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MOVING THROUGH THE ROCKY LEGAL TERRAIN TO FIND A "SAFE" ROYALTY CLAUSE OR A "NEW" MARKET AT THE WELL

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I. INTRODUCTION

Just as the nation's attention has been riveted by natural gas drilling opportunities in the Marcellus and the Utica Shale formations, the oil and gas industry's attention has been focused on a myriad of difficult issues on the road to the effective development of these resources.

Some of the issues are technological and are being resolved through science and engineering. Others are political and are being addressed in various ways, including by administrative agencies, legislation, and to a certain degree, through public education. The issue we deal with in this Article is judicially created by courts that have declined to follow basic rules of contract interpretation and construction, electing instead to reinterpret bargains made between gas producers and royalty owners in a way that confers benefits on royalty owners and corresponding disadvantages on producers regardless of the deal they actually made in the lease contract.

Specifically, the issue explored is how to deal with the calculation of royalty in light of the uncertainty and risk created by various states' holdings regarding allocation of post-production expenses and the implied duty to market. Traditional lease verbiage placing the point of valuation for payment of royalty "at the well" or "at the wellhead" has been the subject of much litigation in recent years. The opportunity for arguing about this exists because such leases are based on the idea that gas is typically sold at the wellhead (as it once was), when, as a result of deregulation and other factors, this has not been the case for nearly twenty years.[4]

The idea for this Article came about as the result of several prominent commentators positing that one of the most roundly criticized decisions—*Estate of Tawney v. Columbia Natural Resources, LLC*—actually created a renewed incentive for producers to sell unprocessed gas at the well in order to be entirely consistent with lease language measuring value of the gas for royalty calculation purposes "at the wellhead."[5] The *Tawney* decision was made by the Supreme Court of

4. *See* Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically?* (pt. 1), 37 NAT. RESOURCES J. 547, 553 (1997); *see also* Bruce M. Kramer, *Interpreting the Royalty Obligation by Looking at the Express Language: What A Novel Idea?*, 35 TEX. TECH L. REV. 223, 224 (2004) ("One of the root causes of the disparate treatment of royalty clauses in the past two decades has been the change of external circumstances regarding the production and marketing of both oil and natural gas that does not mesh with the language used by the parties in instruments which may be decades old.").

5. *See* David E. Pierce, *Royalty Jurisprudence: A Tale of Two States*, 49 WASHBURN L.J. 347, 366–67 (2010) [hereinafter Pierce, *Royalty Jurisprudence*]. *See also* Rachel M. Kirk, *Variations in the Marketable-Product Rule from State to State*, 60

Appeals of West Virginia, a state with great potential for development of both the Marcellus and Utica Shale. While the language of *Tawney* might support such an outcome in West Virginia, recent cases by federal district courts reviewing wellhead sales in other states indicate that some courts might find such sales impermissible, depending on their interpretations of the implied covenant to market the gas.[6]

This Article will explore whether re-emergence of a market at the wellhead is legally viable considering judicial rulings related to the issue and specifically, whether such a development would be held to run afoul of the implied covenant to market. This Article will review the law of each state with potential for developing Marcellus and Utica Shale gas, while keeping in mind that some states have no law on the issue, again creating uncertainty because of the divergent rulings by other states' courts. Finally, this Article will discuss the merits of completely abandoning the "at the well" approach to valuation for purposes of royalty calculation in new leases as the preferred way of avoiding litigation over this issue.

II. The Problem: Allocation of Post-Production Expenses

A. *The Reason for the Fight: A Brief History of the Allocation of Post-Production Expenses*

In the typical lease, the gas company bears all the expenses of exploring for and producing gas. These expenses are called "production costs" and include activities such as exploration, drilling, hydraulic fracturing, and completion of the well. Production is generally understood to occur when the gas breaks the surface of the earth at the well.[7]

Historically, production companies typically sold their gas to pipeline companies at the well location, and the pipeline companies then processed it into "sweet" marketable gas and transported it to the interstate pipeline. This all changed in 1992 when the Federal Energy Regulatory Commission issued Order No. 636, requiring the pipeline companies to "unbundle" transportation from sales and provide common carriage to others, including production companies.[8] The point

OKLA. L. REV. 769, 813 (2007); Scott Lansdown, *The Marketable Condition Rule*, 44 S. TEX. L. REV. 667, 707 (2003).

6. *See* Naylor Farms, Inc. v. Anadarko OGC Co., No. CIV-08-668-R, 2011 WL 7053789, at *3–4 (W.D. Okla. July 14, 2011); Freebird, Inc. v. Merit Energy Co., No. 10-1154-KHV-JPO, 2011 WL 13638, at *4–5 (D. Kan. Jan. 4, 2011). *See also* discussion *infra* Part IV.

7. *See* Cont'l Oil Co. v. Fed. Power Comm'n, 266 F.2d 208, 211 (5th Cir. 1959) ("[I]n the ordinary sense of the terms, production of the gas has been completed at or just above the surface of the ground where it is physically deliverable . . . .").

8. For a full explanation of the process of deregulation culminating in FERC Order 636, see David E. Pierce, *From Extraction to End Use: The Legal Background*, 1 ROCKY MTN. MIN. L. FOUND. 3 app. A (2003) [hereinafter Pierce, *From Extraction to End Use*]. It has also been suggested that this shift away from the well as the point

of sale for the production companies then moved "downstream" to the interstate pipeline connection point, with the producers now performing the processing, treating, gathering, compression, and transportation activities that add value to the gas (or paying others to do so).[9] The costs incurred in doing so are commonly referred to as "post-production expenses."

The question of where the gas should be valued for purposes of royalty calculation has arisen in the context of leases that call for royalty to be calculated based on the value of the gas "at the well" or "at the wellhead" or "net all costs beyond the wellhead." This language has become problematic in recent years because it presumes that gas is sold at the wellhead (as it once was) when, as a result of deregulation and other factors, this is no longer the case.[10]

The majority of oil and gas producing states interpret such "wellhead" language to provide for royalty to be paid as stated in the lease—based on value at the wellhead—absent express language to the contrary, and therefore to allow producers to calculate the royalty through a "net back" or "work back" method, deducting the post-production expenses in order to arrive at the wellhead value. California, Michigan, Mississippi, Montana, New Mexico, North Dakota, Louisiana, Texas, Pennsylvania, and Kentucky follow this majority rule.[11]

The minority approach—followed by Colorado, Kansas, Oklahoma, and West Virginia—expanded the producer's "implied duty to market" gas by creating a "first marketable product" doctrine. This doctrine requires the producer to bear all costs incurred up to the first point of marketability or, in the case of West Virginia, up to the point of sale, absent express language in the lease specifying the expenses to be deducted before calculation of royalty. The highest courts of Colo-

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of sale was also partially due to the reform of the mineral "depletion allowance" under various tax reform statutes. *See* Anderson, *supra* note 4, at 554.

9. *See* Creson v. Amoco Prod. Co., 10 P.3d 853, 857 (N.M. Ct. App. 2000).

10. *See* Anderson, *supra* note 4, at 554. *See also* Kramer, *supra* note 4, at 224.

11. *See, e.g.*, Atlantic Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Ct. App. 1989); Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 893–94 (1997); Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984) (applying Mississippi law); Pursue Energy Corp. v. Abernathy, 77 So. 3d 1094, 1099 (Miss. 2011) (stating that "[w]e agree with the Fifth Circuit's analysis in Piney Woods . . . ."); Mont. Power Co. v. Kravik, 586 P.2d 298, 302–03 (Mont. 1978); Creson v. Amoco Prod. Co., 10 P.3d 853, 857 (N.M. Ct. App. 2000); Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496, 502 (N.D. 2009); Babin v. First Energy Corp., 693 So. 2d 813, 815 (La. Ct. App. 1997); Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996); Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C., 636 F.3d 235, 238 (6th Cir. 2011) (interpreting Kentucky law); Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1149 (Pa. 2010). The Authors' conclusion that Pennsylvania—a Marcellus and Utica state—would follow the majority is based upon the Pennsylvania Supreme Court's holding in *Kilmer,* which construed the issue of allocation of post-production expenses in the context of a minimum royalty statute, as discussed below. It should also be noted that the only recent authority from Kentucky is from a federal district court applying very old precedent from Kentucky's highest court.

rado and West Virginia made their holdings despite lease language stating that royalty would be paid based on the value of the gas at the well, with Colorado's Supreme Court maintaining in *Rogers v. Westerman Farm Co.* that lease language stating that royalty was to be paid on the value of gas "at the well" was "silent" with respect to the allocation of post-production expenses[12] and West Virginia's Supreme Court in *Estate of Tawney v. Columbia Natural Resources, L.L.C.* finding that language providing that royalty to be calculated "at the well" or "at the wellhead," or be "equal to one-eighth of the price, net all costs beyond the wellhead" was "ambiguous."[13]

The remaining state courts with potential Marcellus or Utica Shale gas resources—New York, Ohio, Maryland, Virginia, and Tennessee—have not addressed the issue, though a federal magistrate judge sitting in Virginia recently predicted in recommendations to deny motions to dismiss that Virginia would "impose an implied duty to market on lessees under oil and gas leases . . . and that Virginia courts would construe this duty to market to include a duty to make the product marketable."[14] These recommendations were adopted by the federal district judge without comment on this prediction.[15]

B. *The Dueling Incentives of Lessors and Lessees*

The traditional "at the well" lease language has been challenged for a reason expressed very well by the distinguished Professor Pierce: "When compensation under a contract is based upon a set percentage of the value of something, there will be a tendency by each party to either minimize or maximize the value. This is also the foundation for why there will never be peace under the oil and gas lease."[16] In other words, mineral owners will always want to maximize the amount they are paid, and mineral lessees will always want to maximize their profit.

Treatment and transportation of gas after it leaves the wellhead creates additional economic value. This is true because the value of gas increases in excess of the cost of investments made in treatment and transportation as the gas moves downstream; its improved condition and location make it more valuable.[17] The economic value created in excess of actual post-production expenses provides the producers' incentive to undertake post-production improvements:

12. *See* Rogers v. Westerman Farm Co., 29 P.3d 887, 902 (Colo. 2001) (en banc).
13. Estate of Tawney v. Colum. Natural Res., L.L.C., 633 S.E.2d 22, 30 (W. Va. 2006).
14. Legard v. EQT Prod. Co., No. 1:10cv00041, 2011 WL 86598, at *10 (W.D. Va. Jan. 11, 2011); *see also* Healy v. Chesapeake Appalachia, LLC, No. 1:10cv00023, 2011 WL 24261, at *15 (W.D. Va. Jan. 5, 2011).
15. *Legard*, 2011 WL 4527784, at *1.
16. Pierce, *From Extraction to End Use*, *supra* note 8, at app. A.
17. *See id.*

> As a general proposition, as oil or gas moves downstream from the wellhead it increases in value. This increase in value is comprised of two components: (1) investments made in the production either by the lessee providing a facility or service or purchasing the service from others; and (2) the increased value of the production in a particular form at a particular location. For example, the lessee may spend 50¢/Mcf in gathering and compression costs to transport gas from the wellhead to an interstate pipeline. If we assume the gas has a wellhead value of $1.00/Mcf, and a value at the point where the gathering system enters the interstate pipeline of $1.55/Mcf, the total enhanced value is comprised of the 50¢ in additional investment plus 5¢ in additional value. As the gas moves further downstream from the wellhead it is typically subject to additional value-increasing investment until it is sold to the purchaser that consumes the gas.[18]

Recent court decisions disallowing deduction of post-production expenses for purposes of royalty calculation effectively remove the producers' incentive to add value to their product by post-production treatment and transportation because producers are required to pay royalties not only on the enhanced value of the gas itself, but also on the value of their investments in processing the gas.[19] This results in an economic loss to all parties because where producers are required to pay for *all* post-production expenses and also surrender one-eighth of the final proceeds received, the incentive to generate this additional value disappears.[20] Rather than creating this additional value for both producer and royalty owner, producers are instead encouraged to sell the gas as early in the process as possible in order to avoid additional royalty payments generated wholly at the producer's expense.[21]

18. David E. Pierce, *Judicial Interpretations of Royalty Obligations and the Resulting Drafting Lessons*, 5 ROCKY MTN. MIN. L. FOUND. 7 (2008) [hereinafter Pierce, *Judicial Interpretations of Royalty Obligations*].

