in PURA § 37.056 and PUCT Substantive Rule 25.101. If the PUCT does not grant a CCN for a particular transmission line, the utility will not have the condemnation authority required to get right of way for new transmission lines. The utility also would not be able to recover the costs for construction through the statewide cost recovery mechanism. In traditional contested CCN cases before the Commission, the "used and useful" standard is applied to the particular transmission upgrade for which the CCN is sought.

Significantly, the "used and useful" standard will not be applied in the CREZ CCN cases, though there will still be CCN cases for all of the transmission upgrades resulting from the CREZ process. To understand the CREZ process and timing, it is important to understand not only the CREZ orders and rules but also the transmission approval process. Not only does the CCN process provide the transmission provider with certain legal rights to construct and to be eligible to recover costs for transmission, it also establishes the routing of all the lines. Following CREZ designation and selection of transmission providers, multiple CCN cases will have to be initiated and completed prior to construction of transmission.³² It is important to note that in the Order on Rehearing in

31. See 16 TEX. ADMIN. CODE § 25.231(c)(2) (2009) (Pub. Util. Comm'n of Tex., Cost of Service) (requiring that transmission be "used and useful" prior to including the cost of transmission in the rate base).

32. See *id.* §§ 25.101 (Pub. Util. Comm'n of Tex., Certification Criteria), 25.174.

Docket 35665 (selecting TSPs to build CREZ transmission), the Commissioners determined that the gathering or collection facilities that bring generation to the CREZ transmission lines are not “CREZ transmission facilities” and therefore CCNs for such lines remain subject to the “used and useful” standard in the CCN approval process.

III. CONTESTED CASE TO DESIGNATE CREZS AND TRANSMISSION FOR CREZS

When the Commission adopted the CREZ Rule, the legal standard for construction of transmission was modified from “used and useful”. While the “used and useful” standard is helpful in ensuring that only necessary transmission is built, it also creates the “chicken and egg” problem. To ensure that transmission would be utilized by CREZ wind developers, the Commission imposed other standards in the CREZ Rule, including the following criteria to be considered by the Commission in determining whether to designate an area as a CREZ:

- (A) Whether renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies;
- (B) The level of financial commitment by generators; and
- (C) Any other factors considered appropriate by the Commission as provided by PURA, including, but not limited to, the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone, and the estimated benefits of renewable energy produced in the candidate zone.³³

As a result, in the contested case designating the CREZs in PUCT Docket No. 33672, the Commission met the standards required by the CREZ Rule. Consistent with the rule, the final order specified: the geographic extent of each CREZ, the major transmission improvements required to deliver the CREZ generation in the manner most beneficial and cost-effective to consumers, an estimate of the maximum generating capacity that the Commission expects the transmission to accommodate, and any other criteria deemed appropriate by the Commission and consistent with PURA.³⁴

The Preliminary Order adopted by the Commission required that the testimony filed in the docket address several significant issues, including the designation of the CREZs, review of financial commitments, the relevant power region with which the generation should interconnect,

33. *Id.* § 25.174(a)(4).

34. *See id.* § 25.174(a)(5).

and the transmission improvements.³⁵ The Commission entered an Interim Order that (1) established the general geographic areas of the state that will be CREZs; (2) determined the developers that had shown adequate financial commitment; and (3) made the determination that the power region the CREZ generation will interconnect with is the ERCOT power region instead of the Southwest Power Pool.³⁶

The Interim Order also established four scenarios with varying levels of CREZ MW for which ERCOT would analyze the build-out of transmission to serve the varying amounts of CREZ capacity:

The transfer capability scenarios set forth below begin at a low for Scenario 1 of 5,150 MW, which is the shortfall between the 2007 ERCOT base case of 4,850 MW and the 10,000 MW statutory target for renewable energy provided in PURA § 39.904(a), and a high for Scenario 3, which is determined by adding the total megawatt capacity of development proposed for each designated CREZ. Scenario 4 divides the sum of the total megawatt capacity proposed for the zones desired by Commissioner Parsley among all the zones designated by the Commission, with the exception of zone 4 and that portion of zone 2A that encompasses zone 1.³⁷

The Commission ultimately selected Scenario 2, meaning that roughly 50% of the planned CREZ area generation selected in the Interim Order will have transmission, provided that non-CREZ developers that did not participate in the docket do not site their generation along these CREZ transmission paths.

	Scenario 2 (MW)
Zone 2A	3,191
Zone 4	2,393
Zones 5/6	1,859
Zone 9A	3,047
Zone 19	1,063
CREZ transfer capability	11,553
Total transfer capability	16,403

Once the Commission determined the total MW to be served, ERCOT was ordered to develop transmission plans supporting the Scenarios. ERCOT's Transmission Optimization Study, which included base case and CREZ generation to be served, was filed in the CREZ proceeding by

35. Pub. Util. Comm'n of Tex., *Preliminary Order*, Docket No. 33672, 2 (Mar. 23, 2007).

36. See *Interim Order*, *supra* note 19, at 1-38.

37. *Id.* at 9.

ERCOT on April 2, 2008. In addition to requesting transmission plans with infrastructure to support the four Scenarios of CREZ MW, the Commission had also asked what impact the addition and integration of new CREZ generation would have on the reliability of ERCOT operations. General Electric Company performed an ancillary services study examining the impacts of reliably integrating 15,000 MW of wind and concluded that such wind penetration could be reliably sustained.

The selection of Scenario 2 resulted in the plan for major transmission improvements associated with CREZ reflected in Appendix 1, which follows this article.³⁸ The plan incorporates Panhandle areas of the state previously considered to be in the Southwest Power Pool.

IV. THE TSP SELECTION RULEMAKING AND TSP SELECTION DOCKET

The Commission's determination that the "most beneficial and cost-effective" transmission would be achieved through a competitive selection of transmission service providers led it to adopt a rule that relates to TSP selection specifically for CREZ transmission.³⁹ The selection of TSPs is to occur in the TSP Selection Docket, a contested case that has been completed at the PUCT (although the decision is expected to be appealed).⁴⁰

Several TSPs presented testimony seeking to be selected for various transmission projects in the ERCOT Optimization Study, including incumbent TSPs, electric cooperatives, municipally-owned utilities ("MOUs"), and new market entrants. Certain projects were designated "default" projects, as only one TSP sought to build those projects.

No MOUs were selected to build CREZ transmission because the MOUs took the position that the Commission could not exercise authority over them, despite the fact that they might have been building transmission outside of their service territories. It is difficult to determine the weighting the Commission gave to various TSPs in making the selection because no uniform filing was required. Testimony from the TSPs was extremely voluminous and did not lend itself to easy comparison.

Several primarily incumbent TSPs filed a joint proposal. One, ETT, had recently been granted a CCN by the Commission, which was later appealed. The District Court reversed the Commission's granting of the

38. Appendix 1 provides a list of each transmission improvement and the name of the TSP it was assigned to.

39. 16 TEX. ADMIN. CODE § 25.216 (2009) (Pub. Util. Comm'n of Tex., Selection of Transmission Service Providers).

40. Pub. Util. Comm'n of Tex., *Commission Staff's Petition for the Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable Energy Zones*, Docket No. 35665 (May 21, 2008).

CCN, stating that a TSP must also have a distribution service territory.⁴¹ Since new entrant TSPs were selected to build CREZ transmission, that decision must be either overturned on appeal or harmonized because all of the new entrant TSPs would be serving transmission customers and not distribution customers; new entrants will have no distribution service territory within the state.

V. DISPATCH PRIORITY

The Dispatch Priority Proceeding in PUCT Project No. 34577 is the rulemaking established by the PUCT to determine if and how CREZ generators will be given preference in using the CREZ transmission for which their financial commitments ensured construction. The financial commitment (to be posted 45 days following the filing of a CCN case) is required before CREZ transmission can be built, but only for CREZ generators.⁴² The CREZ transmission, however, will be open to any generators that seek to use it.

The concept of dispatch priority in § 25.174(e) of the CREZ Rule seeks to ensure CREZ generators the use of CREZ transmission by allowing them to be selected first to run. This can be accomplished through several different mechanisms currently being discussed.

The first is the “do nothing” option. This would entail allowing non-CREZ generators (that site during and after the building of the CREZ transmission) to use the transmission and potentially squeeze out CREZ generators.

A second option is to use Congestion Revenue Rights (“CRRs”) that are open to auction by CREZ generators to hedge against risk. However, CRRs are a financial hedge only, and they value the risk with the CRR payment. As a result, the use of the CRR in this scenario should be a wash, not providing any true benefit to CREZ generators relating to CREZ transmission. A CRR also may not compensate a wind generator for the production tax credit that is lost by having that generator’s wind turbines idled.

The third option is the Automated Offer Curve (“AOC”) approach. This would submit varying bid curves for CREZ generators to ERCOT to ensure that those generators are selected to run first and to allow the generator to recover the production tax credit.

41. *City of Harlingen v. Pub. Util. Comm’n of Tex.*, No. D-1-GV-08-00253 (345th Dist. Ct., Travis County, Tex., Oct. 8, 2008), *appeal docketed*, No. 03-08-00793-CV (Tex. App.—Austin Dec. 31, 2008).

42. 16 TEX. ADMIN. CODE § 25.174(c)(6) (2009) (Pub. Util. Comm’n of Tex., Competitive Renewable Energy Zones§).

It is unclear how long a dispatch priority mechanism would be in place. Although there have now been two workshops as well as comments filed in the Dispatch Priority Project, no draft rule has been circulated or proposed for publication. It is unclear when a draft proposal will be offered, though it is possible that a draft rule will be circulated in June or July of 2009.

VI. NEXT STEPS

The TSP Selection has been finalized at the PUCT, and the designated TSPs have one year to prepare their respective CCNs for filing. During this time, both the CREZ Docket 33672 appeal and the ETT CCN appeal will continue; the TSP Selection proceeding will also likely be appealed; and the dispatch priority proceeding will proceed. It is also possible that this year a dispatch priority contested case will be initiated to designate which entities will receive dispatch priority and at what level.

With all of these proceedings to follow, it will be challenging to construct CREZ transmission beginning in 2012, though the transmission is increasingly needed and the process is steadily moving forward. The earlier the transmission is completed, the sooner wind generation will be able to provide downward pressure on generation prices for Texas consumers in the ERCOT market.

APPENDIX 1

The following is Exhibit B from the Commission's Final Order in Docket 35665. This chart describes all of the transmission projects that were assigned to Transmission Service Providers in that docket. These projects will be built in order to bring electricity generated in the CREZs onto the ERCOT grid and to load.

Description	Miles	New/Upgrade Existing	Cost (\$M)	Designation	1/29/09 Selected TSP
300 MVAR Cap Bank on Oklaunion		New	11.00	Default* (priority dependent)**	AEP TNC
Upgrade terminal equipment on Abilene to Mulberry 138-kV line		Upgrade Existing	1.00	Default	AEP TNC
Upgrade Abilene South to Leon 138-kV line [AEP TNC portion of line as depicted in Oncor proposal, Map O]	56	Upgrade Existing	56.00	Default	AEP TNC
Open the Saps to Yellowjacket 138-kV line			0.00		AEP TNC
Open the Bradshaw to Winters 69-kV line			0.00		AEP TNC
Open the Fort Stockton to Barilla 69-kV line			0.00		AEP TNC
		AEP TNC Total	<u>68.00</u>		
Add 138-kV auto at Bandera		New	4.00	Default	Bandera
Rebuild Verde Creek to Bandera	16	New	16.00	Default	Bandera
		Bandera Total	<u>20.00</u>		

No. 2]

RECENT DEVELOPMENTS

383

Add a 345-kV auto at Whitney		New	5.00	Default	Brazos
		Brazos Total	<u>5.00</u>		
Panhandle A C to PanOakMid double-circuit 345-kV line (One circuit looping into Tesla 345 bus. Line from Tesla to PanOakMid is 2-1433 ACSS) <i>[Panhandle A C to Tesla portion; mileage as depicted in Appendix B of Lone Star post-hearing brief]</i>	80	New	136.69		Cross Texas
PanhandleB B to Oklaunion double-circuit 345-kV line (One circuit looping into Tesla 345-kV bus) <i>[Panhandle B B to Tesla portion; as depicted in CTO Study Scenario 4]</i>	105	New	176.72		Cross Texas
50% compensation on Panhandle A C to Tesla		New	25.00		Cross Texas
Panhandle B B to Panhandle B A double-circuit 345-kV line	37	New	62.16		Cross Texas
50 MVAR Reactive Compensation on PanhandleB B		New	2.00		Cross Texas
		Cross Texas Total	<u>402.57</u>		

Oklaunion to PanOakMid double-circuit 345-kV line	62	New	104.16		ETT
Panhandle A C to PanOakMid double-circuit 345-kV line (One circuit looping into Tesla 345 bus. Line from Tesla to PanOakMid is 2-1433 ACSS) [<i>Tesla to PanOakMid portion, mileage as depicted in Appendix B of Lone Star post-hearing brief</i>]	25	New	42.71		ETT
Panhandle A D to PanOakMid double-circuit 345-kV line	37	New	62.16		ETT
Panhandle B B to Oklaunion double-circuit 345-kV line (One circuit looping into Tesla 345-kV bus) [<i>Tesla to Oklaunion portion as depicted in the CTO study, scenario 4</i>]	45	New	75.28		ETT
PanOakMid to Central C double-circuit 345-kV line	117	New	219.96		ETT
50% compensation on PanOakMid to Central C		New	60.00		ETT
Tesla 345-kV station		New	20.00		ETT
100 MVAR Reactive Compensation on Tesla		New	3.00		ETT
150 MVAR Cap Bank on Tesla		New	6.00		ETT
PanOakMid 345-kV station		New	15.00		ETT
200 MVAR Cap Bank on PanOakMid		New	9.00		ETT

No. 2]

RECENT DEVELOPMENTS

385

200 MVAR Reactive Compensation on PanOakMid		New	5.50		ETT
Central B to Willow Creek double-circuit 345-kV line <i>[Central B to area identified in CTO study, scenario 1B as Clear Crossing portion]</i>	68	New	127.84		ETT
50% compensation on Central B to Willow Creek <i>[One-half of this project's total series compensation is assigned to ETT.]</i>		New	30.00		ETT
50% compensation on McCamey D to Kendall		New	60.00	Priority Dependent	ETT
		ETT Total	840.61		
Gillespie to Newton single-circuit, double-circuit-capable 345-kV line	105	New	136.50	Priority	LCRA
Kendall to Gillespie single-circuit, double-circuit-capable 345-kV line	18	New	23.40	Priority	LCRA
Mason to Pittsburg 138-kV line	18	New	18.00		LCRA
McCamey A to Odessa single-circuit, double-circuit-capable 345-kV line	50	New	70.00		LCRA
McCamey B to North McCamey 138-kV line on existing structures	15	New	3.75	Default	LCRA
Add 2 345-kV autos at North McCamey		New	16.00	Default	LCRA
Close the bus ties at North McCamey bus			0.00		LCRA

McCamey C to McCamey A single-circuit, double-circuit-capable 345-kV line	12	New	16.80		LCRA
McCamey D to Kendall double-circuit 345-kV line	137	New	257.56	Priority	LCRA
McCamey D to Twin Butte single-circuit, double-circuit-capable 345-kV line	31	New	46.50	Priority	LCRA
100 MVAR Reactive Compensation on McCamey D		New	3.00	Priority Dependent	LCRA
Rebuild Kendall CTEC to Kendal 138-kV line	0.09		0.09	Default (priority dependent)	LCRA
Replace 345-kV auto at Kendall		New	8.00	Default (priority dependent)	LCRA
Rebuild Raymond Barker to Verde Creek 138-kV line	2		2.00	Default	LCRA
Rebuild the Goldthwaite to Evant 138-kV line		Upgrade Existing	25.00	Default	LCRA
Add second circuit to existing towers on Divide to Twin Butte	25	New	7.00	Default	LCRA
Gillespie 345-kV station		New	20.00	Default (priority dependent)	LCRA
100 MVAR Reactive Compensation on Gillespie		New	3.00	Default (priority dependent)	LCRA
Add a 345-kV auto at Gillespie		New	8.00	Default (priority dependent)	LCRA

No. 2]

RECENT DEVELOPMENTS

387

Twin Buttes to Brown 345-kV line on existing structures [Twin Buttes to Brown County line portion, as depicted in Oncor proposal, Map N]	94	New	28.20	Priority & Default	LCRA
Upgrade terminal equipment on Morgan Creek to Twin Buttes 345-kV line [split responsibility 50/50 with Oncor]		Upgrade Existing	1.50	Default (priority dependent)	LCRA
		LCRA Total	694.30		
Central A to Central C double-circuit 345-kV line	75	New	141.00		Lone Star
Central C to Navarro/Sam Switch double-circuit 345-kV line (148/168 miles)	168	New	308.24		Lone Star
50% compensation on Central C to Navarro/Sam Switch		New	60.00		Lone Star
150 MVAR Reactive Compensation on Central C		New	4.50		Lone Star
Navarro 345-kV station		New	30.00		Lone Star
Sam Switch 345-kV station		New	20.00		Lone Star
		Lone Star Total	563.74		
Bluff Creek to Brown double-circuit 345-kV line	75	New	141.00	Priority	Oncor
Central A to Tonkawas double-circuit 345-kV line	43	New	80.84	Priority	Oncor

