

IN THE NEW ERA OF OIL AND GAS ROYALTY ACCOUNTING:
DRAFTING A ROYALTY CLAUSE THAT ACTUALLY SAYS
WHAT THE PARTIES INTEND IT TO MEAN

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I. INTRODUCTION

Through much of the twentieth century, most oil and gas leases required that lessees pay royalties to their lessors on the basis of the price or market value of their oil and gas production “at the well.”¹ Although this “at the well” language may have seemed unfamiliar to less sophisticated royalty owners, courts generally tended to interpret this language consistently from state to state. Historically, courts interpreted this “at the well” language to mean that lessees could use a “workback” methodology to calculate their royalty payments—i.e., a methodology allowing lessees to determine the value of their production at the wellhead by subtracting their post-production expenses from the downstream value of their production.²

Today, in the second decade of the twenty-first century, oil and gas lessors, with easier access to information, tend to be more sophisticated than their counterparts from the twentieth century. With greater sophistication, oil and gas lessors now have much greater bargaining power than they enjoyed a generation ago.³ The law, at least in some states, has also evolved to lessors’ advantage. Oil and gas leases still often use the “at the well” language that became commonplace in the twentieth century, but courts no longer interpret that language consistently from state to state.⁴ In particular, courts in several states—first marketable product states—have concluded that even under leases containing “market value at the well” royalty clauses, lessees generally should calculate their royalty payments on the basis of the value of their production at the downstream location where they first acquire a marketable product.⁵

In what is now a new era of royalty accounting, oil and gas royalty clauses requiring that lessees calculate their royalty payments on the basis of the price or value of their production “at the well” may have an entirely different meaning in one state than in another. The parties to an oil and gas lease can no longer assume that royalty terms which became commonplace

¹ See discussion *infra* Section II.B.

² See *infra* text accompanying notes 73–95.

³ See *infra* text accompanying notes 12–15.

⁴ See, e.g., *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 906 (Colo. 2001); *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203, 1205 (Okla. 1998).

⁵ See discussion *infra* Section IV.B.

in the twentieth century will be sufficient in themselves to express their contractual intent. In the new era of royalty accounting, the parties to an oil and gas lease will need to draft royalty clauses that more explicitly say what they intend them to mean.

II. THE ROYALTY CLAUSE IN AN OIL AND GAS LEASE

An oil and gas lease is a contract between the lessor and the lessee.⁶ Under a typical oil and gas lease, the lessor agrees to give the lessee the right to explore for and produce oil, gas, or other minerals.⁷ The lessee, in turn, agrees to pay the lessor a royalty on any oil or gas that the lessee may produce from the lease.⁸

The royalty clause in an oil and gas lease defines the way in which a lessee must calculate the lessor's royalty on any oil or gas production. There is no standard or uniform royalty clause.⁹ Indeed, a lease may contain more than one royalty clause, with separate clauses for oil production, gas production, or even other forms of production such as carbon dioxide, natural gas liquids, or mineral byproducts.¹⁰ The terms of a royalty clause are subject to negotiation.¹¹

⁶Harris v. Ohio Oil Co., 48 N.E. 502, 506 (Ohio 1897); see Exxon Corp. v. Emerald Oil & Gas Co., 348 S.W.3d 194, 201 (Tex. 2011).

⁷See David E. Pierce, *Incorporating a Century of Oil and Gas Jurisprudence Into the "Modern" Oil and Gas Lease*, 33 WASHBURN L.J. 786, 788–89 (1994).

⁸See Jefferson D. Stewart & David F. Maron, *Post-Production Charges to Royalty Interests: What Does the Contract Say and When Is It Ignored?*, 70 MISS. L.J. 625, 628 (2000).

⁹See Bruce M. Kramer, *Interpreting the Royalty Obligation by Looking at the Express Language: What a Novel Idea?*, 35 TEX. TECH L. REV. 223, 263 (2004) ("Oil and gas leases are not uniform. Royalty clauses are not uniform."); see also Union Pac. Res. Grp., Inc. v. Neinast, 67 S.W.3d 275, 279 (Tex. App.—Houston [1st Dist.] 2001, no pet.).

¹⁰See Michael P. Irvin, *The Implied Covenant to Market in the Deregulated Natural Gas Industry*, 42 ROCKY MTN. MIN. L. INST. § 18.03[4], at 18-26 to -27 (1996).

¹¹See Jack O'Neill & Byron C. Keeling, *Valuation of Oil Royalties: From the Perspective of the Payor*, 47 INST. ON OIL & GAS L. & TAX'N § 6.02[1][a], at 6-4 (1996); see also Jeff King, *Natural Gas Royalties: Lessor vs. Lessee and the Implied Covenant to Market*, 63 TEX. BAR J. 854, 854 (2000) ("Oil and gas leases are negotiated contracts. . . . As to the royalty amount, the parties to the lease are free to decide and define the type, basis, or standard for the royalties to be paid.") (footnotes omitted); Shannon H. Ratliff & S. Jack Balagia, Jr., *Oil and Gas Royalty Class Action Litigation: Pushing the Limits of Rule 23 and Comparable State Class Action Rules*, 46 ROCKY MTN. MIN. L. INST. § 21.01[2][b], at 21-9 (2000) ("[O]il and gas leases are frequently and fiercely negotiated. . . ."); Brian S. Wheeler, *Deducting Post-Production Costs When Calculating Royalty: What Does the Lease Provide?*, 8 APPALACHIAN J.L. 1, 1 (2008) ("Parties to an oil and

Most oil and gas negotiations begin with a form lease that a prospective lessee may present to a lessor for review. Many lessors and other royalty owners,¹² however, are sophisticated enough to realize that they need not acquiesce to the terms of a form lease.¹³ The oil and gas market is competitive. With the advent of new technologies for recovering oil and gas, producers have raced against each other in many oil and gas fields to acquire large blocks of leases from which they can maximize their efforts to drill productive wells.¹⁴ Consequently, since the mid-1990s and arguably up through the present, landowners and other potential lessors have largely enjoyed a “seller’s market” and have been increasingly successful in requesting favorable lease terms from prospective lessees, particularly in the language of the royalty clause.¹⁵

gas lease *always* are permitted to negotiate the terms for the payment of royalty and the deduction of post-production costs.”).

¹²While virtually all lessors are royalty owners entitled to receive royalties from their lessees, not all royalty owners are lessors. Some royalty owners, known as overriding royalty interest owners, may acquire their royalty interests through a contractual agreement entirely separate from an oil and gas lease, often as compensation for services that they may have provided to a lessee to prepare an oil and gas prospect for potential production. *See* *Alamo Nat’l Bank v. Hurd*, 485 S.W.2d 335, 339 (Tex. Civ. App.—San Antonio 1972, writ ref’d n.r.e.).

¹³*See* John W. Broomes, *Waste Not, Want Not: The Marketable Product Rule Violates Public Policy Against Waste of Natural Gas Resources*, 63 U. KAN. L. REV. 149, 186 (2014) (noting that legal services are abundantly available to lessors for oil and gas lease negotiations).

¹⁴*See, e.g.,* Benjamin E. Apple, *Mapping Fracking: An Analysis of Law, Power, and Regional Distribution in the United States*, 38 HARV. ENVTL. L. REV. 217, 218 (2014) (“[T]he industry has rushed to begin drilling wells and extracting oil and gas from subterranean shale deposits across the country.”); Jonas Armstrong, *What the Frack Can We Do? Suggestions for Local Regulation of Hydraulic Fracturing in New Mexico*, 53 NAT. RES. J. 357, 359 (2013) (“Fracking has fueled a ‘natural gas rush’ in many regions of the United States”); Benjamin Robertson, *Top Lease Vultures: Title Failure, Bad Faith Pooling, and the Validity of Top Leases in the Texas Shale Plays*, 44 TEX. TECH L. REV. 463, 465 (2012) (“In response to the new economic viability of vast domestic gas reserves, oil companies rushed to lease as many minerals as possible”).

¹⁵*See, e.g.,* J. Zach Burt, *Playing the “Wild Card” in the High-Stakes Game of Urban Drilling: Unconscionability in the Early Barnett Shale Gas Leases*, 15 TEX. WESLEYAN L. REV. 1, 4 (2008); *see also* David E. Pierce, *The Renaissance of Law in the Law of Oil and Gas: The Contract Dimension*, 42 WASHBURN L.J. 909, 917 (2004) (noting, after a review of Union Pacific Resources leases in Texas, that “[t]he vast majority of the documents indicate they were the product of active negotiation between the lessor (or the lessor’s legal counsel or other representative) and the lessee”). The recent decline in oil and gas prices has forced oil and gas producers to slow their leasing efforts, arguably creating a “buyer’s market” for lessees. Continued lower oil and gas prices may make potential lessees much more reluctant to grant favorable concessions to lessors. *See* Russell Gold et al., *Energy Boom Can Withstand Steeper Oil-Price Drop*, WALL ST. J. (Oct. 29, 2014), <https://www.wsj.com/articles/energy-boom-can->

As a matter of historical practice, a royalty clause does not set a fixed price—such as \$3.00 per barrel of oil—for royalty payments. A royalty clause instead will tie royalty payments to a yardstick that rises or falls with any changes in the oil and gas market.¹⁶ For example, a royalty clause might state that the lessee will pay the lessor a royalty of:

- 1/8th of the market value of the lessor's production at the well; or
- 25% of the net proceeds that the lessee receives for its production at the well; or
- 1/5th of the price that the lessee receives for its production at the point of sale.

Thus, a royalty clause commonly includes at least three components: (i) the royalty fraction—e.g., 1/8th, 25%, 1/5th; (ii) the yardstick—e.g., market value, proceeds, price; and (iii) the location for measuring the yardstick—e.g., at the well, at the point of sale.

Until the advent of the first marketable product doctrine, lessors tended to focus their negotiating efforts on the size of the royalty fraction. Each of the components of a royalty clause, however, is negotiable. Both the yardstick itself, as well as the location for measuring the yardstick, may have a significant effect on the amount of the royalty payments that a lessor may receive from a lessee.

A. *The Yardstick: Market Value or Proceeds*

Generally, lessees must pay monetary royalties to their royalty owners.¹⁷ In calculating the amount of a royalty payment, a lessee must multiply three

withstand-steeper-oil-price-drop-1414627471 (noting that those producers which “spent too much to lease property” are most likely to suffer in a declining oil market); cf. Cyrus Sanati, *Oil Price Drops: Don't Panic, Really*, FORTUNE (Dec. 8, 2014), <http://fortune.com/2014/12/08/oil-prices-drop-impact/> (“But as the oil price drops, so will costs, bringing the ‘break-even’ price down with it.”).

¹⁶ See *infra* text accompanying notes 18–23.

¹⁷ See Byron C. Keeling & Carolyn King Gillespie, *The First Marketable Product Doctrine: Just What is the “Product”?*, 37 ST. MARY'S L.J. 1, 13 (2005). Some royalty clauses may permit lessors to receive royalties “in kind.” Under an “in kind” royalty clause, the lessor is entitled to receive a share of the lessee's actual production: in other words, the lessor is entitled to receive its royalty in the form of oil or gas rather than money. See Daniel M. McClure, *Developments in Oil and Gas Class Action Litigation*, 52 INST. ON OIL & GAS L. & TAX'N § 3.06[1][a], at 3-24 (2001). The end result, however, is usually the same under an “in kind” royalty clause as under a monetary royalty clause. “As a practical matter, most royalty owners lack the resources to receive delivery of oil in kind.” O'Neill & Keeling, *supra* note 11, § 6.02[1][a], at 6-6. If a lessor makes no arrangements to receive a royalty share of the lessee's production, then typically—but subject

numbers: (i) the royalty owner's royalty fraction, (ii) the volume of production over the payment period, and (iii) the yardstick measurement for the lessee's production at the applicable yardstick location.¹⁸

Suppose, for example, a lessee produces 30 barrels of crude oil over a monthly payment period and sells the oil in an arm's length transaction at the wellhead for \$100 a barrel. Under a royalty clause specifying that the lessor will receive a royalty of "1/5th of the price that the lessee receives for its production at the point of sale," the lessor's royalty on the lessee's production would be \$600—30 barrels of oil x \$100 a barrel x a royalty fraction of .20. One of the key drivers in that calculation, of course, is the yardstick—in this example, the *price* that the lessor receives for its oil at the point of sale.

Just as there is no standard form of royalty clause,¹⁹ there is no standard form of yardstick for a royalty clause.²⁰ Some royalty clauses may require that the lessee calculate its royalty payments on the basis of the *market value* or *market price* of its oil or gas production.²¹ Other royalty clauses

to the terms of the royalty clause—the lessee may market the lessor's share of the production along with the lessee's share and pay to the lessor the amount that the lessee receives for the lessor's share of the production, minus the lessor's share of any applicable post-production costs. See Keeling & Gillespie, *supra* note 17, at 18–19 n.68.

¹⁸ *E.g.*, Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996).

¹⁹ See *supra* text accompanying note 9.

²⁰ See Byron C. Keeling & Karolyn King Gillespie, *A New Era of Royalty Accounting: Practical Advice for the Payor*, 44 ROCKY MTN. MIN. L. FOUND. J. 15, 16 (2007). The yardstick may vary from lease to lease. *Id.* Sometimes the yardstick may even vary from clause to clause within a single lease: for example, a royalty clause that governs gas production may use a different yardstick than a royalty clause in the same lease that governs oil production. See Irvin, *supra* note 10, § 18.03[1], at 18-21.

²¹ See Bruce M. Kramer, *Royalty Interest in the United States: Not Cut from the Same Cloth*, 29 TULSA L.J. 449, 459 (1994). Technically, the term "market price" does not mean exactly the same thing as the term "market value." *Id.* The term "market price" is largely objective: it refers to the prevailing price for an item at an existing market. *Id.* By comparison, the term "market value" is more subjective: it refers to the value that an item would likely have in an open market, whether or not there is actually a market for the item. *Id.* While the "market price" of an item may establish its "market value," the term "market value," unlike the term "market price," does not require any comparable sales at an existing market. *Id.* An item does not need any evidence of a market or prior comparable sales to have a market value: for example, the Mona Lisa may not have a market price, but it unquestionably has a market value. *Id.* Nonetheless, many courts have treated the terms "market value" and "market price" to mean essentially the same thing in a royalty clause—the value of the lessee's oil and gas production, as opposed to the price at which the lessee may have sold the production. *E.g.*, Sartor v. United Gas Pub. Serv. Co., 84 F.2d 436, 440 (5th Cir. 1936); Ark. Nat. Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935).

may require that the lessee calculate its royalty payments on the basis of the *proceeds* or *amount realized* that the lessee receives for its oil or gas production.²² Still other royalty clauses, especially oil royalty clauses, may require that the lessee calculate its royalty payments on the basis of a *posted price*.²³

The various forms of royalty yardsticks, particularly as between “market value” and “proceeds,” may produce different results in different jurisdictions.

In many states (known as the *Vela*²⁴ states), courts have distinguished “market value” or “market price” royalty clauses from “proceeds” or “amount realized” royalty clauses.²⁵ Courts in *Vela* states recognize that the terms “market value” and “proceeds” are not synonymous: the market value of a lessee’s oil or gas production may not necessarily be the same as the price or sales proceeds that a producer receives for its production, even in an arm’s length transaction.²⁶ Thus, for leases that have a market value royalty clause, a lessee in a *Vela* state may calculate its royalty payments

²² See Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 16; see also *Tana Oil & Gas Corp. v. Cernosek*, 188 S.W.3d 354, 360 (Tex. App.—Austin 2006, pet. denied) (“The term ‘amount realized’ has been construed by Texas courts to mean the proceeds received from the sale of the gas or oil.”).

²³ See Gary B. Conine, *Crude Oil Royalty Valuation: The Growing Controversy Over Posted Prices and Market Value*, 43 ROCKY MTN. MIN. L. INST. § 18.01, at 18-2 to -3 & n.1 (1997). “Posted prices” are prices that industry sources publish or “post” on their websites or in industry publications as benchmark prices for crude oil production from particular fields. *Id.*; see also Michael P. Royal, Note, *Oil and Gas Law: Hull v. Sun Refining and Marketing Company: Are Division Orders a Condition Precedent to Payment or Merely an Oppressive Condition?*, 44 OKLA. L. REV. 571, 582 n.114 (1991). Many large oil and gas companies, such as Flint Hills Resources and Sunoco Logistics, will post benchmark prices for various types of crude oil production. See *infra* notes 244–245. These posted prices often provide the foundation for crude oil sales contracts. For instance, a producer in the Salt Flat Field in Caldwell County, Texas, may agree to sell its crude oil production to a pipeline purchaser at “Flint Hill’s posted price for West Texas Intermediate (WTI) crude oil at Midland, Texas, minus \$1.50 a barrel.”

²⁴ *Tex. Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968).

²⁵ See, e.g., *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 236 (5th Cir. 1984); *Mont. Power Co. v. Kravik*, 586 P.2d 298, 302 (Mont. 1978); *West v. Alpar Res., Inc.*, 298 N.W.2d 484, 488 (N.D. 1980); *Vela*, 429 S.W.2d at 871.