19. *See id.* ("The lessee will note that if it is required to pay royalty on the downstream value, it will not be paying royalty on just the oil or gas, instead it will be paying a royalty on the oil, gas, and money the lessee spent to move the gas from the wellhead to the pipeline. Without an appropriate adjustment, the more the lessee pays in expenses, the higher its royalty – not on the production, but rather on expenses incurred to enhance the value of the production as it moves away from the wellhead.") (emphasis in original).

20. *See* Pierce, *Royalty Jurisprudence*, *supra* note 5, at 349 ("[R]oyalty litigation merely re-slices the old pie without bringing anything new to the table. In some instances, the prospective effect of a state's royalty jurisprudence can result in a smaller "old pie" with all parties worse off. This could occur when a lessee, fearful of its ability to deduct or defend downstream costs, elects to enter into an arm's length sale at the wellhead instead of investing additional capital to pursue downstream markets.").

21. *See* Kirk, *supra* note 5, at 813 (recognizing that "[a]lthough the West Virginia Supreme Court was attempting to put a more stringent requirement on the lessee to bear costs and to protect the lessor from improper deductions, the court did neither. This is because the West Virginia rule's requirement that a lessee bear all costs incurred until the point of sale may encourage producers to sell at or near the wellhead. This is contrary to the implied covenant to market, which historically required the

It should be recognized, then, that a wellhead market is less lucrative for both producers and royalty owners than a downstream market. The questions then become whether the producer has a duty to seek a downstream market and whether it is legally viable to do so.

III. The Implied Covenant to Market: How Expansive is the Covenant in the Marcellus and Utica States?

The principal question to be addressed in assessing the viability of marketing gas at or near the wellhead is how expansively the implied covenant to market will be applied by the courts in question. The implied covenant to market generally provides that "the lessee has the duty to produce a marketable product, and the lessee alone bears the expense in making the product marketable."[22] The question is whether a producer can satisfy the duty to produce a marketable product if it actually sells gas at the well to a willing buyer in its raw, unprocessed form.

A. *Differing Judicial Approaches*

Traditionally, an oil and gas lease was treated and construed like any other contract.[23] Accordingly, courts applying the traditional approach to evaluating oil and gas leases, such as those in Texas, California, New Mexico, and Michigan, would consider their principal task to be giving effect to the parties' intent in making a bargain under the circumstances prevailing at the time it was made.[24] In *Yturria v. Kerr-McGee Oil & Gas Onshore, LP* for example, the court framed its analysis of an oil and gas lease around the parties' freedom to contract, declaring that "the parties to a contract are considered masters of their own choices and to that end they must select the terms and provisions to include in a contract before they execute it .... Because

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lessee to diligently market the product and obtain the best possible price and terms. The practice of selling at or near the wellhead at arm's length would comply with the West Virginia rule because the lessee would incur all costs up to the point of sale. This practice, however, could result in a lessee selling the gas inefficiently-perhaps even before the gas is actually in a marketable condition, thus contradicting the rule's purpose."). *See also* Lansdown, *supra* note 5, at 707 ("By allowing the lessee to deduct transportation costs when calculating royalty, the lessee is encouraged to market gas for the best possible price and terms. In addition to upsetting well-established principles, the marketable-location rule will adversely affect the marketing of gas by encouraging producers to market gas close to the wellhead even though that location may not be the most efficient marketplace.").

22. Sternberger v. Marathon Oil Co., 894 P.2d 788, 799 (Kan. 1995).

23. *See* Yturria v. Kerr-McGee Oil & Gas Onshore, LP, No. 7:05-CV-181, 2006 WL 3227326, at *7 (S.D. Tex. Nov. 6, 2006) ("Texas courts consider an oil and gas lease a contract."), *aff'd sub nom.* Yturria v. Kerr-McGee Oil & Gas Onshore, L.L.C., 291 F. App'x 626 (5th Cir. 2008).

24. *See* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121 (Tex. 1996) ("In construing an unambiguous oil and gas lease our task is to ascertain the parties' intentions as expressed in the lease.").

the parties are masters of their own fate, they may thus voluntarily bind themselves in the manner they choose."[25] Under this approach, courts refuse to "rewrite an agreement between parties or make a new contract for the parties, one they did not make."[26] A court will not, moreover, "change the contract merely because it or one of the parties dislikes the provision or think[s] it unfair."[27]

This is principally because "[f]or a court to change the parties' agreement merely because the Court did not like the agreement, or because one of the parties subsequently found it distasteful, would be to undermine not only the sanctity afforded the contract but also the expectations of those who created and relied upon it."[28] In other words, if a lease was negotiated at the time that all gas was sold to a pipeline company at the well, a sale at the wellhead was all that was contemplated and bargained for. If a court departs from this, it is rewriting the parties' agreement. Applying these well-settled principles of contract interpretation, Texas (and other) courts have concluded that "[m]arket value at the well has a commonly accepted meaning in the oil and gas industry,"[29] namely, "value at the well, net of any value added by compressing the gas after it leaves the wellhead."[30]

Courts applying the traditional approach to lease construction have been reluctant to impose implied covenants that add to or contradict the express intent of the mineral lease: "A covenant will not be implied unless it appears from the express terms of the contract that 'it was so clearly within the contemplation of the parties that they deemed it unnecessary to express it.'"[31] In other words, these courts refuse to create an implied covenant "to achieve what [the court] believes to be a fair contract or to remedy an unwise or improvident contract."[32]

Although most states continue to apply these same basic principles of construction to nearly every other form of contract,[33] a number of

25. *Yturria*, 2006 WL 3227326, at *7.

26. Barn-Chestnut, Inc. v. CFM Dev. Corp., 457 S.E.2d 502, 509 (W. Va. 1995).

27. *Yturria*, 2006 WL 3227326, at *7 (citing HECI Exploration Co. v. Neel, 982 S.W.2d 881, 888–89 (Tex. 1998)).

28. Cross Timbers Oil Co. v. Exxon Corp., 22 S.W.3d 24, 26–27 (Tex. App.—Amarillo 2000, no pet.).

29. *Heritage Res., Inc.*, 939 S.W.2d at 122.

30. Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 135 (Tex. 1996); Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C., 636 F.3d 235, 238 (6th Cir. 2011) (interpreting Kentucky law); Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1149 (2010); Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496, 501 (N.D. 2009).

31. HECI Exploration Co. v. Neel, 982 S.W.2d 881, 888 (Tex. 1998) (quoting Danciger Oil & Ref. Co. of Tex. v. Powell, 154 S.W.2d 632, 635 (Tex. 1941)).

32. *Id.* at 889.

33. Even the Supreme Court of Appeals of West Virginia, which has been widely criticized for disregarding clear terms such as "at the wellhead" in *Estate of Tawney v. Colum. Natural Res., L.L.C.*, 633 S.E.2d 22, 27 (W. Va. 2006) would apply traditional principles of construction in other circumstances. *See, e.g.*, Barn-Chestnut, Inc. v. CFM Dev. Corp., 457 S.E.2d 502, 509 (W. Va. 1995) (holding in the context of a

courts have abandoned the "freedom of contract" model when interpreting royalty provisions in oil and gas leases and have instead employed numerous devices to supply terms to make contracts "fair" regardless of the parties' intent upon entering into the contract.[34] Each approach has been applied to nearly identical lease royalty provisions, leading to wildly divergent results in producing states.

B. *The Notable Detour: Colorado Expands the Implied Covenant to Market to Impose Heightened Condition and Location Requirements Despite Language in the Lease Providing that Royalty Will be Based on Value "At the Well"*

While this Article deals primarily with the jurisprudence in states with Marcellus and Utica Shale potential, the implied covenant to market was first applied to invalidate or re-interpret "at the well" type language in Colorado, Kansas, and Oklahoma. In order to fully understand the later development of royalty jurisprudence in the Marcellus and Utica states, it is first necessary to discuss the judicial devices applied by the Colorado Supreme Court.

In *Garman v. Conoco, Inc.*, the Colorado Supreme Court started down the road that led to *Rogers* by holding that an overriding royalty owner was not responsible for a pro-rata share of post-production expenses.[35] In reaching this conclusion, the *Garman* Court recognized two distinct lines of authority addressing the allocation of post-production expenses. The first approach, applied by courts in Texas and Louisiana, holds that "gas is 'produced' when it is severed from the land at the wellhead."[36] On the other hand, courts in Kansas and Oklahoma hold that gas is not "produced" until it is available for market, requiring the lessee "to get the product to the place of sale in marketable form" at its own expense.[37] The *Garman* Court held that this duty to market is implied in every Colorado lease and concluded that "the implied covenant to market obligates the lessee to incur those post-production costs necessary to place gas in a condition ac-

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commercial franchise agreement that "where the express intention of contracting parties is clear, a contrary intent will not be created by implication."). *See also* Freebird, Inc. v. Merit Energy Co., No. 10-1154-KHV-JPO, 2011 WL 13638, at *7 (D. Kan. Jan. 4, 2011) (recognizing that "absent an express lease provision to the contrary, Kansas courts seem to presume that implied covenants apply to all oil and gas leases" but noting that "[t]his approach is particularly striking because it stands in stark contrast to Kansas implied covenant jurisprudence in other areas.").

34. *See* Kramer, *supra* note 4, at 238–40.

35. Garman v. Conoco, Inc., 886 P.2d 652, 653 (Colo. 1994).

36. *Id.* at 657–58 (quoting Martin v. Glass, 571 F. Supp. 1406, 1415 (N.D. Tex. 1983), which recognized a duty to market but held that "the duty to market is a separate and independent step, once or more removed from production, and as such is a post-production expense, and the lessee is entitled to a pro rata reimbursement.").

37. *Id.* at 658 (quoting Wood v. TXO Prod. Corp., 854 P.2d 880, 882 (Okla. 1992)).

ceptable for market. Overriding royalty interest owners are not obligated to share in these costs."[38]

The *Garman* Court limited its holding to those expenses "required to transform raw gas into a marketable product" and recognized that expenses required to enhance an already marketable product are to be shared. The Court recognized that a product is marketable when it is "fit to be offered for sale in a market; being such as may be justly and lawfully bought or sold . . . wanted by purchasers."[39] The Court further noted the definition of marketability offered by the leading treatise on oil and gas, Williams & Meyers: "sufficiently free from impurities that it will be taken by a purchaser."[40] The Court did not address whether gas could be considered marketable at the wellhead if a purchaser was willing to buy it there.

The definition of marketability was a central issue a few years later in *Rogers v. Westerman Farm Co.*[41] In *Rogers*, a dispute arose between royalty holders and working interest owners regarding the expenses that could be deducted from royalty payments. The Court recognized that some of the gas in dispute was sold directly at the wellhead, and royalty was calculated as one-eighth of the proceeds of the sale. The Court recognized that the gas at issue was both sweet and dry at the wellhead, but the plaintiffs nonetheless complained that this gas was not "marketable" at the well and contended that they would have received higher royalties if the gas had been sold downstream.[42]

Rather than determining that the leases, which provided for payment of royalties "at the well" or "at the mouth of the well," controlled the allocation of post-production costs, the *Rogers* Court concluded that the leases were entirely silent with respect to such expenses, freeing the Court to apply judicially created standards based on the implied duty to market:

> We conclude that the leases in this case are silent with respect to allocation of costs. We disagree with those jurisdictions that conclude that "at the well" is sufficient to allocate costs. Moreover, we disagree with the conclusion that "at the well" language addresses transportation costs, while not addressing other costs incurred in processing the gas. Instead, we conclude that because the leases are silent, we must look to the implied covenant to market, and our previous decision in *Garman v. Conoco*, to determine the proper allocation of costs.[43]

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38. *Id.* at 659.
39. *Id.* at 661 n.28 (quoting WEBSTER'S THIRD NEW INTERNATIONAL DICTIONARY 1383 (1986)).
40. *Id.* at 665 (quoting HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 692 (1993)).
41. Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001) (en banc).
42. *Id.* at 892–93.
43. *Id.* at 902.