Central B to Central A double-circuit 345-kV line	12	New	22.56	Priority	Oncor
100 MVAR Reactive Compensation on Central A		New	3.00	Priority Dependent	Oncor
Central B to Willow Creek double-circuit 345-kV line <i>[area identified in CTO study, scenario 1B as Clear Crossing to Willow Creek portion]</i>	100	New	188.00		Oncor
50% compensation on Central B to Willow Creek [One-half of this project's total series compensation is assigned to Oncor.]		New	30.00		Oncor
150 MVAR Reactive Compensation on Central B		New	4.50	Priority Dependent	Oncor
Central Bluff to Bluff Creek double-circuit 345-kV line	6	New	11.28	Priority	Oncor
Eagle Mountain-Hicks-Alliance-Roanoke 345-kV line terminal equipment		Upgrade Existing	2.00	Default	Oncor
Add 345-kV auto at Eagle Mountain		New	8.00	Default	Oncor
Newton to Killeen 345-kV line	26	New	7.28	Priority	Oncor
Oklunion to West Krum double-circuit 345-kV line	106	New	199.28		Oncor
Parker to Everman E 345-kV line on existing structures	110	New	30.80	Default	Oncor
Rebuild Jacksboro to Willow Creek 345-kV as double-circuit	18	Upgrade Existing	33.84	Default	Oncor

No. 2]

RECENT DEVELOPMENTS

389

Rebuild Willow Creek to Parker 345-kV as double circuit	18	New	33.84	Default	Oncor
Reconductor Bowman to Jacksboro 345-kV line	37	Upgrade Existing	9.62	Default	Oncor
Sweetwater to Central Bluff double-circuit 345-kV line	25	New	47.00	Priority	Oncor
Tonkawas to Sweetwater double-circuit 345-kV line	18	New	33.84	Priority	Oncor
Upgrade terminal equipment on Bowman to Fisher Road 345-kV line		Upgrade Existing	1.00	Default (priority dependent)	Oncor
Upgrade terminal equipment on Bowman to Graham 345-kV line		Upgrade Existing	1.00	Default (priority dependent)	Oncor
Upgrade terminal equipment on Roanoke to Alliance 345-kV line		Upgrade Existing	1.00	Default	Oncor
West B to Moss single-circuit 138-kV line	6	New	6.00		Oncor
West Krum to Anna double-circuit 345-kV line	43	New	80.84		Oncor
West Krum to Carrolton NW 345-kV line on existing structures	60	New	16.80	Default	Oncor
Willow Creek to Hicks double-circuit 345-kV line	31	New	58.28		Oncor
Bowman to Oklaunion double-circuit 345-kV line	37	New	62.16	Priority	Oncor

Brown to Newton/Salado double-circuit 345-kV line (Newton line is 2-1433 ACSS/TW and Salado line is 2-1590)	88	New	132.80	Priority (Killeen - Salado portion is also Default)	Oncor
Brown 345-kV station		New	15.00	Priority Dependent	Oncor
150 MVAR Reactive Compensation on Brown		New	4.50	Priority Dependent	Oncor
Hicks 345-kV station		New	25.00		Oncor
Newton 345-kV station		New	20.00	Priority Dependent	Oncor
West Krum 345-kV station		New	20.00		Oncor
Upgrade Abliene South to Leon 138-kV line [<i>Oncor portion as depicted in Oncor proposal, Map O</i>]	10	Upgrade Existing	10.00	Default	Oncor
Twin Buttes to Brown 345-kV line on existing structures [<i>Oncor portion as depicted in Oncor proposal, Map N</i>]	12	New	3.60	Priority & Default	Oncor
Open the Seymour to Bomarton 69-kV line			0.00		Oncor
Upgrade terminal equipment on Morgan Creek to Twin Buttes 345-kV line [<i>split responsibility 50/50 with LCRA</i>]		Upgrade Existing	1.50	Default	Oncor
		Oncor Total	1346.16		

No. 2]

RECENT DEVELOPMENTS

391

Panhandle A A to Panhandle A B single-circuit, double-circuit-capable 345-kV line	25	New	35.00		Sharyland
Panhandle A A to Panhandle A C single-circuit, double-circuit-capable 345-kV line	56	New	78.40		Sharyland
Panhandle A B to Panhandle B A single-circuit, double-circuit-capable 345-kV line	60	New	84.00		Sharyland
50 MVAR Reactive Compensation on Panhandle A B		New	2.00		Sharyland
Panhandle B A to Panhandle A C double-circuit 345-kV line	56	New	94.08		Sharyland
Panhandle A C to Panhandle A D double-circuit 345-kV line	56	New	94.08		Sharyland
100 MVAR Cap Bank on Panhandle A C		New	4.00		Sharyland
50 MVAR Reactive Compensation on Panhandle A C		New	2.00		Sharyland
		Sharyland Total	<u>393.56</u>		
McCamey C to McCamey D single-circuit, double-circuit-capable 345-kV line	75	New	105.00		STEC
		STEC Total	<u>105.00</u>		

Central D to Divide single-circuit, double-circuit-capable 345-kV line	6	New	8.40		WETT
Central E to Central D single-circuit, double-circuit-capable 345-kV line	27	New	37.80		WETT
Panhandle A D to Central B double-circuit 345-kV line	68	New	114.24		WETT
50 MVAR Cap Bank on Panhandle A D		New	2.50		WETT
50 MVAR Reactive Compensation on Panhandle A D		New	2.00		WETT
West A to West C single-circuit, double-circuit-capable 345-kV line	25	New	35.00		WETT
West A to Central D single-circuit, double-circuit-capable 345-kV line	50	New	70.00		WETT
West C to Odessa single-circuit, double-circuit-capable 345-kV line	43	New	60.20		WETT
Central A to West A double-circuit 345-kV line	43	New	72.24		WETT
		WETT Total	402.38		

No. 2]

RECENT DEVELOPMENTS

393

Rebuild Sonora to Hamilton 138-kV line	88	Upgrade Existing	88.00	Default	AEP TCC and AEP TNC
Open the Rock Springs to Friess Ranch 69-kV line [approximately 10 miles owned by AEP TNC and approximately 22 miles owned by AEP TCC]			0.00		AEP TCC and AEP TNC
		TCC/TNC Total	<u>88.00</u>		
Upgrade terminal equipment on both Singleton to Gibbons Creek 345-kV lines		Upgrade Existing	2.00	Default: TMPA and CenterPoint	TMPA and Center Point
		TMPA/CenterPoint	<u>2.00</u>		
		Total :	<u>4931.32</u>		

III. RECENT DEVELOPMENTS IN UNITED STATES ENERGY LAW

A. *Federal Oil, Gas, and Energy Case Summaries*

1. *Kerr-McGee Oil and Gas Corp. v. U.S. Department of Interior*, 554 F.3d 1082 (5th Cir. 2009).

Issue: Can the Department of Interior suspend royalty relief for certain OCS deepwater leases issued from 1996–2000 when price thresholds have been met but production thresholds have not?

The Fifth Circuit addressed the issue of when price thresholds trigger an end to royalty relief on deepwater oil and gas leases in the Gulf of Mexico. It held that the Department of Interior (“DOI”) could not charge royalties on certain Kerr-McGee leases because, although price thresholds had been met, volume thresholds applied and had not been reached.

During the period from 1996–2000, Kerr-McGee obtained eight deepwater leases in the Gulf of Mexico that were subject to royalty relief. Each of these leases contained price threshold provisions stating that payment of royalties should commence when the price thresholds were met. (The thresholds were average annual NYMEX prices of \$28.00 per barrel for oil or \$3.50 per million British thermal units (“BTU”) for gas.) All of the leases were also subject to § 304 of the Outer Continental Shelf Deep Water Royalty Relief Act (the “DWRRA”), which states that “the suspension of royalties shall be set at a volume of not less than [certain stated volume thresholds, depending on the water depth of the lease].”⁴³

In 2003 and 2004 average annual NYMEX prices exceeded the price thresholds in Kerr-McGee’s leases for gas, and in 2004 price thresholds were also exceeded for oil. Subsequently, the DOI issued a final agency order in which it determined that although § 304’s volume thresholds had not been met, it had authority to suspend royalty relief because prices had exceeded the thresholds. Kerr-McGee challenged the decision in federal district court, which granted summary judgment in favor of the oil company, ruling that the DOI did not have the authority to suspend royalty relief when production fell below the volume thresholds established by Congress in § 304.

In reviewing the district court’s grant of summary judgment, the Fifth Circuit applied the *Chevron* doctrine to the DOI’s interpretation of its

43. Pub. L. No. 104-58, 109 Stat. 557 (1995) (uncodified, but present in a note to 43 U.S.C. § 1337).

statutory authority.⁴⁴ Applying the first step in the *Chevron* doctrine's two-part test, the court inquired whether the DWRRA was ambiguous regarding the DOI's ability to charge royalties when production thresholds had not been met. The court found that § 304's statement that "the suspension of royalties shall be set at a volume not less than [stated volume thresholds]" was not ambiguous.⁴⁵ Additionally, it noted the previous Fifth Circuit decision of *Santa Fe Snyder Corp. v. Norton* in which it held that § 304 of the DWRRA "unambiguously provides that royalty suspensions apply in full to each [n]ew [l]ease qualifying under its terms."⁴⁶ Because Kerr-McGee's leases fell under § 304's royalty relief provisions, the court held that the statute was unambiguous and that the DOI's interpretation in the agency order was incorrect. It consequently affirmed the district court's ruling without having to apply the second part of the *Chevron* test.

2. *Piedmont Environmental Council v. Federal Energy Regulatory Commission*, 558 F.3d 304 (4th Cir. 2009)

Issue: Do provisions in the 2005 Energy Policy Act allow FERC to overrule timely state agency denials of electric transmission facility construction permit applications in designated national interest corridors?

The Fourth Circuit overruled an interpretation by the Federal Energy Regulatory Commission ("FERC") of certain provisions in the Energy Policy Act of 2005. The court held that, contrary to FERC's interpretation, the statutory changes did not grant FERC authority to overrule timely state agency denials of permit applications for construction or modification of electric transmission facilities in areas designated as *national interest corridors* by the Secretary of Energy.

The Energy Policy Act added a new § 216 to the Federal Power Act ("FPA"). Section 216 gives FERC limited jurisdiction over the approval of permits for transmission facility siting and construction in the national interest corridors. Among other things, it states that, in national interest corridors, FERC can issue permits for the construction or modification of transmission facilities when state regulators have "withheld approval for more than one year after the filing of an application" for a permit.⁴⁷

In a November 2006 final rulemaking, FERC interpreted the phrase "withheld approval for more than one year" to include situations where state regulators deny permits during the one-year period following a

44. *See, e.g., Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837 (1984).

45. *Kerr-McGee Oil and Gas Corp. v. U.S. Dep't of Interior*, 554 F.3d 1082, 1086-87 (5th Cir. 2009).

46. *Santa Fe Snyder Corp. v. Norton*, 385 F.3d 884, 890, 892 (5th Cir. 2004).

47. 16 U.S.C.A. § 824p(b)(1)(C)(i) (West Supp. 2008).

permit application.⁴⁸ Under this interpretation, the § 216 provision would give FERC the authority to grant permits within the national interest corridors even if the application had been denied in a timely fashion by state regulators.

The four petitioners in this case—Piedmont Environmental Council, the Public Service Commission of the State of New York, the Minnesota Public Utilities Commission, and Communities Against Regional Interconnect—filed a motion for rehearing on FERC’s interpretation, which was subsequently denied by FERC.⁴⁹ The petitioners then filed petitions for review in three different federal circuit courts. These were combined in the Fourth Circuit, and several state regulatory bodies, state attorney generals, and electric industry groups intervened and participated in the case.

The Fourth Circuit reviewed FERC’s interpretation of the statute by applying the two-step *Chevron* doctrine: first inquiring whether the statute was ambiguous, then inquiring whether the agency’s interpretation was based on a permissible construction of the statute.⁵⁰ Upon reviewing the phrase “withheld approval for more than one year,” the court found no ambiguity and held that the statutory language expressed a clear intent of congress that FERC be allowed to grant permits only when state regulators’ “action on a permit application has been held back continuously for more than one year.”⁵¹

Based on its interpretation of the statute, the court held that FERC’s interpretation was incorrect, stating that such an interpretation “would mean that Congress has told state commissions that they will lose jurisdiction unless they approve every permit application in a national interest corridor.”⁵²

Because the court ruled that the language was unambiguous, it did not reach the second step of the *Chevron* analysis. There were three additional holdings not summarized here: (1) that FERC was not required to prepare an environmental assessment or environmental impact statement in connection with its issuance of regulations; (2) that FERC violated Council on Environmental Quality (“CEQ”) regulation by revising its regulations implementing the Nation Environmental Policy Act (“NEPA”) without first consulting with CEQ; and (3) that challenges raised to amended NEPA regulations were not ripe for review.

48. Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, 71 Fed.Reg. 69,440, 69,444 (Dec. 1, 2006).

49. Order Denying Rehearing, Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, 119 FERC ¶ 61,154 (2007).

50. *See, e.g.*, *Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837 (1984).

51. *Piedmont Env'tl. Council v. Fed. Energy Regulatory Comm'n*, 558 F.3d 304, 315 (4th Cir. 2009).

52. *Id.* at 314.

B. MASTER LIMITED PARTNERSHIPS: AT THE CROSSROADS?

PHILIP H. PEACOCK*

I. INTRODUCTION	397
II. AN INTRODUCTION TO MASTER LIMITED PARTNERSHIPS	398
A. The Formation and Structure of Master Limited Partnerships.....	398
1. Parent/Sponsor.....	400
2. General Partner	400
3. Master Limited Partnership	400
4. Operating Subsidiaries.....	401
5. Public Unitholders.....	401
B. Unique Features of Master Limited Partnerships	402
1. Cash Distributions.....	402
2. Incentive Distribution Rights.....	403
3. Subordinated Units	406
C. The Advantages of the Master Limited Partnership Structure	407
D. The Disadvantages of the Master Limited Partnership Structure	410
III. THE CURRENT CHALLENGING ENVIRONMENT FOR MASTER LIMITED PARTNERSHIPS	414
IV. WHAT DOES THE FUTURE HOLD?	416
A. Return to Retail.....	416
B. Consolidation	417
C. Going Private	418
D. Emphasis on MLPs with Strong Sponsorship and Solid Drop-Down Potential	418
E. A Break from E&P MLPs	419
V. CONCLUSION	419

I. INTRODUCTION

The year 2008 was not kind to master limited partnerships (“MLPs”). The Alerian MLP Index, a widely used index based on the float-adjusted market capitalization of 50 prominent energy related MLPs, declined

* Philip H. Peacock is an associate in the Corporate/Securities section of the Houston office of Andrews Kurth LLP. He graduated from The University of Virginia School of Law in 2003 and would like to give special thanks to Mike O’Leary and Robert McNamara for their contributions to this article.

more than 36% on a total return basis during the year.⁵³ Given the breadth and depth of the market meltdown in 2008, this would not be surprising, except that MLPs have been touted as having a relatively low correlation to the broader market.⁵⁴ In addition, several MLPs cut their distributions and capital expenditure budgets while MLP yields skyrocketed as trading prices declined. All this has led some to question whether MLPs will have a significant role in the energy industry in the future. This article first offers an explanation of the MLP structure and its advantages and disadvantages. It then explores some of the reasons why the MLP market was so difficult in 2008 and offers a few predictions about the future.

II. AN INTRODUCTION TO MASTER LIMITED PARTNERSHIPS

A master limited partnership is a unique business structure that offers some significant advantages over other forms of business organization. However, master limited partnerships also have several limitations, and it was these limitations that took center stage during 2008.

A. *The Formation and Structure of Master Limited Partnerships*

A master limited partnership is a limited partnership that has publicly traded limited partner interests called common units.⁵⁵ MLPs are typically organized in Delaware because Delaware has a very flexible limited partnership statute that, among other things, provides that the liability of the general partner to the limited partners may be limited by contract.⁵⁶ Although common units are very different in several respects from the common stock of a corporation, they are bought and sold by investors on the New York Stock Exchange, the NASDAQ Stock Market, and other securities exchanges just like publicly traded shares of common stock. Some entities that are commonly referred to as MLPs are actually

53. See ALERIAN CAPITAL MANAGEMENT, MLP INDEX HISTORICAL PERFORMANCE DATA, available at <http://www.alerian.com/insight.html> (last visited May. 24, 2009) [hereinafter ALERIAN MLP INDEX] (a performance index of all publicly traded energy MLPs calculated by Standard & Poor's for the period Dec. 1995–Present.).