²⁶ See *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 372 (Tex. 2001) (“Market value may be wholly unrelated to the price the lessee receives as the proceeds of a sales contract.”).

based on the actual value of its production, irrespective of the price that the lessee may have received for its production in a sales transaction.²⁷

In other states (known as the *Tara*²⁸ states), courts have declined to distinguish “market value” or “market price” royalty clauses from “proceeds” or “amount realized” royalty clauses.²⁹ Courts in *Tara* states presume that the sales price which a lessee receives for its production in an arm’s length transaction automatically establishes the market value of that production.³⁰ Thus, for leases that have a market value royalty clause, a lessee in a *Tara* state must calculate its royalty payments based on the actual price that the lessee received for its production in an arm’s length transaction, irrespective of whether the lessee arguably could have used comparable sales from other transactions to show that the value of its production was lower than the price that the lessee received for it.³¹

The difference of opinion between *Vela* states and *Tara* states arises from differing views about lease interpretation. *Vela* states seek to give effect to what they regard as the parties’ express contractual intent: they contend that they must enforce the parties’ intent as the parties themselves expressed it in the plain terms of their lease and may not presume that the parties really meant “proceeds” when their lease actually uses the term “market value.”³² *Tara* states seek to give effect to what they regard as the parties’ implied contractual intent: they contend that even if the dictionary definition of “market value” is different from the definition of “proceeds,” the parties to an oil and gas lease would normally anticipate that the lessor’s royalty will be the same under either a “market value” royalty clause or a “proceeds” royalty clause.³³

²⁷ See *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 246 (Tex. 1981); see also *Yzaguirre v. KCS Res., Inc.*, 47 S.W.3d 532, 539 (Tex. App.—Dallas 2000) (“Under a market value royalty, the lessor receives a royalty based on the current market value for the oil and gas. In contrast, a royalty based on proceeds is calculated on what the lessee actually receives for the oil and gas.”), *aff’d*, 53 S.W.3d 368 (Tex. 2001).

²⁸ *Tara Petroleum Corp. v. Hughey*, 630 P.2d 1269, 1272 (Okla. 1981).

²⁹ See, e.g., *Hillard v. Stephens*, 637 S.W.2d 581, 584–85 (Ark. 1982); *Tara*, 630 P.2d at 1272.

³⁰ See, e.g., *Hillard*, 637 S.W.2d at 584–85; *Tara*, 630 P.2d at 1272.

³¹ See Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 2*, 37 NAT. RES. J. 611, 613–14 (1997) (advocating the position of the *Tara* states).

³² See *Yzaguirre*, 53 S.W.3d at 372.

³³ See *Tara*, 630 P.2d at 1273; see also Anderson, *Part 2*, *supra* note 31, at 683–84.

The difference of opinion between the *Vela* and *Tara* states is not itself a new development: the Supreme Court of Texas handed down the *Vela* decision in 1968, while the Supreme Court of Oklahoma handed down the *Tara* decision in 1981.³⁴ The *Tara* states' efforts to give effect to the parties' implied contractual intent paved the way for the later emergence of the first marketable product doctrine.³⁵ Not surprisingly, *Vela* states have proved much less receptive to the first marketable product doctrine than *Tara* states.

B. The Location of the Yardstick: At the Well or Downstream of the Wellhead

Most royalty clauses in oil and gas leases will not only identify a yardstick for calculating royalty payments; they will also specify a location for the yardstick—the point at which the lessee must determine the price or value of its production to calculate its royalty payments. Until fairly recently, the vast majority of royalty clauses required that the lessee calculate its royalty payments “at the well” or “at the wellhead.”³⁶ Some royalty clauses used slightly different terms, such as “in the field of production,” to convey essentially the same meaning—that the lessee should calculate its royalty payments at the wellhead or near the point of production.³⁷

By comparison, an increasing number of royalty clauses suggests that the lessee may have to calculate its royalty payments at a location other than the wellhead or the field of production.³⁸ These kinds of royalty clauses, which became more common as lessors enjoyed greater bargaining power during the period of rising oil prices in the early 2000s, may specify that the lessee should calculate its royalty payments at the “point of sale” or at the “point of delivery to a third party purchaser.”

The location of the yardstick may be a huge factor in the amount of royalties that a lessor receives from a lessee.³⁹ Generally, the value of oil or gas production increases as the lessee moves it from the wellhead to a

³⁴Tex. Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968); *Tara*, 630 P.2d 1269.

³⁵See discussion *infra* Section IV.B.

³⁶See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 15–16.

³⁷See *id.* at 16.

³⁸See *id.*

³⁹See David E. Pierce, *Royalty Jurisprudence: A Tale of Two States*, 49 WASHBURN L.J. 347, 352 (2010).

downstream sales location.⁴⁰ Oil and gas production is less valuable at the wellhead because any arm's length purchaser will assume that it will have to incur the cost to remove impurities from the production, to transport it from the wellhead, or otherwise to get it ready for sale to a downstream market or the general public.⁴¹ An arm's length purchaser typically will pay more for oil and gas that the lessee has already transported to a downstream market and compressed, processed, treated, and otherwise made ready for a downstream sale.⁴²

From the early years of oil and gas jurisprudence through the mid-1990s, courts in most states uniformly assumed that the location of the yardstick in a royalty clause identified the place where a lessee should calculate the yardstick—so that, if a royalty clause were to require that the lessee pay a royalty of 1/8th of the market value of its production “at the well,” the lessee would have to calculate the value of its production at the wellhead, not at some other location.⁴³ That changed with the rise of the first marketable product doctrine. Courts in first marketable product states have concluded that the term “at the well,” if it means anything at all, does not necessarily mean “at the wellhead.”⁴⁴

⁴⁰ See Byron C. Keeling, *A New Era in Oil and Gas Royalty Accounting*, OIL & GAS FIN. J., Sept. 2005, at 20 (“Oil and gas is potentially more valuable at a commercial trading location than at the wellhead.”); Matthew J. Salzman & Ashley Dillon, *Royalty Litigation Update—Where We Have Been, Where We Are, and Where We May Be Going, in Kansas and Beyond*, 62 ROCKY MTN. MIN. L. INST. § 18.01, at 18-2 (2016) (“The value of produced oil and gas generally increases as the production moves from the upstream wellhead down through the stream of commerce until it is sold to and consumed by the end user. This increase in value reflects the costs and expenses required to transport and process oil and gas as it moves downstream.”).

⁴¹ See Kevin C. Abbott & Ariel E. Nieland, *Leasing and Development in the Marcellus Shale Region: Avoiding the Pitfalls*, DEVELOPMENT ISSUES IN THE MAJOR SHALE PLAYS, Paper No. 10, § I(A) (Rocky Mtn. Min. L. Inst. 2010) (“Although the gas theoretically could be sold at the wellhead, in the current structure of the industry, it is more typically sold downstream. Between the point of production and the point of sale, various costs can be incurred that improve the condition and value of the gas. The gas can be processed or dehydrated in order to improve its quality, it can be compressed in order to allow it to flow into higher pressure pipelines, and it can be transported to a delivery point for sale.”).

⁴² See Broomes, *supra* note 13, at 152 (“The work-back method recognizes the marketplace realities associated with the production of any commodity—as the product is transformed from its raw form to a finished product, its value increases; and as that same product is transported from its place of origin or manufacture to its final destination for consumption or other use, its value is likewise enhanced.”).

⁴³ See *infra* text accompanying notes 70–95.

⁴⁴ See discussion *infra* Section IV.B.

III. THE IMPLIED COVENANT TO MARKET

In almost all oil and gas states, lessees owe an implied duty to their lessors and royalty owners—the implied covenant to market.⁴⁵ The implied covenant to market requires that a lessee market its oil and gas production in a way that mutually benefits both the lessee and its lessors.⁴⁶ A lessee breaches the implied covenant to market if the lessee acts in a way that benefits only itself and unfairly has the effect of reducing the size or amount of a lessor's royalty payments.⁴⁷

At least historically, the implied covenant to market encompassed both a timing and pricing element.⁴⁸ Under the timing element of the implied covenant, a lessee must market its production within a reasonable period of time.⁴⁹ The timing element of the covenant ensures that once a lessee begins producing oil or gas in sufficient quantities to sustain a lease, the lessee will then make reasonable efforts to identify and pursue a market for its production so that it may begin making royalty payments to its lessors.⁵⁰ A lessee may not unreasonably delay its marketing efforts for speculative purposes.⁵¹

Under the pricing element of the implied covenant to market, a lessee must market its production for a reasonable price.⁵² The pricing element of the implied covenant ensures that where a royalty clause requires a lessee to calculate its royalty payments based on the proceeds or price that the lessee actually receives for its production, the lessee will not sell its production at

⁴⁵ See, e.g., *Harding v. Cameron*, 220 F. Supp. 466, 470 (W.D. Okla. 1963); *Gilmore v. Superior Oil Co.*, 388 P.2d 602, 606 (Kan. 1964); *Severson v. Barstow*, 63 P.2d 1022, 1024 (Mont. 1936); *Libby v. De Baca*, 179 P.2d 263, 265 (N.M. 1947); *Amoco Prod. Co. v. Alexander*, 622 S.W.2d 563, 567 (Tex. 1981).

⁴⁶ See *Irvin*, *supra* note 10, at § 18.02[2], at 18-11; Brian S. Tooley & Keith D. Tooley, *The Marketable Product Approach in the Natural Gas Royalty Case*, 44 ROCKY MTN. MIN. L. INST. § 21.02, at 21-3 (1998).

⁴⁷ See, e.g., *El Paso Nat. Gas Co. v. Am. Petrofina Co.*, 733 S.W.2d 541, 550 (Tex. App.—Houston [1st Dist.] 1986, writ ref'd n.r.e.).

⁴⁸ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 23.

⁴⁹ See John S. Lowe, *Interpreting the Royalty Obligation: The Role of the Implied Covenant to Market*, SPECIAL INST. ON PRIV. OIL & GAS ROYALTIES pt. 6, at 6-4 to -6 (Rocky Mtn. Min. L. Inst. 2003); Tooley & Tooley, *supra* note 46, § 21.02, at 21-4.

⁵⁰ See, e.g., *Bristol v. Colo. Oil & Gas Corp.*, 225 F.2d 894, 896 (10th Cir. 1955); *Robbins v. Chevron U.S.A., Inc.*, 785 P.2d 1010, 1014 (Kan. 1990); *Swamp Branch Oil & Gas Co. v. Rice*, 70 S.W.2d 3, 5 (Ky. 1934); *Hutchinson v. Atlas Oil Co.*, 87 So. 265, 270 (La. 1921).

⁵¹ See Tooley & Tooley, *supra* note 46, § 21.02, at 21-4.

⁵² See Lowe, *supra* note 49, at 6-15 to -17; Tooley & Tooley, *supra* note 46, § 21.02, at 21-4.

artificially low prices to minimize its royalty payments to its lessors; instead, the lessee must sell its production for the “best price reasonably available.”⁵³

The implied covenant to market has a long history and dates back to at least the 1890s.⁵⁴ For many of those years, courts imposed limits on the potential reach of the covenant:

- First, they applied the covenant only where the lessee’s marketing efforts might potentially affect the size or amount of a lessor’s royalties.⁵⁵ They reasoned that the implied covenant to market is irrelevant where the parties’ lease did not require the lessee to calculate its royalty payments on the basis of the price that it actually received for its production.⁵⁶
- Second, they applied the covenant only for the purpose of protecting the common good of both the lessee and the lessor.⁵⁷ They recognized that a lessee generally is not a fiduciary and owes no responsibility to subordinate its own interests to those of its lessors.⁵⁸

⁵³ Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987); see Craig v. Champlin Petroleum Co., 300 F. Supp. 119, 125 (W.D. Okla. 1969), *rev’d on other grounds*, 435 F.2d 933 (10th Cir. 1971); El Paso Nat. Gas Co. v. Am. Petrofina Co., 733 S.W.2d 541, 550 (Tex. App.—Houston [1st Dist.] 1986, writ *ref’d n.r.e.*).

⁵⁴ E.g., Iams v. Carnegie Nat. Gas Co., 45 A. 54, 55 (Pa. 1899); see Bruce M. Kramer & Chris Peason, *The Implied Marketing Covenant in Oil and Gas Leases: Some Needed Changes for the 80’s*, 46 LA. L. REV. 787, 792 (1986) (dating the implied covenant to market back to *Iams*).

⁵⁵ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 24.

⁵⁶ E.g., *El Paso Nat. Gas Co.*, 733 S.W.2d at 550; see Phillips Petroleum Co. v. Yarbrough, 405 S.W.3d 70, 78 (Tex. 2013) (“A duty to market is implied in leases that base royalty calculations on the price received by the lessee for the gas.”); see also James C.T. Hardwick & J. Kevin Hayes, *Gas Marketing Royalty Issues in the 1990s*, OIL AND GAS ROYALTIES ON NON-FEDERAL LANDS, Paper No. 2, § 2.05[1], at 2-30 (Rocky Mtn. Min. L. Inst. 1993) (“Logic suggests that the duty imposed upon a lessee to obtain the best price possible would apply only for leases containing royalty clauses under which the lessor is compensated based upon the price received by the lessee—i.e., a proceeds type clause.”).

⁵⁷ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 25.

⁵⁸ See, e.g., *Minerva Oil Co. v. Sohio Petroleum Co.*, 84 N.E.2d 167, 169 (Ill. App. Ct. 1949); *Waechter v. Amoco Prod. Co.*, 537 P.2d 228, 248 (Kan. 1975); *Bunger v. Rogers*, 112 P.2d 361, 363 (Okla. 1941); *Amoco Prod. Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280, 285 (Tex. Civ. App.—El Paso 1979), *writ ref’d n.r.e.*, 611 S.W.2d 610 (Tex. 1980).

- Third, they applied the covenant to require only a standard of reasonableness, not a strict standard of care.⁵⁹ Interpreting the covenant to hold only that a lessee must act as a reasonably prudent operator,⁶⁰ they declined to use the covenant as a means to second-guess, with the benefit of hindsight, a lessee's objectively reasonable marketing decisions.⁶¹

With the rise of the first marketable product doctrine, courts began to expand the reach of the implied covenant to market. Courts in first marketable product states cited the implied covenant to market as the foundation for the doctrine.⁶² But in doing so, they applied the covenant in a way that largely ignored its historical limits.⁶³ They concluded that the implied covenant to market may apply to all types of royalty clauses; they

⁵⁹ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 27; Kramer & Pearson, *supra* note 54, at 810–11; see also Scott Lansdown, *The Implied Marketing Covenant in Oil and Gas Leases: The Producer's Perspective*, 31 ST. MARY'S L.J. 297, 323 (2000) (noting that the standard is one of "prudence, not of prescience").

⁶⁰ See, e.g., Klein v. Jones, 980 F.2d 521, 526 (8th Cir. 1992); Sword v. Rains, 575 F.2d 810, 813 (10th Cir. 1978); Eggleston v. McCasland, 98 F. Supp. 693, 695 (E.D. Okla. 1951); Fey v. A.A. Oil Corp., 285 P.2d 578, 587 (Mont. 1955); Libby v. De Baca, 179 P.2d 263, 265 (N.M. 1947); Fisher v. Grace Petroleum Corp., 830 P.2d 1380, 1391 (Okla. Civ. App. 1991); Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987); Transamerican Nat. Gas Corp. v. Finkelstein, 933 S.W.2d 591, 596 (Tex. App.—San Antonio 1996, writ denied).

⁶¹ See Nordan-Lawton Oil & Gas Corp. of Tex. v. Miller, 272 F. Supp. 125, 137–38 (W.D. La. 1967), *aff'd*, 403 F.2d 946 (5th Cir. 1968); Robbins v. Chevron U.S.A., Inc., 785 P.2d 1010, 1015 (Kan. 1990); McDowell v. PG&E Res. Co., 658 So. 2d 779, 784 (La. Ct. App. 1995). Historically, the standard of reasonable prudence required only that a lessee obtain the best price, and not necessarily the highest price, for its production. See Judith M. Matlock, *Payment of Gas Royalties in Affiliate Transactions*, 48 INST. ON OIL & GAS L. & TAX'N § 9.06[3], at 9–48 (1997) (noting that "[t]he implied covenant to market has never required a purchaser to get the highest price in a vacuum."). Even under the implied covenant to market, a lessee had the right to exercise reasonable business judgment. The fact that a lessee may be able to secure a higher price from one purchaser than a second purchaser does not necessarily mean that the first purchaser is the best option, especially if the second purchaser is a more stable company or is able to offer a longer term contract. See Conine, *supra* note 23, § 18.04[4], at 18–35. Thus, over the years, courts have recognized that a lessee did not necessarily violate the implied covenant to market by failing to sell its production at the highest possible market price. See Amoco Prod. Co. v. First Baptist Church of Pyote, 611 S.W.2d 610, 610 (Tex. 1980) ("Although, in a proper factual setting, failure to sell at market value may be relevant evidence of a breach of the covenant to market in good faith, it is merely probative and not conclusive."); see also Parker v. TXO Prod. Co., 716 S.W.2d 644, 646 (Tex. App.—Corpus Christi 1986, no writ).

⁶² See *infra* text accompanying notes 105–141.