The *Rogers* Court focused on when and under what conditions a product can be considered to be "marketable." The Court stated that "deductibility of costs is determined by whether gas is marketable, not by the physical location of the gas or the condition of the gas."[44] The Court held, moreover, that "if gas is not marketable at the physical location of the well, either because it is not in a marketable condition, or because it is not acceptable for a commercial market, then the lessee has not met its burden of making the gas marketable."[45] The Court concluded that "because the lessees had a duty to make the product marketable, they alone must bear any expenses incurred in order for the gas to reach that marketable condition."[46]

In determining how to define marketability, the *Rogers* Court recognized and adopted the definitions of "marketable" set out in *Garman*. The Court went beyond these definitions, however, looking to the first marketable product doctrine for guidance. The Court explained that

> [t]he first-marketable product rule states that 'the point where a marketable product is first obtained is the logical point where the exploration and production segment of the oil and gas industry ends, is the point where the primary objective of the lease contract is achieved, and therefore is the logical point for the calculation of royalty.'[47]

Applying the first marketable product doctrine, the *Rogers* Court adopted a definition of marketability with reference to both physical and geographical considerations: "Gas is marketable when it is in the physical condition such that it is acceptable to be bought and sold in a commercial marketplace, and in the location of a commercial marketplace, such that it is commercially saleable in the oil and gas marketplace."[48]

The Court specifically rejected the lower court's conclusion that the gas was marketable at the wellhead as a matter of law because it was sold there. While recognizing that a sale of gas in good faith was *evidence* of marketability, the Court declared that "[g]as is not marketable merely because it is sold."[49] Rather, the Court stated that "the gas

44. *Id.* at 900–01.
45. *Id.* at 900.
46. *Id.* at 903.
47. *Id.* at 904 (quoting Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically?* (pt. 2), 37 NAT. RESOURCES J. 611, 636–37 (1997)). Professor Anderson responded to this citation of his article by sending a letter to the Colorado Supreme Court protesting its mischaracterization of his commentary. The Court relied on his commentary as recognizing a duty to transport gas to the location of a commercial market, which as Professor Anderson later pointed out, "is the opposite of what I had actually said." Owen L. Anderson, *Rogers, Wellman, and the New Implied Marketplace Covenant*, 1 ROCKY MTN. MIN. L. FOUND. 13A (2003).
48. *Rogers*, 29 P.3d at 906.
49. *Id.* at 910.

must be more than merely sold in order for the lessee to meet the duty to market the gas. Instead, . . . the gas must meet the standard of being suitable for a commercial market."[50] The Court concluded, moreover, that "the determination of marketability is a question of fact."[51]

Although the *Rogers* decision does not expressly foreclose a finding of marketability at the mouth of the well, the Court held that such a conclusion would only be appropriate where a jury finds that there is a "commercially viable market for the gas" at that location. It provided no guidance regarding what it would consider to be a "commercial marketplace" but rejected the elementary economic proposition that a market exists where there is a willing buyer and a willing seller. Where no "commercial marketplace exists at the wellhead," it is likely that the Colorado Supreme Court would require royalties to be paid based on the value of the gas wherever a jury decides is a commercial market—likely measured by what a jury considers to be appropriate comparable sales—even if the gas is actually sold at the well.

C. *Application/Expansion of the Implied Covenant to Market in the Marcellus and Utica States*

1. West Virginia Adopted the Reasoning of *Garman* in *Wellman v. Energy Resources, Inc.* but Declined to Address Direct Sales at the Well

While the decisions in *Garman* and *Rogers* turned on the definition of "marketability," West Virginia's jurisprudence took a slightly different route. The West Virginia Supreme Court first addressed the allocation of post-production expenses in *Wellman v. Energy Resources, Inc.*[52] In *Wellman*, the Court recognized that "[f]rom the very beginning of the oil and gas industry it has been the practice to compensate the landowner by selling the oil by running it to a common carrier and paying [the landowner] one-eighth of the sale price received."[53] The Court negatively characterized the deduction of post-production expenses, clearly revealing its disposition:

> In spite of this, there has been an attempt on the part of oil and gas producers in recent years to charge the landowner with a pro rata share of various expenses connected with the operation of an oil and gas lease such as the expense of transporting oil and gas to a point of sale, and the expense of treating or altering the oil and gas so as to put it in a marketable condition. To escape the rule that the

50. *Id.* at 911.
51. *Id.* at 905; *see also* Pierce, *Royalty Jurisprudence*, *supra* note 5, at 359 (noting that the "location-based assessment" of marketability—i.e., the holding in *Rogers* that the gas must be "saleable in a commercial marketplace"—has created a new term, the meaning of which "is left for a jury to determine").
52. Wellman v. Energy Res., Inc., 557 S.E.2d 254 (W. Va. 2001).
53. *Id.* at 264.

lessee must pay the costs of discovery and production, these expenses have been referred to as "post-production expenses."[54]

The *Wellman* Court recognized the implied duty to market and followed Colorado, Kansas, and Oklahoma in concluding that costs incurred in order to market gas should be borne by the producer. The Court discussed *Garman* at length, stating that "[i]mplied lease covenants related to operations typically impose a duty on the oil and gas lessee . . . . Accordingly, the lessee bears the cost of compliance with these promises."[55] The Court concluded that "[t]his Court believes that the rationale employed by Colorado, Kansas, and Oklahoma in resolving the question of whether the lessor or the lessee should bear 'post-production' costs is persuasive. Like those states, West Virginia holds that a lessee impliedly covenants that he will market oil or gas produced."[56] The Court accordingly concluded in Syllabus Point 4[57] that "[i]f an oil and gas lease provides for a royalty based on proceeds received by the lessee, unless the lease provides otherwise, the lessee must bear all costs incurred in exploring for, producing, marketing, and transporting the product to the point of sale."[58]

The *Wellman* Court based its decision exclusively on the implied duty to market, declining to analyze the language of the leases at issue. The Court recognized that the language of the leases at issue might be construed to allocate transportation expenses to the lessors: "this Court believes that the language of the leases in the present case indicating that the 'proceeds' shall be from the 'sale of gas as such at the mouth of the well where gas . . . is found' might be language indicating that the parties intended that the Wellmans, as lessors, would bear part of the costs of transporting the gas from the wellhead to the

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54. *Id.* To be fair, the Court was likely influenced by the factual scenario in *Wellman*. The Court noted that the producer paid royalties based on $.87 per thousand cubic feet even though it had received $2.22 per thousand cubic feet when it sold the gas downstream. *Id.* at 258. While the producer claimed that this difference was explained by post-production processing costs, it failed to produce any evidence to show that the claimed expenses were actually incurred or that they were reasonable. *Id.* at 264.

55. *Id.* (quoting Garman v. Conoco, Inc., 886 P.2d 652, 658 (Colo. 1994)).

56. *Id.* at 265.

57. In decisions of the Supreme Court of Appeals of West Virginia, the syllabus points are provided as part of the Court's decision and are binding precedent. West Virginia's state constitution requires the Supreme Court of Appeals to incorporate syllabus points of applicable law into the beginning of each of its decisions, which points represent the Court's holdings on the law. Because they are adopted as general propositions, syllabus points may have greater precedential force than language parsed from the body of the decision. W. VA. CONST. ART. VIII, § 4 ("[I]t shall be the duty of the court to prepare a syllabus of the points adjudicated in each case in which an opinion is written and in which a majority of the justices thereof concurred, which shall be prefixed to the published report of the case."); *see also* Walker v. Doe, 558 S.E.2d 290, 291 (W. Va. 2001) ("This Court will use signed opinions when new points of law are announced and those points will be articulated through syllabus points as required by our state constitution.").

58. *Wellman*, 557 S.E.2d at syl. pt. 4.

point of sale."[59] Nonetheless, the Court declined to consider the actual language of the leases, reasoning that "whether that was actually the intent and the effect of the language of the lease is moot because Energy Resources, Inc., introduced no evidence whatsoever to show that the costs were actually incurred or that they were reasonable."[60] The Court recognized, however, that appropriate lease language, supported by sufficient proof, could compel a different result: "if an oil and gas lease provides that the lessor shall bear some part of the costs incurred between the wellhead and the point of sale, the lessee shall be entitled to credit for those costs to the extent that they were actually incurred and they were reasonable."[61]

The *Wellman* Court declined to address what it referred to as gas "sold directly," explaining that "[w]here leases call for the payment of royalties based on the value of oil or gas produced, and sold directly, the Court perceives that there are possibly different issues, and they are excluded from this discussion."[62] It is unclear what the Court meant by this, but it is possible that the Court was referring to gas sold at the well.

2. The Court in *Estate of Tawney v. Columbia Natural Resources, L.L.C.* Declined to Follow *Rogers* but Held That "At the Well" Language Did Not Suffice to Allocate a Share of Post-Production Costs to Lessors

Although the *Wellman* Court declined to interpret the "at the well" language of the leases in that case, such lease language was directly at issue in *Estate of Tawney v. Columbia Natural Resources, L.L.C.*[63]

In determining whether "at the wellhead" type language served to allocate post-production expenses, the Court recognized the split of authority among the courts addressing the issue. The *Tawney* Court acknowledged *Creson v. Amoco Production Co.*, a New Mexico decision holding that such lease language was unambiguous and required that lessors bear a share of such expenses.[64] It further recognized *Rogers v. Westerman Farm Co.*, noting that the Colorado court had found such language entirely silent and relied instead on the implied duty to market to hold that the producer could not allocate a portion of post-production costs.[65] Declining to follow the reasoning set forth in either *Creson* or *Rogers*, the *Tawney* Court opted instead to "look to our own settled law" in analyzing the issue, stating that "tradition-

59. *Id.* at 267.
60. *Id.* at 265.
61. *Id.* at 265.
62. *Id.* at 263 n.3.
63. Estate of Tawney v. Columbia Natural Res., L.L.C., 633 S.E.2d 22 (W. Va. 2006).
64. *Id.* (citing Creson v. Amoco Prod. Co., 10 P.3d 853, 855 (N.M. Ct. App. 2000)).
65. *Id.* at 26–27 (citing Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001)).

ally in this State the landowner has received a royalty based on the sale price of the gas received by the lessee."[66]

The Court acknowledged its statement in *Wellman* that "at the well" type language might serve to allocate costs. Nonetheless, the Court stated that the meaning of the language was not necessary to its prior decision in *Wellman*, and was therefore not binding. Rather, in what has been widely criticized as a result-driven analysis, the *Tawney* Court held that the "at the well" lease language was ambiguous "because it [was] susceptible to more than one construction and reasonable people [could] differ as to its meaning."[67]

While acknowledging lessee's representation that many of the lessors were sophisticated business entities, had the assistance of sophisticated counsel in entering the leases, and had actually negotiated certain revisions to the leases, the Court chose to apply "[t]he general rule as to oil and gas leases . . . that such contracts will generally be liberally construed in favor of the lessor, and strictly as against the lessee."[68] Stating that the "at the well" language was drafted by the lessees, the Court also determined that "[u]ncertainties in an intricate and involved contract should be resolved against the party who prepared it."[69] Applying this rule of construction, the Court concluded that the lessees had not adequately addressed allocation of post-production expenses:

> Simply put, if the drafter of the leases below originally intended the lessors to bear a portion of the transportation and processing costs of oil and gas, he or she could have written into the leases specific language which clearly informed the lessors exactly how their royalties were to be calculated and what deductions were to be taken from the royalty amounts for post-production expenses.[70]

Although the *Tawney* decision is unfavorable to lessees in requiring them to bear all post-production costs, it was based on the stated rationale that royalties are to be paid on amounts received. As such, the *Tawney* decision does not limit sales of gas at the well like the *Rogers* decision appears to do in announcing an expanded implied covenant to market. Rather, paying royalties based on the amount realized from a sale of gas at the wellhead appears to be entirely consistent with the holding in *Tawney*, as long as no expenses whatsoever are

66. *Tawney*, 633 S.E.2d at 27.
67. *Id.* at 29.
68. *Id.*
69. *Id.*
70. *Id.* at 29–30. This analysis, of course, ignores that the question about the parties' intent should have been: On what basis did the lessors expect to be paid at the time the contract was entered into? By definition, as gas was typically not sold downstream at the time the leases were entered into, post-production expenses were not at issue, and allocation of them was therefore irrelevant. What was relevant, if one were to apply the language of the leases in the context of the time they were executed, was the parties' agreement that royalty should be based on the value of gas at the well.

deducted from payment of such royalties, and so long as the sale is made at arm's length for a commercially reasonable price.