54. See, e.g., WACHOVIA CAPITAL MARKETS, LLC, MLP PRIMER—THIRD EDITION 7 (Jul. 14, 2008), available at <http://www.naftp.org/documentlinks/071508wacoviaprimer.pdf>; ALERIAN CAPITAL MANAGEMENT LLC, MASTER LIMITED PARTNERSHIP PRIMER 9 (2009), available at <http://www.alerian.com/MLPprimer.pdf> [hereinafter ALERIAN MLP PRIMER]. The Alerian MLP Index's decline during 2008 corresponded closely to the S&P 500's decline of 38% on a total return basis during 2008. See Standard & Poor's Index Services, S&P 500 Monthly Returns, www2.standardandpoors.com/spf/xls/index/MONTHLY.xls (showing the one year change as of Dec. 2008 to be -38.49%).

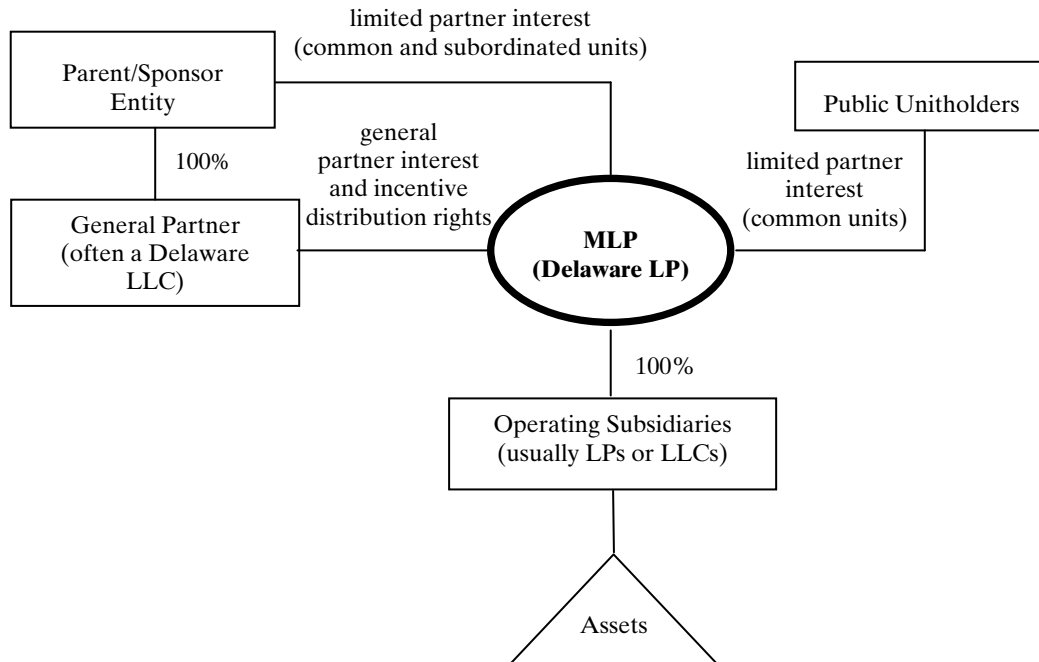
55. STANDARD & POOR'S, MASTER LIMITED PARTNERSHIPS—A PRIMER 1 (Nov. 2008), available at http://www2.standardandpoors.com/spf/pdf/index/MLP_Primer_Nov2008.pdf. MLPs do not have to be publicly traded, but for purposes of this article, we will be focusing on those that are.

56. DEL. CODE ANN. tit. 6, §§ 15-103(f), 17-403(b) (2008).

organized as limited liability companies (“LLCs”), rather than limited partnerships. Although structurally different from “true” MLPs (among other things, LLCs do not have a general partner), they are usually considered together with “true” MLPs because they have the same tax advantages. As will be discussed below, tax advantages are the *raison d’être* of the MLP structure.

There are currently over 90 publicly traded MLPs, and although there are a few MLPs that are not in the energy sector, a substantial majority of them are energy related.⁵⁷ This is because the business activities described in the provision of the federal tax code that allows MLPs to exist overlap largely, although not exclusively, with business activities carried out in the energy sector.

The diagram below shows the basic MLP structure:



57. *Hearing on Fair and Equitable Tax Policy for America's Working Families, Before the House Comm. on Ways and Means, 110th Cong. (2007)* (statement of Nat'l Ass'n of Publicly Traded P'ship).

The major roles in the formation and structure of an MLP are as follows.

1. Parent/Sponsor

The parent or sponsor of the MLP forms the limited partnership that will become the MLP and its general partner. In the typical formation transaction, the parent/sponsor is the entity that contributes the initial assets to the MLP.

2. General Partner

As with any limited partnership, an MLP must have a general partner. The general partner of an MLP has exclusive control over the operations and activities of the MLP. The limited partners cannot, in fact, have any control over the business of the MLP if they wish to maintain their limited liability for the obligations of the partnership.

The general partner is typically wholly owned by the parent/sponsor, and as a result, the parent/sponsor maintains complete control over the assets that it contributes to the MLP. There are obvious advantages to the parent/sponsor to maintaining this control, but frequently the parent/sponsor considers such control a business necessity. For example, a diversified energy company that forms an MLP may contribute to it the gathering systems that are crucial for transporting to market the oil and gas that the sponsor produces. In such a situation, the sponsor is unwilling to turn control of the assets over to a third party.

The officers and directors of an MLP typically reside at the general partner level and have the same functions and authority that the officers and directors of a corporation do. However, an MLP is not required to have the same corporate governance features as a typical publicly traded corporation. For example, MLPs need not have a majority of independent directors, a nominating/corporate governance committee, or a compensation committee,⁵⁸ although several voluntarily do so in order to enhance their corporate governance and therefore appeal more strongly to investors, particularly institutional investors.

3. Master Limited Partnership

The master limited partnership, controlled by the general partner and initially wholly owned by the parent/sponsor, is the entity that “goes public” through an initial public offering of its common units. The MLP

58. NEW YORK STOCK EXCHANGE, LISTED COMPANY MANUAL § 303A.00, *available at* <http://www.nyse.com> (follow “For Listed Companies” tab and find “Listed Company Manual” under “General Information”).

entity itself is typically an empty shell that owns no assets directly (other than its ownership interests in its subsidiaries) and has no officers, directors, or employees. By only indirectly owning its assets through subsidiaries, the MLP provides an additional degree of separation between the limited partners of the MLP and control of the MLP's business, which helps to maintain the limited liability of the limited partners. Owning assets through subsidiaries also allows operational flexibility, as new subsidiaries can be created, and existing subsidiaries can be combined or divided, with relative ease. As noted above, usually the officers and directors of an MLP are, technically speaking, officers and directors of the general partner, although they are often referred to as the officers and directors of the MLP itself. In addition, a typical MLP has no direct employees; the people who perform work for it are generally employees of the parent/sponsor, the general partner, or some other entity affiliated with the general partner.

4. Operating Subsidiaries

The typical MLP has one or more operating subsidiaries, which are almost always LLCs or limited partnerships. The operating subsidiaries are the entities that directly own and operate the MLP's assets.

5. Public Unitholders

In the MLP's initial public offering, public investors provide capital to the MLP in exchange for common units. It is not unusual for the parent/sponsor to initially sell only a small portion (15-20%) of the total limited partner interests in the initial public offering and retain the rest.

The most obvious difference between the unitholder of an MLP and the stockholder of a corporation is that unitholders have relatively little influence over the MLP or its operations. Stockholders in a corporation have numerous voting rights provided by statute, including with respect to the election of directors. Limited partners, by contrast, have only the rights provided to them by contract through the partnership agreement, and in order to maintain their limited liability, those rights are specific and limited. For example, limited partners have no right to elect the MLP's directors, who are instead appointed by the owner of the general partner, and most MLPs do not even bother to have annual meetings. The limited partners in an MLP generally only have a vote on extraordinary matters, such as mergers or removal of the general partner.

B. Unique Features of Master Limited Partnerships

One of the most important features of an MLP is its tax treatment, which is addressed separately in Section II.C below. However, MLPs have other features which make them both unique and complex.

1. Cash Distributions

At this point, one might ask why anyone would ever become a unitholder in an MLP, given that MLPs are not subject to the same corporate governance standards as typical corporations and that MLP unitholders do not have the same rights and powers that corporate stockholders have. The answer lies in the cash distributions that unitholders in an MLP receive.

When an MLP goes public, it promises to pay to its unitholders a regular, quarterly cash distribution of at least a certain amount, referred to as the *minimum quarterly distribution* (“MQD”). This promise to pay is not a legal obligation, as the MLP is not required by statute to pay cash distributions. It is not even a contractual obligation, in the sense that the MLP must pay the cash distributions “come what may.” However, the typical MLP does obligate itself, through the partnership agreement, to distribute to its unitholders all of its *available cash* each quarter. The definition of available cash is usually fairly complex, but reduced to its essence, available cash means cash flow less reserves established at the discretion of the general partner for items such as capital expenditures, operating expenditures (including debt service), and distributions to be made in the future. Although the general partner has wide discretion in establishing reserves, the unwritten understanding is that the general partner will not hold cash “just in case” and must have an identifiable reason for holding cash in reserve rather than distributing it. But it is important to note that the obligation to pay cash distributions is subject, most fundamentally, to the MLP’s having cash to distribute in the first place. If an MLP does not generate any cash during a particular quarter, the failure to pay a distribution is not a default under or breach of the partnership agreement in the way that a failure to pay interest on a note would be a default.

At first glance the cash distribution feature appears somewhat unremarkable. Many corporations pay regular dividends every quarter, and some have been doing so for decades. However, even those corporations that have been paying regular dividends for years have no *obligation*, contractual or otherwise, to continue doing so. Each quarter, a corporation with excess cash on hand has the option to pay it out in the form of a dividend, spend it as it sees fit, or hold it for any reason (or no reason). MLPs contractually obligate themselves, in advance, to

distribute all free cash in excess of amounts reserved for certain specified purposes. In addition, the *yield* of an MLP (which is calculated by multiplying its most recent quarterly distribution by four and then dividing the product by the price of its common units) is frequently higher than the dividend yield of a corporation. For example, many MLPs have gone public promising to pay their unitholders an MQD of \$0.30 per common unit per quarter, or \$1.20 per common unit per year. A unitholder who purchased a common unit for \$20.00 in the initial public offering would receive a yield of 6% a year. Even before the market crash, when MLP common unit prices were at their peak and yields were therefore at their nadir, yields of 5-6% per year were common, which was substantially higher than the dividend yield of many corporations. Finally, the cash distributions paid out by MLPs get more favorable treatment under the federal tax laws than corporate dividends do—more on this below.

The cash distribution story does not end there. MLPs are designed not just to pay a regular cash distribution every quarter, but to pay a distribution that *increases* over time. As a result, for the individual investor, the primary reason for buying MLP common units is the promise of cash distributions that are paid every quarter and increase over time. Our hypothetical investor above, who started out with a yield of 6%, would see his or her yield increase every time the MLP increased its cash distribution. Within a few years, if all went well, this unitholder might be receiving \$2.00 per unit per year in cash distributions, which would give him or her a yield of 10% based on his or her initial investment of \$20.00 per unit. Ten percent a year is an attractive return under any circumstances, and that return does not take into account any increase in the value of the common units.

2. Incentive Distribution Rights

As described above, MLPs are designed to pay cash distributions that grow over time. It is the incentive distribution rights that drive that growth.

Incentive distribution rights (“IDRs”) are a special class of limited partnership interest that entitle the holder to an increasing percentage of the cash distributions that the MLP pays out to its partners as certain thresholds are met. Typically the IDRs are held by the general partner, but they can be transferred separately from the general partner interest in the MLP. The IDRs are intended to incentivize the general partner to manage the MLP in a cost efficient manner and to increase the MLP’s cash flow by growing its asset base (through the expansion of existing assets, the construction of new assets, and acquisitions).

There are typically four levels of increasing distributions, or *splits*, built into the IDRs. Initially, 98% of any available cash is paid to the limited partners, and 2% is paid to the general partner. If, however, in any particular quarter, the MLP has generated enough cash to pay the common unitholders more than an amount that is referred to as the *first target distribution*, then the limited partners will receive 85% of the cash in excess of the amount required to pay the common unitholders the first target distribution, and the general partner will receive 15%. The cash will continue to be divided 85/15 until the second target distribution is exceeded. If in that quarter the MLP has generated enough cash to pay the common unitholders more than the second target distribution, then the limited partners will receive 75% of the cash in excess of the amount required to pay the common unitholders the second target distribution, and the general partner will receive 25%. Once the third target distribution is exceeded, additional dollars are split 50/50 between the limited partners and the general partner. This level is sometimes referred to as the *high splits*.

The table below shows a hypothetical set of target distributions and incentive distribution splits:

	Total quarterly distribution per common unit	Marginal percentage interest in distributions	
		Limited partners	General partner
First target distribution (\$1.00)	Up to and including \$1.00	98%	2%
Second target distribution (\$1.50)	Above \$1.00, up to and including \$1.50	85%	15%
Third target distribution (\$2.00)	Above \$1.50, up to and including \$2.00	75%	25%
Thereafter	Above \$2.00	50%	50%

Imagine an MLP that has 98 common units outstanding, representing an aggregate 98% limited partner interest, and a general partner holding a 2% general partner interest and the IDRs. If this MLP were to generate \$300.00 in available (or distributable) cash in a quarter, the limited partners would each receive a distribution of \$2.39, and the general partner would receive a distribution of \$65.78.⁵⁹ In this example, the

59. The general partner would first divide the cash 98/2 until each common unit had been allocated \$1.00; using a 98/2 split, it takes \$100.00 to allocate each common unit \$1.00. The

common unitholders would in the aggregate receive \$234.22, or about 78% of the total distribution, while the general partner would receive about 22% of the total distribution.

The general partner's marginal share of the MLP's cash distributions only increases if the distributions to the limited partners are also increasing, so the IDRs create a win-win situation, although it must be noted that the general partner is an ever-bigger winner, and the limited partners are ever-smaller winners, as the cash distribution increases. As a result, the incentive distribution rights serve as a powerful motivator to the general partner to increase the quarterly cash distributions, and some of the country's wealthiest men, including Dan Duncan and Rich Kinder, made their fortunes by turning the MLPs they operate into aggressive growth machines for the benefit of all partners (but especially the general partner, which they control).

Even though they are intended to encourage growth, the IDRs can paradoxically become a drag on growth over time. It is important for any acquisition or internal growth project that an MLP contemplates to be accretive to the common unitholders, meaning that it must generate enough additional cash not only to pay the MLP's current quarterly distribution on any new common units sold to finance the acquisition or growth project, but also to increase the distribution on all of the MLP's common units. If an acquisition or growth project is not accretive, then public investors will not buy the common units the MLP needs to sell to finance it.⁶⁰ For an MLP that is in the high splits (the 50/50 split), finding an acquisition or project that is meaningfully accretive to the common unitholders can be a challenge. Recall that for every dollar that such an MLP distributes to its common unitholders, it must distribute one dollar to its general partner, and so the contemplated acquisition or growth project must generate *twice as much* cash as the MLP hopes to distribute to its common unitholders. The bottom line is that, in order to make the economics work, an MLP that is in the high splits simply cannot afford to pay as much for a new asset as an MLP that is not because the former's

general partner would then start dividing the cash 85/15 until each common unit had been allocated a total of \$1.50; using an 85/15 split, it would take another \$57.65 to allocate to each common unit another \$0.50 (for a total of \$157.65). The general partner would then start dividing the cash 75/25 until each common unit had been allocated a total of \$2.00; using a 75/25 split, it would take another \$65.33 to allocate to each common unit another \$0.50 (for a total of \$222.98). The remaining \$77.02 would be divided 50/50 between the general partner and the common unitholders; each common unitholder would receive an additional 50% of \$77.02, divided by 98, or \$0.39.

60. MLPs generally attempt to maintain an approximate 50/50 balance between debt and equity financing, so they frequently seek to finance acquisitions or growth projects by selling additional common units. An acquisition or growth project that is not accretive causes an MLP's quarterly cash distribution to be *reduced* following its completion. Investors understandably have little interest in purchasing common units to finance a project that would have such an effect.

cost of capital is simply too high. As a result, an MLP that is in the high splits may find itself being outbid for new assets, and its growth may slow or come to a halt. This-too-much-of-a-good-thing effect has caused several general partners to voluntarily reduce their IDRs on a temporary or even permanent basis so that their MLPs will be able to compete effectively for new assets and begin growing again.⁶¹

3. Subordinated Units

When a parent/sponsor takes its MLP public, it usually only sells a relatively small portion of the aggregate limited partnership interest to the public and retains the rest, along with its general partner interest and the IDRs.⁶² The retained limited partnership interest is made up partially of common units that are exactly the same as the common units sold to the public and partially of subordinated units that are a creature unique to the world of MLPs.