⁶³ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 29.

concluded that the implied covenant may require a lessee to elevate its lessors' interests over the lessee's own interests; and they concluded that the implied covenant may permit courts to second-guess a lessee's marketing decisions.⁶⁴

Nonetheless, the implied covenant to market is, by definition, only an implied covenant. Even in first marketable product states, most courts agree that the express terms of a lease—if plain and unambiguous—may control over the implied covenant to market.⁶⁵ The question in many cases, of course, is whether the express terms of a lease unambiguously convey an intent that is contrary to the implied covenant to market. Language that to some courts is plain and unambiguous has to other courts not been so clear.⁶⁶

IV. ROYALTY ACCOUNTING

Whenever a royalty dispute arises between a lessee and a lessor, a court must look first to the terms of the royalty clause in the parties' lease.⁶⁷ Because an oil and gas lease is a contract, a court must apply the standard principles of contract interpretation to construe the meaning of the terms in a royalty clause.⁶⁸ A fundamental principle of contract interpretation requires that if the parties' contract is plain and unambiguous, a court must enforce the parties' contract as it is written.⁶⁹

For many years, courts consistently found that the term “at the well”—the most common term that oil and gas parties used to specify the location

⁶⁴ See *infra* text accompanying notes 105–141.

⁶⁵ See Pierce, *Royalty Jurisprudence*, *supra* note 39, at 374–75 (“The Colorado and West Virginia courts make it clear that it is lawful, and perfectly permissible, to allow for the deduction of costs downstream of the wellhead—one just has to use the right language.”); Patricia Proctor et al., *Moving Through the Rocky Legal Terrain to Find a “Safe” Royalty Clause or a “New” Market at the Well*, 19 TEX. WESLEYAN L. REV. 145, 182 (2012) (“Even the most restrictive courts have observed that express language covering particular subject matter should prevail over implied covenants regarding the same subject matter.”); see also Rachel M. Kirk, Comment, *Variations in the Marketable-Product Rule from State to State*, 60 OKLA. L. REV. 769, 769 (2007) (“[A] state’s rule regarding post-extraction costs affects the drafting of royalty provisions in oil and gas leases, because parties may contract around a state’s default rule on the allocation of post-extraction costs.”).

⁶⁶ See *infra* text accompanying notes 142–225.

⁶⁷ Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 16.

⁶⁸ *Id.*; see *Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 860 (Tex. 2005).

⁶⁹ Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 16; see *Sun Oil Co. (Del.) v. Madeley*, 626 S.W.2d 726, 728 (Tex. 1981).

of the royalty yardstick—was plain and unambiguous.⁷⁰ Consequently, the prevailing rule in most states—the “historical rule”—was that if a royalty clause provided that the lessor was to receive a fractional share of the value or price of the lessee’s production “at the well,” the lessee must calculate its royalty payments to the lessor on the basis of the value or price of the lessee’s production at the wellhead, not on the basis of the value or price of the lessee’s production at a location downstream of the wellhead.⁷¹

The first marketable product doctrine challenged the historical rule for calculating royalty payments. In first marketable product states, a lessee—even under leases containing “at the well” language in their royalty clauses—may have to calculate its royalty payments to its lessors on the basis of the value or price of the lessee’s production at a location downstream of the wellhead.⁷²

A. *The Historical Rule*

Under the historical rule, a lessee may calculate its royalty payments based on the value or price of its production at the wellhead.⁷³ The historical rule is consistent with most royalty clauses, which commonly specify that a lessee should pay its lessors their royalty share of the value or price of the lessee’s production “at the well” or “at the wellhead.” But even in the absence of any “at the well” language in a royalty clause, courts routinely concluded that the historical rule was the default rule; in other words, they routinely concluded that unless the parties’ lease expressly required the lessee to calculate its royalty payments at a location other than

⁷⁰ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 29 (“Prior to the first marketable product doctrine, the law governing the calculation of royalty payments was fairly uniform.”).

⁷¹ See, e.g., *Martin v. Glass*, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983); *Atl. Richfield Co. v. State*, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989); cf. Jeffrey C. King, *The Compression of Natural Gas: Is it Production or Post-Production? Is it Deductible from Royalties? If so, How Much?*, 1 TEX. J. OIL, GAS & ENERGY L. 36, 45 (2006) (“The ‘mouth of the well’ or ‘wellhead’ is the location where the gas exits the earth. Consequently, by placing the point of valuation at that location, the parties have established the type of commodity for which royalties shall be paid – raw natural gas in its natural state.”).

⁷² See Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 21.

⁷³ See *supra* text accompanying note 43.

the wellhead,⁷⁴ the lessee could properly calculate its royalty payments on the basis of the value or price of its production at the wellhead.⁷⁵

The preferred way for a lessee to calculate the value or price of its production at the wellhead is the “comparable sales method,” which requires the lessee to act like an appraiser and examine the prices that the lessee and other producers are receiving at the wellhead for comparable sales of oil and gas production.⁷⁶ But while the comparable sales method is the preferred way of calculating the wellhead value of oil and gas production, the vast majority of lessees do not use—and have never used—the comparable sales method to calculate their royalty payments.⁷⁷ This is true, as a practical matter, because wellhead sales of oil and gas have become increasingly less common since the early 1990s.⁷⁸ Most lessees use a different methodology for calculating their royalty payments—the “workback method,” which permits them to calculate the value of their production at the wellhead by subtracting post-production costs from the price that they receive for their production at a downstream sales location.⁷⁹

Some courts and commentators imprecisely suggest that the historical rule permits lessees to “deduct” post-production costs from their royalty payments.⁸⁰ More precisely, the historical rule permits lessees to use the workback method to calculate the value or price of their oil and gas

⁷⁴ See *infra* text accompanying note 96.

⁷⁵ See, e.g., *La Fitte Co. v. United Fuel Gas Co.*, 284 F.2d 845, 849 (6th Cir. 1960); *Warfield Nat. Gas Co. v. Allen*, 88 S.W.2d 989, 992 (Ky. 1935); see also A.W. Walker, Jr., *The Nature of the Property Interests Created by an Oil and Gas Lease in Texas*, 10 TEX. L. REV. 291, 310–11 (1932) (“Even where leases are silent on this point the courts have held that the market price is to be determined at the well, or at the pipe line with which the well is connected.”).

⁷⁶ See *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 238–39 (5th Cir. 1984); *Mont. Power Co. v. Kravik*, 586 P.2d 298, 303 (Mont. 1978).

⁷⁷ See William T. Silvia, Comment, *Slouching Toward Babel: Oklahoma’s First Marketable Product Problem*, 49 TULSA L. REV. 583, 585 (2013) (“[M]ore often than not, the comparable sales method is not a viable option because there are frequently no comparable sales available to evaluate, and use of the work-back method is generally permitted.”).

⁷⁸ See King, *supra* note 11, at 856; see Richard B. Noulles, *What is Required for Gas to be a Marketable Product in Oklahoma?*, 85 OKLA. BAR J. 139, 141–42 (2014).

⁷⁹ See Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 21; see also *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 136 (Tex. 1996) (“[V]alue at the well means the value of the gas before . . . other value is added in preparing and transporting the gas to market.”).

⁸⁰ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 36; see also Wheeler, *supra* note 11, at 29 (“[T]he ‘net-back’ method does not ‘charge’ the lessor with any expenses at all, but instead is simply a method of determining what the wellhead value of the gas would have been if there had been a market for the gas at the wellhead.”).

production at the wellhead.⁸¹ The workback method rests on the theory that because oil and gas has greater value at a downstream sales location than at the wellhead, the lessee may determine the value of its production at the wellhead by “working backward” from the enhanced downstream sales price for its production—i.e., by subtracting from the downstream sales price the post-production costs that the lessee incurred to enhance the value of its production for sale in a downstream market.⁸² These post-production costs may include transportation, gathering, compression, treatment, and marketing costs.⁸³ Thus, if a lessee sold its crude oil production at a downstream location for \$80 a barrel after incurring \$20 a barrel in post-production costs, the workback method would permit the lessee to calculate its royalty payments on the basis of a price or value at the wellhead of \$60 a barrel.

⁸¹ See *Potts v. Chesapeake Expl., L.L.C.*, 760 F.3d 470, 475 (5th Cir. 2014); *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 130 (Tex. 1996) (Owen, J., concurring); *Leggett v. EQT Prod. Co.*, 800 S.E.2d 850, 856 n.8 (W. Va. 2017); see also Scott Lansdown, *The Marketable Condition Rule*, 44 S. TEX. L. REV. 667, 673 (2003) (“[T]he issue may best be framed not as whether post-production costs are deductible, but rather the point at which royalty is to be calculated.”). A typical royalty clause will require that the lessee calculate the value of its production “at the well.” The parties to a lease, however, may agree to a different location at which the lessee must calculate the value or price of its production—for example, the tailgate of any plant at which the lessee processes its gas production. See *infra* text accompanying note 96.

⁸² See, e.g., *Hemler v. Union Producing Co.*, 40 F. Supp. 824, 832 (W.D. La. 1941), *rev’d on other grounds*, 134 F.2d 436 (5th Cir. 1943); *Tana Oil & Gas Corp. v. Cernosek*, 188 S.W.3d 354, 361 (Tex. App.—Austin 2006, pet. denied); see also *Atl. Richfield Co. v. State*, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) (“[I]t is commonly understood that ‘market price at the well’ is often determined by working back from the price at the point of sale, deducting the cost of processing and transportation to the wellhead, to determine ‘market value at the wellhead.’”); *Heritage Res., Inc.*, 939 S.W.2d at 130 (Owen, J., concurring) (“Evidence of market value . . . can be proven by the so-called net-back approach, which determines the prevailing market price at a given point and backs out the necessary, reasonable costs between that point and the wellhead.”).

⁸³ See, e.g., *Poplar Creek Dev. Co. v. Chesapeake Appalachia, L.L.C.*, 636 F.3d 235, 238–39 (6th Cir. 2011); *Ramming v. Nat. Gas Pipeline Co. of Am.*, 390 F.3d 366, 372 (5th Cir. 2004) (“Reasonable post-production costs include transporting the gas to the market and those expenses incurred to make the gas marketable.”); *Cartwright v. Cologne Prod. Co.*, 182 S.W.3d 438, 444–45 (Tex. App.—Corpus Christi 2006, pet. denied) (“These post-production costs include taxes, treatment costs to render the gas marketable, compression costs to make it deliverable into a purchaser’s pipeline, and transportation costs.”); see also Edward B. Poitevent, II, *Post-Production Deductions from Royalty*, 44 S. TEX. L. REV. 709, 714 (2003).

Even today, many states—if not the majority of states⁸⁴—continue to adhere to the historical rule, including Texas,⁸⁵ Kentucky,⁸⁶ Louisiana,⁸⁷ North Dakota,⁸⁸ Pennsylvania,⁸⁹ and probably also Alabama,⁹⁰ California,⁹¹ Mississippi,⁹² Montana,⁹³ Ohio,⁹⁴ and Utah.⁹⁵

⁸⁴See *Emery Res. Holdings, LLC v. Coastal Plains Energy, Inc.*, 915 F. Supp. 2d 1231, 1240 (D. Utah 2012) (“The majority of courts to consider the topic have found ‘at the well’ royalty clauses to mean that natural gas is valued for royalty purposes at its wellhead location and condition.”); *Bice v. Petro-Hunt, L.L.C.*, 768 N.W.2d 496, 500 (N.D. 2009) (“Currently, the majority of states interpret the term ‘market value at the well’ to mean royalty is calculated based on the value of the gas at the wellhead.”). John Burritt McArthur, a frequent critic of the historical rule, argues that the first marketable product doctrine is actually the majority rule. John Burritt McArthur, *Some Advice on Bice, North Dakota’s Marketable-Product Decision*, 90 N.D. L. REV. 545, 550 (2014). He suggests that Arkansas, New Mexico, and Virginia may be first marketable product states. *Id.* at 550, 554–56. Although he questions whether the historical rule states should include those in which federal courts have reaffirmed the historical rule, he is quick to point out that federal courts in New Mexico and Virginia have embraced the first marketable product rule. *Id.*

⁸⁵*Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 135 (Tex. 1996); *Heritage Res., Inc.*, 939 S.W.2d at 122.

⁸⁶*Poplar Creek Dev. Co.*, 636 F.3d at 244; see also *Appalachian Land Co. v. EQT Prod. Co.*, 468 S.W.3d 841, 843 (Ky. 2015); *Baker v. Magnum Hunter Prod., Inc.*, 473 S.W.3d 588, 595 (Ky. 2015); *Reed v. Hackworth*, 287 S.W.2d 912, 913 (Ky. 1956).

⁸⁷*Freeland v. Sun Oil Co.*, 277 F.2d 154, 159 (5th Cir. 1960); *Dickson v. Sklarco L.L.C.*, No. 5:11-CV-0352, 2014 WL 4443423, at *2 (W.D. La. Sept. 9, 2014); *Wall v. United Gas Pub. Serv. Co.*, 152 So. 561, 564 (La. 1934); *Culpepper v. EOG Res., Inc.*, 92 So. 3d 1141, 1144 (La. Ct. App. 2012).

⁸⁸*Bice*, 768 N.W.2d at 501; see also *Kittleson v. Grynberg Petroleum Co.*, 876 N.W.2d 443, 446 (N.D. 2016).

⁸⁹*Kilmer v. Elexco Land Servs., Inc.*, 990 A.2d 1147, 1158 (Pa. 2010); see also *Pollock v. Energy Corp. of Am.*, No. 10-1553, 2012 WL 6929174, at *7 (W.D. Pa. Oct. 24, 2012).

⁹⁰See *Scott Paper Co. v. Taslog, Inc.*, 638 F.2d 790, 799 (5th Cir. 1981); *State v. Phillips Petroleum Co.*, 638 So. 2d 893, 895 (Ala. 1994).

⁹¹*Alamitos Land Co. v. Shell Oil Co.*, 44 P.2d 573, 576 (Cal. 1935); *Atl. Richfield Co. v. State*, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989).

⁹²*Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 231 (5th Cir. 1984); see *Pursue Energy Corp. v. Abernathy*, 77 So. 2d 1094, 1099 (Miss. 2011).

⁹³*S Bar B Ranch v. Omimex Can., Ltd.*, 942 F. Supp. 2d 1058, 1062 (D. Mont. 2013); *Mont. Power Co. v. Kravik*, 586 P.2d 298, 303 (Mont. 1978).

⁹⁴*Lutz v. Chesapeake Appalachia, LLC*, No. 4:09-cv-2256, 2017 WL 4810703, at *7 (N.D. Ohio Oct. 25, 2017).

⁹⁵*Emery Res. Holdings, LLC v. Coastal Plains Energy, Inc.*, 915 F. Supp. 2d 1231, 1240 (D. Utah 2012).

But even in these historical rule states, the historical rule is neither absolute nor irrebuttable. The historical rule arises from courts' interpretation of the term "at the well" in a typical royalty clause. Because the historical rule is simply a product of the principles of contract interpretation, the parties to an oil and gas lease may agree to terms that would require the lessee to calculate its royalty payments on the basis of the price or value of its production at a location downstream of the wellhead.⁹⁶

B. *The First Marketable Product Doctrine*

Several states have rejected the historical rule in favor of a rule that they have described as the first marketable product doctrine or the marketable condition doctrine. In particular, the highest courts in four states—Kansas, Oklahoma, Colorado, and West Virginia—have issued opinions adopting variations of the first marketable product doctrine.⁹⁷ These courts have

⁹⁶ See, e.g., *Warren v. Chesapeake Expl., L.L.C.*, 759 F.3d 413, 417 (5th Cir. 2014); see also *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996) ("[T]he parties may modify this general rule by agreement.").

⁹⁷ See *infra* text accompanying notes 107–141. Three other states—Michigan, Nevada, and Wyoming—have enacted statutes that arguably codify the first marketable product doctrine. See MICH. COMP. LAWS SERV. § 324.61503b(1) (LexisNexis Supp. 2015); NEV. REV. STAT. ANN. § 522.115(1)(a) (West Supp. 2015); WYO. STAT. ANN. § 30-5-304(vi) (Supp. 2015).