3. Virginia State Courts Have Not Addressed the Issue, but a Federal Magistrate Judge Has Predicted That Virginia Would Follow Colorado Down the Road to an Expansive Implied Covenant to Market

Virginia's state courts have expressed no opinion to date regarding the allocation of post-production expenses or the implied covenant to market. In a letter opinion issued on June 10, 2009, then-Virginia Attorney General William Mims stated that "[i]t is my opinion that the Virginia Gas and Oil Board may issue compulsory pooling orders that permit deduction of post-production costs downstream of the wellhead when computing gas owners' one-eighth royalty interests."[71] In so concluding, the Attorney General noted that "[t]he source of the 'at the wellhead' language developed from industry practice where common carriers regularly purchased the gas at the well."[72] The advisory opinion further notes that "[t]raditionally, 'at the well' or 'wellhead' has been used to describe not only location but also quality. In many jurisdictions, 'at the well' describes a cruder product with a market value that is not yet enhanced in value by processing and transportation to far-reaching retail markets."[73] Based on this reasoning, and the statutory authority granted to the Board, Attorney General Mims concluded that the Virginia Gas and Oil Board could properly provide for allocation of post-production expenses when pooling unleased coalbed methane interests.[74]

For a short time, the Virginia Attorney General's advisory opinion seemed to provide general support for allocating post-production expenses. However, in 2011, a federal magistrate judge predicted in two nearly identical recommendations that the Virginia Supreme Court would reach exactly the opposite conclusion.[75] Magistrate Judge Pamela Sargent acknowledged in *Legard v. EQT* that "the parties have not cited, and I cannot find, any Virginia authority interpreting similar ['at the well' type] language in oil and gas leases."[76] Magistrate Judge Sargent declared, however, that "I am persuaded by the reasoning of the Oklahoma Supreme Court in *Wood*," holding that because producers receive a larger share of proceeds, they must bear

71. VA. ATT'Y GEN. OP. NO. 09-018, 2009 WL 1716837, at *1 (June 10, 2009).

72. *Id.* at *3.

73. *Id.* at *4 (emphasis in original).

74. *Id.* at *6.

75. *See* Legard v. EQT Prod. Co., No. 1:10cv00041, 2011 WL 86598, at *10 (W.D. Va.), *report and recommendation adopted*, 2011 WL 4527784 (W.D. Va. Sept. 28, 2011); Healy v. Chesapeake Appalachia, L.L.C., No. 1:10cv00023, 2011 WL 24261 (W.D. Va. Jan. 5, 2011).

76. *Legard*, 2011 WL 86598, at *10.

the risk and the cost of producing a marketable product.[77] Based on this persuasive authority, Magistrate Judge Sargent concluded, "I hold that Virginia courts would follow the 'first marketable product' rule, and hold the lessee solely responsible for all costs making the gas produced from the well marketable, unless . . . the parties specifically agree otherwise."[78] Relying on *Garman v. Conoco, Inc.*,[79] Magistrate Judge Sargent also concluded that "Virginia courts would recognize an implied duty on the part of oil and gas lessees to operate diligently and prudently, including a duty to market the gas produced."[80]

Magistrate Judge Sargent's report and recommendation in *Legard* was accepted without discussion by the district court judge.[81] Such federal trial court opinions are not, of course, binding on the Virginia state courts, and notwithstanding her prediction, Magistrate Judge Sargent's discussion acknowledges the lack of authority from Virginia state courts suggesting how the Virginia Supreme Court might actually rule on the issue. There is, however, reason for producers to hope that Magistrate Judge Sargent's analysis would not be adopted by the Virginia Supreme Court. William Mims, former Virginia Attorney General and author of the advisory opinion discussed above, was appointed to the Virginia Supreme Court in March 2010 to fill a vacancy left when Judge Barbara M. Keenan was appointed to the United States Court of Appeals for the Fourth Circuit. Judge Mims's term will not expire until March 31, 2022, providing him ample opportunity to weigh in on any royalty litigation that might reach that state's highest court in years to come. It is likely, however, that these battles will continue to be waged in federal court, as removal is generally possible, and royalty owners have enjoyed a hospitable "welcome" there. Of course, producers have the option of requesting certification of the question to the Virginia Supreme Court if they decide that it would likely enforce their contracts as written.

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77. *Id.* at *10–11 (citing Wood v. TXO Prod. Corp., 854 P.2d 880, 882–83 (Okla. 1992)).

78. *Id.* at *11.

79. Garman v. Conoco, Inc., 886 P.2d 652 (Colo. 1994).

80. *Legard*, 2011 WL 86598 at *13; *but see* Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C., 636 F.3d 235, 241 (6th Cir. 2011) (noting that "[o]ur task is not to determine which approach is best, but rather to decide the approach that the Kentucky Supreme Court would adopt if the issue were before it.").

81. *See Legard*, 2011 WL 4527784, at *1.

D. *Pennsylvania and Kentucky Follow the Majority of Producing States, Holding That "At the Well" Signifies the Condition and Location of Gas for Purposes of Royalty Valuation*

1. The Pennsylvania Supreme Court Has Applied the Reasoning of the Traditional Approach When Construing the State's Minimum Royalty Statute

In contrast to the supreme courts of West Virginia and Colorado, and the federal district court in Virginia, Pennsylvania's highest court has held that reasonable post-production expenses can be allocated to the royalty owner. In *Kilmer v. Elexco Land Services, Inc.*, the Supreme Court of Pennsylvania considered whether deduction of post-production expenses was allowable under Pennsylvania's Guaranteed Minimum Royalty Act ("GMRA").[82] The GMRA requires oil and gas lessees to pay "at least one-eighth royalty of all oil, natural gas or gas of other designations removed or recovered from the subject real property."[83] The Act, enacted by the Pennsylvania General Assembly in 1979, does not specifically address allocation of post-production expenses.

The leases at issue in *Kilmer* explicitly provided for deduction of a one-eighth share of post-production expenses. The landowner plaintiffs sought cancellation of their leases claiming that the deduction of expenses violated the minimum royalty statute because they did not in effect receive a full one-eighth share of gas recovered. The plaintiffs argued that the Court should follow Colorado, Oklahoma, and Kansas in applying the first marketable product doctrine and hold that an oil and gas lessee is responsible for all expenses required to treat and move gas to a downstream market.

The *Kilmer* Court recognized that historically, and at the time the GMRA was enacted in 1979, producers merely explored for and produced oil and gas and sold the resulting unprocessed minerals to a pipeline company at the wellhead. The royalty due to landowners was calculated based on the price received at the wellhead for the unprocessed gas. The Court determined that the term "royalty" should be defined with reference to the realities at the time the GMRA was enacted and in accordance with the technical definitions provided by industry practice. The Court accordingly recognized that royalty is understood in the oil and gas industry to mean "[t]he landowner's

82. *See* Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1151 (Pa. 2010). *Kilmer* was one of more than seventy cases brought by Pennsylvania mineral owners seeking to invalidate leases negotiated prior to the recent Marcellus rush that resulted in more lucrative lease terms for new lessors. *Id.* at 1149 n.1. With seventy cases pending involving the same issues, and because of concern that delay could stymie economic development, the Pennsylvania Supreme Court granted a motion to exercise extraordinary jurisdiction to immediately issue a definitive interpretation of the GMRA. *Id.*

83. *Id.* at 1150.

share of production, free of expenses of production."[84] The Court further noted that "expenses of production" are generally understood to include only those expenses of drilling and bringing oil and gas to the surface, but do not include post-production expenses of treatment or transportation.[85]

The *Kilmer* Court noted that mineral royalties are technically payable either as a share of the oil or gas produced or as a share of the value of such minerals.[86] The Court acknowledged the inconsistency that would result if some lessors were to receive royalties based on the enhanced value of treated minerals while those who received royalties in-kind necessarily received a less valuable royalty of unprocessed minerals. The Court concluded that "[t]he use of the net-back method eliminates the chance that lessors would obtain different royalties on the same quality and quantity of gas coming out of the well depending on when and where in the value-added production process the gas was sold."[87]

Despite this ruling, mineral owners in some of the pending cases continued to argue that the *Kilmer* ruling should be limited to royalty clauses identical to those considered in *Kilmer* and furthermore, that *Tawney*'s requirements for express language specifically allowing deduction of post-production expenses should apply in Pennsylvania. In April 2011, U.S. District Court Judge John E. Jones III dismissed one such complaint:

> We cannot imagine that the Pennsylvania Supreme Court . . . meant to render a holding so narrow as to invite its consideration of myriad other cases involving leases that were not entirely identical to the Kilmer lease. We empathize with Plaintiffs' desire to escape what they consider to be bad bargains. But they have put too fine a point on *Kilmer* in aid of voiding their leases. Both the Pennsylvania Supreme Court, and this Court, recognize the need for finality. A holding contrary to the one we render today would trigger havoc in a multi-billion dollar industry. More importantly, it would be in error.[88]

Similarly, the Pennsylvania Superior Court recently declined to declare an oil and gas lease void in *Katzin v. Central Appalachia Petroleum*, rejecting the plaintiff's argument that a lease violated the GMRA on its face simply because it was vague with respect to what

84. *Id.* at 1157 (quoting HOWARD R. WILLIAMS & CHARLES J. MEYERS, MANUAL OF OIL AND GAS TERMS § R (Patrick H. Martin & Bruce M. Kramer eds., 14th ed. 2009)).

85. *Id.* at 1157.

86. While recognizing that in-kind gas royalties are rare due to the processing required to make gas usable, the Court noted that the GMRA also governs oil royalties, which can be physically paid in kind. *Id.* at 1156–57.

87. *Id.* at 1158.

88. Ulmer v. Chesapeake Appalachia, L.L.C., No. 4:08-cv-2062, 2011 WL 1344596, at *3 n.1 (M.D. Pa. Apr. 8, 2011).

expenses could be deducted before calculating royalties.[89] The court instead noted that a promise to take action necessary to carry out the purpose of the contract is implied in every contract, and concluded that "we must therefore imply a promise by Central Appalachia . . . to comply with the mandates of the [GMRA]."[90] In so holding, the court left open the possibility of a claim that the lessee had *breached* this implied promise by improperly allocating post-production expenses but declined to terminate the lease as a matter of law.[91]

Under *Kilmer* and its progeny, Pennsylvania courts will almost certainly allow deduction of a pro rata share of post-production expenses where the lease provides for valuation of the gas for royalty purposes at the wellhead and does not otherwise expressly forbid such deductions. Where the lease provides that all post-production expenses are to be borne by the lessee, it is still likely that a Pennsylvania court would find that an arm's length sale of gas at the wellhead is appropriate.

2. The United States Court of Appeals for the Sixth Circuit Has Predicted That Kentucky Would Follow the "At the Well" Rule

Although Kentucky state courts have not recently addressed the implied covenant to market or the allocation of post-production expenses, in *Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C.*, the United States Circuit Court of Appeals for the Sixth Circuit predicted in 2011 that Kentucky would follow the "'at-the-well' rule, which allows for the deduction of post-production costs before paying appropriate royalties."[92] In so holding, the court relied on several old Kentucky cases construing the lessor's royalty obligations.