Subordinated units are limited partnership interests that are subordinated, for some period of time, to the common units in that they are not entitled to receive any cash distributions unless and until the common units have been paid the minimum quarterly distribution in full, and any arrearages in the payment of the minimum quarterly distribution to the common units have been eliminated. The subordination period is typically three years, although it can terminate earlier if the MLP meets certain financial tests (such as distributing an amount equal to or greater than 150% of the MQD for four consecutive quarters). At the end of the subordination period, the subordinated units convert into common units.

Why does a sponsor accept a limited partnership interest that is a “second class citizen”? It does so in order to reassure the new, public investors in the MLP that they will receive the cash distributions they have been promised. Any new business venture entails a certain amount of risk, and an MLP, in spite of the risk, promises to pay investors a certain amount in cash every quarter. The subordinated units provide a cushion for the benefit of the new public unitholders—if there is not enough cash to pay the full MQD on both the common and subordinated units, then the common units will be paid in full and the subordinated

61. See, e.g., Press Release, TC Pipelines, LP, TC PipeLines, LP to Acquire North Baja from TransCanada and to Eliminate General Partner's 50% Incentive Distribution Rights (May 20, 2009), <http://www.tcpipelineslp.com/news/2009/20090520.html>; Press Release, Enterprise Products Partners L.P., Enterprise Eliminates General Partner's 50% Incentive Rights (Dec. 17, 2002), <http://phx.corporate-ir.net/phoenix.zhtml?c=80547&p=irol-newsArticle&ID=364755&highlight>.

62. Boardwalk Pipeline Partners, LP initially offered to the public a 14.5% limited partner interest; the remaining 83.5% limited partner interest, the 2% general partner interest, and the IDRs were retained by the sponsor. *Boardwalk Pipeline Partners, LP Announces Pricing of Initial Public Offering*, BUS. WIRE, Nov. 9, 2005, available at http://findarticles.com/p/articles/mi_m0EIN/is_2005_Nov_9/ai_n15786386/pg_2/?tag=content:coll.

units held by the sponsor will receive a lesser, or no, distribution. Note, however, that the subordinated units provide only a cushion, not a guarantee. If there is not enough cash to pay the full MQD on even the common units, the common unitholders have no recourse other than selling their units, although the MLP must make up any shortfalls prior to making any distributions on the subordinated units.

Of course, when a parent/sponsor takes an MLP public, it expects to be able to pay at least the MQD on all of the units, both common and subordinated, every quarter; the amount of cash that the MLP is expected to generate determines the MQD and not the other way around.⁶³ But if the parent/sponsor turns out to be wrong, its willingness to hold as much as half of its limited partnership interest in the form of subordinated units provides a margin of error that makes the common units more appealing to new public investors.

C. *The Advantages of the Master Limited Partnership Structure*

The advantages of the MLP structure can be captured in one word: Taxes. Under the federal tax code, MLPs are not required to pay the corporate income tax, and MLP unitholders are therefore not subject to the double taxation that stockholders in a corporation face.⁶⁴

When a corporation generates income, the corporation itself must pay income tax at a rate of up to 35%. If the corporation then decides to pay some or all of the cash that remains after payment of the corporate income taxes to its stockholders in the form of a dividend, the stockholders will pay income taxes on that dividend. As a result, any money that a corporation pays out as a dividend is taxed twice: first at the corporate level and then again at the stockholder level.

MLPs are treated as partnerships for federal income tax purposes and are therefore *pass-through entities* that pay no taxes at the entity level; all income flows through to the partners and is taxed only once, through the income tax paid by each of the partners. Imagine an MLP and a corporation that generate the same amount of cash during a year. Because, unlike the corporation, the MLP will not have to pay some of that cash to the government before making its distributions, the amount of cash that the MLP will be able to distribute to its unitholders will be significantly greater than the amount the corporation will be able to distribute to its stockholders.

63. A significant portion of any MLP's initial public offering prospectus is dedicated to demonstrating that the MLP will in fact be able to pay the full MQD to all of the common and subordinated units each quarter. As might be expected, however, this projection of the ability to successfully pay the MQD is subject to numerous assumptions, qualifications, and caveats.

64. See 26 U.S.C. § 7704(c) (2006). A corporation's earnings and profits are taxed at both the entity level and at the distribution level. See, e.g., 26 U.S.C. §§ 1(h)(11), 331, 336 (2006).

Being pass-through entities also gives MLPs a competitive advantage over corporations when it comes to acquiring new assets. Whenever a business entity pursues an acquisition, it makes projections about how much income the acquired assets will generate, and how much it is therefore willing to pay for them. When a corporation makes these calculations, it must account for the fact that any income generated by the new assets will be subject to the corporate income tax, but an MLP does not. As a result, an MLP can in fact pay *more* for the assets than a rival corporate bidder and yet still achieve a greater return on its investment than the corporation would be able to achieve.

The tax advantages do not end there. In addition to avoiding double taxation, unitholders in an MLP are generally able to largely defer paying taxes on the cash distributions they receive. Because an MLP is a pass-through entity, all income passes through to the partners, and the partners are required to pay taxes each year on the income they are allocated, *not the cash distributions they receive*. MLPs, like any other business, get the benefit of deducting significant non-cash expenses such as depreciation when calculating their income. Consequently, the amount of taxable income that they initially allocate to their partners can be (and usually is) smaller than the amount of cash that they pay out to their partners.⁶⁵ At the point of their initial public offerings, many MLPs estimate that the amount of income they will allocate to the partners in the three to five year period following the offering will be 20% or less of the amount of cash they distribute during that period.⁶⁶ Such an MLP might pay its unitholders \$1.00 per unit in cash distributions in a year, but only allocate \$0.15 per unit in taxable income for that year, and its unitholders will not pay taxes that year on the difference of \$0.85. The taxes on that \$0.85 are only deferred, not eliminated altogether; a unitholder will have to pay taxes on the cumulative excess of his cash distributions over his taxable income upon selling his units.⁶⁷ But a tax paid tomorrow is generally better than a tax paid today.

To summarize, the tax benefits of the MLP structure are substantial. Because MLPs are not subject to entity-level taxation, they have more cash available to distribute to their unitholders and have a competitive

65. It is important to note that this distinction between income and cash distributions can cut both ways. Although typically an MLP distributes more cash than it allocates in income, it is at least theoretically possible for an MLP to generate no cash and yet still generate taxable income, in which case the unitholders would owe taxes even though they received no cash distributions from the MLP.

66. This percentage almost always increases over time as the MLP's depreciation deductions taper off over the depreciable lives of the MLP's assets. As a result, this particular tax benefit diminishes over time.

67. In short, the cumulative excess will reduce the unitholder's tax basis in his units, resulting in increased capital gains taxes, ordinary income taxes, or some of both upon disposition of the units.

advantage over taxable entities such as corporations. Unitholders in MLPs get the benefit of those increased cash distributions, and better yet, are able to largely defer the taxes on the distributions they receive.

If the benefits of the MLP structure are so significant, why hasn't every company in America converted to an MLP? Congress was at one point worried that such a mass conversion might in fact happen, wiping out the corporate tax base. The first MLPs were formed in the early 1980s, and by the mid-1980s businesses in a variety of industries were setting up or converting into MLPs.⁶⁸ By 1986, Congress had seen the writing on the wall and acted to limit the growth of MLPs by restricting the businesses that were eligible for the special tax treatment of MLPs.

Under the federal tax code, an MLP must receive at least 90% of its annual gross income from certain qualifying sources. These qualifying sources include "income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber)."⁶⁹ This definition of qualifying income was recently amended to include income derived from the storage and transportation of ethanol and biodiesel.⁷⁰ As a result of this limitation, MLPs are most commonly involved in natural resource extraction, processing and transportation, and related businesses. Entities that do not receive at least 90% of their income from qualifying sources, even if they are organized as partnerships under the laws of their home state, will be taxed as corporations (and therefore pay entity level taxes). If an MLP were to accidentally fail to meet the test during a taxable year, it too would be taxed as a corporation for that year and each subsequent year, depriving its limited partners of the primary benefit they seek when investing in MLPs. An MLP that failed the test could dissolve and then reorganize as a partnership, but that course of action has its own adverse tax consequences.

The logic of forming an MLP becomes clear once the tax advantages are considered. In the typical *drop-down* formation transaction, a parent/sponsor entity, which is often a corporation, has some assets that would generate qualifying income for purposes of the tax code. While those assets are owned by the corporation, the income from those assets is taxable at the entity level. However, if those assets were to be held by an MLP, the income from those assets would not be taxable at the entity

68. The Boston Celtics were at one time organized as an MLP.

69. 26 U.S.C. § 7704(d) (2006).

70. Energy Improvement and Extension Act of 2008, Pub. L. No. 110-343, § 208, 122 Stat. 3807, 3840 (2008).

level. As a result, the assets are actually *worth more* if they are transferred to an MLP, and the parent company can therefore unlock some value by taking “MLP-able” assets and transferring them to an MLP subsidiary. The parent/sponsor retains control of the MLP through holding the general partner (“GP”) interest, and the MLP then raises cash through an initial public offering (which is typically paid over to the parent/sponsor). To the extent that it owns additional MLP-able assets, the parent/sponsor can over time engage in additional drop-down transactions with the MLP, selling additional assets to the MLP in exchange for cash, additional partnership interests, or a combination of both. Because of the tax benefits of the MLP structure, the MLP can afford to pay the parent/sponsor more for the assets than a taxable entity could pay, and the parent/sponsor can then use the money to invest in other parts of its business that potentially offer greater returns than the MLP assets do but that do not generate qualifying income or the steady cash flows that the MLP structure requires.

D. The Disadvantages of the Master Limited Partnership Structure

MLPs also have several disadvantages. These, rather than their tax advantages, drew the bulk of investors’ attention in 2008.

The first disadvantage of the MLP structure is its structural complexity. Common units, subordinated units, the GP interest, IDRs—each of these interests is a separate security with its own features. A simple set of bylaws for a corporation can be drawn up in a few pages; the partnership agreement of the typical MLP can extend for 100 pages or more.⁷¹ In addition, allocations of income or loss on the partnership interests require detailed calculations and a complex tracking process. There are numerous complicated tax provisions that apply to MLPs in addition to the qualifying income limitation, and the qualifying income provision is much more complex than it might at first appear. There are several gray areas that separate clearly qualifying (or “good”) income from clearly non-qualifying (or “bad”) income. For example, income derived from the transportation of certain petroleum products is qualifying income, while income derived from the transportation of other petroleum products that are only one or two additional steps down the processing chain is not. Shipping MLPs in particular must be careful not to transport too many cargoes of non-qualifying products lest they find themselves on the wrong side of the qualifying income test.

71. See, e.g., First Amended and Restated Agreement of Limited Partnership of Williams Pipeline Partners L.P., available at <http://idea.sec.gov/Archives/edgar/data/1411583/000095012908000388/h53359exv3w1.htm>.

A second disadvantage of MLPs is their relatively limited ability to accumulate cash. As noted above, MLPs contractually obligate themselves to distribute 100% of their available cash each quarter. As a result, MLPs cannot build up war chests like traditional corporations and are therefore highly dependent upon external sources of financing to fund their growth projects and acquisitions.

A third disadvantage of MLPs is the limited liquidity of their common units. MLP common units are an excellent *buy and hold* security because their primary attraction is their cash distributions, and an investor must hold the common units over time to receive the benefit of the distributions. Although the trading price of an MLP's common units can be expected to increase incrementally as the MLP expands its operations and raises its quarterly cash distributions, any such increase will likely occur over a relatively long period of time (when compared to the price increase one would expect to see in a growth stock). Common unitholders are, however, paid an attractive (and tax advantaged) current yield in the meantime. Because common units are a yield-oriented security rather than a growth-oriented security—they generally are not expected to rapidly increase in value—investors tend to buy and hold them rather than trading in and out of them in short intervals to take advantage of short-term price fluctuations.⁷² As a result, daily trading volumes in MLP common units are typically in the hundreds of thousands rather than the millions.⁷³

Why is a low trading volume a disadvantage? Large institutional investors such as mutual funds and pension funds, which routinely invest in the common stock of publicly traded corporations, have only recently begun investing in MLPs in a meaningful way. For some time, this was a result of legal barriers to such investment.⁷⁴ However, even after the laws changed, institutional investors were still somewhat reluctant to invest in MLP securities. Institutional investors, which have large pools of money

72. During the recent market turmoil, however, common units were by no means immune to speculative trading.

73. As of February 20, 2009, the largest MLP by market capitalization, Kinder Morgan Energy Partners, had a market capitalization of approximately \$12.25 billion and a 13-week average daily trading volume of just under 975,000 common units. By comparison, Boston Scientific Corp., an NYSE listed medical devices company with a market capitalization of approximately \$12.28 billion, had a 13-week average daily trading volume of more than 14 million shares. MSN Money Stock Quote for Kinder Morgan Energy Partners LP, http://moneycentral.msn.com/detail/stock_quote?Symbol=kmp&getquote=Get+Quote (last visited Feb. 21, 2009); MSN Money Stock Quote for Boston Scientific Corp., http://moneycentral.msn.com/detail/stock_quote?Symbol=BSX%2C (last visited Feb. 21, 2009).

74. For example, until 2004, mutual funds were essentially prohibited from investing in MLPs because, under the laws governing mutual funds, income from MLP securities was not permissible income. Mutual funds are still prohibited from investing more than 25% of their assets in MLPs and cannot own more than 10% of any single MLP. American Jobs Creation Act of 2004, Pub. L. 108-357, § 331(f) (2004) (codified at 26 U.S.C. § 851(b)(3) (2006)).

to work with, generally take large positions in the securities in which they choose to invest. Because they take such large positions, the ability to liquidate those positions quickly in response to changing circumstances is extremely important to them. With the limited trading volumes typical of MLPs, an institutional investor cannot sell a large number of common units without significantly depressing their market price. If only 300,000 common units are bought on a typical day, a mutual fund that holds 100,000 common units cannot sell them quickly without flooding the market. With common units, institutional investors must largely give up the ability to quickly liquidate their positions that is so important to them. As a result, institutional interest in MLPs has remained relatively limited, and a significant potential source of the outside capital that MLPs are dependent upon is to some extent eliminated.

Another disadvantage of MLPs that relates to the limited trading volume of their common units is the difficulty MLPs have in selling additional common units to the public without causing a significant drop in the price of those common units. Any sale of additional common stock or common units is a dilutive event for existing stockholders or unitholders and could be expected to cause the value of each share or unit to decrease to some extent. After all, after new shares of common stock or common units are issued, each existing share or unit will represent a slightly smaller stake in the issuer. With MLPs, however, the decrease is much more pronounced than one might otherwise expect because speculative investors profit from an MLP's announcement of an equity offering by selling that MLP's common units short. They know that with the units' limited trading volume, it will only take a handful of other investors doing the same thing to cause the price of the common units to drop significantly. These investors can then profit by buying the common units back at the lower price. Understandably, this kind of trading infuriates parent/sponsors because it undermines the price they hope to secure in the offering for their MLPs' common units. But there is very little that they can do to prevent investors from engaging in such trading, other than conducting rapid *overnight* offerings whereby the offering is announced after the market closes on one day and is wrapped up by the time the markets open the next morning. In these offerings investors are effectively denied the opportunity to trade on the announcement. But overnight offerings have several shortcomings. Because they are carried out in only a few hours while the markets are closed, the MLP's ability to meet with investors to drum up interest in the offering by "telling its story" is limited, and the MLP does not have the opportunity to gather the market intelligence that these meetings can provide. In addition, even with an overnight offering, the price of the MLP's common units almost always falls once the market opens the next

day, and it frequently falls below the price the new investors have agreed to pay, which obviously makes both the new and existing unitholders unhappy. Corporations with greater trading volumes can conduct offerings over several days, in broad daylight, without having to worry about the price of their common stock because it is more difficult for a small group of short sellers to drive the price down when so many shares are changing hands.

Finally, although all MLPs share certain fundamental characteristics—the generation of qualifying income and the distribution of a high proportion of their cash flow—not all MLP assets are created equal, and the similarities of any two MLPs from a structural point of view may cause investors to minimize or even overlook the important differences that distinguish them. Since paying cash distributions is paramount to the success of an MLP, businesses that generate dependable cash flows are better suited to the MLP structure than businesses that are exposed to commodity price risk and/or production risk. Interstate pipelines are the classic MLP asset because they do not own the products they ship and therefore have little exposure to commodity price risk, and they frequently have long-term “firm” contracts pursuant to which their customers pay them regardless of whether the customers actually ship any hydrocarbons through the pipeline. They are like toll roads—they get paid a fee to ship a product from point A to point B, and it does not matter (to them) what the price of that product is. As long as people keep shipping hydrocarbons, the interstate pipelines can make money. Exploration and production MLPs in particular were severely punished during 2008 because they are riskier. While today’s upstream MLPs were generally formed with mature oil and gas properties that have slow production decline curves and frequently yield drilling success rates of near 100%, zero-risk reserves do not exist. In addition, despite sophisticated hedging strategies, it is impossible to completely eliminate commodity price risk.⁷⁵

Dependence on outside capital and limited liquidity proved to be MLPs’ Achilles’ heel during 2008.