In another three states, the prevailing rule is unclear:

a) *Arkansas*. Some commentators have suggested that Arkansas is a first marketable product state. *E.g.*, Wheeler, *supra* note 11, at 10. However, a federal court in Arkansas has stated: "Arkansas law is, in fact, unclear, and . . . at this point, it can not be said that Arkansas has joined the states of Colorado and Oklahoma in adopting what is a minority position with respect to the deduction of post-production costs." *Riedel v. XTO Energy Inc.*, 257 F.R.D. 494, 505 (E.D. Ark. 2009).

b) *New Mexico*. The Tenth Circuit ruled in 2005 that New Mexico would follow the historical rule. *Elliott Indus. L.P. v. BP Am. Prod. Co.*, 407 F.3d 1091, 1114 (10th Cir. 2005). In 2015, a federal court in New Mexico stated that while the Tenth Circuit's opinion in *Elliott Industries* was binding on it, it believed that the New Mexico Supreme Court would adopt the first marketable product doctrine. *Anderson Living Trust v. WPX Energy Prod., LLC*, 306 F.R.D. 312, 429–30 (D.N.M. 2015); see also *Anderson Living Tr. v. ConocoPhillips Co.*, No. CIV 12-0039 JB/KBM, 2016 WL 1158341, at *15 & n.12 (D.N.M. March 1, 2016). To date, the New Mexico Supreme Court has declined to reach the issue. See *ConocoPhillips Co. v. Lyons*, 299 P.3d 844, 860 (N.M. 2012); *Davis v. Devon Energy Corp.*, 218 P.3d 75, 81 (N.M. 2009).

c) *Virginia*. A federal court in Virginia has concluded that the Virginia Supreme Court would adopt the first marketable product doctrine. *Adkins v. EQT Prod. Co.*, No. 1:11CV00031, 2011 WL 6178438, at *5 (W.D. Va. Dec. 13, 2011). On the other hand, a

concluded that the doctrine arises from the implied covenant to market,⁹⁸ which in their view requires that lessees bear sole responsibility for all of the costs necessary to achieve a marketable product, including almost all post-production costs such as gathering, compression, treatment, and marketing expenses.⁹⁹ To justify their adoption of the first marketable product doctrine, these courts have routinely argued that they must construe oil and gas leases against lessees and in favor of lessors.¹⁰⁰

At its essence, the first marketable product doctrine holds that a lessee or producer generally may not calculate its royalty payments on the basis of the price or value of its production at the wellhead, but instead must calculate its royalty payments on the basis of the price or value of its production at the downstream location where it first acquires a marketable product.¹⁰¹ The devil, however, is in the details. Each of the four major first marketable product states applies the doctrine differently.¹⁰² “This has resulted in a wide spectrum of marketable-product rules”¹⁰³

Just as the historical rule is neither absolute nor irrebuttable in historical rule states, the first marketable product doctrine is neither absolute nor irrebuttable in first marketable product states. Even in first marketable product states, the parties to an oil and gas lease may agree to terms that

former attorney general for the Commonwealth of Virginia has argued that Virginia would adopt the historical rule. Office of the Attorney General of the Commonwealth of Va., Op. No. 09-018, 2009 WL 1716837, at *4 (June 10, 2009).

⁹⁸ See, e.g., *Fawcett v. Oil Producers, Inc.* of Kan., 352 P.3d 1032, 1034 (Kan. 2015) (noting that the first marketable product doctrine is a “corollary of the duty to market”).

⁹⁹ See *infra* text accompanying notes 107–133.

¹⁰⁰ E.g., *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 901 (Colo. 2001); *Gilmore v. Superior Oil Co.*, 388 P.2d 602, 605 (Kan. 1964); *Estate of Tawney v. Columbia Nat. Res., L.L.C.*, 633 S.E.2d 22, 29 (W. Va. 2006).

¹⁰¹ See Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 21.

¹⁰² See Kirk, *supra* note 65, at 808.

¹⁰³ Kirk, *supra* note 65, at 770; see Poitevent, *supra* note 83, at 759 (“As a result, a lessee in a marketable product state cannot predict its right to deduct post-production costs with certainty.”); Silvia, *supra* note 77, at 586 (“Unlike the at the well approach, which has a general consistency in its definition across jurisdictions, the first marketable product doctrine is the subject of many interpretations, and there is no single cross-jurisdictional definition or approach for the principle.”); see also *Wallace B. Roderick Revocable Living Tr. v. XTO Energy, Inc. (Roderick I)*, 679 F. Supp. 2d 1287, 1294 (D. Kan. 2010) (acknowledging that there are “nontrivial differences” in the laws of the various first marketable product states).

would permit the lessee to calculate its royalty payments on the basis of the price or value of its production at the wellhead.¹⁰⁴

But in each of the first marketable product states, the mere fact that a royalty clause contains “at the well” language is not in itself sufficient to disclaim the first marketable product doctrine.¹⁰⁵ Each state requires more explicit language. Not surprisingly, the required level of specificity varies from state to state.¹⁰⁶

1. Kansas

Kansas was arguably the first state to abandon the historical rule in favor of a variation of the first marketable product doctrine.¹⁰⁷ In Kansas, a lessee must itself bear all of the post-production expenses—except for transportation costs—necessary to achieve a marketable product.¹⁰⁸ Thus, in the absence of express lease terms to the contrary, a lessee in Kansas must calculate its royalty payments on the basis of the price or value of its production at the location where the lessee first acquires a marketable product, minus the reasonable costs that the lessee must incur to transport its production from the wellhead to the place where it acquires a marketable product.¹⁰⁹ Generally, a lessee in Kansas may not calculate its royalty

¹⁰⁴ See Pierce, *Royalty Jurisprudence*, *supra* note 39, at 374–75; Proctor et al., *supra* note 65, at 182. This appears to be true even in states that have adopted statutory versions of the first marketable product doctrine. *E.g.*, MICH. COMP. LAWS SERV. § 324.61503b(1) (LexisNexis 2017).

¹⁰⁵ See, *e.g.*, Fankhouser v. XTO Energy, Inc., No. CIV-07-798-L, 2012 WL 601415, at *2 (W.D. Okla. Feb. 23, 2012); Wallace B. Roderick Revocable Living Tr. v. XTO Energy, Inc. (*Roderick II*), 281 F.R.D. 477, 482–83 (D. Kan. 2012).

¹⁰⁶ See Foster v. Apache Corp., 285 F.R.D. 632, 638 n.13 (W.D. Okla. 2012) (“There is disagreement . . . as to how specific the lease language must be to alter the default rule.”).

¹⁰⁷ See Keeling & Gillespie, *A New Era of Royalty Accounting*, *supra* note 20, at 21.

¹⁰⁸ Sternberger v. Marathon Oil Co., 894 P.2d 788, 799 (Kan. 1995). See *Roderick I*, 679 F. Supp. 2d at 1294 n.2 (“Kansas has explicitly held that transportation costs are allocable to lessors . . .”).

¹⁰⁹ See *Sternberger*, 894 P.2d at 800; see also Fawcett v. Oil Producers, Inc. of Kan., 352 P.3d 1032, 1034–35 (Kan. 2015) (“Broadly speaking, the rule requires operators to make gas marketable at their own expense.”). The Kansas Supreme Court in *Sternberger* made clear that “reasonable transportation expenses are shared by the lessor and the lessee where royalties are paid (in oil or gas or in money) ‘at the well’ but there is no market at the well.” *Sternberger*, 894 P.2d at 797. In its more recent *Coulter* opinion, the Kansas Supreme Court used language which may have seemed to suggest, contrary to *Sternberger*, that a lessor is responsible for a proportional share of the lessee’s transportation costs only *after* the lessee has achieved a marketable product. See *Coulter v. Anadarko Petroleum Corp.*, 292 P.3d 289, 306 (Kan. 2013).

payments on the basis of the price or value of its production at the wellhead unless its production is “marketable at the well.”¹¹⁰

The term “marketable” in Kansas does not actually require the existence of a commercial market.¹¹¹ For oil or gas production to be “marketable,” it must be in a condition in which the lessee *could* sell it to a willing commercial buyer.¹¹² Thus, if oil or gas production is in a condition in which the lessee *could* potentially sell it at the wellhead, then the production is marketable at the wellhead.¹¹³ Whether and at what point oil and gas production is marketable, however, appears to be largely a question of fact.¹¹⁴ Under the Kansas version of the first marketable product doctrine, the burden of proving the point of “marketability” falls on the plaintiff lessor or royalty owner.¹¹⁵

The parties to an oil and gas lease in Kansas may contractually agree to authorize the lessee to calculate its royalty payments on the basis of the value or price of its production at the wellhead.¹¹⁶ However, a lessee may use a workback methodology to calculate its royalty payments at the wellhead only if its lease with the lessor “clearly and expressly” allows the lessee to do so; in the absence of any such clear and express language, a

(stating that “once the gas is in [a] marketable condition, regardless of whether a market actually exists at that point, the lessor (royalty owner) can be charged with his/her/its proportionate share (e.g., 1/8) of the cost to transport the gas to a market”). But from the context of *Coulter*, it seems doubtful that the Kansas Supreme Court intended to overrule or modify *Sternberger*.

¹¹⁰ See *Sternberger*, 894 P.2d at 800; see *Fawcett*, 352 P.3d at 1042.

¹¹¹ See *Fawcett*, 352 P.3d at 1042. But see *Coulter*, 292 P.3d at 306 (noting that under the analysis in Colorado first marketable product cases, Kansas’s conclusion “that gas can be in marketable condition at a point at which no market exists may be questionable”).

¹¹² See *Sternberger*, 894 P.2d at 799.

¹¹³ See *Fawcett*, 352 P.3d at 1042; see also Salzman & Dillon, *supra* note 40, at § 18.02(2) (“*Fawcett* appears to be the death knell for several previously common royalty interest owner claims. Most important among them was the claim that gas is per se not marketable at the wellhead and does not become marketable until it is ‘commercially fungible’ or ‘pipeline quality,’ meaning that it satisfies interstate pipeline specifications. Even if this were a legally credible argument before *Fawcett*, it is not now.”).

¹¹⁴ See *Sternberger*, 894 P.2d at 799–800; cf. *Fawcett*, 352 P.3d at 1041 (holding, as a matter of law, that gas was marketable at the wellhead when the lessee did in fact sell it at the wellhead even though it could arguably have sold the gas for higher prices at a downstream location, and stating: “What it means to be ‘marketable’ remains an open question. But the answer is not simply . . . interstate pipeline quality standards or downstream index prices.”). But see Kirk, *supra* note 65, at 787 (arguing that “the Kansas rule seems to treat marketability as a question of law”).

¹¹⁵ See *Smith v. Amoco Prod. Co.*, 31 P.3d 255, 258 (Kan. 2001).

¹¹⁶ See *Fawcett*, 352 P.3d at 1042.

lessee in Kansas must calculate the value of its production at the point where it first achieves a marketable product—i.e., if it uses a workback methodology, it may work backwards only to the point at which it first achieves a marketable product.¹¹⁷

2. Oklahoma

Oklahoma's version of the first marketable product doctrine is similar to, but not quite identical to, Kansas's version. Under Oklahoma's version, a lessee typically must bear all of the post-production costs necessary to achieve a marketable product, including any transportation costs that the lessee incurs to move its oil or gas production to a place where it may achieve a marketable product.¹¹⁸ In Oklahoma, the lessee may share transportation costs with its lessors only if the lessee pays those costs for the purpose of moving an already marketable product to a place where the lessee may actually sell it.¹¹⁹

As in Kansas, a lessee in Oklahoma must calculate its royalty payments on the basis of the price or value of its production at the location where the

¹¹⁷ *Id.*

¹¹⁸ Kirk, *supra* note 65, at 806 (“In Oklahoma, royalty valuation occurs when a marketable product is obtained. The Oklahoma rule requires that the lessee bear all costs incurred in obtaining a marketable product pursuant to the implied covenant to market, and a lessee cannot deduct post-extraction costs from a lessor’s royalty if the costs were necessary to prepare the product for market.”); *see, e.g.*, Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1205, 1208 (Okla. 1998); Howell v. Texaco, Inc., 112 P.3d 1154, 1159–60 (Okla. 2004). Interestingly, the first marketable product doctrine in Oklahoma only benefits royalty owners, not *overriding* royalty owners. XAE Corp. v. SMR Prop. Mgmt. Co., 968 P.2d 1201, 1208 (Okla. 1998). Under an overriding royalty agreement that requires a lessee to pay royalties on the basis of the market value or price of its production at the wellhead, the lessee may apply a workback methodology to calculate its royalty payments to its overriding royalty owners. *Id.*; *see* Kirk, *supra* note 65, at 815 (“Although Oklahoma’s version of the marketable-product rule applies to royalty interests, the at-the-well rule applies to overriding royalty interests.”); Silvia, *supra* note 77, at 596 (“Oklahoma courts do not afford overriding royalty interests the protections of the implied duty to market that is derived from the lessor-lessee relationship, and therefore, unlike standard royalties, deductions for post-production costs are allowed.”).

¹¹⁹ *See* Kirk, *supra* note 65, at 807 (“[T]he Oklahoma rule allows for the deduction of transportation costs if there is no market available on the leased premises and the costs are incurred to transport already marketable gas to a distant market off of the leased premises.”); Silvia, *supra* note 77, at 595–96 (“Transportation costs [in Oklahoma] are generally proportionately allocable if the pipeline connecting to the point of sale is beyond the leased premise, but there is no sharing of the costs of transporting gas offsite for processing if the reason for doing so is to achieve a marketable product.”).

lessee first acquires a marketable product.¹²⁰ And as in Kansas, the “marketability” of oil and gas production is apparently a question of fact in Oklahoma.¹²¹ Moreover, as in Kansas, the term “marketable” refers simply to the condition of the production and does not actually require the existence of a commercial market—or, for that matter, any willing buyer at all—at the point where the lessee acquires a marketable product; in Oklahoma, oil and gas production is marketable once it is in a condition where the lessee could sell it to a willing buyer, even if the lessee must then transport its production to another location to sell it to that willing buyer.¹²²

But in Oklahoma, the burden of proof falls on the lessee, not the royalty owner.¹²³ A lessee in Oklahoma may use a workback methodology to calculate its royalty payments only if the lessee can prove (i) that its actual revenues at the point of sale increased in proportion to the post-production costs which it intends to subtract from its revenues to calculate the value of its production at a location upstream of the point of sale, (ii) that the post-production costs which it intends to subtract from its revenues merely enhanced the value of an already marketable product and were not themselves necessary to acquire a marketable product, and (iii) that the post-production costs which it desires to subtract from its revenues were reasonable.¹²⁴

As in Kansas, the first marketable product doctrine is not an absolute rule in Oklahoma. And as in Kansas, the parties to an oil and gas lease in Oklahoma may contractually agree that the lessee can use a workback

¹²⁰ See *Mittelstaedt*, 954 P.2d at 1209.

¹²¹ *Foster v. Merit Energy Co.*, 282 F.R.D. 541, 548–49 (W.D. Okla. 2012); see *Foster v. Apache Corp.*, 285 F.R.D. 632, 643 (W.D. Okla. 2012) (“*Mittelstaedt* did not provide a categorical answer to the question of when gas is in a marketable condition and plainly viewed the question as *not* being one subject to a categorical answer.”); see also *Noules*, *supra* note 78, at 142 (noting that the Oklahoma Supreme Court has made it “clear that determining whether gas is a marketable product is a fact intensive question dependent in large part on the custom and usage in the industry”). But see *Kirk*, *supra* note 65, at 806 (“Some of the language in Oklahoma cases seems to treat marketability as a question of law rather than of fact.”).

¹²² *Mittelstaedt*, 954 P.2d at 1206. This rule is not a model of clarity for practitioners. The courts in Oklahoma offer little guidance about what is necessary for oil or gas to be marketable—probably precisely because they view “marketability” as a fact issue that the parties may best resolve by presenting their arguments to a jury or other fact finder. See *Merit Energy*, 282 F.R.D. at 549; see also *Noules*, *supra* note 78, at 141.

¹²³ *Mittelstaedt*, 954 P.2d at 1208.

¹²⁴ *Id.* at 1205.

methodology to calculate its royalty payments on the basis of the value of its production at the wellhead.¹²⁵

3. Colorado

Colorado's version of the first marketable product doctrine is even more favorable to lessors than Kansas's or Oklahoma's version. Under Colorado's version, the implied covenant to market requires that a lessee bear all costs, including transportation costs, necessary to achieve a first marketable product.¹²⁶ "Royalty calculations should therefore be made at the point where a first marketable product is obtained."¹²⁷

In Colorado, the term "marketability" refers not only to the condition of the lessee's oil or gas production, but also to its location.¹²⁸ Thus, the first marketable product doctrine in Colorado requires not only that a lessee do whatever is necessary to place its oil or gas production in a marketable condition (i.e., a condition in which the lessee could potentially sell it), but also that the lessee transport its production to a marketable location (i.e., a place with a commercial market where the lessee may actually sell it).¹²⁹ This component of the first marketable product doctrine in Colorado means that, even after a lessee has incurred the cost to place its oil or gas

¹²⁵ See, e.g., *Wood v. TXO Prod. Corp.*, 854 P.2d 880, 883 (Okla. 1992) ("If a lessee wants royalty owners to share in compression costs, that can be spelled-out in the . . . lease."); see also *Merit Energy*, 282 F.R.D. at 549 ("[T]he *Mittelstaedt* decision makes it clear that lease language can make a difference.").

¹²⁶ *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 906 (Colo. 2001); see *Garman v. Conoco, Inc.*, 886 P.2d 652, 659 (Colo. 1994).

¹²⁷ *Patterson v. BP Am. Prod. Co.*, 360 P.3d 211, 222 (Colo. App. 2015).

¹²⁸ *Rogers*, 29 P.3d at 905.

¹²⁹ *Id.* The Colorado Supreme Court in *Rogers* explained the marketable condition and marketable location components of its first marketable product doctrine as follows:

In defining whether gas is marketable, there are two factors to consider, condition and location. First, we must look to whether the gas is in a marketable condition, that is, in the physical condition where it is acceptable to be bought and sold in a commercial marketplace. Second, we must look to location, that is, the commercial marketplace, to determine whether the gas is commercially saleable in the oil and gas marketplace. . . [U]nder our definition of marketability, the gas must be in such a physical condition and location that it is available for commercial exchange, in a viable market, i.e., a commercial marketplace.