One of the cases that the *Poplar Creek* court relied upon was *Warfield Natural Gas Co. v. Allen*, in which the court was asked to construe a lease provision providing for "[t]he lessee to pay for each gas well from the time and while the gas is marketed the sum of one-eighth of proceeds received from the sale thereof."[93] While gas was typically sold at the well at the time this dispute arose, the defendant had actually sold the gas off the lease for a higher price but had calculated the royalty based on the value of the gas at the well. The court noted that "[i]t was as much [lessee's] duty to find the market as to find the gas."[94] Nevertheless, the court recognized that gas was ordinarily sold at the well and "that custom prevailed there when these

89. Katzin v. Cent. Appalachia Petroleum, 39 A.3d 307, 309 (Pa. Super. Ct. 2012).
90. *Id.*
91. Due to the extremely favorable bonus and royalty terms currently being offered to oil and gas lessors in the Marcellus and Utica Shale, termination of old leases, rather than damages for breach, is the royalty owners' preferred remedy.
92. Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C., 636 F.3d 235, 238 (6th Cir. 2011).
93. Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989, 990 (Ky. 1935).
94. *Id.* at 991.

leases were made."[95] Accordingly, the court concluded that "this lease must be held to mean one-eighth of the gross proceeds of a sale of the gas at the well side, and that is all for which defendant must account even though it may market the gas elsewhere and get a much greater sum for it."[96]

The *Poplar Creek* court also cited the 1923 decision in *Rains v. Kentucky Oil Co.*[97] In *Rains*, the Court acknowledged that a lessee has a duty to market the gas produced from leased property but refused to cast this duty so broadly as to require additional treatment or processing in order to obtain a better price:

> While the lessee of a gas well may be under the duty of using reasonable effort to market the gas, we are not inclined to the view that this duty, in the absence of a contract to that effect, is so exacting as to require him to market the gas by obtaining a franchise from some town or city and distributing the gas to the inhabitants thereof. On the contrary, he fully complies with his duty if he sells the gas at a reasonable price at the well side to another who is willing to undergo the risk of expending a large amount of money for the purpose of distributing the gas to the ultimate consumers.[98]

The Sixth Circuit also cited its own prior decision in *La Fitte Co. v. United Fuel Gas Co.*, holding that under Kentucky law, "a presumption exists that the wellhead is the point of sale and delivery at which point the royalty is to be computed, absent an express stipulation to the contrary."[99] The *Poplar Creek* court accordingly held that Kentucky would follow the "at the well" rule, allowing appropriate post-production expenses and that the term "'at-the-well' refers to gas in its natural state, before the gas has been processed or transported from the well."[100]

Although based on strong state precedent, *Poplar Creek* and *La Fitte Co.* do not bind Kentucky courts in construing the duty to market. A Kentucky court taking up the question more than seventy years later could more carefully scrutinize the allocation of post-production expenses in the modern gas industry where gas is normally sold downstream after processing. Even so, the sale of gas at the wellhead itself would seem to be entirely consistent with these holdings, and there does not appear to be any reason to believe that a Kentucky court would rewrite a lease providing for wellhead sales to disallow those very sales should a producer choose to sell gas at the well site.

95. *Id.*
96. *Id.* at 992.
97. Rains v. Ky. Oil Co., 255 S.W. 121, 122 (Ky. 1923).
98. *Id.*
99. Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C., 636 F.3d 235, 242 (6th Cir. 2011) (citing La Fitte Co. v. United Fuel Gas Co., 284 F.2d 845, 848 (6th Cir. 1960)).
100. *Id.* at 244.

E. *Ohio, Tennessee, and New York Remain Undecided*

1. Ohio Has Recognized the Implied Duty to Market, but Only in the Context of Lessees Who Failed to Produce Oil and Gas

Ohio law is relatively undeveloped with respect to oil and gas royalty issues; there is no recent case law regarding allocation of post-production expenses. As Ohio is experiencing much activity with respect to Marcellus and Utica leases, it is likely that such questions will soon reach Ohio's state or federal appellate courts. How these courts will answer the questions posed is currently a matter of speculation, but there is some old Ohio precedent that suggests that Ohio would construe an oil and gas lease like any other contract, according to its terms and the circumstances prevailing when the deal was made.

In an 1898 decision, the Ohio Supreme Court was asked to construe a lease that provided simply for royalty to be paid of "one-eighth of income dollars."[101] The Court concluded that the term "income" referred to the gross amount received by the lessor. In reaching this conclusion, however, the Court made clear that "the meaning of 'income' must generally be determined by the intention of the parties as deduced from the context, the subject-matter of the contract and the character of the person contracting." The Court accordingly recognized that the term "income" used by a merchant or a farmer might mean total receipts less cost of goods or operation. Nevertheless, the Court concluded that because the lease in question provided for delivery of one-eighth of all oil to the lessor in-kind, the parties likely intended the same result with respect to gas sold from the lease.[102] Although (unsurprisingly considering the time period involved) the Court did not differentiate between production and post-production costs, the Court's analysis indicates that the meaning of lease terms is to be determined according to the circumstances prevailing when the contract was entered into.

Nearly a hundred years after the *Busbey* decision, the Ohio Court of Appeals in *American Energy Services v. Lekan* recognized the implied duty to market, holding that "[t]he covenant to market the product places an obligation upon a lessee to use due diligence to market the gas and/or oil produced from a well."[103] However, this statement was made in the context of a lessee who drilled a well but failed to produce any oil or gas from the well for seventeen years, relying instead on payment of a "shut in" royalty provided for in the lease. Although this decision indicates that Ohio courts will recognize a lessee's duty to produce and market gas, this duty was narrowly circumscribed within the context of a lessee's failure to produce gas in any form. Nothing in *American Energy* suggests that an Ohio court

101. Busbey v. Russell, 1898 WL 1419 (Ohio Cir. Ct. Nov. 9, 1898).
102. *Id.* at 26–27.
103. Am. Energy Serv. v. Lekan, 598 N.E.2d 1315, 1321–22 (Ohio Ct. App. 1992).

would expand this duty to impose a particular condition or location requirement on the sale of gas.

More recently, in 2008, the Ohio Court of Appeals again considered the implied duty to market in a case similar to *American Energy Services*. In *Moore v. Adams*, the court confirmed that "[t]he covenant to market the product places an obligation upon a lessee to use due diligence to market the gas and/or oil produced from a well" and held that "[t]his covenant is not eliminated by a shut-in royalty clause."[104] This holding was again made in the context of non-production and did not deal with issues regarding the condition or the location of gas at the time of sale or the allocation of post-production expenses. The court affirmed, however, that leases are to be treated like other contracts:

> The rights and remedies of the parties to an oil or gas lease must be determined by the terms of the written instrument, and the law applicable to one form of lease may not be, and generally is not, applicable to another and different form. Such leases are contracts, and the terms of the contract with the law applicable to such terms must govern the rights and remedies of the parties.[105]

Although increased development of Marcellus and Utica Shale resources in Ohio will undoubtedly spur litigation regarding the proper manner of calculating royalties, a recent decision of the United States District Court for the Northern District of Ohio casts some light on one possible reason for the present lack of authority on this topic. In *Lutz v. Chesapeake Appalachia, L.L.C.*, the court dismissed the plaintiffs' claims for underpayment of royalties based on Ohio's unique statute of limitations.[106] Specifically, section 2305.041 of the Ohio Revised Code, enacted in 2006, provides in relevant part that

> [w]ith respect to a lease or license by which a right is granted to operate or to sink or drill wells on land in this state for natural gas or petroleum and that is recorded in accordance with section 5301.09 of the Revised Code, an action alleging breach of any express or implied provision of the lease or license concerning the calculation or payment of royalties shall be brought within the time period that is specified in section 1302.98 of the Revised Code. An action alleging a breach with respect to any other issue that the lease or license involves shall be brought within the time period specified in section 2305.06 of the Revised Code.[107]

Section 1302.98 of the Ohio Revised Code, referenced in this section, provides that "[a]n action for breach of any contract for sale

104. Moore v. Adams, No. 2009AP090066, 2008 WL 4907590, at *5 (Ohio Ct. App. Nov. 17, 2008).
105. *Id.* at *3.
106. Lutz v. Chesapeake Appalachia, L.L.C., No. 4:09CV2256, 2010 WL 2541669, at *1 (N.D. Ohio June 18, 2010).
107. OHIO REV. CODE ANN. § 2305.041 (LexisNexis 2009).

must be commenced within four years after the cause of action has accrued," and it additionally provides that "[a] cause of action accrues when the breach occurs, regardless of the aggrieved party's lack of knowledge of the breach."[108] Pursuant to section 2305.06 of the Ohio Revised Code, on the other hand, any other breach of contract claim enjoys a fifteen-year statute of limitations.[109]

The *Lutz* court rejected the plaintiffs' claim that the enactment of this statute retroactively impaired a substantive right, holding that "a statute of limitations is remedial or procedural and not substantive."[110] More interestingly, however, the court also rejected the plaintiffs' claim that the breach was continuous, creating a new breach each time a "fraudulent" royalty payment was made. The court instead held that a breach occurred only when the decisions affecting future royalty payments were made: "Plaintiffs have alleged breaches of contract that occurred on two occasions: in 1993 when the contract was breached by a change in the deduction methodology and in 2000 when the contract was breached by a change in the rate methodology."[111] Finding that these breaches occurred more than four years prior to suit being filed, the court dismissed the plaintiffs' claims.[112]

Lutz suggests that a particular method of royalty calculation, as long as it is consistently applied for more than four years, simply cannot be challenged. Although Ohio's law remains unclear regarding the allocation of post-production expenses and the location where gas can be permissibly sold, assuming that Ohio's supreme court would agree with the district court's interpretation, Ohio's unique statute of limitations will likely foreclose truly "high stakes" royalty litigation seen in other states because the recovery window is so limited. *Lutz* is not, however, binding on the Ohio Supreme Court, and its premise is likely to be challenged in future royalty litigation.

In summary, while Ohio's holdings regarding lease interpretation could be taken as indicating that its courts would enforce contracts as written, the issue remains untested there.

2. Tennessee Has Only Recognized the Implied Duty to Market in Passing but Has Indicated That It Would Construe Leases Against the Lessor

Like Ohio, Tennessee law is relatively undeveloped with respect to oil and gas royalty issues. The implied duty to market was briefly acknowledged in *Waddle v. Lucky Strike Oil Co.*, where the court noted that

108. OHIO REV. CODE ANN. § 1302.98 (LexisNexis 2009).
109. OHIO REV. CODE ANN. § 2305.06 (LexisNexis 2009).
110. *Lutz*, 2010 WL 2541669, at *3.
111. *Id.* at *2.
112. *Id.* at *4.

> [i]mplied covenants against the lessee comprise an important phase of the law of oil and gas. While there is some difference of opinion as to the best classification of these implied covenants, Merrill and Kulp discuss the legal problems involved under the following descriptive titles: (1) to drill an exploratory well; (2) to drill off-set wells; (3) to drill additional wells during and after the exploratory period; and (4) to diligently operate and market.[113]

Waddle is also instructive regarding the Court's construction of oil and gas leases. In *Waddle*, the lessee drilled a well and found gas, but because the well was drilled too close to the adjoining property line, the Tennessee Oil and Gas Board "red-tagged" the well and refused to allow production.[114] Even though the well never produced oil or gas, the lessee failed to pay shut-in royalties, claiming that the lease was held by production because it had found gas. In construing the lease terms, the Tennessee Supreme Court recognized that "instruments of this character are construed most favorably to development . . . time is the essence of the contract, and the real motive for the giving of such instruments is the development of the leased property. Therefore such a lease or option is properly construed strongly against the lessee, so as to secure such speedy development."[115] The Court accordingly found that the lessee had failed to perform duties necessary to hold the lease. The lessee attempted to avoid forfeiture of the lease, citing the following lease provision:

> It is agreed that this lease shall never be terminated, forfeited, or cancelled for failure to perform in whole or in part, any of its implied covenants, conditions or stipulations, until it shall have been first finally determined that such failure exists, and after such final determination, lessee is given a reasonable time therefrom to comply with any such covenants, conditions or stipulations.[116]

The Court declared, however, that "[t]he validity of such a provision, where the issue is the performance by lessee of one of the implied covenants of an oil and gas lease, is questionable" and concluded that "the no termination or forfeiture clause has no application to those obligations."[117] Notably, such "judicial ascertainment" clauses

113. Waddle v. Lucky Strike Oil Co., 551 S.W.2d 323, 327 (Tenn. 1977). The citation to Professor Merrill is instructive as he advocates expansive application of implied covenants to achieve "fairness" to the lessors.