75. Many of the MLPs that were formed in the early 1980s were engaged in exploration and production activities, but their reserves were much riskier than the reserves characteristic of upstream MLPs today, and hedging instruments were much less sophisticated. As a result, many of them were unable to pay the quarterly cash distributions they had promised to investors and therefore failed. These early failures cast a cloud on the entire concept of exploration and production MLPs that lasted for 20 years, until the initial public offering of Linn Energy, LLC in 2006.

III. THE CURRENT CHALLENGING ENVIRONMENT FOR MASTER LIMITED PARTNERSHIPS

MLP investors took it on the chin during 2008. As noted at the outset of this article, the Alerian MLP Index was down more than 36% on a total return basis for the year.⁷⁶ One might have expected MLP common units, with their tax advantages and steady and relatively high cash distributions, to have been less subject to the broader market meltdown, but such was not the case. In addition, although the first rule of MLPs is to never cut your cash distribution, several MLPs announced in the second half of 2008 that they were going to do just that, and observers at the time expected that more would follow suit. The widespread and substantial price declines throughout the MLP universe during 2008 pushed MLP yields up, and by the end of the year, many MLPs were trading at yields in excess of 20%, and some had yields in excess of 50%.⁷⁷ By point of comparison, for the years 2004–2007, the average yield of all MLPs was in the 5–8% range.⁷⁸ Also noteworthy was the disconnect between MLP yields and U.S. Treasury yields that emerged during 2008. For the years 2004–2006, the average yield of the MLP universe was roughly 3% higher than the yield on the 10-year U.S. Treasury. During 2007, the spread between MLP yields and 10-year U.S. Treasury yields was smaller still, and remarkably enough, approached zero for a time.⁷⁹ In other words, MLPs were trading at prices that provided a yield that was no greater than that offered by the 10-year U.S. Treasury, the prototypical “riskless” security. But during 2008 and the flight to safety that was both a contributing cause and a result of the stock market decline, the spread between the average MLP yield and the 10-year U.S. Treasury yield universe spiked dramatically, peaking in the neighborhood of 20%.⁸⁰ Finally, many MLPs, even the stronger ones, went into defensive mode and cut their capital expenditure budgets during 2008. Smaller capital expenditure budgets mean slower growth and therefore slower (or no) growth in quarterly cash distributions for at least the medium term.

76. ALERIAN MLP INDEX, *supra* note 53.

77. Yield calculations based on historical prices and quarterly distributions, on file with author. An MLP’s yield is calculated by multiplying its most recent quarterly distribution per common unit by four and then dividing the product by the current trading price per unit. As a result, like the yield on a bond, the yield on an MLP unit moves inversely to its price. As investors perceive that there is more risk associated with a particular MLP, they drive the price of its common units down, which causes its yield to increase.

78. KAYNE ANDERSON FUND ADVISORS, MLP MARKET UPDATE 16 (Aug. 21, 2008), available at http://www.kaynefunds.com/pdf/State_of_MLP_Market_082108.pdf.

79. *Id.*; ALERIAN MLP PRIMER, *supra* note 54, at 36.

80. Investment bank research report, on file with author.

What happened? Part of the blame can go to the overall economy and broader stock market collapse, and if there was any good news during 2008 for MLP investors, it was that MLP investments fared no worse than many other securities. In a market in which investor fear and the flight to safety was so pronounced that the yield on the three-month U.S. Treasury was briefly *negative*,⁸¹ it is not difficult to understand why MLP common units fared so poorly. Despite their pretensions during 2007, MLP common units are not riskless securities.

But 2008 was also a year that exploited the specific weaknesses of MLPs and their common units. First, the dependence of MLPs on external financing caused MLP valuations to begin weakening as far back as the late summer of 2007, when what we then almost quaintly referred to as the “credit crunch” first began to manifest itself. By the fall of 2008, when things had escalated into a full-blown credit crisis, MLPs went from facing a challenging lending environment to effectively being unable to borrow any new money at all. There was only one MLP debt offering during the four month period from August–November 2008, a highly unusual lull in such activity. Although the dislocation in the credit markets we witnessed during the second half of 2008 was (one hopes) a once-in-a-lifetime event, no one expects the loose credit environment of the middle years of this decade, in which MLPs were able to thrive, to return any time soon, if at all. As a result, the mantra that MLPs have easy access to credit to finance growth may need to be viewed with increased skepticism in the future by sponsors and investors alike.

Second, at a time when institutional investors such as hedge funds were forced into selling securities in order to cover redemptions from their own investors, the smaller trading volumes of MLPs became a significant liability. As many others have noted, this forced selling feeds on itself—selling causes a security’s price to decline, which causes margin calls, which causes additional selling. Many investments suffered as a result of the involuntary deleveraging that occurred during 2008, especially during the fourth quarter, but MLP common units were particularly vulnerable. The market for the typical MLP’s common units simply cannot absorb a significant number of sell orders without the price for those common units declining, sometimes in dramatic fashion. Notably, MLPs with significant institutional ownership suffered significantly greater price

81. Daniel Kruger & Cordell Eddings, *Treasury Bills Trade at Negative Rates as Haven Demand Surges*, BLOOMBERG.COM, Dec. 9, 2008, <http://www.bloomberg.com/apps/news?pid=20601087&refer=worldwide&sid=aOGXsWKEI6F4>. Although the 3-month U.S. Treasury traded at a negative yield only briefly, that it did so at all is truly astonishing. Investors were, in effect, so fearful of losing an unknown amount of money in other investments that they were willing to buy an investment in which they were absolutely *guaranteed* to lose a small and predictable amount of money.

declines during 2008 than those with limited institutional ownership.⁸² Some observers have gone so far as to blame much of the MLP market's troubles on the demise of a single financial institution that was a major player in the MLP universe.

Finally, due to the qualifying income limitation, most MLPs are in the energy industry, and commodity price volatility during 2008 wreaked havoc on all energy investments, including MLPs.⁸³ If the increase in the price of oil to over \$140 per barrel in July of 2008 was surprising, the decline to under \$40 per barrel in just a few months was dizzying. Many MLPs are largely insulated from the direct effects of hydrocarbon price declines through hedging arrangements or because they only transport, and do not own, hydrocarbons. But even interstate pipelines that never take title to any oil or natural gas could eventually feel the effects of a sustained decline in the commodity prices if producers shut in production and stop drilling. And upstream MLPs rarely, if ever, hedge 100% of their production. It is not a coincidence that exploration and production MLPs and gathering and processing MLPs (the revenues of which are often tied to the market price of the products extracted through their operations) took the worst beating during 2008.

IV. WHAT DOES THE FUTURE HOLD?

The following trends, some of which have already started to develop, may be significant factors in the MLP market for the remainder of 2009 and beyond.⁸⁴

A. Return to Retail

Common units were initially considered to be most appropriate for retail or individual, "mom and pop" investors. As noted above, they have the characteristics of an excellent buy and hold security, and they don't

82. Investment bank research report, on file with the author.

83. The common units of SemGroup Energy Partners LP lost more than 50% of their value on July 17, 2008, in connection with the announcement by its parent that the parent was considering a bankruptcy filing as a result of hedging losses caused by the dramatic increase in the price of oil. *SemGroup stock falls; parent considers bankruptcy*, TULSA WORLD, Jul. 17, 2008, available at http://www.tulsaworld.com/news/article.aspx?articleID=20080717_5_TheSt77131. They later fell to less than \$1.00 per unit in November, having peaked at over \$30.00 per unit during the summer of 2007. The parent company made large bets that the price of oil would fall in the two years leading up to July 2008, when, of course, oil prices reached an all-time high of over \$145 per barrel. These wrong-way bets resulted in \$2.4 billion in losses and a bankruptcy filing for the parent. Because a significant portion of SemGroup Energy Partners' revenues was derived from contracts with its parent, the bankruptcy filing had predictably dire consequences for the unitholders. *SGLP stock slips below \$1*, TULSA WORLD, Nov. 22, 2008, available at http://www.tulsaworld.com/news/article.aspx?articleID=20081122_351_E1_hTheSe613712.

84. The author does not claim to have any special insight into the future of MLPs; the trends discussed here are based solely on his own observations and conversations with others who follow MLPs.

lend themselves to short-term, speculative trading. In addition, there were legal barriers to substantial institutional ownership of MLP securities. After the legal barriers fell away, institutions began to invest in MLPs in a meaningful way, and several funds that invest almost exclusively in MLP securities were formed. But the MLP market in the second half of 2008 may have left many of these institutional investors feeling burned. Large holders of MLP investments were faced with two unpleasant alternatives: stand by and watch their MLP holdings decline in value, or sell them and, in doing so, further undermine the price of the very security they were trying to sell. Institutions of course faced these alternatives with all of their investments that were losing value, but the dilemma was particularly acute with MLP common units due to their low trading volumes. As a result, MLPs are finding that institutional interest in buying their units has waned, and they have been forced to call primarily upon individual investors.

B. Consolidation

The conditions may be right for some of the bigger, stronger MLPs to acquire some of the MLPs that are struggling to arrange financing and that have either already cut their cash distributions or had to consider cutting them. By using its common units to pay for an acquisition, an MLP can grow without having to access the capital markets. To the extent that a large MLP does not want to use common units to pay for an acquisition, it would have an advantage in raising funds for an acquisition in the current capital constrained environment. And the unitholders of some of the smaller MLPs would likely welcome the opportunity to exchange their units for the units of a more viable MLP. However, even the MLPs that are in the best position to potentially acquire another MLP have had to trim their capital expenditure budgets and cast a more critical eye on the internal growth projects already available to them. As low as the valuations of some MLPs have fallen, stronger MLPs may believe that their own internal growth projects offer a better return than an acquisition, and they may choose to focus their (now smaller) capital expenditure budgets on those projects. But if a struggling MLP has an asset base that strategically complements the business of a stronger MLP, the stronger MLP may be unable to resist, even in the face of budget cuts and financing difficulties.

C. *Going Private*

Another alternative that one MLP has already explored is going private.⁸⁵ There are significant costs associated with being a publicly traded company, including everything from legal and accounting fees to Sarbanes-Oxley compliance. With MLP valuations so low, some sponsors may decide that the best course of action is just to buy out the public unitholders and take their MLPs private again. Why pay investors a yield of 15% when you could keep it for yourself?

D. *Emphasis on MLPs with Strong Sponsorship and Solid Drop-Down Potential*

Of the last six equity issuances by MLPs during 2008, five were transactions in which the MLP issued common units to its parent/sponsor, either in exchange for additional assets in a drop-down transaction or for cash that was used to fund growth projects. An MLP that can issue common units to its parent/sponsor in exchange for assets or to raise cash is substantially less dependent on external financing and can therefore continue growing when other MLPs cannot. With the capital markets all but closed to MLPs from mid-September to mid-December, having a parent/sponsor that was both willing and able to buy additional common units proved to be an extremely valuable asset, and investors may increasingly favor MLPs that have that attribute.⁸⁶ As an MLP investing blog put it after Loews Corporation, the sponsor of Boardwalk Pipeline Partners, LP, announced that it was willing to provide up to \$1 billion of equity financing to Boardwalk, "it pays to have a sugar daddy."⁸⁷ However, even sponsors that have shown a willingness to take additional common units in their MLPs may reach their limit at some point. Sponsors form MLPs with the intention of reducing and monetizing their

85. The owners of the general partner of Buckeye GP Holdings L.P. announced a tender offer for all of the common units of Buckeye GP Holdings L.P. not already owned by them in October 2008. Press Release, Buckeye GP Holdings L.P., Buckeye GP Holdings L.P. Confirms Receipt of Unsolicited Proposal from BGH GP Holdings, LLC, (Oct. 22, 2008), *available at* <http://www.buckeyegp.com/InvestorCenter/NewsReleases/tabid/56/Default.aspx>. The special committee of the board of directors that was responsible for evaluating and approving the going private transaction later rejected the proposal. Press Release, Buckeye GP Holdings L.P., Buckeye GP Holdings Issues Response/Recommendation Statement Regarding Tender Offer of BGH GP Holdings, LLC (Nov. 19, 2008), *available at* <http://www.buckeyegp.com/InvestorCenter/NewsReleases/tabid/56/Default.aspx>.

86. One of the MLPs that engaged in a drop-down transaction with its parent during the fall of 2008 was Western Gas Partners, LP. Western Gas's parent is Anadarko Petroleum Corporation, which has numerous assets that could be dropped down into Western Gas in the future. It is of course impossible to isolate one factor that affects the price of an MLP's common units, but Western Gas's yield of 8.2% as of May 15, 2009, as compared to the average yield for gathering and processing MLPs of 12.9%, may in part be due to Anadarko's demonstrated support of its MLP in a challenging environment.

87. Master Limited Partnerships, <http://limitedpartnerships.blogspot.com> (Oct. 27, 2008, 7:34 a.m.)

ownership of the MLP assets by selling it off over time, not with the intention of increasing their ownership.

E. A Break from E&P MLPs

Exploration and production MLPs were extremely popular during 2006 and 2007. Several of them doubled in value within only a few months of their initial public offerings,⁸⁸ but when the music stopped during 2008, upstream MLPs were left without a seat. At the end of 2008, the *average* yield offered by the ten E&P MLPs was over 32%. As of mid-May 2009, their average yield was still in excess of 14%,⁸⁹ and we will not see any new E&P MLPs until that yield comes back down. Investors are clearly worried about the risks associated with this section of the MLP universe, despite the fact that many of the upstream MLPs have substantial portions of their production hedged for several years at prices well in excess of the current price. For some time now, investors have shown a preference for the fee-based revenues and limited commodity price exposure characteristic of transportation and storage MLPs. The liquids transportation and storage MLPs offered an average yield of 10.1% as of mid-May 2009, and the gas transportation and storage MLPs offered an average yield of only 7.9%.⁹⁰

V. CONCLUSION

The MLP market has improved somewhat since the end of 2008. As of mid-February 2009, the Alerian MLP Index was up over 28% on a total return basis since December 31, 2008, although it still has a long way to go to recover all the ground lost during 2008.⁹¹ The three largest MLPs by market capitalization, Enterprise Products Partners, Kinder Morgan Energy Partners, and Energy Transfer Partners, took the lead in reopening the public markets for MLP securities, and each conducted both debt and equity offerings in December and January. A few MLPs have since followed them back into the capital markets, and it therefore appears that a partial thaw may be under way.

Which way will MLPs go? Some MLPs have clearly not worked out the way their sponsors and investors thought that they would, and some sponsors have apparently been thinking about whether their MLPs' investors would be better off with a more liquid security, even at the cost

88. *See, e.g.*, Constellation Energy Partners, LLC, which went public at \$21.00 per unit in November 2006 and was trading in excess of \$49.00 per unit by July 2007. MSN Money Price History for Constellation Energy Partners, LLC, <http://moneycentral.msn.com/investor/charts/chartdl.aspx?iax=1&Symbol=CEP&CP=0&PT=8>.

89. Yield calculations based on historic prices and quarterly distributions, on file with author.

90. Yield calculations based on historic prices and quarterly distributions, on file with author.

91. *See* ALERIAN MLP INDEX, *supra* note 53.

of giving up the advantageous tax treatment that MLPs receive. By converting to a corporation, an MLP would lose its tax advantages but potentially open the doors to vast new pools of institutional capital that cannot, or choose not to, invest in MLPs. Despite the problems experienced by MLPs during 2008, however, it seems unlikely that the formation of new MLPs will come to a permanent halt.⁹² MLP yields have, over the long term, averaged closer to 10% than 5%, and yet many MLPs were nevertheless formed.

Before the credit crisis and market meltdown, the MLP market was almost certainly infected to some extent by the now famous “irrational exuberance”—an unrealistic discounting of risk and overly optimistic assumptions about the future, especially with respect to the value of MLP assets and the cheap and easy credit that was available to MLPs. Economist Nouriel Roubini, in a recent interview, said of the overall economy that “over and over again, [we] get into these periods of irrational exuberance, when not only is there an asset bubble and a credit bubble, but people believe these are sustainable over a long time.”⁹³ He could just as easily have been talking about MLPs in particular. We may never see yields of 5-6% again, and, going forward, MLPs will likely have to reconcile themselves to a yield and a cost of capital that are a few points higher, which would make MLPs less lucrative for their sponsors. But MLPs were previously *extremely* lucrative, so being less lucrative would not necessarily be the end of the world. To some extent, what we saw during 2008 was simply a return to the mean. And despite all the remarkable changes that occurred during 2008, the tax advantaged status of MLPs did not change. As a result, the basic advantages that the MLP structure offers—no entity level taxation and favorable tax treatment of cash distributions—are as relevant today as they ever were. There are billions of dollars worth of assets out there that generate qualifying income and that are therefore MLP-able, and the owners of those assets can still unlock value by transferring them to MLPs. Investors may view MLPs with additional (and perhaps healthy) skepticism in the future, but the fact remains that the basic reason MLPs exist has not changed. MLPs got started as a way to provide ordinary investors with a tax advantaged, yield-oriented investment. That relatively simple premise may have gotten a little lost in the heady markets of 2004–2007, but it remains a valid one.