Id. at 905, 910.

production in a marketable condition, the lessee still must bear all of the transportation costs necessary to move its production to a sales location.¹³⁰

As in Kansas and Oklahoma, the marketability of oil and gas production is a question of fact in Colorado.¹³¹ The burden of proving the point of marketability apparently falls on the lessee, not the royalty owner.¹³²

The parties to an oil and gas lease in Colorado may contractually agree that the lessee may calculate its royalty payments on the basis of the value or price of its production at the wellhead.¹³³ However, the words “at the well” are themselves insufficient to evidence such an agreement. The Colorado Supreme Court has concluded that the words “at the well” in the royalty clause of an oil and gas lease are “silent as to allocation of all costs, including transportation costs.”¹³⁴

4. West Virginia

West Virginia has adopted perhaps the most extreme version of the first marketable product doctrine.¹³⁵ As with the courts in Colorado, the West Virginia courts hold that the implied covenant to market requires a lessee to bear all of the costs, including transportation costs, necessary to achieve a marketable product and move it to a commercial market.¹³⁶ However, going

¹³⁰ See Lindsey Scheel, *Oil and Gas Law—Rent or Royalties: North Dakota Joins the Majority of States in Adopting the “At the Well” Rule for Calculating Royalties on Oil and Gas Leases*, *Bice v. Petro-Hunt, L.L.C.*, 2009 ND 124, 768 N.W.2d 496, 85 N.D. L. REV. 919, 929 (2009) (noting that lessees in Colorado “usually shoulder transportation costs, in addition to other expenses incurred in creating a marketable product”); cf. *Fawcett v. Oil Producers, Inc. of Kan.*, 352 P.3d 1032, 1042 (Kan. 2015) (declining to follow *Rogers* in Kansas and noting that where a royalty clause permits the lessee to calculate its royalty payments at the wellhead, the lessor must bear a proportionate share of the transportation costs necessary to deliver the production to a downstream market).

¹³¹ *Patterson*, 360 P.3d at 222.

¹³² See *Parry v. Amoco Prod. Co.*, No. 94CV105, 2003 WL 23306663, at *13 (Colo. Dist. Ct. Oct. 6, 2003).

¹³³ See *Pierce*, *Royalty Jurisprudence*, *supra* note 39, at 374–75 (noting that Colorado courts “make it clear that it is lawful, and perfectly permissible, to allow for the deduction of costs downstream from the wellhead — one just has to use the right language”).

¹³⁴ *Rogers*, 29 P.3d at 906.

¹³⁵ See *Abbott & Nieland*, *supra* note 41, § I(B)(4) (“[T]he West Virginia Supreme Court has adopted the most hostile view to the deduction of post-production costs . . .”).

¹³⁶ *Wellman v. Energy Res., Inc.*, 557 S.E.2d 254, 265 (W. Va. 2001). Although *Wellman* purported merely to interpret a proceeds royalty clause, the West Virginia Supreme Court subsequently stated in *Tawney* that its reasoning in *Wellman* would apply equally to a market

even beyond Colorado's version, West Virginia's version of the first marketable product doctrine apparently requires—at least for now—that the lessee calculate its royalty payments at the “point of sale” rather than at the point where its production first becomes marketable.¹³⁷ As the West Virginia Supreme Court has explicitly stated: “[U]nless 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.”¹³⁸

As in all other first marketable states, the parties to an oil and gas lease in West Virginia may contractually agree to allow the lessee to calculate its royalty payments on the basis of the value or price of its production at the wellhead rather than at the point of sale.¹³⁹ Such an agreement, however, requires greater specificity than language stating merely that the lessor will receive a fractional share of the value or price of the lessee's production “at the well” or “at the wellhead.” The West Virginia Supreme Court has declared:

We believe that the “wellhead”-type language at issue is ambiguous. First, the language lacks definiteness. In other

value royalty clause. *Estate of Tawney v. Columbia Nat. Res., L.L.C.*, 633 S.E.2d 22, 28 (W. Va. 2006).

¹³⁷ *Estate of Tawney*, 633 S.E.2d at 28; *Wellman*, 557 S.E.2d at 265; see Kirk, *supra* note 65, at 799 (“This extension of the implied covenant to market seemingly surpasses Colorado's extension of the covenant in *Rogers*. Under *Rogers*, once a product is marketable, the court allowed the deduction of additional costs incurred to improve or transport the product as long as they were reasonable. In contrast, the rule announced in *Tawney* makes no such exceptions for costs incurred after a product is marketable.”); Pierce, *Royalty Jurisprudence*, *supra* note 39, at 369 (“[T]he *Tawney* approach [in West Virginia] is much broader than the *Rogers* approach [in Colorado]”); see also R. Cordell Pierce, Note, *Making a Statement Without Saying a Word: What Implied Covenants “Say” When the Lease is “Silent” on Post-Production Costs*, 107 W. VA. L. REV. 295, 324 (2004).

Significantly, the West Virginia Supreme Court has recently signaled that it may substantially revise its version of the first marketable product doctrine. *Leggett v. EQT Prod. Co.*, 800 S.E.2d 850, 862–63 (W. Va. 2017). The supreme court in *Leggett* pointedly criticized its prior opinions in *Wellman* and *Tawney*, suggesting that its reasoning in those prior opinions stands on “faulty legs.” *Id.* at 862. Nonetheless, the court declined to overrule *Wellman* or *Tawney*. It stated: “[H]owever under-developed or inadequately reasoned this Court observes *Wellman* or *Tawney* to be, the issue presently before the Court simply does not permit intrusion into these issues. We therefore leave for another day the continued vitality and scope of *Wellman* and *Tawney*.” *Id.* at 863.

¹³⁸ *Wellman*, 557 S.E.2d at 265. But see *Leggett*, 800 S.E.2d at 859 n.13 (“[T]he holding articulated in *Wellman* bears little resemblance to the fully-formed marketable product rules adopted by other such states.”).

¹³⁹ *Estate of Tawney*, 633 S.E.2d at 28.

words, it is imprecise. While the language arguably indicates that the royalty is to be calculated at the well or the gas is to be valued at the well, the language does not indicate *how* or *by what method* the royalty is to be calculated or the gas is to be valued. For example, notably absent are any specific provisions pertaining to the marketing, transportation, or processing of the gas. In addition, in light of our traditional rule that lessors are to receive a royalty of the sale price of gas, the general language at issue simply is inadequate to indicate an intent by the parties to agree to a contrary rule—that the lessors are not to receive 1/8 of the sale price but rather 1/8 of the sale price less a proportionate share of deductions for transporting and processing the gas.¹⁴⁰

In short, the first marketable product doctrine—which, at least in West Virginia, is more properly a first “point of sale” doctrine—is the default rule in West Virginia. For the parties to disclaim the default rule, the royalty clause in their oil and gas lease must not only express a contrary intent, but it must specify the precise method by which the lessee will calculate its royalty payments.¹⁴¹

V. INTERPRETATIONAL DILEMMAS

Both the historical rule and the first marketable product doctrine are, at their essence, rules of contract construction: they provide guidance to courts that are seeking to interpret the terms of a royalty clause. Generally, rules of contract interpretation serve as aids to assist courts in their goal of effectuating the intent of the contracting parties.¹⁴² In most states, courts will first and foremost try to enforce the plain terms of a contract as the

¹⁴⁰ *Id.*

¹⁴¹ *See id.*; Abbott & Nieland, *supra* note 41, at § I(B)(4) (“[T]he West Virginia Supreme Court has made clear that no post-production deductions are permitted at any time, even after the gas is in marketable condition, unless, at the very least, the lease expressly permits the deductions. *Tawney* goes one step further, and requires the lease also to include language describing the method by which the deductions are calculated.”).

¹⁴² *E.g.*, *Ruff v. Charter Behavioral Health Sys. of Nw. Ind., Inc.*, 699 N.E.2d 1171, 1176 (Ind. Ct. App. 1998).

contract is written; the rules of contract interpretation assist courts in determining whether terms are in fact plain and unambiguous.¹⁴³

The key difference between the historical rule and the first marketable product doctrine is their respective understanding of the term “at the well.” In historical rule states, the term “at the well” is unambiguous.¹⁴⁴ Indeed, the courts that first invoked the historical rule likely never thought that they were applying a “rule” at all. They probably understood simply that the term “at the well” is not mere surplusage and must mean exactly what it says—that a lessee should calculate its royalty payments on the basis of the price or value of its production at the wellhead, not on the basis of the price or value of its production at some downstream sales location.¹⁴⁵

By comparison, courts in first marketable product states contend that the term “at the well” is either ambiguous or meaningless.¹⁴⁶ Because, in their view, the term “at the well” does not expressly specify the parties’ contractual intent, courts in first marketable product states—following the model in *Tara*—seek to give effect to what they regard as the parties’ implied contractual intent.¹⁴⁷ Relying on the implied covenant to market, they argue that, absent any language more explicit than merely the words “at the well,” the parties to an oil and gas lease would normally anticipate that the lessor is entitled to receive a royalty share of the price or value of the lessee’s production at the point where the lessee’s production is first marketable.¹⁴⁸

One problem that has arisen both with the historical rule and the first marketable product doctrine is that, over time, courts have often tended to regard them less as interpretational aids and more as obligations that the parties may disclaim only if they do so specifically and explicitly.¹⁴⁹ This is particularly true in first marketable product states, which commonly rest their decisions in the idea that the implied covenant to market applies to all

¹⁴³ See *supra* text accompanying notes 67–72.

¹⁴⁴ See *Creson v. Amoco Prod. Co.*, 10 P.3d 853, 857 (N.M. Ct. App. 2000).

¹⁴⁵ See, e.g., *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 231 (5th Cir. 1984); *Atl. Richfield Co. v. State*, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989); *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996).

¹⁴⁶ See, e.g., *Estate of Tawney*, 633 S.E.2d at 28.

¹⁴⁷ See *supra* text accompanying notes 28–31.

¹⁴⁸ *Estate of Tawney*, 633 S.E.2d at 27.

¹⁴⁹ See, e.g., *Potts v. Chesapeake Expl., L.L.C.*, 760 F.3d 470, 474–75 (5th Cir. 2014); *Comm’r of the Gen. Land Office of Tex. v. Sandridge Energy, Inc.*, 454 S.W.3d 603, 612 (Tex. App.—El Paso 2014, pet. denied).

royalty clauses and may require the lessee to market its oil and gas production at a downstream market for the benefit of its lessors.¹⁵⁰ Applying these rules as binding obligations is a patriarchal view of the law of contract: it essentially assumes that courts are better able to draft an oil and lease for the parties than the parties themselves.¹⁵¹

The patriarchal view of the law of contract is what gave rise to *Tara* and its perspective that “market value” does not necessarily mean “market value.”¹⁵² *Tara*, in turn, gave rise to the first marketable product doctrine and its perspective that “at the well” does not necessarily mean “at the well.”¹⁵³

But the patriarchal view of the law of contract is hardly unique to first marketable product states. Even states that follow the historical rule are susceptible to the patriarchal view that they know better than the parties themselves how the parties’ contracts are supposed to work.

A. *The Heritage Dilemma*

In purely economic terms, the historical rule largely favors lessees, while the first marketable product doctrine largely favors lessors and royalty owners. Because oil and gas production typically increases in value as the lessee transports it downstream of the wellhead, a lessor’s royalties will generally be higher if the lessee must calculate them on the basis of the value or price of the lessee’s production at a downstream location rather than at the wellhead.¹⁵⁴ Understandably, sophisticated lessors have sought

¹⁵⁰ See *supra* text accompanying note 97.

¹⁵¹ See David E. Pierce, *Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market*, in 48 PROCEEDINGS OF 48TH ANNUAL ROCKY MOUNTAIN MINERAL LAW INSTITUTE 10-2 (ROCKY MTN. MIN. L. INST., 2002) (“Fundamental freedom of contract concepts require that courts enforce the parties’ contract—not a contract of the court’s making.”); cf. Kramer, *Royalty Interest*, *supra* note 21, at 459 (“[C]ourts sometimes ignore the express language in order to reach results that are deemed to serve other public purposes than freedom of contract.”).

¹⁵² See *supra* text accompanying notes 28–31.

¹⁵³ See *supra* text accompanying notes 105–141.

¹⁵⁴ See Pierce, *Royalty Jurisprudence*, *supra* note 39, at 352 (“From the lessor’s perspective, she can obtain an increased royalty if she can push the royalty calculation point downstream away from the wellhead. The lessor can obtain an even greater royalty if she can force the lessee to carry all the costs associated with obtaining the downstream price.”); see also *supra* text accompanying note 40.

to negotiate royalty clauses that would maximize the royalty payments they receive from their lessees.¹⁵⁵

In an effort to maximize royalty payments to lessors, oil and gas attorneys, and advocacy groups supporting royalty owners, have crafted “anti-deduction” clauses for lessors to request that lessees insert into their oil and gas leases.¹⁵⁶ Many of those anti-deduction clauses contain language like the following: “All royalties paid to the lessor shall be free of all of the costs and expenses related to the exploration, production or marketing of the oil or gas production from the lease, including but not limited to any of the costs of transporting, gathering, processing, compressing, or otherwise treating the oil, gas or other minerals.”¹⁵⁷

The problem with this language is that it incorrectly assumes that the purpose of the historical rule is to permit lessees to deduct post-production costs from royalty payments; to the contrary, the purpose of the historical rule, which arises from “at the well” language in the royalty clause, is to permit lessees to calculate their royalty payments at the wellhead, either by applying the workback methodology or some other methodology.¹⁵⁸ Thus, an oil and gas lease that contains both “at the well” language and anti-deduction language sends mixed signals: “at the well” language suggests that a lessee may calculate its royalty payments on the basis of the value of its oil or gas production at the wellhead, while anti-deduction language suggests that the lessee must calculate its royalty payments on the basis of the value of its oil or gas production after the lessee has invested the post-production costs necessary to market it at a downstream location.

The Texas Supreme Court examined the tension between “at the well” language and anti-deduction language in *Heritage Resources, Inc. v.*

¹⁵⁵ Pierce, *Royalty Jurisprudence*, *supra* note 39, at 352. As Professor Pierce has noted, each of the parties to a royalty clause “will seek to maximize her rights under the relevant contract as the parties compete with one another for their piece of the finite production pie.” *Id.*

¹⁵⁶ Cf. Robert Theriot & Josh Downer, *Our Texas Heritage: The Summer of the No Deductions Clause*, 52 HOUS. LAW. 26, 26 (2014) (“Understandably, royalty owners, hearing the reports of the booming oil and gas industry, often balk when their royalty check comes with an attached list of fees subtracted from their interests, leading many to attempt to contract out of this general rule [the historical rule].”).

¹⁵⁷ See, e.g., *Potts v. Chesapeake Expl., L.L.C.*, 760 F.3d 470, 475 (5th Cir. 2014) (noting that a workback methodology is “nothing more than a method of determining market value at the well in the absence of comparable sales data at or near the wellhead. The value of the gas, and therefore the value of the royalty, was not reduced. . . . A ‘net-back’ method of calculation does not ‘burden’ or reduce the value of the royalty.”).

¹⁵⁸ See *supra* text accompanying notes 73–83.

NationsBank.¹⁵⁹ Each of the parties' leases in *Heritage* contained royalty clauses requiring that the lessee calculate its gas royalty payments on the basis of the market value of its gas production "at the well."¹⁶⁰ Those same royalty clauses included a proviso containing anti-deduction language: "provided, however, there shall be no deductions from the value of Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation, or other matter to market such gas."¹⁶¹ Yet, despite the anti-deduction language in the parties' royalty clauses, the supreme court in *Heritage* agreed that the lessee could calculate its royalty payments by using a workback methodology to determine the market value of its gas production at the wellhead:

We recognize that our construction of the royalty clauses . . . arguably renders the post-production clause unnecessary where gas sales occur off the lease. However, the commonly accepted meaning of the "royalty" and "market value at the well" terms renders the post-production clause in each lease surplusage as a matter of law.

. . . .

Because there is no evidence to support the comparable sales method of computing market value at the well, we use the alternative [workback] method. Under that method, *Heritage* must pay a royalty based on the market value at the point of sale less the reasonable post-production marketing costs.¹⁶²

In a separate concurring opinion which later effectively became the court's plurality opinion,¹⁶³ Justice Priscilla Owen noted:

The concept of "deductions" of marketing costs from the value of the gas is meaningless when gas is valued at the well. Value at the well is already net of reasonable

¹⁵⁹939 S.W.2d 118, 122–23 (Tex. 1996).

¹⁶⁰*Id.* at 120–21.

¹⁶¹*Id.* at 130.

¹⁶²*Id.* at 123.