114. *Id.* at 325. A representative of the lessee explained that the drilling contractor "encountered a boulder" and moved the well location twenty-one feet to the south east of the original well location "in the middle of the night," resulting in violation of certain well spacing regulations. *Id.*

115. *Id.* at 326 (quoting Mountain States Oil Corp. v. Sandoval, 125 P.2d 964, 967 (Colo. 1942)).

116. *Id.* at 327.

117. *Id.*

are held to be void by many states, so Tennessee is not unique in this regard.[118]

Similarly in *Lone Star Oil & Gas, Inc. v. Howard*, the Tennessee Court of Appeals applied the same principles of construction where the lessor ceased production of gas and failed to pay shut-in royalties. The court acknowledged that "[a] lease should be considered in its entirety, and it is construed according to the plain meaning of the language used unless the language is ambiguous."[119] The court noted, however, that "if disputed language in a contract is ambiguous, or uncertain, it will be construed most strong[ly] against the author," and it reiterated the principle from *Waddle* that "such a lease or option is properly construed against the lessee, so as to secure such speedy development."[120] Applying these principles to lease provisions requiring shut-in royalties, the court declared, "[w]e construe this uncertain term against Lessee and find that the shut-in royalty payments were due monthly."[121]

While not addressing the duty to market or the allocation of post-production expenses, *Waddle* and *Lone Star* are instructive regarding Tennessee's general treatment of implied covenants in oil and gas leases and how lease terms are likely to be construed. Although it is not clear that an inference against the lessee exists in every case, it is clear that the Tennessee Supreme Court will not hesitate to apply such a rule of construction when it deems it appropriate to do so.

3. New York Has Recognized the Implied Duty to Market but Has Not Indicated That It Would Apply It Expansively to Impose Specific Condition or Location Requirements

There is little authority discussing the implied covenant to market or the allocation of post-production expenses in New York. In *La Barte v. Seneca Resources Corp.*, and *Cherry v. Resources American, Inc.*, the plaintiffs sued the oil and gas lessees and various affiliates for breach of the implied covenant to market under leases providing for royalty to be calculated at the "mouth of the well," at the "connecting point," "at the wellhead," or based on "the field price."[122] The plain-

118. *See, e.g.*, Frick-Reid Supply Corp. v. Meers, 52 S.W.2d 115, 118 (Tex. Civ. App.—Amarillo 1932, no writ) (holding that such judicial ascertainment clauses are void because they would preclude a final judgment and would result in "piecemeal" litigation); Wellman v. Energy Res., Inc., 557 S.E.2d 254, 256 syl. pt. 3 (W. Va. 2001) ("'Judicial ascertainment' clauses in oil and gas leases in West Virginia are void under the public policy of this State . . . .").

119. Lone Star Oil & Gas, Inc. v. Howard, No. E2009-00428-COA-R3-CV, 2010 WL 520934, at *3 (Tenn. Ct. App. Feb. 12, 2010) (citing Cali-Ken Petroleum Co. v. Slaven, 754 S.W.2d 64, 65 (Tenn. Ct. App. 1988)).

120. *Id.* at *3.

121. *Id.* at *6.

122. La Barte v. Seneca Res. Corp., 728 N.Y.S.2d 618, 620 (App. Div. 2001); Cherry v. Res. Am., Inc., 727 N.Y.S.2d 848, 849 (N.Y. App. Div. 2001).

tiffs contended that their royalty should have been based on the price received from "end-users" and that the defendants breached their contractual duties by manipulating the price received through "sham" sales to third-party gas marketers. The defendants moved for dismissal of plaintiffs' claims.

Without construing the lease language in either case, a New York intermediate appellate court, in two nearly identical memorandum opinions issued on the same day, found that the plaintiffs had stated sufficient facts "to withstand a pre-answer motion to dismiss" on their breach of contract claims.[123] The court equated the implied covenant to market with the covenant of good faith and fair dealing:

> [B]ecause every contract contains an implied covenant of good faith and fair dealing in the course of performance of the contract, we further conclude that the court properly denied that part of defendants' motion seeking dismissal of the cause of action for breach of an implied covenant to market the gas . . . .[124]

In addressing the plaintiffs' claims for breach of fiduciary duty, the court recognized that "[w]hether a fiduciary relationship exists between parties 'is necessarily fact-specific to the particular case.'"[125] Citing Oklahoma authority, the court noted that "in at least one oil-producing state, it has been recognized that the operator of an oil and gas lease owes a fiduciary duty to royalty owners to market oil or gas at the highest market price available."[126] The court declined to adopt this rule outright, but instead it concluded that "it is unclear at this stage of the litigation whether plaintiffs will ultimately succeed in establishing a fiduciary relationship with Seneca that is separate and distinct from their contractual relationship."[127]

Although the *La Barte* and *Cherry* cases do not define the parameters of the implied covenant to market, they do indicate that such a duty would be recognized and that the sale of gas to third party marketers might constitute a breach of this covenant under an "at the well" type lease. In equating the duty to market with the implied covenant of good faith and fair dealing, moreover, the court suggested that this will be treated as an inherently factual matter.[128]

123. *La Barte*, 728 N.Y.S.2d at 621.

124. *Id.* (citations omitted).

125. *Id.* at 622 (quoting Wiener v. Lazard Freres & Co., 672 N.Y.S.2d 8, 14 (App. Div. 1998)).

126. *Id.* (citing Coosewoon v. Meridian Oil Co., 25 F.3d 920, 931 (10th Cir. 1994)); *but see infra* note 153.

127. *Id.*

128. *See* Pernet v. Peabody Eng'g Corp., 248 N.Y.S.2d 132, 135 (App. Div. 1964) ("Generally, in every case, the question [of bad faith] would be one of fact."). *See also* Rus, Inc. v. Bay Indus., Inc., 322 F. Supp. 2d 302, 309 (S.D.N.Y. 2003) ("If the terms are not clear, the interpretation of the contract becomes a question of fact for the jury and extrinsic evidence of the parties' intent is admissible.").

IV. Can the Market Really Return to the Wellhead?

A. *Re-Emergence of a Market at the Wellhead Would Once Again Marry Lease Language to Practice, but Decisions from Kansas and Oklahoma May Provide a Roadblock*

As noted above, it appears that a return to a wellhead market would be permissible in West Virginia, Pennsylvania, and Kentucky. In Kentucky and Pennsylvania, the jurisprudence permits allocation of post-production expenses in "wellhead" leases, making a return to a wellhead market unnecessary. It is unclear, on the basis of existing cases, whether courts in Ohio, New York, or Tennessee would find that such sales run afoul of some implied duty to market (although based on New York's and Ohio's general jurisprudence honoring contracts, it seems unlikely). Finally, the only rulings in Virginia incorporate the reasoning of a federal magistrate judge and predict that Virginia would imply an expanded duty to market. Opinions by the former state attorney general contradict this. The probable view of the Virginia Supreme Court is therefore unclear.

A return to the practice of marketing gas at the wellhead rather than downstream would have the positive effect of realigning lease language with the marketing model contemplated by that language. On its face, a market at the well, while not economically optimal for either party, is consistent with the traditional lease language calling for royalty to be calculated based on the value of gas "at the well."[129] However, the minority states have disregarded this history in construing oil and gas leases and have instead implied covenants to reach a result they deem "fair." The clear language of the lease, and the circumstances in which it was made, cannot necessarily be relied upon as determinative of whether a market at the well is viable. Federal courts in Oklahoma and Kansas, moreover, have recently signaled that selling gas at the wellhead could violate an implied duty to market. While these decisions do not bind courts in the Marcellus or Utica states, courts such as West Virginia's have been open to such reasoning before, and could be again.[130]

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129. *See* Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989, 991 (Ky. 1935) (noting that gas was ordinarily sold at the location of the well, and "that must have been what the parties contemplated when they made this lease").

130. *See* Kramer, *supra* note 4, at 257–58 (describing the approach of courts that apply the traditional approach of contract construction as "parsing" and the approach of the Colorado and West Virginia courts as "extrinsic," and concluding that "it does not necessarily follow that a state that tends to follow the parsing approach will limit the application of implied covenants, nor does it necessarily follow that a state that tends to follow the extrinsic approach will ignore the express language of the instrument. Having said that . . . a certain confluence inherently exists between the parsing and express covenant approaches and the extrinsic and implied covenant approaches.") Professor Kramer concludes that "regarding the effect of express leasehold language on the implication of covenants, most court decisions tend to fall somewhere in between, realizing that the courts are not free to rewrite a written

B. *Are Old Marketing Methods Compatible with the Newly Expanded Covenant to Market? Perhaps Not, According to Federal Judges in Oklahoma and Kansas*

Attempts to sell gas directly at the well were recently addressed by federal courts in both Kansas and Oklahoma, resulting in further expansion of the implied covenant to market to include a requirement to put gas in near perfect condition seemingly without reference to the existence of an actual market, or the demands thereof. This conclusion seems to foreclose any possibility of a market for gas at the well in those states, even though that is exactly what the parties originally contemplated when they entered into the leases.

Merit Energy Co., a gas producer in Kansas, attempted to forego any value that might be added by post-production processing and transportation, and instead opted to sell its unprocessed gas to a third party at the wellhead. As a result, in *Freebird, Inc. v. Merit Energy Co.*, the royalty owners brought suit alleging that the producer breached the implied covenant to market and sought class certification in the United States District Court for the District of Kansas.[131]

In opposition to class certification, the defendant argued that the predominance requirement was not met because an inquiry would have to be made regarding the existence of a market for gas at each individual well. The court rejected this argument, instead holding that "[a]lthough the Kansas Supreme Court has not expressly held that application of the implied covenant to market does not require a fact specific, lease-by-lease inquiry, its jurisprudence in this area indicates that no such inquiry is required."[132] In support of this holding, the court recognized prior Kansas authority discussing the location of the market to differentiate between transportation and gathering costs.[133] Nevertheless, the court concluded that this market location inquiry only applied where gas is *already* marketable at the well.[134] Without

agreement, but taking the temporizing view that an oil and gas lease may not cover all of the future events that can impact the relationship between the parties." Kramer, *supra* note 4, at 261.

131. Freebird, Inc. v. Merit Energy Co., No. 10-1154-KHV-JPO, 2011 WL 13638 (D. Kan. Jan. 4, 2011).

132. *Id.* at *7; *see also* Hershey v. ExxonMobil Oil Corp., No. 07-1300-JTM, 2011 WL 1234883, at *11 (D. Kan. Mar. 31, 2011) (citing *Freebird* for the proposition that no lease-by-lease inquiry is required to apply the implied duty to market.).

133. *See* Sternberger v. Marathon Oil Co., 894 P.2d 788, 801 (Kan. 1995).