92. It should be noted that as an associate at a law firm that does a significant amount of work with MLPs, the author has a vested interest in the long-term success of the MLP business model.

93. Nouriel Roubini, ‘Nationalize’ the Banks, WALL ST. J., Feb. 21, 2009, at A9.

C. THE MODERNIZATION OF THE OIL AND GAS DISCLOSURE AND RESERVES RULES OF THE SECURITIES AND EXCHANGE COMMISSION

JAMES M. PRINCE*

On December 31, 2008, the United States Securities and Exchange Commission (“SEC”) issued final revisions to its rules on disclosures relating to oil and gas activities, including the reporting of oil and gas reserves estimates. The SEC issued Securities Act Release No. 8995 (the “Adopting Release”), which makes sweeping changes to oil and gas disclosure requirements and the reserves definitions applicable to periodic reports and registration statements filed with the SEC by companies with significant oil and gas activities.⁹⁴

The new rules represent the first major revision to SEC oil and gas disclosure requirements for publicly reporting companies in over 25 years, during which time the industry has experienced extensive globalization and major technological advances in exploration, development, and production activities. The adoption of these final rules concludes an SEC initiative launched in May 2007 when the SEC announced that it intended to appoint an Academic Engineering Fellow to assist in the examination of the reserves reporting requirements. Dr. W. John Lee, Regents Professor and holder of the L.F. Peterson Endowed Chair of Petroleum Engineering at Texas A&M University, was selected for that position in October 2007.⁹⁵ The SEC issued an initial concept release for public comment in December 2007⁹⁶ and issued comprehensive proposed revisions to rules in June 2008, subject to public comment.⁹⁷ The revised rules in the Adopting Release significantly

* Mr. Prince is a partner at Vinson & Elkins L.L.P. where he represents private and publicly traded companies in various capacities and major investment banking firms on a transactional basis, as well as providing corporate representation in oil and gas and oil service transactions. His experience includes mergers and acquisitions, joint ventures and partnerships, SEC compliance matters, capital markets offerings, private placements, secured financings, and venture capital financings.

94. Modernization of Oil and Gas Reporting, Securities Act Release No. 8995, Exchange Act Release No. 59192, 74 Fed. Reg. 2158 (released Dec. 31, 2008), *available at* <http://www.sec.gov/rules/final/2008/33-8995.pdf> [hereinafter Adopting Release].

95. Press Release, U.S. Sec. and Exch. Comm’n, SEC Division of Corporate Finance Appoints Academic Engineering Fellow (Oct. 3, 2007), *available at* <http://www.sec.gov/news/press/2007/2007-211.htm>.

96. Concept Release on Possible Revisions to the Disclosure Requirements Relating to Oil and Gas Reserves, Securities Act Release No. 8870, Exchange Act Release No. 56945, 72 Fed. Reg. 71610 (released Dec. 12, 2007), *available at* <http://www.sec.gov/rules/concept/2007/33-8870.pdf>.

97. Modernization of the Oil and Gas Reporting Requirements, Securities Act Release No. 8935, Exchange Act Release No. 58030, 73 Fed. Reg. 39526 (released June 26, 2008), *available at* <http://www.sec.gov/rules/proposed/2008/33-8935.pdf>.

refined the proposed rules, largely in response to extensive industry feedback.

The revised rules are scheduled to apply to annual reports filed with the SEC by domestic and foreign filers for fiscal years ending on or after December 31, 2009, and all registration statements filed after that date.⁹⁸ Companies are not permitted to voluntarily comply with the new rules at an earlier date. Some reporting companies, however, have elected to supplement disclosures under current rules with a few of the new disclosures in press releases and annual reports for the year ended December 31, 2008.

Some highlights of the revised rules in the Adopting Release include:

New Reserves Definitions. The new rules adopt revised and new definitions relating to hydrocarbon reserves and reserves categories, relying heavily on current industry standards including the Petroleum Resources Management System (“SPE-PRMS”).⁹⁹ The revised *proved oil and gas reserves* definition incorporates a new definition of *reasonable certainty* using the SPE-PRMS standard of “high degree of confidence” for deterministic method estimates, or a 90% recovery probability for probabilistic methods used in estimating proved reserves.¹⁰⁰

New Reserves Pricing. For reserves reporting purposes, end-of-the-year oil and gas reserves pricing economics are replaced with an unweighted average first-day-of-the-month pricing for the past twelve fiscal months.¹⁰¹ The SEC also noted that it is in discussions with the accounting standard setters, the Financial Accounting Standards Board (“FASB”) and International Accounting Standards Board (“IASB”),¹⁰² to eliminate or minimize the differences between disclosure pricing and accounting pricing models for oil and gas reserves by implementing a similar twelve-month unweighted average pricing method in determining

98. The SEC indicated in the Adopting Release that it may consider delaying the effective date of all or a portion of the revised final rules in the event certain conforming changes to oil and gas accounting rules could not be adopted by accounting standards setters. Adopting Release, 74 Fed. Reg. at 2162.

99. The Petroleum Resources Management System is a widely accepted standard for the management of petroleum resources, developed by the Society of Petroleum Engineers, the World Petroleum Council, American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. *See generally* SOC’Y OF PETROL. ENG’RS, ET AL., PETROLEUM RESOURCES MANAGEMENT SYSTEM (2007), available at http://www.spe.org/spe-site/spe/spe/industry/reserves/Petroleum_Resources_Management_System_2007.pdf.

100. Adopting Release, 74 Fed. Reg. at 2160, 2164.

101. *Id.* at 2161.

102. *Id.* at 2162. The FASB has been the designated organization in the private sector for establishing standards for financial accounting and reporting in the United States. The IASB is the standard-setting body of the International Accounting Standards Committee that is committed to developing a single set of global accounting standards known as the International Financial Reporting Standards. The FASB has begun the steps to make the conforming changes to U.S. oil and gas accounting standards to conform to the SEC’s revised rules set forth in the Adopting Release.

reserves and related values for accounting purposes.¹⁰³ This would impact depletion cost calculations of all oil and gas companies and *ceiling test* limitations of capitalized costs by companies using the full-cost accounting method. Costs associated with future development and production of such reserves will continue to be measured based upon costs in effect on the last day of the fiscal year.¹⁰⁴

Broader Recognition of Proved Undeveloped Reserves. The new rules provide more latitude to establish undeveloped reserves as proved by satisfying the *reasonable certainty* criteria through the use of data and reliable technologies. This is done in lieu of requiring actual production tests and without categorically limiting undeveloped reserves to drilling spacing units adjacent to a producing well or a limited number of horizontally drilled laterals.

Including Unconventional Extractive Activities. The definition of oil and gas producing activities is expanded to include the extraction of oil and gas from non-traditional or unconventional sources, including oil sands and bitumen production, by focusing on the final product of such activities instead of the extraction technology used. For example, coal and oil shale that is intended to be converted into oil and gas is classified as oil and gas reserves rather than mining reserves.

Sanctioning Newer Reserves Estimation Technologies. The use of newer reliable technologies is permitted to establish the reasonable certainty of recovery of reserves if those technologies have been empirically shown to lead to reliable conclusions about reserves volume. *Reliable technology* includes field-tested technology demonstrated to provide reasonably certain results with consistency and repeatability in the evaluated formation or an analogous one.

Optional Probable and Possible Reserves Disclosure. The prior prohibition on disclosure of probable and possible reserves estimates in SEC filings has been eliminated in favor of permitting optional disclosures of these estimates. This is information that is already widely distributed by many companies in investor presentations and press releases. If a company elects to disclose probable or possible reserves estimates in SEC filings, the estimates must conform with the new SEC definitions of these reserves categories and must be provided with the same level of geographic detail as proved reserves, distinguish between developed and undeveloped reserves, and disclose the relative uncertainties associated with these classifications.

Expanded Geographic Reporting. Geographic disclosures are now required to be divided between continents, groups of countries within a

103. *Id.* at 2169.

104. *Id.*

continent, or individual countries, including—unless such disclosure is prohibited by law—disclosure of separate reserves for each country with 15% or more of the company's total global proved reserves and three-year historical production for each country *or field* with 15% or more of the company's total global proved reserves.

Revised Reserves Tables. A revised tabular presentation of reserves is now required—including any optional disclosure of probable and possible reserves—by development category and final product type, as well as oil and gas activity disclosure by geographic regions and significant fields.

Optional Reserves Sensitivities. The new rules provide a framework for optional disclosure of sensitivity analyses showing the impact of changes in pricing, costs, or other variables on reserves estimates and value measures.

Filing of Third Party Reserves Reports. The new rules require the public filing with the SEC of third party summary reserves reports, including process review reports and reserves audit reports, if such reports are prepared by third parties and disclosed as being relied upon.

Reserves Estimation Process Disclosures. A general discussion of the internal controls a company uses to ensure objectivity in the reserves estimation process and the qualifications of the technical person (or persons) with primary responsibility for providing reserves estimates and audit reports, including in-house persons, is now required. Certain minimum disclosures are also required for third party reserves review and audit reports disclosed in SEC filings.

New Oil and Gas MD&A Guidance. The rules provide guidance regarding management's discussion and analysis of exploratory and development operational results, including comments on known trends and uncertainties.

Prohibition of Hydrocarbon Quantification Beyond Reserves. Disclosure in SEC filings of estimates of quantities of oil or gas resources that do not meet the revised SEC definition of *reserves* is now prohibited. These are prohibited on the grounds that such estimates are “too speculative and may lead investors to wrong conclusions.”¹⁰⁵

The most anticipated, if not most dramatic, effect of the revised rules and definitions is the possible impact on reported oil and gas reserves quantities. The SEC definitions of proved, probable, and possible oil and gas reserves will now embrace most of the non-economic standards set forth in the industry standard SPE-PRMS, including the use of both

105. Estimates of resources other than reserves may be disclosed in SEC filings if required by federal or state law, or in a filing related to an acquisition, merger, or consolidation transaction, if such estimates have been previously provided to potential participants in the transaction.

deterministic or probabilistic methods of arriving at the varying degrees of likelihood of recovery. Previously unrecognized by the SEC, probabilistic methods of estimation of reserves incorporate from SPE-PRMS the well known recovery probability percentages: greater than 90% probability of successful recovery required of proved reserves quantities (1P), greater than 50% recovery success required of proved plus probable reserves quantities (2P), and greater than 10% recovery success required of proved plus probable plus possible reserves quantities (3P).

One significant difference between the SPE-PRMS approach to reserves estimation and the SEC approach remains under the revised rules. SPE-PRMS sanctions a subjective determination of *commerciality* to establish the economics of reserves in order to justify or *book* them. Thus, SPE-PRMS refers to commerciality as viewed in the eyes of the beholder, dependent upon such things as targeted internal rates of return and management views on future pricing and development costs. The SEC reserves pricing paradigm is static, arbitrary, and intended to achieve more comparable company-to-company valuations for use by investors. If resources in the ground cannot be produced profitably under the SEC's mandated twelve-month average pricing and current cost structure, then they cannot be booked as reserves. But the SEC model is still not a totally objective evaluation system. The subjective judgment of management weighs in, as management must commit to a defined development project in order to transform resources to reportable reserves. Those decisions are influenced by internal views of required return on investment, allocation of capital, and other factors.

While the embrace of industry standards for reserves estimation is a weighty development, the most significant changes affecting proved reserves estimation are likely to come from two other SEC rule revisions: the move from year-end single-day reserves pricing and the expanded permissive use of reliable technologies to meet reasonable certainty requirements, including in the establishment of proved undeveloped reserves beyond old rule limitations. The change from current end-of-year pricing of SEC reserves to the use of a twelve-month average should temper the effects of oil and gas price changes on reported reserves quantities and present values. In an upward trending oil and gas market year, the twelve-month average price will lag behind the end-of-year price, reducing the potential gain from the price increase. Conversely, in a down year, the full impact of a price decline will be tempered by the use of the higher twelve-month average price. This has a significant accounting impact. Assuming the FASB (and possibly the IASB) take the SEC's cue and adopt the twelve-month average pricing concept for quantifying and valuing reserves for accounting purposes, the impact to

companies using the full-cost method of accounting for oil and gas activities could be significant in determining ceiling test limitations on capitalized costs. In a declining price market during the averaging year, use of the average price would tend to delay the effects of a limitation on capitalized costs. Conversely, in a rising price market, use of the average price would impose a lower ceiling on capitalized costs than under present rules. The use of twelve-month average pricing will also impact depletion charges, as the amount of estimated reserves from which per unit depletion cost is calculated would likely be different than under the end-of-year pricing convention.

Predicting the impact on the permissive use of reliable technologies to establish reserves quantities is difficult absent further engineering experience with the new rules and discussions with the SEC staff. Similarly, the potential to expand undeveloped reserves using the new *reasonable certainty* standard to establish well locations and horizontally drilled laterals beyond the prior proximity limitations will only be seen with experience.¹⁰⁶

The final frontier for the new rules is the reporting of non-proved reserves in SEC filings. Initial use of these non-proved reserves estimates may be limited somewhat, at least in the initial year, for several reasons. First, the absence of any experience with the SEC staff in interpreting these rules may have an initial dampening effect. Second, probable and possible reserves estimates under SEC definitions may differ from the estimates of these reserve categories that have been previously made public by the company, causing the company to have to explain the revisions.¹⁰⁷ Lastly, there may be a general lack of comfort in accepting potential liability for such estimates, particularly by outside directors or potential underwriters.¹⁰⁸ On the other hand, in light of the significant number of companies that currently report non-proved reserves, it is

106. Under a strict reading of the definition of *undeveloped oil and gas reserves* under the revised rules, it appears that the *reasonable certainty* standard applicable to establishing certain additional well locations as proved undeveloped oil and gas reserves would also apply to probable or possible undeveloped reserves, rather than the lower standard of certainty otherwise applicable to those reserves categories. The early consensus of professional engineers and legal practitioners is that this literal interpretation was not intended.

107. Although it is not entirely clear in the Adopting Release, it appears that the twelve-month first-day-of-the-month average pricing may also apply to probable and possible reserves under the revised rules. Previously published estimates of these reserves categories will likely not have been prepared on that basis. Thus, a company that previously has publicly disclosed such estimates may need to consider providing an explanation for changes in its methodology to conform to SEC definitions, or otherwise consider the appropriateness or adequacy of disclosure in providing, outside of SEC filings, non-proved reserves estimates that have been prepared on a basis other than under the revised rules.

108. Under the Securities Act of 1933, as amended, the use of reserves estimates prepared by a qualified outside engineering consulting firm may significantly reduce this concern in capital markets transactions if the consulting firm is willing to be named as an expert and consents to the use of their estimates and report in registration statements.

unlikely the new rules will impact the continued publication in press releases and investor presentations of various non-proved reserves quantities. This may also be true of publication of various oil and gas non-reserves resource quantifications under various names, such as *potential resources*, *resource potential*, *risked resources*, *un-risked resources*, *resources in place*, *gas in place*, or *oil in place*, notwithstanding the SEC's caveat in the Adopting Release regarding the speculative nature of such estimates.

These new rules will apply to both domestic and foreign private issuers that are subject to SEC reporting requirements. While changing reserves definitions and permitting disclosure of additional reserves categories will close the gap in reserves information under various regulatory regimes, differences may still remain in reporting reserves under SEC rules and other international regulatory regimes.

**D. RENEWABLE TRANSPORTATION FUEL:
A COUNTERINTUITIVE WINDFALL
TO THE OIL INDUSTRY**

EVAN N. TURGEON*

I.	INTRODUCTION	428
II.	CONCERNS OVER BIOFUEL STANDARDS	429
III.	THE RFS'S UNACHIEVABLE GOALS	430
	A. Technical Snags.....	431
	B. Unstable Fuel Markets.....	431
	C. Barriers to Consumption	432
	D. Likely Results	434
IV.	BENEFITS FOR THE OIL INDUSTRY	434
	A. Oil Price Dynamics.....	434
	B. Consumption Projections	435
	C. Peaking Global Production?	436
	D. High Future Demand and Price.....	438
	E. Perfect Strategic Positioning	439
V.	CONCLUSION	439

I. INTRODUCTION

Recent government initiatives heavily promote non-petroleum *biofuels* as America's transportation fuel of the future. One such program, the Renewable Fuel Standards ("RFS"), which mandates yearly increases in biofuels mixed into vehicle fuel sold in the United States, has caused concerns for both the agricultural and oil industries, helping prompt Texas governor Rick Perry to request a waiver for his state.¹⁰⁹ However, although it is not their intended purpose, these efforts to promote biofuels may provide the oil industry significant economic and strategic benefits.

This article proceeds in three parts: first, describing the RFS requirements and concerns that they raise; second, discussing the myriad obstacles to RFS success; and third, forecasting the likely economic and

* Mr. Turgeon holds a J.D. from the University of Virginia School of Law and a B.A. with honors in International Relations and German from Tufts University. During law school, he served as Notes Editor for the Virginia Journal of Social Policy & the Law. Mr. Turgeon has published widely on energy policy, national security, and economic philosophy. He can be reached at ent2e@virginia.edu.