¹⁶³*Chesapeake Expl., L.L.C. v. Hyder*, 483 S.W.3d 870, 875 & n.25 (Tex. 2016) (noting that Justice Owen's concurring opinion "became the plurality opinion for the Court").

marketing costs. The value of gas “at the well” represents its value in the marketplace at any given point of sale, less the reasonable cost to get the gas to that point of sale, including compression, transportation, and processing costs. Evidence of market value is often comparable sales, as the Court indicates, or value can be proven by the so-called net-back approach, which determines the prevailing market price at a given point and backs out the necessary, reasonable costs between that point and the wellhead. But, regardless of how value is proven in a court of law, logic and economics tell us that there are no marketing costs to “deduct” from value at the wellhead. . . . [P]rohibiting deductions “from the value of Lessor’s royalty” is not the equivalent of directing that value be based on anything other than “market value at the well.”¹⁶⁴

Under the specific facts in *Heritage*, the Texas Supreme Court reached a correct result. The parties’ leases expressly authorized the lessee to calculate its royalty payments on the basis of the market value of its production at the wellhead. The lessee could have used the comparable sales method to determine the market value of its production at the wellhead; but instead, relying on established Texas law, the lessee used a workback methodology to determine the market value of its production at the wellhead.¹⁶⁵ The anti-deduction language in the parties’ leases was therefore irrelevant. The lessee in *Heritage* did not “deduct” post-production costs from its royalty payments. It determined the wellhead

¹⁶⁴ *Heritage*, 939 S.W.2d at 130 (Owen, J., concurring) (citation omitted). Because Texas is a *Vela* state, the result in *Heritage* would have been much different if the parties’ lease had used a different yardstick for royalty calculation and required that the lessee to calculate its royalty payments based on its “gross proceeds” or “amount realized” from the sale of its production, rather than on the “market value” of its production at the wellhead. *See supra* text accompanying notes 24–27; *see also* *Hyder*, 483 S.W.3d at 873; Niravkumar Patel, Comment, *Enhancing Recovery and Royalties: The Flawed Decision in French v. Occidental Permain Ltd. and How Lessors Can Overcome Lease Language Barriers to Prohibit Post-Production Deductions*, 48 TEX. TECH L. REV. 505, 530 (2016) (“Leases with royalty valuation based on gross proceeds or amount realized are more compatible with a no deductions clause.”).

¹⁶⁵ *Heritage*, 939 S.W.2d at 121.

value of its production by working backwards from a downstream sales price.¹⁶⁶

But even a royalty clause requiring that the lessee calculate its royalties at the point of sale, rather than at the wellhead, does not necessarily protect a lessor against a workback methodology. The lessors in *Potts v. Chesapeake Exploration, L.L.C.*, seemingly did everything they possibly could to share in the downstream value of their lessee's production.¹⁶⁷ Unlike the lease in *Heritage* which required that the lessee calculate its royalty payments "at the well," the parties' lease in *Potts* required that the lessee pay a gas royalty of 1/4 of the market value of its gas production "at the point of sale."¹⁶⁸ As in *Heritage*, the parties' lease in *Potts* contained an anti-deduction clause:

Notwithstanding anything to the contrary herein contained,
all royalty paid to Lessor shall be free of all costs and

¹⁶⁶*Id.* at 123; see *Warren v. Chesapeake Expl., L.L.C.*, 759 F.3d 413, 417–18 (5th Cir. 2014); *Yturria v. Kerr-McGee Oil & Gas Onshore, LLC*, 291 F. App'x 626, 632 (5th Cir. 2008) ("[W]e must determine the value of Lessors' royalty before accessing [sic] the impact of the leases' separate 'no deduct' provisions."); *Comm'r of the Gen. Land Office of Tex. v. Sandridge Energy, Inc.*, 454 S.W.3d 603, 611 (Tex. App.—El Paso 2014, pet. denied) (stating that a lease which specifies that the lessee must calculate its royalty payments at the wellhead "effectively nullifies a clause attempting to exempt the royalty from post-production expenses"); see also *supra* text accompanying notes 80–83.

The North Dakota Supreme Court reached the opposite result in *Kittleson v. Grynberg Petroleum Co.*, 876 N.W.2d 443 (N.D. 2016). The royalty clause in the parties' lease required the defendant to pay royalties to the plaintiff on the basis of the market value of the defendant's gas production at the well. *Id.* at 445. At the same time, the royalty clause stated: "provided however, that there shall be no deductions from the value of the Lessor's royalty of any required processing, cost of dehydration, compression, transportation, or other matter to market such gas." *Id.* The court in *Kittleson* stated:

Here, "market value at the well" and "no deductions from the . . . royalty" are in conflict. Under the "at the well" rule, calculating market value using the work-back method allows a lessee to deduct post-production costs from the royalty. The "no deductions" language in the royalty clause, however, specifically prohibits deductions of post-production costs from the royalty. We hold the more specific "no deductions" language qualifies and prevails over "market value at the well." We conclude that under the "no deductions" language of the royalty clause, Grynberg is not allowed to deduct from Kittleson's royalty the post-production costs required to make the gas marketable.

Id. at 447 (alteration in original). The North Dakota Supreme Court in *Kittleson* did not discuss or address the Texas Supreme Court's decision in *Heritage*. See *id.*

¹⁶⁷760 F.3d 470 (5th Cir. 2014).

¹⁶⁸*Id.* at 473.

expenses related to the exploration, production and marketing of oil and gas production from the lease including, but not limited to, costs of compression, dehydration, treatment and transportation.¹⁶⁹

The lessee, Chesapeake, calculated its royalty payments on the basis of 1/4 of the price that it received from selling its gas production to an affiliated company, which bought the gas at the wellhead and paid Chesapeake a weighted average of the affiliate's downstream sales prices for the gas, *minus post-production costs*.¹⁷⁰ Chesapeake argued that its royalty payments were consistent with the terms of the parties' lease because the "point of sale" for its gas production was the wellhead.¹⁷¹

The Fifth Circuit in *Potts* agreed with Chesapeake. Judge Priscilla Owen, the same former Texas Supreme Court justice who had written the concurring opinion in *Heritage*, reasoned:

In this case, the language of the lease . . . make[s] clear that the royalty due the lessors is a percentage of the market value of the gas at the point at which the lessee sells the gas. . . . [H]ad Chesapeake sold the gas at a point downstream from the wellhead, then the royalty would be 1/4 of the market value of the gas at that point. . . . But Chesapeake has sold the gas at the wellhead. That is the point of sale at which market value must be calculated under the terms of the lessors' lease.¹⁷²

¹⁶⁹ *Id.* at 474.

¹⁷⁰ *Id.* at 472.

¹⁷¹ *Id.* at 474.

¹⁷² *Id.* at 476. The Fifth Circuit in *Potts* did not address whether Chesapeake violated the implied covenant to market by selling its gas production to an affiliate. In Texas, the implied covenant to market does not typically forbid a lessee from selling its production to an affiliate where the lessee must calculate its royalty payments based on the market value or market price of its production at the wellhead. *Union Pac. Res. Grp. v. Hankins*, 111 S.W.3d 69, 74 (Tex. 2003). That is because, at least conceptually, the price at which a lessee sells its production to an affiliate should not affect the amount of its royalty payments to its lessors—i.e., its lessors would still be entitled to receive their fractional share of the "market value" or "market price" of the production even if the lessee sold its production for less than market value. *Id.* ("A producer could provide its affiliate with gas at any price it chose, but the royalty owners would be protected because their payment would be 'based on the prevailing market price at the time of sale.'" (quoting *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 372 (Tex. 2001))).

In *Potts* as in *Heritage*, the anti-deduction language in the parties' lease was of no benefit to the lessors. Where the point of sale is in fact the wellhead, there is nothing for the lessee to "deduct" to calculate the value or price of its production at the wellhead: as long as the price that the lessee receives at the wellhead is not artificially deflated and instead legitimately reflects the market value of the production at the wellhead (e.g., based on prevailing wellhead sales prices in the same area), then the lessee may properly calculate its royalty payments on the basis of that price—under either a *Heritage* "market value at the well" royalty clause or a *Potts* "market value at the point of sale" royalty clause.¹⁷³

Such is *not* true, however, if a lessee uses an affiliate sale to bypass an anti-deductions provision in the royalty clause of an oil and gas lease—as Chesapeake arguably did in *Potts*. The implied covenant to market requires that a lessee sell its production in a way that benefits equally both the lessee and its lessors and does not unfairly reduce the lessee's royalty payments to its lessors. See *supra* text accompanying notes 52-53.

Under the facts in *Potts*, Chesapeake arguably violated the implied covenant to market: its sales to its affiliate likely benefited only Chesapeake and unfairly reduced the amount of its royalty payments to its lessors, who reasonably would have expected to receive royalties on the price that Chesapeake could have received from selling its production at a downstream location, with no post-production deductions. See Joyce Colson, *Upstream, Midstream, Downstream—The Valuation of Royalties on Federal Oil and Gas Leases*, 70 U. COLO. L. REV. 563, 569 (1999) ("The concern that develops under this scheme is whether sales to affiliates constitute sham transactions designed to minimize the price upon which royalties are paid or whether such affiliates serve legitimate marketing purposes."); Arthur J. Wright & Carla J. Sharpe, *Direct Gas Sales: Royalty Problems for the Producer*, 46 OKLA. L. REV. 235, 236 (1993) ("[T]he marketing affiliate can be used by the producer to conveniently 'capture costs' of marketing, therefore allowing the producer to deduct costs from the sale proceeds payable to royalty owners and other working interest owners in a specific well."); cf. *Fawcett v. Oil Producers, Inc. of Kan.*, 352 P.3d 1032, 1042 (Kan. 2015) ("We are sensitive to the potential for mischief given an operator's unilateral control over production and marketing decisions. But we believe royalty owners' interests are adequately protected by the operator's implied covenant of good faith and fair dealing and the implied duty to market.").

¹⁷³*Potts*, 760 F.3d at 476. Interestingly, the parties' lease in *Potts* contained a provision stating (i) that the lessee should calculate its royalty payments "based on sales of leased substances to unrelated third parties at prices arrived at through arms length transactions" and (ii) that if the lessee sold its production to any related parties in transactions that were not arms length, then it should determine its royalties "based on prevailing values at the time in the area." *Id.* at 475-76. Without actually addressing any evidence, the Fifth Circuit suggested that this provision had no effect on the outcome of the case because Chesapeake sold its production to its affiliate at prevailing wellhead prices. *Id.* at 476. Presumably, because Texas is a *Vela* state, the Fifth Circuit would have reached a different outcome in *Potts* if (a) the parties' lease had required that the lessee pay a gas royalty of 1/4 of the *proceeds* or *amount realized* at the point of sale and (b) the parties' lease had expressly forbidden the lessee from relying on any affiliate sales to determine

Unfortunately, *Heritage* and its progeny, especially *Potts*, fostered the perception that the historical rule for calculating royalty payments in Texas is an absolute rule of law which lessors can never effectively disclaim.¹⁷⁴ As some royalty owner advocates complained in a Fifth Circuit brief: “It has become too easy for courts to avoid considering explicitly negotiated lease language and simply stamp it as ‘See *Heritage*, *Return to Sender*,’ without opening the envelope.”¹⁷⁵ If an oil and gas lease is truly a contract that reflects a negotiated bargain between consenting parties, then the parties—should they agree to do so—ought to be able to draft an enforceable royalty clause that effectively disclaims the historical rule.

The recent opinion in *Chesapeake Exploration, L.L.C. v. Hyder* confirmed that the parties to an oil and gas lease may effectively disclaim the historical rule if they plainly express the intent to do so.¹⁷⁶ The lease in *Hyder* contained a gas royalty clause specifying that for any gas which the lessee produced from wells on the lease, the lessors would receive the following royalty:

[Lessee covenants and agrees to pay] 25% of the price actually received by Lessee for such gas . . . free and clear of all production and post-production costs and expenses . . . including but not limited to, production, gathering, separating, storing, dehydrating, compressing, transporting, processing, treating, marketing, delivering, or any other costs and expenses incurred between the wellhead and Lessee’s point of delivery or sale of such share to a third party.¹⁷⁷

Additionally, the lease contained an overriding royalty clause specifying that for any gas which the lessee produced from off-lease wells adjacent to or near the lease, the lessors would receive a “perpetual, cost-free (except

the amount that it realized for its production at the point of sale. *See infra* text accompanying notes 176–181; *see also* *Chesapeake Exploration, L.L.C. v. Hyder*, 483 S.W.3d 870, 873 (Tex. 2016).

¹⁷⁴ *See Potts*, 760 F.3d at 474–75.

¹⁷⁵ *Warren v. Chesapeake Expl., L.L.C.*, 759 F.3d 413, 416 (5th Cir. 2014) (quoting from the lessors’ brief).

¹⁷⁶ 483 S.W.3d 870, 876 (Tex. 2016) (“*Heritage Resources* does not suggest, much less hold, that a royalty cannot be made free of postproduction costs. *Heritage Resources* holds only that the effect of a lease is governed by a fair reading of its text.”).

¹⁷⁷ *Id.* at 871 & n.5.

only its portion of production taxes) overriding royalty of five percent (5%) of gross production obtained from each such well.”¹⁷⁸

The Texas Supreme Court in *Hyder* ruled that under each of these royalty clauses, the lessee could not use a workback methodology to calculate its royalty payments.¹⁷⁹ On the gas royalty clause, the supreme court reaffirmed *Vela* and emphasized that a workback methodology is improper under a lease requiring that the lessee calculate its royalty payments on the basis of the price or proceeds that it actually receives for its gas production at a location downstream of the wellhead:

The gas royalty in the lease does not bear postproduction costs because it is based on the price Chesapeake actually receives for the gas through its affiliate, Marketing, after postproduction costs have been paid. Often referred to as a “proceeds lease,” the price-received basis for payment in the lease is sufficient in itself to excuse the lessors from bearing postproduction costs.¹⁸⁰

Significantly, the court in *Hyder* noted that the anti-deduction language in the gas royalty clause was largely irrelevant: “It might be regarded as emphasizing the cost-free nature of the gas royalty, or as surplusage.”¹⁸¹

On the overriding royalty clause at issue in *Hyder*, the supreme court concluded that the term “cost-free,” as the parties used it in the context of that particular royalty clause, barred the lessee from using a workback methodology to calculate its overriding royalty payments.¹⁸² The overriding royalty clause in *Hyder* contained no royalty yardstick expressly requiring the lessee to calculate its royalty payments on the basis of the “market value” of its production;¹⁸³ instead, the clause stated simply that the lessors

¹⁷⁸ *Id.* at 872; see *Chesapeake Expl., L.L.C. v. Hyder*, 427 S.W.3d 472, 474–75, 478 (Tex. App.—San Antonio 2014), *aff’d*, 483 S.W.3d 870 (Tex. 2016).

¹⁷⁹ 483 S.W.3d at 876.

¹⁸⁰ *Id.* at 873; see *id.* at 875 (“The gas royalty does not bear postproduction costs . . . because the amount is based on the price actually received by the lessee, not the market value at the well.”).

¹⁸¹ *Id.* at 873

¹⁸² *Id.* at 875.

¹⁸³ *Id.* at 871–72. The supreme court in *Hyder* did not overrule *Heritage*. If the overriding royalty clause in *Hyder* had specified that the lessors’ override was 5% of the “market value” of the lessee’s production at the well, then the supreme court would likely have reached a different interpretation of the overriding royalty clause. “The market value at the well should equal the

were to receive a cost-free override of 5% of gross production.¹⁸⁴ The supreme court noted that the general term “cost-free,” under its plain and ordinary meaning, “does not distinguish between production and post[-] production costs and thus literally refers to all costs.”¹⁸⁵ Consequently, the court in *Hyder* reasoned that for the lessee to be able to charge the lessor with any part of its post-production costs, the lessee would have to show from other language in the lease that the term “cost-free” did not encompass post-production costs.¹⁸⁶ The lessee was unable to do so. The supreme court stated:

Chesapeake argues that the gas royalty provision shows that when the parties wanted a post[-]production-cost-free royalty, they were much more specific. But as we have already said, the additional detail in the gas royalty provision serves only, if anything, to emphasize its cost-free nature. The simple “cost-free” requirement of the overriding royalty achieves the same end.¹⁸⁷

commercial market value less the processing and transporting expenses that must be paid before the gas reaches the commercial market.” *Id.* at 873.

¹⁸⁴ *Id.* at 871–72.

¹⁸⁵ *Id.* at 874; *see also* Burlington Res. Oil & Gas Co. v. Texas Crude Energy, LLC, 516 S.W.3d 638, 648 (Tex. App.—Corpus Christi 2017, pet. filed). The supreme court in *Hyder* noted that overriding royalty owners usually must bear their proportional share of post-production costs unless the parties “modify this general rule by agreement,” which the court ruled that the parties in *Hyder* did with the words “cost-free.” 483 S.W.3d at 872–73. Ironically, while Oklahoma is a first marketable product state and Texas is not, the Texas opinion in *Hyder* is seemingly more friendly to overriding royalty owners than Oklahoma case law. *See supra* note 118; XAE Corp. v. SMR Prop. Mgmt. Co., 968 P.2d 1201, 1208 (Okla. 1998).

¹⁸⁶ 483 S.W.3d at 876.