134. *Id.* at 800 (holding that "[o]nce a marketable product is obtained, reasonable costs incurred to transport or enhance the value of the marketable gas may be charged against nonworking interest owners"); *see also* Roderick Revocable Living Trust v. XTO Energy, Inc., 679 F. Supp. 2d 1287, 1292 (D. Kan. 2010) (holding that "*excess* dehydration to an already marketable product is to be allocated proportionately to the royalty interest when such costs are reasonable, and when actual royalty revenues are increased in proportion to the costs assessed against the royalty interest. It is the lessee's burden to show that the excess dehydration costs charged against the royalty interest occurred to a marketable product, i.e., that the cost is a post-production cost") (emphasis in original).

discussing how marketability would be defined, the court accepted at face value the plaintiffs' allegations that the gas was not in marketable condition at any well in issue and concluded, "[t]herefore, *Sternberger* does not apply here."[135]

While rejecting the need to inquire into the availability of a market at each individual well in order to establish the *existence* of a covenant to market, the *Freebird* decision glosses over the need for such an inquiry to establish a *breach* of that covenant. The court noted that *Sternberger* "did not rely on a fact-specific inquiry to determine whether the implied covenant to market applied to the lease." Rather than recognizing that such a fact-specific inquiry is required to establish a breach, the court accepted the plaintiffs' representation that proof of breach could be made by "common evidence."[136]

Under *Freebird,* therefore, a producer could conceivably be found in breach of the implied covenant to market regardless of whether there is an actual commercial market at the well if the condition of the gas does not meet some arbitrary standard for "marketability." This "marketability" standard was not defined by the court.

In *Naylor Farms v. Anadarko OGC Co.*, the United States District Court for the Western District of Oklahoma picked up on the merits of the question, holding as a matter of law that the gas producer violated the implied covenant to market by selling raw gas at the well.[137] In *Naylor Farms*, a class of royalty owners alleged that the producer, QEP, had breached its duty to produce a marketable product by selling the raw gas produced from its wells to an unrelated company, DCP Midstream, L.P., which in turn processed and sold the gas downstream. In return, DCP paid QEP a percentage of its sales proceeds, and QEP calculated royalty payments based on these receipts.[138] The plaintiffs alleged that QEP had a duty to put the gas in a marketable condition and deliver it to a commercial market location free of charge to the royalty owners and that QEP's sale of raw "unmarketable" gas at the well inappropriately circumvented this duty. Interpreting Oklahoma law, the federal district court agreed.[139]

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135. *Freebird*, 2011 WL 13638, at *6.

136. *Id.* at *8.

137. Naylor Farms, Inc. v. Anadarko OGC Co., No. CIV-08-668-R, 2011 WL 7053789, at *4 (W.D. Okla. July 14, 2011).

138. *Id.* at *1.

139. *Id.* at *1–4. The court provided the following example to illustrate how this arrangement resulted in increased profits for the defendant and reduced royalty for the mineral owners:

> In a class well in which, for ease of example, Defendant QEP owns 100 percent of the working interest and under a POP or POPI contract with DCP, QEP receives $900 from DCP and DCP sells the gas for $1,000, a one-eighth royalty interest owner who, for ease of example, was the lessor of all mineral rights in the drilling and spacing unit, would receive $112.50 and Defendant QEP would receive $787.50. However, if the royalty owner's royalty was properly calculated, without improperly allocating the costs of making the

The court held that the duty to market required a "free and open market at the wellhead[ ] . . . where there were two or more perspective [sic] willing purchasers."[140] Strangely, however, the court held that proof of the existence of a commercial market for raw gas at the well would not satisfy the producer's duty to put the gas in marketable form. In a footnote, the court noted that in its view, existing Oklahoma case law distinguished between "marketable" and "saleable." Although the court acknowledged that "it would be hard to imagine any gas not being saleable at least for some price the moment it comes out of the ground," it went on to conclude that the duty to make gas marketable requires the producer to put the gas in "interstate or intrastate pipeline quality."[141]

After the *Naylor Farms* decision was issued on July 14, 2011, the defendants moved for reconsideration, pointing out that existing Oklahoma case law specifically held that gas did *not* have to be in interstate pipeline condition in order to be marketable.[142] While agreeing with the defendants that Oklahoma precedent "did not impose an interstate or intrastate pipeline quality standard for gas marketability," the court nonetheless declined to reverse its prior holding because the defendants had failed to produce evidence that the processes performed by DCP "enhanced an already marketable product, that the costs were reasonable and that the royalty revenues increased in proportion to those costs."[143] While recognizing that this proof should have been made to justify any deduction from royalties, the court nevertheless dismissed the possibility that this proof ever could be made:

> If the gas is marketable at the well, it requires no dehydration, compression or processing for the pipeline purchaser to accept it, although it is necessary for the gas to be transported to the point of purchase, i.e., to the pipeline. The fact that the transportation costs (and such costs only) are chargeable to the royalty interest is not surprising . . . .[144]

Thus, under *Naylor Farms*, the marketable condition requirement is wholly divorced from the location or demands of an actual commercial market, and evidence of a market for a particular grade or form of gas will not establish marketable condition. These decisions seem to wholly negate the purpose of the rule that excess treatment to an already marketable product is deductible since it seems to be impossible

> gas marketable to the royalty owner, the royalty owner would receive $125.00 and Defendant QEP would receive $775.00.

Id. at *5.

140. *Id.* at *3.
141. *Id.* at *4 n.2.
142. *Id.* at *1.
143. *Id.* at *2.
144. *See id.*

to prove that gas is in marketable form unless it is already in interstate pipeline condition.

The *Naylor Farms* court's seemingly harsh treatment of the gas operator can be explained at least in part by its conclusion that a fiduciary duty existed between the operator of a statutory pooling unit and the royalty owners. The court noted that

> the Oklahoma Supreme Court described the trustee relationship between a unit . . . operator in relation to all who are interested in production from the unit . . . to act for the benefit of the beneficiaries and not to benefit the unit and/or operator in antagonism to the beneficiaries and not to use the advantage of the position as trustee to gain any benefit for himself at the expense of the cestui que trustent.[145]

Against this backdrop, it is perhaps less surprising that the court would conclude that

> Defendant QEP, by marketing gas for itself and other working interest owners and paying royalty interests in the manner it did, benefitted itself and the other working interest owners at the expense of the royalty owner class Plaintiffs, in breach of its fiduciary duties as operator of each of the drilling and spacing units in which the class wells are located.[146]

The Oklahoma Supreme Court's recognition of a fiduciary duty appears to arise from the unitization order or agreement, and not from the lease itself.[147] Kansas has also applied fiduciary "principles" to reach an equitable result in limited circumstances,[148] but these two states appear to be unique in this regard.[149] Of the Marcellus and Utica Shale states addressed in this Article, a federal court in West Virginia has rejected attempts to impose a fiduciary relationship between lessee and lessor in *Wellman v. Bobcat Oil & Gas, Inc.*,[150] and a federal magistrate judge sitting in Virginia similarly rejected the exis-

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145. *Id.* at *4.

146. *Id.* at *5.

147. *See* ENI Producing Props. Program Ltd. P'ship v. Samson Invs., Co., 1999 OK 21, ¶ 14, 977 P.2d 1086, 1088.

148. *See* Short v. Cline, 676 P.2d 76, 84 (Kan. 1984). The unit operator in that case held the reversionary interest in a certain lease and attempted to terminate the royalty owners' defeasible term interest held in production under the lease by ceasing production. *Id.* at 78–79. The court concluded that

> [i]t would violate the terms and intent of the [unit] agreement and work a substantial inequity upon defendants here to permit plaintiff to repudiate the agreement by claiming termination of the Wertman lease by reason of lapse of production when he is both the operator-lessee who specifically assumed the obligation of producing the leases in the unit and owner of the reversion in the Bartlesville formation on termination of the Wertman lease.

Id. at 84.

149. *See* HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 990 (Patrick H. Martin & Bruce M. Kramer eds., 46th ed. 2011).

150. Wellman v. Bobcat Oil & Gas, Inc., No. 3:10-0147, 2010 WL 2720748 (S.D. W. Va. July 8, 2010).

tence of a fiduciary duty in the context of a voluntary lease in *Healy v. Chesapeake Appalachia, L.L.C.*[151] The same magistrate judge later relied on Oklahoma law, however, in predicting that Virginia would recognize a fiduciary duty on forced pooled unit operators in the context of coalbed methane production.[152] An intermediate appeals court in New York has recognized Oklahoma's position, but it has held that the existence of a fiduciary relationship "is necessarily fact-specific."[153] Courts in Pennsylvania, Ohio, and Tennessee have not yet addressed the question.

C. *Additional Obstacles on the Road to the Wellhead Market: Title, Measurement, and Affiliate Issues*

Gas producers may be tempted to sell gas at the wellhead to a marketing affiliate that will then compress, treat, and transport the gas to a downstream market. Through this arrangement, the producer would claim a sale at the wellhead and calculate royalties based on the wellhead value of the gas. If anything is clear from the flood of litigation regarding royalty issues in recent years, however, it is that any transaction in which a producer sells gas to an affiliate is fraught with peril and should be avoided:

> In spite of a demanding body of corporate law on when a court can disregard the corporate separateness of affiliated entities, these situations do not play well in the courtroom. Even when you have defensible separate corporate entities that are affiliates, you still must contend with the reality of an upstream sales number, which was used to calculate the "wellhead" royalty, that will always be smaller than the sales number obtained by the purchasing affiliate when it resells into a downstream market. The jury is then informed that all the stock of Marketing Affiliate is owned by Producing Affiliate and that many of the directors, officers, and employees of Market-

151. Healy v. Chesapeake Appalachia, LLC, No. 1:10cv00023, 2011 WL 24261 (W.D. Va. Jan. 5, 2011).

152. *See* Adair v. EQT Prod. Co., No. 1:10cv00037, 2011 WL 4527433, at *25 (W.D. Va. Jan. 21), *report and recommendation adopted*, No. 1:10cv0037, 2011 WL 4527647 (W.D. Va. Sept. 28, 2011).

153. La Barte v. Seneca Res. Corp., 728 N.Y.S.2d 618, 622 (App. Div. 2001). Note that the court in *La Barte* cited the Tenth Circuit's decision in *Coosewoon* for the propositions that "[u]nder Oklahoma law, an operator of an oil or gas lease owes a fiduciary duty to royalty owners to market oil or gas at the highest market price available at the time of any production under the lease." *Id.* at 622 (citing Coosewoon v. Meridian Oil Co., 25 F.3d 920, 931 (10th Cir. 1994)). This interpretation of Oklahoma law clearly goes too far in suggesting that the fiduciary duty is owed by every oil and gas lessee. Rather, Oklahoma courts have made clear that these fiduciary obligations arise from the involuntary nature of coerced unitization, not from lease agreements themselves. *See, e.g.*, Leck v. Cont'l Oil Co., 800 P.2d 224, 229 (Okla. 1989) ("This is not a duty created by the lease agreement but rather by the unitization order and agreement."); Howell v. Texaco Inc., 2004 OK 92, ¶ 25, 112 P.3d 1154, 1160 (recognizing that a fiduciary relationship was not created by communitization agreements, which the court pointed out "are contracts just as the leases are contracts").

> ing Affiliate are the same as Producing Affiliate. It is impossible to blunt the impact of "little number/big number" with explanations of the law of corporate separateness, service agreements, and the legitimate isolation of risk in separate business enterprises.[154]

In *Rogers v. Westerman Farm Co.*, discussed *supra*, the plaintiffs claimed that the gas producer had sold gas to an affiliate in a less than arm's-length transaction.[155] The Colorado Supreme Court agreed that the plaintiffs in that case had been prejudiced because the jury was not fully instructed on the appropriate standards to determine whether this behavior constituted bad faith. The Oklahoma Supreme Court has similarly found that "[w]hen the actual value is not obtainable because of a producer's self-dealing, the courts will carefully scrutinize the transactions on which the royalty payments are based . . . an intra-company gas sale cannot be the basis for calculating royalty payments."[156]

It is clear, therefore, that any sale of gas at the wellhead should be through an arm's-length transaction with an unaffiliated entity. Even where gas is actually sold at the wellhead in an arms-length transaction, moreover, it must be abundantly clear that title to the minerals is actually transferred at that location. This is particularly true where a mineral lessee owns its own gathering lines and equipment, making it unclear at what point the lessee's interest in the gas terminates.