¹⁰⁹ Letter from Rick Perry, Governor, State of Texas, to Stephen L. Johnson, Administrator, U.S. Evtl Prot. Agency (Apr. 25, 2008), available at <http://www.epa.gov/otaq/renewablefuels/rfs-texas-letter.pdf>.

strategic benefits accruing to the oil industry as a result of pro-biofuel policies.

II. CONCERNS OVER BIOFUEL STANDARDS

The Renewable Fuel Standards created by the 2005 Energy Policy Act¹¹⁰ and expanded by the 2007 Energy Independence and Security Act¹¹¹ (“EISA”) require that growing volumes of specific types of biofuels be mixed into transportation fuel sold in the United States. RFS requirements took effect in 2008, requiring that 9 billion gallons of renewable fuel be sold in that year and that this amount increase yearly until 2022 when 36 billion gallons must be sold.¹¹² In 2022 ethanol fermented from corn may provide 15 billion gallons of this total, but advanced biofuels must provide the remaining 21 billion gallons—including 16 billion gallons of ethanol fermented from plant cellulose, called *cellulosic biofuel*.¹¹³

Legislators intend these requirements to increase the percentage of the United States’ transportation fuels that is produced domestically, thereby decreasing petroleum imports and promoting energy independence and security.¹¹⁴ Massive federal funding accompanies biofuel programs, including stipends for research,¹¹⁵ funding for refinery construction,¹¹⁶ direct subsidies to biofuel producers,¹¹⁷ and indirect tax incentives to small biofuel producers and blenders.¹¹⁸

The government’s aggressive promotion of alternative transportation fuels has caused concerns for the oil and farm industries. Seeing the

110. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1501(a), 119 Stat. 594 (2005) (amending Clean Air Act § 211, 42 U.S.C. § 7545 (1990)).

111. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 202, 121 Stat. 1492 (2007) (amending Clean Air Act § 211, 42 U.S.C. § 7545 (1990)).

112. 42 U.S.C.A. § 7545(o) (West 2009).

113. *Id.*

114. Energy Independence and Security Act of 2007 (Caption: “An Act To move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, buildings, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes.”); see Energy Info. Admin., *Annual Energy Outlook 2008 with Projections to 2030*, at 130, available at [http://www.eia.doe.gov/oiaf/aeo/pdf/0383\(2008\).pdf](http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf) [hereinafter *Annual Energy Outlook*] (showing that passenger vehicles currently consume by far the most oil in the transportation sector, over 60% in 2006, and are expected to continue to make up a significant percentage of total consumption, approximately 57% in 2030.).

115. See, e.g., Biomass Research and Development Act of 2000, 7 U.S.C. § 7624 (2000) (amended 2005).

116. See 42 U.S.C.A. § 7545(s)(3)(A-C) (authorizing a total of \$750 million for fiscal years 2006-2008).

117. See Food, Conservation, and Energy Act of 2008, § 9001(a), 7 U.S.C. § 8105(g) (2008) (mandating advanced biofuel producer funding totaling \$300 million for fiscal years 2009-2012, and authorizing discretionary funding of \$25 million per year).

118. See 26 U.S.C.A. § 40 (2008) (authorizing tax credits for small biofuel producers and blenders).

government's biofuel initiative as costly, ineffective, and posing compliance problems, the oil industry has opposed the RFS.¹¹⁹ Additionally, well-documented increases in food prices resulting from the biofuel industry's consumption of agriculturally grown products have worried sectors of the agricultural community. While higher crop prices can benefit corn farmers, they also increase the costs of animal feed for the livestock industry.¹²⁰

Fears that these concerns could result in economic harm prompted Texas Governor Rick Perry to petition the EPA, requesting that Texas be granted "a waiver of 50% of the mandate for the production of ethanol derived from grain."¹²¹ Although his request primarily discussed food and feed price effects of biofuel mandates, Governor Perry recognized oil industry concerns, stating that Texas is "a leading producer of our nation's domestic fuel supply."¹²² However, the EPA denied Texas's waiver request, finding that the RFS would have "no impact on corn, food, or fuel prices" during the "2008/2009 corn marketing year," and "even if the RFS mandate were to have an impact on the economy . . . it would not be of a nature or magnitude that could be characterized as severe."¹²³ For the short term, at least, it appears the biofuels mandates are here to stay.

III. THE RFS'S UNACHIEVABLE GOALS

There are many reasons to believe, however, that RFS mandates will not achieve their intended purpose of reducing the United States' gasoline consumption meaningfully over the longer term. Despite an enormous amount of federal aid, technical obstacles and fuel market volatility continue to plague the biofuel industry. These continuing problems strongly suggest that the biofuel industry will not produce and Americans will not consume biofuels on the levels mandated by the RFS,

119. See, e.g., *The Renewable Fuels Standard: Issues, Implementation, and Opportunities, Hearing Before the H. Subcomm. on Energy and Air Quality of the H. Energy and Commerce Comm.*, 110th Cong. (2008) (statement of Charles T. Drevna, President, Nat'l Petrochem. & Refiners Ass'n), available at <http://www.npra.org/files/pdf/050608Testimony.pdf> [hereinafter *Renewable Fuels Hearing*]; Jim Snyder, *Oil lobby looks to delay deadlines for new renewable fuels standard*, THE HILL, Feb. 13, 2008, at 14, <http://thehill.com/business--lobby/oil-lobby-looks-to-delay-deadlines-for-new-renewable-fuels-standard-2008-02-12.html>. See also Jad Mouawad, *Oil Industry Says Biofuel Push May Keep Gas Prices High*, N.Y. TIMES, May 24, 2007, at A1.

120. James A. Duffield et al., *Ethanol Policy: Past, Present, and Future*, 53 S.D. L. REV. 425, 444 (2008). See also Evan N. Turgeon, *Federal Forests, Biomass, and Ethanol: Energy Security Sabotaged*, 39 Env'tl. L. Rep. (Env'tl. Law Inst.) 10140 (2009) (discussing the political motivations behind the United States' alternative energy policies).

121. Letter from Rick Perry, *supra* note 109, at 2.

122. *Id.* at 1.

123. EPA Decision on Texas Request for Waiver of Portion of Renewable Fuel Standard (RFS), EPA420-F-08-029 (Aug. 7, 2008), available at <http://www.epa.gov/OMS/renewablefuels/420f08029.htm>.

making it likely that waivers and lessened requirements of the sort Governor Perry requested will be necessary in the future.

A. *Technical Snags*

Most problematically, RFS biofuel requirements rely on nonexistent technology. Although scientists are capable of producing cellulosic ethanol in small quantities in laboratories, no cost-effective process to break down plant hemicellulose and lignin is presently available commercially, despite hefty government subsidies.¹²⁴ Notwithstanding this reality, the RFS mandates that cellulosic ethanol provide the bulk of the biofuel consumed by Americans in the long-term. Beginning in 2010 the RFS requires 100 million gallons of cellulosic biofuel to be mixed into the gasoline consumed by Americans. This volume more than doubles to 250 million gallons in 2011, eventually reaching 16 billion gallons in 2022.¹²⁵ The simple fact that there is no cost-effective process to produce such large quantities of cellulosic ethanol will likely prevent the biofuel industry from meeting the RFS's targets.¹²⁶

Non-cellulosic ethanol produced from corn starch cannot make up the difference. Even if the RFS were amended to permit more than 15 billion gallons of corn-based ethanol to satisfy its strictures, the United States corn supply is and will be inadequate to produce 36 billion gallons of fuel by 2022. Were the United States to devote its entire yearly corn harvest (11 billion bushels) to the production of ethanol—which generally yields around 2.79 gallons of ethanol per bushel¹²⁷—under 31 billion gallons of ethanol would be produced. While this approach might make a trip to the supermarket cleaner, Americans would encounter bare shelves once inside.

B. *Unstable Fuel Markets*

The rising, increasingly volatile prices of crops used in biofuel production also hamper the industry's growth. As biofuel production increases, food and fuel will compete for the nation's agricultural land, increasing the prices of the agricultural products that are inputs of

124. See, e.g., Biomass Research and Development Act of 2000, 7 U.S.C.A § 7624 (West 2009). Although the government provided \$385 million in funding to six cellulosic ethanol plants in February 2008, it seems "highly unlikely those plants will be producing at full capacity in time to meet [EISA targets]." *Renewable Fuels Hearing*, *supra* note 119, at 5.

125. Energy Independence and Security Act of 2007, 42 U.S.C.A § 7545(o) (West 2009).

126. *Annual Energy Outlook*, *supra* note 114, at 8 ("[T]he current state of the industry and EIA's present view of projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels before 2022 will be insufficient to meet the new RFS targets for cellulosic biofuels . . .").

127. L. Leon Geyer et al., *Ethanol, Biomass, Biofuels and Energy: A Profile and Overview*, 12 *DRAKE J. AGRIC. L.* 61, 74 (2007).

ethanol production and thereby decreasing ethanol's profitability to producers.¹²⁸ This sort of market instability is already apparent: an E3 BioFuels ethanol plant in Mead, Nebraska shut down production in December 2007, after only six months of operation, partially as a result of high corn and declining ethanol prices.¹²⁹ Furthermore, consistent demand for biofuels would expose the nation's fuel supply to agricultural risks such as weather and pests.¹³⁰ Relying on agriculture to satisfy both food and fuel needs magnifies the negative consequences of a bad growing season.

Volatile oil prices also destabilize the nation's fledgling biofuel industry. In addition to government subsidies, biofuel producers depend on massive infusions of private capital to build and operate ethanol plants. However, this capital quickly evaporates when oil prices drop, causing ethanol prices to drop and refinery profits to decline.¹³¹ As happened previously in the 1980s,¹³² lower oil prices today reduce the economic incentives to produce and consume alternative fuels.

C. Barriers to Consumption

Without a reliable and steady supply of and demand for biofuels, ethanol distributors and consumers have little incentive to invest in the equipment capable of utilizing them.¹³³ Fuel blends containing more than 10% ethanol corrode equipment designed to accommodate gasoline. Further, the uncertainty about the future of biofuels discourages distributors from purchasing and installing expensive biofuel-capable distribution equipment.¹³⁴

Incentives discourage drivers from purchasing biofuels as well. The Department of Transportation notes that although there are over 250

128. Indeed, researchers estimate that in 2022 producing the 16 billion gallons of cellulosic ethanol required by the EISA would require a federal subsidy of \$1.86 per gallon. MINDY L. BAKER ET AL., CROP-BASED BIOFUEL PRODUCTION UNDER ACREAGE CONSTRAINTS AND UNCERTAINTY, at Abstract (2008).

129. Sandra Zellmer, *Boom and Bust on the Great Plains: Déjà Vu All Over Again*, 41 CREIGHTON L. REV. 385, 414 (2008) (book review) (citing Art Hovey, *Mead Ethanol Plant Files for Bankruptcy Protection*, LINCOLN J. STAR, Dec. 3, 2007).

130. FRANKLIN TUGWELL, THE ENERGY CRISIS AND THE AMERICAN POLITICAL ECONOMY: POLITICS AND MARKETS IN THE MANAGEMENT OF NATURAL RESOURCES 203 (1988) ("When the two markets interact, price and supply of energy can be expected to be influenced by the same unpredictable forces that have made food, feed, and fiber markets so unstable.").

131. Zellmer, *supra* note 129, at 413-14.

132. See Duffield, *supra* note 120, at 429 ("With oil prices returning to normal trends, much of the interest in ethanol and other alternative energy sources waned.").

133. See *Renewable Fuels Hearing*, *supra* note 119, at 20 ("Without certification and warranties, the infrastructure to accommodate mid-level ethanol blends won't get built.").

134. For example, although the federal government provides service station owners a 30% tax credit (up to \$30,000) towards the cost of installing equipment capable of accommodating biofuels, owners must finance such upgrades out-of-pocket. See 26 U.S.C. § 30C (2006).

million vehicles on the road, just over 12 million of these vehicles are capable of utilizing alternative fuels.¹³⁵ Many of these vehicles are *flex-fuel* vehicles capable of utilizing either E85 or the standard E10.¹³⁶ However, even though drivers of such vehicles could purchase E85, the lack of available, competitively-priced E85 encourages drivers to fill up with E10 most of the time.¹³⁷

Higher gas prices are unlikely to prompt consumers to purchase more expensive vehicles capable of using biofuels: “Once a consumer has purchased equipment that uses a particular fuel, whether it be a car or furnace, he tends to stay with that source, and will be inclined to pay more rather than incur the much greater expense of buying new equipment.”¹³⁸ This behavior makes sense given the volatility of the American transportation fuel market. Moreover, whatever changes in consumer behavior are achieved during periods of high gasoline prices quickly come undone when gasoline prices fall.¹³⁹ Expiring tax credits for purchasers of alternative fuel vehicles also deter consumers from owning equipment capable of utilizing biofuels.¹⁴⁰

However, RFS drafters project the growing supply of biofuels to greatly increase yearly sales of flex-fuel vehicles in the coming decades.¹⁴¹ Incentives discouraging the distribution and use of biofuels suggest that this shift in consumer behavior will not occur. So even if the United States could produce enough biofuels to satisfy the RFS, Americans would not necessarily consume those fuels instead of gasoline.

135. BUREAU OF TRANSP. STATISTICS, U.S. DEPT OF TRANSP., NATIONAL TRANSPORTATION STATISTICS 2008, at T.1-11 http://www.bts.gov/publications/national_transportation_statistics/html (providing data for 2006); Alliance of Auto Mfrs., Alternative Fuel Autos Overview, www.discoveralternatives.org (last visited May 24, 2009).

136. E85 consists of 85% ethanol, 15% gasoline, and E10 consists of 10% ethanol, 90% gasoline. E10 is the transportation fuel most commonly sold at fueling stations in the United States.

137. See Duffield, *supra* note 120, at 430 (stating that “most FFV owners usually use gasoline instead of ethanol.”).

138. TUGWELL, *supra* note 130, at 42.

139. Paul Ingrassia, *The Latest Song of Detroit*, WALL ST. J., Dec. 4, 2008, at A17 (noting that sales of alternative fuel and efficient vehicles plummeted as gasoline prices dropped in the fall of 2008).

140. See *Annual Energy Outlook*, *supra* note 114, at 66 (acknowledging that fuel economy credits to alternative fuel vehicle producers will be phased out by 2020); Mike Spector, *The Incentives to Buy Hybrids are Dwindling*, WALL ST. J., Nov. 6, 2008, at D1 (discussing the expiration of tax credits to hybrid vehicle purchasers).

141. *Annual Energy Outlook*, *supra* note 114, at 66 (projecting an increase from 454,600 flex-fuel vehicles sold in 2006 to 2.7 million sold in 2030 as a result of the increased use of E85).

D. Likely Results

These factors indicate that quantities of biofuels produced and consumed in 2022 will fall well short of RFS requirements,¹⁴² triggering waivers and downward adjustments in the volumes of biofuels required by certain dates.¹⁴³ The EISA expressly allows for such adjustments, providing that the EPA can waive RFS requirements if domestic biofuels supply is inadequate or if implementation of the requirements would cause a state or region serious economic or environmental harm.¹⁴⁴ Although the EPA denied Governor Perry's waiver request, declining to find severe economic harm, it seems likely that future waivers will be granted due to the nation's inability to meet the cellulosic ethanol mandates that take effect in 2010. Consequent downward adjustments in biofuel volume requirements are thus likely in coming years.

The nation's inability to satisfy the RFS and resultant waivers and volume modifications indicate that biofuels will not reduce gasoline consumption anywhere near as much as the RFS's drafters intended. This could be good news for the oil industry.

IV. BENEFITS FOR THE OIL INDUSTRY

Biofuel initiatives are unlikely to negatively affect oil industry profits in the coming decades. Demand for transportation fuel continues to grow but there are many indications that—for both geological and above ground reasons—supply will not increase as rapidly. This means biofuels will not cannibalize oil in the coming decades but rather supplement demand that a lagging oil supply cannot, while simultaneously ensuring that gasoline remains the nation's primary transportation fuel. The demand for oil and corresponding industry profits will thus remain high not only despite biofuel requirements, but partly because of them.

A. Oil Price Dynamics

It is important to note that the American oil industry is a price-taker.¹⁴⁵ According to the U.S. Federal Trade Commission, “[w]orldwide supply,

142. See *Renewable Fuels Hearing*, *supra* note 119, at 20 (“Refiners may then find themselves in a situation where they won’t be able to comply with the law because of their inability to blend the requisite volumes of renewable fuels into the fuel supply.”); *Annual Energy Outlook*, *supra* note 114, at 8 (“[T]he current state of the industry and EIA’s present view of projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels before 2022 will be insufficient to meet the new RFS targets for cellulosic biofuels . . .”).

143. *Annual Energy Outlook*, *supra* note 114, at 8.

144. 42 U.S.C.A. §§ 7545(o)(7)(A)(1) & (2) (West 2009).