¹⁸⁷ *Id.* at 875. Perhaps to counter the concerns that royalty owners had raised after *Heritage* and *Potts*, the supreme court in *Hyder* confirmed that while a lessor’s royalty “usually bears postproduction costs,” the parties to a lease “may agree to a different arrangement.” *Id.* at 873. However, the supreme court’s application of that rule—holding that the term “cost-free” may in itself unambiguously express the parties’ intent to bar the lessee from using a workback method to calculate the value of its gas production—is dubious. As the supreme court recognized in a separate part of its opinion in *Hyder*, the workback method for calculating royalties does not “charge” any costs: it is merely a formula by which a lessee may calculate the price or value of its production at a particular valuation point. *Id.* at 875–76 (quoting *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 120–21 (Tex. 1996) (Owens, J., concurring)). Thus, the fairly generic term “cost-free,” in and of itself, should be equally as much surplusage as was the far more specific anti-deductions clause in *Heritage*. In Justice Jeffrey Brown’s dissenting opinion in *Hyder*, Justice Brown noted that the overriding royalty clause “does not refer to any point of resale

The lesson from *Heritage*, *Potts*, and *Hyder* is simple: the words that the parties use in a royalty clause absolutely matter. At least in *Vela* states, a lease that contains a “market value at the wellhead” royalty clause means something entirely different from a lease that contains a “proceeds” or “amount realized” royalty clause: under a “market value at the wellhead” royalty clause, a lessee may calculate its royalty payments by using the workback method to determine the value of its production at the specified location—the wellhead.¹⁸⁸ And in a lease that contains a “market value at the wellhead” royalty clause, an anti-deductions clause will likely *not* have the effect of barring the lessee from using the workback method to do what the royalty clause expressly allows the lessee to do—calculate its royalty payments based on the value of its production at the wellhead rather than at some unspecified downstream location.

If the parties to an oil and gas lease intend that the lessee should calculate its royalty payments based on the price that the lessee actually receives for its production at a location downstream of the wellhead, then the parties should expressly and unambiguously say so.¹⁸⁹ At a minimum, they should confirm that their lease contains a “proceeds” or “amount realized” royalty clause. To the extent that they desire to further disclaim the historical rule for royalty calculation, they should use plain language that leaves a court, even in a historical rule state, with no option other than to enforce the parties’ lease as written.

B. *The Patterson Dilemma*

The same guiding principle, albeit in reverse, is true for the parties to a lease in a first marketable product state: to the extent that the parties desire to disclaim the first marketable product doctrine, they should use plain language that leaves a court with no option other than to enforce the parties’ lease as written. Generally, in a first marketable product state, the words “at the well” or “at the wellhead” in a royalty clause are insufficient in themselves to ensure that a lessee may use a workback methodology to

downstream. It implicates only one location—the wellhead at which point each directional well produces.” *Id.* at 877 (Brown, J., dissenting). He correctly observed: “As recognized in *Heritage*, royalty clauses that purport to modify a royalty valued at the well are inherently problematic. Here, no post-production costs have been incurred at the time of production, and it means nothing to say the overriding royalty is free of those yet-to-be incurred costs.” *Id.* at 879 (citation omitted).

¹⁸⁸ *Potts v. Chesapeake Expl., L.L.C.*, 760 F.3d 470, 474 (5th Cir. 2014).

¹⁸⁹ See *supra* Section IV.B.

calculate its royalty payments.¹⁹⁰ To disclaim the first marketable product doctrine, the parties to a lease in a first marketable product state must, for all practical purposes, draft and incorporate an “anti-first marketable product doctrine” clause into their lease.

Absent plain language that indisputably disclaims the first marketable product doctrine, the potential costs to the parties—not just the lessee, but also the lessor—may be significant. Those costs, in particular, may include the fees and expenses that will arise if the parties dispute the location at which the lessee’s oil or gas production becomes marketable. In first marketable product states, the location at which a lessee’s production becomes marketable is commonly a question of fact.¹⁹¹ Any dispute over the location at which a lessee’s production becomes marketable will not only require the parties to incur the costs necessary to litigate the dispute, but it also introduces tremendous uncertainty in the lessee’s royalty accounting functions—particularly if different juries reach different results about oil or gas production from the same wells or the same field.¹⁹²

The opinion in *Patterson v. BP America Production Co.* illustrates the dilemma that the parties to an oil and gas lease may encounter if they dispute the location at which the lessee’s production becomes marketable.¹⁹³ The plaintiffs in *Patterson* filed a class action against BP America on behalf of some 4,000 royalty owners.¹⁹⁴ Each of the royalty owners’ leases required that BP America pay gas royalties on the basis of “1/8 of the market value of such gas at the mouth of the well; if said gas is sold by [BP], then as royalty 1/8 of the proceeds of the sale thereof at the mouth of the well.”¹⁹⁵ BP America used a workback methodology to calculate the value of its gas “at the mouth of the well.”¹⁹⁶ After a jury trial in the plaintiffs’ favor, the Colorado Court of Appeals concluded that BP America acted improperly in calculating its royalty payments at the mouth of the well.¹⁹⁷

¹⁹⁰ See *supra* text accompanying notes 105–141.

¹⁹¹ See *supra* text accompanying notes 114, 121 & 131.

¹⁹² Nicole M. Duarte & Krystal P. Scott, *Royalty Wars*, OIL & GAS FIN. J. (Jan. 1, 2014), <http://www.ogfj.com/articles/print/volume-11/issue-1/features/royalty-wars.html>.

¹⁹³ 360 P.3d 211, 222 (Colo. App. 2015).

¹⁹⁴ *Id.* at 215.

¹⁹⁵ *Id.*

¹⁹⁶ *Id.* at 215–16.

¹⁹⁷ *Id.* at 224.

Relying on the case law that developed Colorado's version of the first marketable product doctrine, the court of appeals in *Patterson* stated that where "royalty agreements are silent on the allocation of post-production costs," the lessee "is not permitted to deduct from royalty payments any post-production costs required to make the gas marketable."¹⁹⁸ The court noted: "[T]he determination of who bears the post-production marketability costs when the royalty agreement is silent depends on where the gas is first marketable—more specifically, whether the gas at issue is marketable at the wellhead, and if not, where the first marketable product is obtained."¹⁹⁹ Thus, the court in *Patterson* concluded that BP America could calculate its royalty payments at the mouth of the well only if its gas production was marketable at the wellhead.²⁰⁰

Importantly, the court in *Patterson* emphasized that "the determination of marketability is a question of fact, to be resolved by the fact finder."²⁰¹ The court recited at length the evidence that the plaintiffs and BP America had offered at trial on this "fact" question. The plaintiffs offered the testimony of experts Daniel Reineke and Phyllis Bourque:

- Reineke testified that BP's gas production at the wellhead contained "contaminants" that "needed to be extracted or treated" and, accordingly, that BP consistently treated and processed its gas before selling it.²⁰² He concluded that the first commercial market for BP's gas production was not at the wellhead, but rather at the inlet of the long distance pipelines after BP treated and processed the gas—because "that's where [BP] sold the gas."²⁰³
- Bourque testified that BP's gas was not marketable until it was "in a quality to be accepted by the pipeline."²⁰⁴ Noting that BP consistently sold its gas products after separating out any impurities, Bourque concluded that the first commercial market for BP's gas depended on the specific type of product that BP extracted

¹⁹⁸ *Id.* at 221–22 (citing *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 902–03 (Colo. 2001); *Garman v. Conoco, Inc.*, 886 P.2d 652, 658–59 (Colo. 1994)).

¹⁹⁹ *Patterson*, 360 P.3d at 222.

²⁰⁰ *Id.*

²⁰¹ *Id.*

²⁰² *Id.* at 223.

²⁰³ *Id.*

²⁰⁴ *Id.*

from its gas stream but, regardless, was downstream of the wellhead.²⁰⁵

BP America, in turn, offered the testimony of experts Kyle Pearson and David Posner:

- Pearson testified that BP's gas was sweet gas that contained "relatively low levels" of contaminants.²⁰⁶ Because there were buyers that were willing to buy gas like BP's gas at the wellhead (even if BP itself did not actually sell any gas to those buyers), Pearson concluded that the first location where BP's gas "can be bought and sold is when it can be measured and sampled," which may be done at the wellhead."²⁰⁷
- Posner testified that "there [was] and continues to be an active commercial market for raw gas at the wellhead."²⁰⁸ He noted that at least twenty other operators in the same field in which BP held its leases with the plaintiffs were selling their gas predominantly at the wellhead.²⁰⁹

Besides the testimony of its experts, BP America also offered evidence that it had itself purchased wellhead gas from other operators in the field.²¹⁰ Additionally, as the court in *Patterson* conceded:

BP presented evidence of sales contracts between BP and Panhandle Eastern Pipeline Company . . . demonstrating that BP sold gas to Panhandle at the well. However, Royalty Owners presented contrary testimony that BP only sold specific portions of raw gas to Panhandle and reserved the marketable natural gas liquids for itself, which it thereafter processed, fractioned, and sold elsewhere.²¹¹

The court of appeals in *Patterson* upheld the trial court's judgment in favor of the royalty owners and concluded that the evidence at trial was legally sufficient to support the jury's verdict that BP America had breached its lease agreements by calculating its royalty payments on the

²⁰⁵ *Id.*

²⁰⁶ *Id.*

²⁰⁷ *Id.*

²⁰⁸ *Id.*

²⁰⁹ *Id.*

²¹⁰ *Id.*

²¹¹ *Id.* at 224.

basis of the value of its gas production at the wellhead.²¹² Having already ruled that the point at which BP America's gas production became marketable was a question of fact, the court in *Patterson* noted that it had to view the evidence in the light most favorable to the plaintiff royalty owners.²¹³ The court stated: "[A] reasonable person could believe Royalty Owners' evidence and determine, for the purpose of calculating royalties, that the wellhead was not the first market for gas extracted from the wells. . . ." ²¹⁴

The result in *Patterson* is troubling on several levels. First, the court in *Patterson* appeared to give credence to the testimony of the royalty owners' experts that even if there arguably were a *market* for BP America's gas production at the wellhead, the first *commercial market* for BP America's gas production must necessarily be downstream of the wellhead because "that's where [BP] sold the gas."²¹⁵ In Colorado, however, the first commercial market is not necessarily the place where the lessee actually sells its production; rather, the first commercial market for oil or gas production is the place where the production is first "commercially saleable."²¹⁶ By definition, if arm's length gas purchasers are available and willing to buy a lessee's production at the wellhead (as apparently was the case in *Patterson*), then the lessee's production should be "commercially saleable" at the wellhead.²¹⁷

²¹² *Id.*

²¹³ *Id.*

²¹⁴ *Id.*

²¹⁵ *Id.* at 223 (alteration in original) (internal quotation marks omitted).

²¹⁶ *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 905 (Colo. 2001).

²¹⁷ See Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 109 ("A lessee who can identify an arm's length purchaser for its gas at the wellhead must, by definition, have a marketable product at the wellhead."); Owen L. Anderson, *Royalty Valuation: Calculating Freight in a Marketable-Product Jurisdiction*, 20 ENERGY & MIN. L. INST. § 10.02[2], at 339 n.31 (2000) ("Where there are comparable arm's-length equivalent wellhead sales, the gas is clearly marketable at the wellhead."). The result should be no different even if, as the plaintiffs' experts argued in *Patterson*, the gas contained impurities at the wellhead. The fact that the gas stream may contain impurities does not automatically mean that the lessee has no commercial market for the gas at the wellhead. In determining whether oil or gas is "commercially saleable" at the wellhead, the relevant question is not whether the oil or gas contains impurities or is otherwise less than perfect in quality; rather, the relevant question should simply be whether arm's length purchasers are available and willing to buy the oil or gas at the wellhead. See Lansdown, *supra* note 81, at 705 n.173 (noting that if a party is actually purchasing sour gas at the wellhead, then "it is clearly marketable"); cf. King, *supra* note 71, at 44 (arguing that the "reality is that all natural gas is a marketable product at the well").

Second, the court in *Patterson* appeared to give credence to the testimony of the royalty owners' experts that the first commercial market for BP America's gas production might be the location where it sells the natural gas liquids, or NGLs, that it secures after processing its gas.²¹⁸ Indeed, the court pejoratively asserted that BP America effectively tried to reserve "the marketable natural gas liquids for itself."²¹⁹ NGLs, however, are not a "product" that a producer may simply pluck from the gas like taking feathers from a chicken. A producer may generate NGLs only if its production is "wet"—i.e., the gas contains a large concentration of heavier hydrocarbons.²²⁰ In that event, the producer may *process* its wet gas to generate the NGLs, effectively *manufacturing* the NGLs from the heavier hydrocarbons in the gas stream.²²¹ Even in a first marketable product state, a lessor generally has no right to participate in the profits that a lessee acquires from manufacturing products that did not exist naturally in the gas stream.²²²

²¹⁸ 360 P.3d at 224.

²¹⁹ *Id.*

²²⁰ See HOWARD R. WILLIAMS & CHARLES J. MEYERS, *MANUAL OF OIL AND GAS TERMS* 1151 (16th ed. 2015).

²²¹ See Tooley & Tooley, *supra* note 46, § 21.02, at 21-29 to -30 (discussing the process of processing gas). "Heavier hydrocarbons, such as propane, butane, and pentanes, exist in a gaseous state in the gas stream. Processing the gas to manufacture NGLs changes the physical characteristics of these heavier hydrocarbons." Keeling & Gillespie, *The First Marketable Product Doctrine*, *supra* note 17, at 111. To generate NGLs from wet gas, a processing facility will cool the gas stream and liquify the heavier hydrocarbons into a "raw make." After acquiring the raw make, the processing facility will fractionate the raw make into its components, which it then converts into NGLs. See Tooley & Tooley, *supra* note 46, § 21.02, at 21-29 to -30.

²²² See 3 EUGENE O. KUNTZ, *A TREATISE ON THE LAW OF OIL AND GAS* § 40.5, at 351 (Anderson Publ'g Co. 1989) ("[T]here is a distinction between acts which constitute production and acts which constitute processing or refining of the substance extracted by production."); Anderson, *Part 2*, *supra* note 31, at 653-54 (noting that the extraction of NGLs from wet gas "is a step beyond the exploration and production segment of the industry"). This is why the rule is known as the *first* marketable product doctrine. The *first* marketable product that a lessee produces from an oil or gas well is the oil or gas itself, at least once the lessee places the oil or gas in a condition in which it is marketable to third parties. Any additional products that a lessee may manufacture from the gas stream are *second* or *third* marketable products. See, e.g., *Lomex Corp. v. McBryde*, 696 S.W.2d 200, 203 (Tex. App.—San Antonio 1985, no writ) (holding that a producer had no duty to pay royalties on the value of yellowcake slurry that it manufactured from raw uranium and stating that "the royalty is to be paid out of the oil, gas or other minerals produced and not out of its value after it had been processed into some other product of a higher value").

The lesson from *Patterson* is simple: if an oil and gas lease does not use plain language that leaves a court with no option other than to enforce it as written, then the parties are at risk that a jury or other fact finder, with no oil and gas experience, may interpret the lease for them.²²³ Especially in first marketable product states where marketability is a question of fact, the parties—and lessees in particular—may find that a jury is likely to answer that question based more on whim or fancy than on any guiding principles. As *Patterson* illustrates, courts in first marketable product states will seek to uphold a jury finding that the location at which the lessee’s production first become marketable is downstream of the wellhead, even if that finding may itself push the intellectual boundaries of the first marketable product doctrine.²²⁴

²²³ Cf. *Foster v. Merit Energy Co.*, 282 F.R.D. 541, 549 (W.D. Okla. 2012) (“[L]ease language matters. . .”).

²²⁴ Courts in first marketable product states may seek to justify such a result by arguing that they must construe oil and gas leases in favor of the lessor and against the lessee. *E.g.*, *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 901 (Colo. 2001). This argument is a variation on the *contra proferentem* doctrine, which holds that a court may in some situations construe a contract against the party that drafted it. *See Pierce, supra* note 39, at 363 (noting that the Colorado Supreme Court in *Rogers* presumed that all lessors are unsophisticated and used that presumption “as the predicate for unsheathing contract law’s bluntest of interpretive instruments—the *contra proferentem* rule of construction”). The *contra proferentem* doctrine historically applies only as a matter of last resort—i.e., when a contract is ambiguous and other rules of contract interpretation are insufficient to permit a court to determine the parties’ contractual intent. *E.g.*, *U.S. Fire Ins. Co. v. General Reins. Corp.*, 949 F.2d 569, 573 (2d Cir. 1991); *Moland v. Indus. Claim Appeals Office*, 111 P.3d 507, 510–11 (Colo. App. 2004); *Klapp v. United Ins. Grp. Agency, Inc.*, 663 N.W.2d 447, 455 (Mich. 2003).

The doctrine is no justification for a court automatically to conclude, “Lessor wins, and Lessee loses.” *E.g.*, *In re Aurora Oil & Gas Corp.*, 460 B.R. 470, 481 (Bankr. W.D. Mich. 2011). First, with many oil and gas leases, the lessee is not necessarily the drafting party: with increasing frequency, lessors and their counsel or representatives often either insist on their own lease forms or engage in active negotiations with their lessees to modify forms that otherwise would favor their lessees. *See supra* text accompanying notes 12–14. Second, many lessors are sophisticated parties, and even if the lessee drafted their oil and gas lease, the *contra proferentem* doctrine generally does not apply in favor of sophisticated parties. *See, e.g.*, *Payless Shoesource, Inc. v. Travelers Cos.*, 585 F.3d 1366, 1372 (10th Cir. 2009); *Indus. Risk Insurers v. New Orleans Pub. Serv., Inc.*, 666 F. Supp. 874, 881 (E.D. La. 1987); *FabArc Steel Supply, Inc. v. Composite Constr. Sys., Inc.*, 914 So. 2d 344, 359 (Ala. 2005); *Baxter Int’l, Inc. v. American Guar. & Liab. Ins. Co.*, 861 N.E.2d 263, 268–69 (Ill. App. Ct. 2006); *Kinney v. Capitol-Strauss, Inc.*, 207 N.W.2d 574, 577 (Iowa 1973); *Norcomo Corp. v. Franchi Constr. Co.*, 587 S.W.2d 311, 317 (Mo. App. 1979).