In order to ensure that title is passed at the wellhead, the sale price should be established according to the metered volume of gas physically measured at the well site. A sale price determined according to measurements taken elsewhere—such as at the interstate pipeline interconnect—would bring into question whether the gas was really sold at the well and whether the sale was really an arms-length transaction.[157] It would also retain the disadvantages of a "net-back"—exactly what producers would be seeking to avoid.

V. The Royalty Lease Clauses for the Future: A New Road to Avoiding Litigation?

In the wake of decisions such as *Tawney* and *Rogers*, practitioners drafting new leases have struggled to find language that the most restrictive courts would find acceptable for purposes of allocating post-production expenses and allowing accurate royalty payment for the

154. Pierce, *Judicial Interpretations of Royalty Obligations, supra* note 18.

155. *See* Rogers v. Westerman Farm Co., 29 P.3d 887, 911 (Colo. 2001) (en banc).

156. *Howell*, 2004 OK 92, ¶ 25, 112 P.3d at 1160.

157. Note that one of the problems with the arrangement between the operator and third party purchaser in *Naylor Farms*, discussed *supra* Part IV.B, was that the contract price received by the producer was tied to the final sale price received by the buyer. Such an arrangement could create a question regarding when and where the title to the gas actually passed.

product actually provided by the lessor pursuant to "wellhead" leases—raw gas produced at the wellhead.

It is important to note that in *Tawney,* the West Virginia Supreme Court stated that a lease *could* properly provide for allocation of post-production expenses; it merely must be done in a particular way. According to the Court, language stating that value for royalty purposes is to be based on the value "at the well" (or similar language) is ambiguous and ineffective to allocate to the lessor any portion of the costs incurred between the wellhead and the point of sale. Rather, the Court instructed that

> language in an oil and gas lease that is intended to allocate between the lessor and lessee the costs of marketing the product and transporting it to the point of sale must expressly provide that the lessor [1] shall bear some part of the costs incurred between the wellhead and the point of sale, [2] identify with particularity the specific deduction the lessee intends to take from the lessor's royalty (usually 1/8) and [3] indicate the method of calculating the amount to be deducted from the royalty for such post-production costs.[158]

The Court found "notable" the absence of "any specific provisions pertaining to the marketing, transportation, or processing of the gas."[159]

While practitioners have attempted to formulate royalty provisions that retain the concept of paying royalty based on the value of gas at the wellhead and specifically providing that the lessor will be charged its proportionate share of expenses incurred in gathering, compressing, dehydrating, processing, marketing, and transporting the gas to the point of sale,[160] until a court such as the West Virginia Supreme

158. Estate of Tawney v. Colum. Natural Res., L.L.C., 633 S.E.2d 22, 30 (W. Va. 2006).

159. *Id.* at 28.

160. *See* WILLIAMS & MEYERS, *supra* note 149, § 641 (reciting such a lease clause and explaining that it was provided by two experienced attorneys, who, after reviewing many lease royalty clauses and model clauses, attempted to craft a royalty clause responsive to decisions in the different states). Specifically, the following clause was provided by Milam Randoph Pharo and Gregory R. Danielson:

> ***PROD 88 (2004) PAID UP OIL AND GAS LEASE*** (a.k.a. the *"Modified Lynch Form")*:
>
> *6. Royalty Payment. For all Oil and Gas Substances that are physically produced from the leased premises, or lands pooled, unitized or communitized therewith, and sold, lessor shall receive as its royalty ___% of the sales proceeds actually received by lessee or, if applicable, its affiliate, as a result of the first sale of the affected production to an unaffiliated party, less this same percentage share of all Post Production Costs and this same percentage share of all production, severance and ad valorem taxes. As used in this provision, Post Production Costs shall mean all costs actually incurred by lessee or its affiliate and all losses of produced volumes whether by use as fuel, line loss, faring, venting or otherwise from and after the wellhead to the point of sale. These costs include without limitation, all costs of gathering, marketing, compression, dehydration, transportation, removal of liquid or gaseous substances or impurities from the affected production, and any other treatment or*

Court or the Colorado Supreme Court blesses a particular formulation, it is by definition unknown whether attempts to conform to such instructions will suffice.[161]

Perhaps the best suggestion is that of Professor Pierce, who recommends avoiding future litigation over the "net-back" issue by simply abandoning the "at the well" approach to valuation and replacing the location for purposes of royalty calculation with a downstream point of sale.[162] As he explains,

> Instead of developing patch-up language to respond to ambiguities [declared by courts], we must recognize the basic problem that the traditional royalty clause rarely reflects contemporary marketing patterns. If most lessees now market their gas at a downstream location, it makes more sense to begin, and end, the royalty calculation process using a downstream sales value.[163]

> *processing required by the first unaffiliated party who purchases the affected production. For royalty calculation purposes, Lessee shall never be required to adjust the sales proceeds to account for the purchaser's costs or charges downstream of the point of sale.*
>
> *Lessee or its affiliate shall have the right to construct, maintain and operate any facilities providing some or all of the services identified as Post Production Costs. If this occurs, the actual costs of such facilities shall be included in the Post Production Costs as a per barrel or per mcf charge, as appropriate, calculated by spreading the construction, maintenance and operating costs for such facilities over the reasonably estimated total production volumes attributable to the well or wells using such facilities.*
>
> *If the Lessee uses the Oil and Gas Substances (other than as fuel in connection with the production and sale thereof) in lieu of receiving sale proceeds, the price to be used under this provision shall be based upon arm's length sale(s) to unaffiliated parties for the applicable month that are obtainable, comparable in terms of quality and quantity, and in closest proximity to the leased premises. Such comparable arm's-length sales piece shall be less any Post Production Costs applicable to the specific arm's length transaction that is utilized.*

Milam Randoph Pharo & Gregory R. Danielson, *The Perfect Oil and Gas Lease: Why Bother!*, 50 ROCKY MTN. MIN. L. FOUND. 19, § 19.05 (2004). It should be noted that this clause was offered after the Colorado Supreme Court's decision in *Rogers*, but before the West Virginia Supreme Court decided *Tawney*.

161. For example, exactly what did the court mean by its instruction to include language explaining the "method of calculating" the amount to be deducted? This should be self-explanatory—in a lease providing for one-eighth royalty based on the value of the gas at the wellhead, and specifically listing each and every post-production cost as an expense in which the lessor will proportionately share (one-eighth) of that expense, the "method of calculating" should be the aforementioned description and the arithmetical calculation required to deduct one-eighth of those expenses from the one-eighth royalty on the proceeds received from an arm's-length sale downstream from the well (a "net-back" or "work back" specifically described).

162. Pierce, *Judicial Interpretations of Royalty Obligations, supra* note 18. In his article, Professor Pierce outlines several drafting lessons and exhaustively describes issues to be contemplated in creating a royalty provision, including how to achieve the goals of creating a clear and totally transparent lease and avoid problem situations that enable courts to interfere with the parties' intended bargain. *See id.*

163. *Id.*

He acknowledges that lessees prefer an upstream valuation point and lessors a downstream valuation point "because royalty is most often stated as a fraction of the production or some measure of the value of production," and "following extraction, oil and gas tend to increase in value as they move downstream away from the wellhead." As he explains, "[t]his increase in value is comprised of two components: (1) investments made in the production either by the lessee providing a facility or service or purchasing the service from others; and (2) the increased value of the production in a particular form at a particular location."[164]

As discussed at length above, however, courts have not been universally receptive to lessees' adjustments of downstream values to allow payment of royalty based on wellhead values, even when this is the value designated in the parties' leases. Moreover, adjustments to account for post-production expenses are subject to challenges based on the propriety of each post-production expense deducted and to questions regarding the point at which the production first becomes "marketable" and the definition of a "marketplace." Noting that "[f]ew topics have generated as much litigation, or transferred as much wealth, as the so-called 'deduction of costs' issue," Professor Pierce recommends that future leases be structured to eliminate any net-back process.[165] This could be achieved by drafting a clause that contemplates paying lessors based on an index price or market value discounted by a negotiated percentage. The discount would reflect the value differential from the wellhead to the pipeline connection (his example is "80% of the market value at the XYZ interconnect to Acme Interstate Pipeline Company.")[166]

In the wake of the "implied covenant to market" rulings, *all* leases should include an *express* provision defining the lessee's marketing obligation in order to avoid a court's imposition of an implied duty. Even the most restrictive courts have observed that express language covering particular subject matter should prevail over implied covenants regarding the same subject matter.[167] In a clause electing to pay

164. *Id.*

165. *Id.*

166. *Id.* Of course, the lease should specifically provide for alternatives to be employed should the selected index cease to exist or be viable for whatever reason. Professor Pierce acknowledges that lessors might not want to use a set percentage discount to cover post-production costs, but points out that lessors take the same sort of risk by agreeing to pay a fixed fractional royalty.

167. *See* WILLIAMS & MEYERS, *supra* note 149, § 858 (observing that "implied covenants are displaced by inconsistent express lease provisions . . . . Decisions are few that consider the effect of express lease provisions on the implied covenant to market the product, but the few in existence follow the general rule"). *See also* Rogers v. Westerman Farm Co., 29 P.3d 887, 906 (Colo. 2001) (en banc) ("Absent express lease provisions addressing allocation of costs, the lessee's duty to market requires that the lessee bear the expenses incurred in obtaining a marketable product"); Estate of Tawney v. Colum. Natural Res., L.L.C., 633 S.E.2d 22, 28 (W. Va. 2006) (citing Wellman v.

royalty based on a downstream valuation point, the royalty clause should

> make it clear that the lessee can fulfill its marketing obligations by selling the gas at the wellhead or any point downstream of the wellhead. If using an upstream valuation, an express marketing clause will support the valuation by making it clear the lessee is not obligated to seek out markets further downstream. From the lessor's perspective, a downstream valuation point should be supported with an express marketing obligation requiring the lessee to seek out a designated downstream market, such as the first available pipeline regulated by state or federal government as a common carrier or public utility.[168]

For purposes of litigation avoidance, the approach of avoiding the netback process, with its potential for argument over every component, would certainly be helpful. Moreover, plainly defining the marketing obligation through an express covenant that takes into account a producer's ability to sell the gas at various points in the post-production process would obviate application of an implied covenant to rewrite obligations covered by the express covenant. While nothing can insulate parties from creative attempts to fight over contracts (particularly where large amounts of money are involved), this change in approach would appear to avoid the problems typically litigated with respect to the post-production expense issue.

VI. Conclusion

This road ends as it began: with a desire to avoid having courts rewrite agreements made by lessors and lessees. This Article has explored two possible ways to do so, but both follow the same map: namely, the route of making the marketing practice match the language in the contracts the courts review if litigation ensues as a way of reducing their opportunity to chart courses they think better.

Returning to a wellhead market may be viable in a few states, but doing so would require careful observation of protocol to ensure that arm's-length final transactions are made for commercially reasonable prices. Producers would likely face challenges regarding whether the sales were commercially reasonable and how to demonstrate this through comparable sales. Such sales have been met with resistance in the states more likely to disregard the parties' actual agreements through application of implied covenants. Even though *Tawney* can be read as indicating that such sales would be upheld, the West Virginia court has not specifically addressed whether such sales would

Energy Res., Inc., 557 S.E.2d 254, 265 (W. Va. 2001)) ("If an oil and gas lease provides for a royalty based on proceeds received by the lessee, *unless the lease provides otherwise*, the lessee must bear all costs incurred in exploring for, producing, marketing and transporting the product to the point of sale.") (emphasis added).

168. Pierce, *Judicial Interpretations of Royalty Obligations*, *supra* note 18.

violate the "first marketable product" doctrine. *Freebird* and *Naylor Farms* now provide persuasive authority to look to in considering the question.

For new leases, producers may wish to consider striking a whole new kind of bargain by abandoning the concept of wellhead valuation in favor of a downstream point of valuation. And for *any* type of new lease or modification, the parties should clearly define the producer's duty to market in such a way as to avoid having a court impose its idea of what would be better.