145. See also JOHN R. MORONEY, EXPLORATION, DEVELOPMENT, AND PRODUCTION: TEXAS OIL AND GAS, 1970-1995 xviii (1997) (“The price of Texas oil has not been determined in Texas markets, but instead in the global marketplace where it competed with all other oil.”).

demand, and competition for crude oil are the most important factors in the national average price of gasoline in the U.S.” and “[o]ver the last 20 years, changes in crude oil prices have explained 85 percent of the changes in the price of gasoline in the U.S.”¹⁴⁶ In the first three quarters of 2008, the United States produced approximately 10% of the world’s oil, while the countries of OPEC produced over 41%.¹⁴⁷ OPEC’s commanding share of world production has historically enabled it, rather than the American oil industry, to exercise control over the world price of oil.

B. Consumption Projections

In 2030 the population of the United States is projected to total over 365 million, and passenger vehicles are expected to drive more than four trillion miles that year alone.¹⁴⁸ EISA-mandated increases in vehicle efficiency will improve the fuel-efficiency of the average passenger vehicle on the road in 2030 to 27.9 miles per gallon of gasoline equivalent.¹⁴⁹ Optimistic projections assume that biofuel use in the transportation sector may reach 32.5 billion gallons by 2030.¹⁵⁰ “As a result of the [EISA] RFS, the biofuel component of motor fuels in the transportation sector is projected to grow substantially, as the fossil fuel content of gasoline and diesel declines from 136 billion gallons (96%) in 2006 to 125 billion gallons (83%) in 2030.”¹⁵¹ Overall demand for transportation fuel will increase 13% over the same period, from 8.60 million barrels of oil equivalent per day in 2006 to 9.74 million barrels in 2030,¹⁵² resulting in a decrease in oil consumption by passenger vehicles from 8.28 million barrels of oil per day in 2006 to 8.07 million barrels in 2030.

146. FEDERAL TRADE COMMISSION, GASOLINE PRICE CHANGES: THE DYNAMICS OF SUPPLY, DEMAND, AND COMPETITION iii-iv (2005). See also Karen Wanderscheid, Student Article, *The Environmental Protection Agency’s “Major Emitting Facility” Definition and Its Effect on Ethanol Facilities: A Review of the Amended Rule and Its Potential Pitfalls and Successes in South Dakota*, 53 S.D. L. REV. 548, 575 (2008) (“[O]il refineries are keeping smaller inventories, and oil companies are continuing to purchase crude oil from foreign companies, which is more expensive than purchasing domestic oil.”) (footnotes omitted).

147. ENERGY INFORMATION ADMINISTRATION, WORLD OIL BALANCE, 2004–2008 (2007), www.eia.doe.gov/emeu/ipsr/t21.xls (last visited May 24, 2009); see also *Annual Energy Outlook*, supra note 114, at 50 (noting that this percentage is likely to remain constant through 2030).

148. See *Annual Energy Outlook*, supra note 114, at 129, 161 (projecting 4,069 billion miles to be traveled and a population of 365.59 million in the United States).

149. *Id.* at 7 (“[T]he projection reflects increases in the sale of unconventional vehicle technologies, such as flex-fuel, hybrid, and diesel vehicles, and a slowdown in the growth of new light truck sales.”). The EISA mandates such efficiency increases. See Energy Independence and Security Act of 2007, 49 U.S.C.A. § 32902(b)(2) (2009).

150. *Annual Energy Outlook*, supra note 114, at 81 (assuming that the United States will be able to produce 32.5 billion gallons biofuels by 2022). Total production will likely fall well short of this mark.

151. *Id.* at 82.

152. *Id.* at 130.

C. Peaking Global Production?

Peak oil is a hotly debated topic, but no matter where one stands on this issue, there are reasons to expect that the supply in the U.S. will not meet the growing pace of demand. Projections based on M. King Hubbert's now-famous model, which in 1956 accurately predicted the peak and decline of American oil production would begin in 1970,¹⁵³ indicate that world oil production peaked around November 2005.¹⁵⁴ According to these calculations, "[w]orld oil production has ceased growing, and by the year 2019 production will be down to 90 percent of the peak level."¹⁵⁵ If these analyses prove true, economic and political incentives may cause more drilling, but they will not be able to increase the supply of oil.¹⁵⁶ Consequently, finite resources rather than price or political concerns would limit the future supply of oil.¹⁵⁷

Other analysts disagree with Hubbert's projections, suggesting that oil production will not peak as soon as Hubbert projects and may not decline at all in the foreseeable future.¹⁵⁸ Some dispute that the Hubbert curve

153. M. KING HUBBERT, NUCLEAR ENERGY AND THE FOSSIL FUELS 24 (1956), available at <http://www.hubbertypeak.com/hubberty/1956/1956.pdf>. See also KENNETH S. DEFFEYES, BEYOND OIL: THE VIEW FROM HUBBERT'S PEAK 4 (2005) (projecting world peak in 2000 and discussing this projection's accuracy); *id.* at 40 (noting that the logistic peak may not be the same as the single greatest year of production).

154. DEFFEYES, *supra* note 153, at 43. See also ENERGY INFORMATION ADMINISTRATION, WORLD PRODUCTION OF CRUDE OIL, NGPL, AND OTHER LIQUIDS, AND REFINERY PROCESSING GAIN, MOST RECENT ANNUAL ESTIMATES, 1980-2007, available at www.eia.doe.gov/emeu/international/RecentTotalOilSupplyBarrelsperDay.xls (last visited May 24, 2009) (indicating that more oil per day was produced during 2005 than any year before or since); Colin L. Campbell & Jean H. Laherrère, *The End of Cheap Oil*, SCI. AM., Mar. 1998, at 61, 63 (projecting a world production peak before 2010). *But see* NAT'L PETROL. COUNCIL, HARD TRUTHS: FACING THE HARD TRUTHS ABOUT ENERGY 105 (2007), available at http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/NPC_Facing_Hard_Truths.pdf (projecting a world production peak around 2015). See Hon. Richard D. Cudahy, *The Bell Tolls for Hydrocarbons: What's Next?*, 29 ENERGY L.J. 381, 387 (2008) (calling the National Petroleum Council "weighted toward the [oil] industry and the government").

155. DEFFEYES, *supra* note 153, at 7.

156. See MORONEY, *supra* note 145, at xxxiii; Gary C. Bryner, *Challenges in Developing a Diverse Domestic Energy Portfolio: Integrating Energy and Climate Policy in the Western United States*, 15 N.Y.U. ENVTL. L.J. 73, 79 (2007) ("In response [to dramatically higher oil prices in the 1970s], the United States greatly increased the number of wells drilled. However, these wells were much less productive than earlier ones, and despite the massive increase in drilling activity, U.S. energy production continued its steady decline.").

157. See *Annual Energy Outlook*, *supra* note 114, at 57 ("In all the AEO2008 cases, OECD liquids production is between 23 and 24 million barrels per day in 2030, constrained by resource availability rather than price or political concerns."); Valerie Mercer-Blackman, *Why Hasn't Oil Supply Responded to Higher Prices?*, in WORLD ECONOMIC OUTLOOK: HOUSING AND THE BUSINESS CYCLE 101, 102 (Practising Law Institute 2008) ("[B]ased on evidence presented below, a significant component of these costs is the result of geological constraints—a more permanent rigidity—implying that the responsiveness of supply to high prices is likely to remain low for some time.").

158. See generally, e.g., PETER W. HUBER & MARK P. MILLS, THE BOTTOMLESS WELL: THE TWILIGHT OF FUEL, THE VIRTUE OF WASTE, AND WHY WE WILL NEVER RUN OUT OF ENERGY (2005); PETER R. ODELL, WHY CARBON FUELS WILL DOMINATE THE 21ST CENTURY'S GLOBAL ENERGY ECONOMY (2004); Sadad al-Husseini, *Rebutting the Critics: Saudi*

applies globally and argue that alternative energy sources will have developed by the time oil production eventually peaks in 2025 or 2030.¹⁵⁹ For example, using U.S. Geological Survey data on global oil supplies, the U.S. Energy Information Administration (“EIA”) projects that global oil supplies from conventional sources will peak in 2037 if global demand increases by 2% yearly.¹⁶⁰ Other scholars argue that human ingenuity will succeed where Mother Nature fails, and technology will enable the discovery of new oil reserves and the extraction of oil from presently undrillable reserves, such as tar sands and shales.¹⁶¹ Some analysts even suggest that high oil prices will encourage private investment in unconventional oil and gas sources, thereby overcoming present Saudi Arabian efforts to thwart such developments.¹⁶²

Whether or not we are nearing the peak—or already over it—there is little reason to expect that the downstream facilities serving the United States will be capable of providing major increases in the supply of transportation fuel in the near future. In light of price spikes, refineries in the United States are running close to capacity, and no new refineries have been built since 1976.¹⁶³ Added to this, government mandated biofuels programs may be causing second thoughts on new investment. As Shell Oil president John D. Hofmeister explained, “If the national policy of this country is to push for dramatic increases in the biofuels industry, this is a disincentive for those making investment decisions on expanding capacity in oil products and refining[.]”¹⁶⁴ While some have alleged that the lack of new investment is due to oil company collusion to restrict supply and keep prices high,¹⁶⁵ industry concerns over peaking world oil production and government-mandated shifts away from

Arabia's Oil Reserves and Production Practices Ensure its Cornerstone Role in Future Oil Supply, OIL & GAS J., May 17, 2004, at 16.

159. See Jacqueline Lang Weaver, *The Traditional Petroleum-Based Economy: An “Eventful” Future*, 36 CUMB. L. REV. 505, 512 (2006) (citing projections by Michael Lynch and Peter Odell).

160. JOHN H. WOOD ET AL., ENERGY INFO. ADMIN. LONG-TERM WORLD OIL SUPPLY SCENARIOS, Aug. 18, 2004, at 5, available at http://www.eia.doe.gov/pub/oil_gas/petroleum/feature_articles/2004/worldoilsupply/pdf/itwos04.pdf.

161. See Weaver, *supra* note 159, at 510 (“The Peak Oil opponents argue that energy comes from human ingenuity—a bottomless well. Anything is possible; surely bacteria will be invented to ferment tar sands.”).

162. See *id.*

163. *But see Is Market Concentration in the U.S. Petroleum Industry Harming Consumers?: Hearing Before the J. Econ. Comm.*, 110th Cong. (2007) (statement of Red Cavaney, President and CEO, Am. Petrol. Inst.) (“[O]ver the past 10 years, existing refineries have expanded capacity equivalent to building 10 new refineries”) [hereinafter *Market Concentration Hearing*].

164. Mouawad, *supra* note 119.

165. See *Market Concentration Hearing*, *supra* note 163 (statement of Sen. Charles Schumer, Chairman, U.S. Cong. J. Econ. Comm.) (“If there was more competition in this market, wouldn’t these companies be investing in new production rather than sending their oligopolistic profits back to shareholders?”).

conventional fuels provide a less sinister explanation for the industry's failure to expand capacity.¹⁶⁶ Either way, the end result will be constraints on U.S. supplies of transportation fuel.

D. High Future Demand and Price

While future supplies may be constrained, the shortcomings of existing biofuel programs make a decrease in domestic demand for gasoline extremely unlikely. As a result, “[m]arkets and analysts alike increasingly expect high oil prices to endure” as little switching to biofuels occurs.¹⁶⁷ An analysis of rational consumer behavior confirms as much. Considering the 29% loss in energy by volume incurred by utilizing E85 rather than gasoline, EIA price projections indicate that it will never be cost-effective between now and 2030 to purchase E85 rather than gasoline.¹⁶⁸ Government incentives promoting biofuels will therefore fail to reduce demand for gasoline, despite increased fuel-efficiency and anticipated high future oil prices.¹⁶⁹

A general trend of price increases is thus likely to continue into the near future. While future oil prices are impossible to predict with complete accuracy, projections *assuming continually increasing production* estimate that real prices will reach \$57 per barrel in 2016 and \$70-\$80 per barrel in 2030.¹⁷⁰ If production declines, oil prices will likely be much higher, perhaps well over \$100 per barrel.¹⁷¹ Both producers and refiners gain from price spikes in light of consumers' demand for

166. *See id.* (statement of Red Cavaney, President and CEO, Am. Petrol. Inst.) (“[Government] agencies have explained price spikes by supply/demand conditions that had nothing to do with manipulation of supplies or illegal agreements among companies.”).

167. Mercer-Blackman, *supra* note 157, at 53 (noting further that “[i]n their recent long-term reports, the International Energy Agency and the U.S. Department of Energy predicted that prices would remain around current levels (in 2005 dollars) in 2030 under current policies.”). *See also Annual Energy Outlook*, *supra* note 114, at 91 (“Continued growth in fuel use for transportation is expected despite high prices and newly tightened fuel economy standards.”).

168. *See Annual Energy Outlook*, *supra* note 114, at 138 (projecting E85 and gasoline costs in five-year increments between 2005 and 2030). Proportionally combining projections for pure ethanol and pure gasoline to evaluate E10 against E85 yields similar results. Although E85 proves 1.5¢ cheaper per gallon than E10 in one year, 2020, it seems unlikely that this temporary cost savings would appeal to consumers given flex-fuel vehicles' higher initial cost compared to traditional vehicles.

169. *Id.* at 91 (“Although the average fuel efficiency of vehicles . . . continues to improve, the changes under currently enacted laws and regulations are insufficient to offset the projected increase in transportation demand.”).

170. *Annual Energy Outlook*, *supra* note 114, at 96 (referencing its own study and estimates formulated by Deutsche Bank). Given that the RFS goals cannot be met in full, actual prices will likely exceed the Energy Information Administration estimates. *See id.* at 97 (noting that Energy Information Administration projections assume more robust domestic oil production and lower domestic demand than most studies). Increased volatility will likely accompany these high prices. *See DEFFEYES*, *supra* note 153, at 31-33 (warning that uncertainty about future prices reduces incentives for long-term investment); TUGWELL, *supra* note 130, at 41 (“Oil, like coal, is prone to market instability under free market conditions.”).

171. *See Annual Energy Outlook*, *supra* note 114, at 83 (high price scenario).

transportation fuel, which is notoriously inelastic in the short term. Such spikes have already yielded oil companies record profits in recent years.¹⁷²

E. Perfect Strategic Positioning

In addition to high prices and resulting high profits, RFS mandates play to the oil industry's strategic advantage as well. An industry only "loses market power when alternative sources are found"¹⁷³ if those alternatives provide a replacement for its product. As discussed, RFS-required biofuels cannot replace gasoline and likely will not reduce its market price. So even as the demand for oil grows and prices continue to increase, it seems clear that government policies promoting biofuels will not have the intended effect of weaning the United States off its "addiction" to oil and that oil prices will remain high in the long term. Consequently, RFS requirements will only ensure that existing oil is consumed more slowly than it otherwise would be, extending its production horizon. In light of increasing prices, this slowdown in consumption will increase oil industry profits over the long-term.

The RFS program may thus prove more beneficial for the oil industry than inaction by the federal government would have been, and it almost certainly provides the oil industry greater benefits than other strategies the government might have elected to pursue. The government's promotion of liquid biofuels that can be mixed with gasoline places any alternative transportation energy options not wedded to liquid fuel (such as electric cars) at a severe disadvantage. The RFS effectively ensures that the demand for oil as a transportation fuel will not decline in the coming decades, guaranteeing that oil companies will continue to profit from the existing market infrastructure until oil reserves are eventually exhausted. Moreover, subsidized biofuels may keep transportation fuel affordable to Americans, preventing a large-scale shift in consumer behavior. Relative to almost any other possible alternative energy initiative, the oil industry should see EISA's RFS as an enormous gain.

V. CONCLUSION

Although one might expect its representatives to desire a different outcome, the RFS likely will not harm the oil industry in practice. In fact, the industry may actually benefit from the government's promotion of

172. See, e.g., Clifford Krauss, *Exxon's Second-Quarter Earnings Set a Record*, N.Y. TIMES, Aug. 1, 2008, at C2 ("High commodity prices are driving the record earnings, not growth in production volumes of oil and gas.").

173. Franklin A. Lopez & Patricia E. Norris, *The Economics of Natural Resources*, in ECOLOGY, LAW AND ECONOMICS: THE SIMPLE ANALYTICS OF NATURAL RESOURCE AND ENVIRONMENTAL ECONOMICS 125, 139 (Nicholas Mercuro ed., 2d Ed. 1997) (discussing cartels such as OPEC).

biofuels. The RFS's unrealistic goals of widespread biofuel use are unlikely to be achieved, but even if RFS mandates are met, the demand for and price of oil will remain high, providing the oil industry high profits. Additionally, government-mandated biofuel regulations forego more efficient transportation fuel policies, thereby securing gasoline's continuing domination as the United States' primary transportation fuel. The oil industry could scarcely have hoped for a better outcome. Lawmakers might recognize the shortcoming of current policies and formulate a more effective strategy to reduce domestic gasoline consumption. Given their track record, however, the oil industry should lose little sleep over the prospect of decreasing demand.