Before entering into an oil and gas lease, any party, whether a lessor or lessee, should ensure that the lease actually says what the party intends it to say.²²⁵ If the parties to an oil and gas lease intend that the lessee may use a workback method to calculate its royalty payments, then the parties should expressly say so. If the parties intend that the historical rule for calculating royalty payments should apply rather than the first marketable product doctrine, then they should expressly say so. In either event, failing to do so could mean that a jury interprets their lease to mean something quite different from what the parties actually intended it to mean.

VI. THE ROYALTY CLAUSE IN THE NEW ERA OF ROYALTY ACCOUNTING

The *Heritage* and *Patterson* dilemmas are the inevitable by-product of a new era of royalty accounting.²²⁶ With the rise of the first marketable product doctrine, lessors and lessees may no longer assume that the language in a form royalty clause—such as the “at the wellhead” language in an old Producer’s 88 lease—will have the same meaning from state to state.²²⁷ The *Heritage* dilemma, which confounds lessors in historical rule states, arises from the *Vela* philosophy that what the parties say in a royalty clause is more important than any extrinsic evidence of what the parties may have actually meant.²²⁸ The *Patterson* dilemma, which confounds lessees in first marketable product states, arises from the *Tara* philosophy

²²⁵ See Kramer, *Royalty Obligation*, *supra* note 9, at 224 (“Perhaps everyone would have been better off and the national forests saved from an onslaught of articles, tomes, and treatises if lease drafters had followed the simple advice given by Professor A.W. Walker, Jr., in 1932: ‘Too much care cannot be devoted to the preparation of a royalty clause in an oil and gas lease.’” (quoting Walker, *supra* note 75, at 291)).

²²⁶ The new era of royalty accounting is no longer quite so new. See Keeling, *supra* note 40, at 20 (discussing the “new era of royalty accounting” as of 2005). As a practical matter, the new era of royalty accounting dawned with the rise of the first marketable product doctrine, which Kansas arguably adopted as early as the 1960s. See *supra* text accompanying note 107–117. Regardless, the *Heritage* and *Patterson* dilemmas illustrate that while the new era of royalty accounting may already have some history, it continues to raise issues that confound both lessors and lessees.

²²⁷ See, e.g., Keeling, *supra* note 40, at 24 (“Producers may no longer assume that they may calculate their royalty payments the same way in each state in which they have production.”); Cordell Pierce, *supra* note 137, at 328 (“[I]t would be wise for oil and gas producers to retire the old ‘Producer’s 88’ and replace it with a lease that clearly and expressly allocates costs.”).

²²⁸ See *supra* text accompanying notes 24–27.

that what the parties meant in a royalty clause is more important than what the parties may have actually said.²²⁹

The parties to an oil and gas lease are free to negotiate the terms of a royalty clause that deviates from the prevailing rule in their state. In historical rule states, the parties may agree to a royalty clause that requires the lessee to calculate its royalty payments on the basis of the price that the lessee receives for its oil or gas production at a downstream sales location.²³⁰ In first marketable product states, the parties may agree to a royalty clause that permits the lessee to calculate its royalty payments on the basis of the value of its oil or gas production at the wellhead, irrespective of the price that the lessee may receive for the production at a downstream sales location.²³¹ But either way, the parties must craft a royalty clause that avoids the *Heritage* or *Patterson* dilemmas and leaves a court with no option other than to enforce the clause as written.

In short, the parties must craft a royalty clause which actually says what they intend it to mean.

A. *From the Lessor's Perspective*

Lessors in historical rule states should presume that, absent any express lease language revising the default historical rule, lessees will calculate royalties on the basis of the value of their oil or gas production at the wellhead.²³² Therefore, if lessors wish to receive royalties on the basis of the enhanced value of the oil or gas production at a downstream location, they will need to negotiate language in the royalty clauses of their leases expressly requiring their lessees to pay royalties on the price that those lessees actually receive on selling the oil or gas at a downstream location—at a minimum, by eliminating any “at the wellhead” language in the royalty clause and by disclaiming the default rule for calculating royalties in historical rule states.

Candidly, the same is no less true even in first marketable product states. Prudent lessors, guarding against the risk that courts in those states might abandon the first marketable product doctrine, would want to ensure that the royalty clauses in their leases expressly require their lessees to

²²⁹ See *supra* text accompanying notes 28–31.

²³⁰ See *supra* text accompanying note 96.

²³¹ See *supra* text accompanying note 104.

²³² See *supra* text accompanying notes 74–75.

calculate their royalty payments on the price that the lessees actually receive after selling their oil or gas at a downstream location.

Of course, there is no perfect “one size fits all” royalty clause form that lessors should use for *all* of their oil and gas leases. A lease in a state that favors lessees, such as Texas, may require different and much more explicit language than a lease in Colorado or West Virginia. A lease in a sour gas field may require different language than a lease in a sweet gas field. But in general, the following language may serve as a model of the various terms that lessors may wish to consider in seeking to maximize their royalty payments under a royalty clause:

For any oil or gas that Lessee produces from the lease, including casinghead gas, condensate, distillate, natural gas, any other gaseous or liquid substance or mineral, or any constituent product contained in the oil or gas that Lessee produces from the lease,²³³ Lessee shall pay Lessor

²³³ Many oil and gas leases have more than one royalty clause—commonly both an oil royalty clause and a gas royalty clause, with different royalty obligations in the two separate clauses. Under most of these leases, the oil royalty clause, unlike the gas royalty clause, contains “in kind” royalty language that gives the lessor the right to receive an actual royalty share of the lessee’s oil production. An “in kind” royalty provision essentially gives the lessor the option to receive its oil royalties in the form of the oil itself, rather than a monetary payment. *See Keeling & Gillespie, The First Marketable Product Doctrine*, *supra* note 17, at 17.

But, while many leases continue to include oil royalty clauses with “in kind” royalty language, “in kind” royalty language is a relic of a past era. “As a practical matter, most royalty owners lack the resources to receive delivery of oil in kind.” O’Neill & Keeling, *supra* note 11, at 6-6. If the lessor has no means to receive and sell its royalty share of the oil production, then any “in kind” royalty language is largely unnecessary, and both the lessor and the lessee should consider removing it from their lease. Under “in kind” royalty language, the lessor effectively owns title to its royalty share of the oil production. *See Keeling & Gillespie, supra* note 17, at 18. A lessor who has no means to receive any oil, however, likely does not want to bear any environmental responsibility for its royalty share of the oil. *See David E. Pierce, Structuring Routine Oil and Gas Transactions to Minimize Environmental Liability*, 33 WASHBURN L.J. 76, 174 (1993). And if the lessor cannot take physical possession of its royalty share of the oil, the lessee likely does not want the potential tort liability, in conversion or negligence, for having to handle and sell the lessor’s share of the oil. *See David E. Pierce, Drafting Royalty Clauses*, 18TH ANNUAL ADVANCED OIL, GAS & MINERAL LAW COURSE, Sept. 21–22, 2000, at 1, 3. If the lessor and lessee agree to remove any “in kind” royalty language from their lease, “the oil royalty clause will be very similar to the gas royalty clause.” *Id.* at 4.

If, for whatever reason, the parties wish to include “in kind” royalty language in their lease, they may want to draft the language to confirm that it applies *only* when the lessor actually takes physical possession of the royalty oil. Such language might state as follows:

royalties on such oil or gas in an amount equal to 25%²³⁴ of the price, free of costs, that Lessee actually receives on selling the oil or gas to an unrelated and unaffiliated third party in an arm's length transaction.²³⁵ In the event that the Lessee sells any of its oil or gas production to an Affiliate, then Lessee shall pay Lessor royalties on such oil or gas in an amount equal to 25% of the price, free of costs, that the Affiliate, or any subsequent Affiliate in the chain of sale, actually receives on the first sale of the oil or gas to an unrelated and unaffiliated third party in an arm's length transaction.²³⁶

The parties agree that Lessee shall pay Lessor royalties not only on the oil or gas that Lessee produces and sells from the lease, but also on any oil or gas that Lessee produces and does not sell from the lease, such as any oil or gas that Lessee may use on the leased premises. For any such oil or

Lessor, at its option, may elect to receive its royalties on Lessee's oil production in kind. In such event, Lessor agrees to receive, and Lessee agrees to deliver free of cost, 25% of the oil that Lessee produces from the lease as Lessor's royalty on Lessee's oil production. To exercise its option to receive its oil royalties in kind, Lessor must notify Lessee in writing both of its intent to take physical possession of its royalty share of the oil and of its specific instructions for taking physical possession of its royalty share of the oil. After Lessee receives this written notification, Lessee will comply with its all of its oil royalty obligations to Lessor by delivering Lessor's share of the oil production to Lessor in accordance with Lessor's instructions.

²³⁴The royalty fraction here, 25%, is an arbitrary number and serves only as an illustration. The size of the royalty fraction is matter of negotiation between the lessor and lessee.

²³⁵Generally, even in historical rule states, a royalty clause specifying that the lessee will pay royalties on the "price" that it receives at the point of sale or the "amount realized" from any sale of its production will bar the lessee from calculating its royalty payments on the basis of the value of its production at the wellhead. *E.g.*, *Chesapeake Expl., L.L.C. v. Hyder*, 483 S.W.3d 870, 873 (Tex. 2016); *see supra* text accompanying notes 180–181.

²³⁶Absent language covering affiliate sales, a creative lessee with multiple affiliates—like *Chesapeake* in *Potts*—could sell its production to an affiliate at the wellhead and argue that it is entitled to calculate its royalty payments on the basis of that wellhead sales price, rather than the price that its affiliate may secure in a downstream arm's length sale to an unaffiliated third party. *See* 760 F.3d 470, 476 (5th Cir. 2014); *see supra* text accompanying notes 172–173. The parties will want to define the term "Affiliate" and specify exactly what constitutes an affiliate sale as opposed to an arm's length sale.

gas that Lessee produces but does not sell from the lease, Lessee shall pay Lessor royalties in an amount equal to 25% of the price, free of costs, that Lessee would actually have received if the Lessee had sold the oil or gas, along with the oil and gas that Lessee produced and sold from the lease, to an unrelated and unaffiliated third party in an arm's length transaction.²³⁷

If the Lessee processes its gas production before selling it to an unrelated and unaffiliated third party in an arm's length transaction, then Lessee shall pay Lessor royalties on all of the products that Lessee may generate or receive from processing the gas, including residue gas and any and all forms of natural gas liquids. The royalties that Lessee shall pay to Lessor on each of those products shall equal to 25% of the price, free of costs, that Lessee actually receives on selling those products to an unrelated and unaffiliated third party in an arm's length transaction. In the event that the Lessee sells any of those products to an Affiliate, then Lessee shall pay Lessor royalties on those products in an amount equal to 25% of the price, free of costs, that the Affiliate, or any subsequent Affiliate in the chain of sale, actually receives on the sale of each product to an unrelated and unaffiliated third party in an arm's length transaction.²³⁸

The parties intend that the Lessor's royalties shall be free and clear of all production and post-production costs and expenses that the Lessee may incur either before or after producing the oil or gas. In calculating Lessor's royalties, the Lessee may not use any form of "workback" or "netback" method of calculating its royalty payments, as the parties specifically intend that the Lessee shall calculate

²³⁷ A lessor generally is not entitled to receive royalties on oil or gas that the lessee uses at the wellhead in the absence of specific language authorizing the lessor to receive those royalties. *See, e.g., Tana Oil & Gas Corp. v. Cernosek*, 188 S.W.3d 354, 362 (Tex. App.—Austin 2006, pet. denied).

²³⁸ If a lessor wishes to receive royalties on NGLs, then as a matter of prudence, the lessor should try to negotiate a specific provision in his lease authorizing him to receive royalties on NGLs. *See supra* text accompanying notes 218–221.

Lessor's royalties on the basis of the actual price that the Lessee receives for its production at the point of sale. In particular, the Lessee may not deduct or subtract from its royalty payments to Lessor any part of Lessee's costs or expenses, including but not limited to any gathering, separating, storing, dehydrating, compressing, transporting, processing, treating, marketing, and delivering costs, or any other costs and expenses that the Lessee may incur from the wellhead to the Lessee's point of sale.²³⁹

Even in a historical rule state, such language is probably sufficient to require the lessee to calculate its royalty payments on the basis of the actual sales price of its production at the downstream point of sale.²⁴⁰

B. From the Lessee's Perspective

Lessees in first marketable product states should presume that, absent any express lease language disclaiming the first marketable product rule, they must calculate their royalty payments consistently with the version of the first marketable product rule that applies to their oil or gas production.²⁴¹ If lessees wish to ensure that their royalty owners pay a share of the lessees' post-production costs, then they will need to negotiate language in the royalty clauses of their leases expressly authorizing them to use a netback methodology for calculating their royalty payments. In first marketable product states, lessees cannot validly expect that "at the wellhead" language in a royalty clause will, in and of itself, permit them to use a netback methodology for calculating their royalty payments.²⁴²

Some commentators have suggested that the parties to an oil and gas lease should remove any "at the wellhead" language from their royalty clauses and instead draft their royalty clauses in the same way that

²³⁹ Any "anti-deductions" clause is probably unnecessary in a lease containing a "proceeds" or "amount realized" royalty clause. *See, e.g., Hyder*, 483 S.W.3d at 873. Nonetheless, even under a proceeds or amount realized royalty clause, a provision which expressly states that the lessee may not use a workback methodology to calculate its royalty payments may be useful to confirm the parties' intent that the lessee must pay royalties on the actual price that it receives for its production at the point of sale, not the value or price of its production at the wellhead.

²⁴⁰ *E.g., id.*

²⁴¹ *See supra* text accompanying notes 100–103.

²⁴² *See supra* text accompanying notes 105–141.

producers often draft sales contracts.²⁴³ Commonly, in long-term contracts for the sale of oil or gas to downstream purchasers, the sales price is tied to a downstream index price: for example, a crude oil contract might require that the purchaser pay the “Flint Hills WTI Purchase Price minus \$1.00”²⁴⁴ or the “Platts Oilgram WTI Cushing Price minus \$1.50”²⁴⁵ for each barrel of oil that a producer produces from a particular well. And certainly, the parties to an oil and gas lease may, if they wish, craft royalty clause language requiring that the lessee calculate its royalty payments on the basis of a downstream index price—e.g., “Lessee shall pay Lessor royalties in an amount equal to 25% of the Platts Oilgram WTI Cushing Price, minus \$1.50 per barrel, in effect as of the date of production for each barrel of oil that Lessee produces from the lease.”

But for a variety of reasons, the parties to an oil and gas lease may *not* want to tie the lessee’s royalty payments to a downstream index price:

- First, an oil and gas lease may potentially outlast the index. If the lessee is successful in producing oil or gas from a lease, the lease may remain in effect for years and even decades. The amount of royalties that the lessee owes to the lessor under such a lease may become unclear if the lease ties that amount to an index that ceases to exist.²⁴⁶
- Second, a lease that ties the amount of royalty payments to a downstream index price is not particularly responsive to changing

²⁴³ See, e.g., Proctor et al., *supra* note 65, at 182–83.

²⁴⁴ Many oil purchasers publish “posted prices”—i.e., prices that they will pay for a specified grade of oil from a particular field. E.g., Royal, *supra* note 23, at 582, n.114. Flint Hills Resources is one of the most prominent companies that posts prices for crude oil. It posts prices for several different fields and types of oil production—e.g., Colorado D-J Basin, North Dakota Light Sweet, Eagle Ford Sour, West Texas/New Mexico Intermediate, etc. See Flint Hills Posted Prices, Feb. 2017, www.fhr.com/products-services/fuels-and-aromatics (last visited Feb. 2, 2017). West Texas/New Mexico Intermediate crude is commonly abbreviated as WTI. Notably, Flint Hills warns that its prices are “subject to deduction without notice for trucking, pipeline gathering, market adjustments, and other related changes on crude oil purchased from leases.” *Id.*

²⁴⁵ *Platts Oilgram* is a daily industry publication that assesses prices for crude oil at various delivery points. *Oilgram Price Report*, PLATTS, <https://www.platts.com/products/oilgram-price-report> (last visited Feb. 2, 2017). Cushing is a downstream oil delivery hub in Oklahoma. Because Cushing is farther downstream than Midland for WTI, the price of WTI at Cushing is usually higher than the price of WTI at Midland.

²⁴⁶ Cf. Proctor et al., *supra* note 65, at 182, n.166 (“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.”).

market conditions. In many sales contracts, the parties will adjust the index price with a modifier—e.g., “minus \$1.50 per barrel”—to reflect the market value of the oil or gas production at a location upstream of the index valuation point. Such a modifier works well enough for sales contracts, which typically remain in effect only for a limited time. However, such a modifier may not work as well for an oil and gas lease: a modifier of “minus \$1.50 per barrel” that is appropriate when the value of WTI at Cushing is \$60.00 a barrel may be much less appropriate when the value of WTI at Cushing rises to \$100.00 a barrel.²⁴⁷

- Third, index prices typically reflect only the value of high quality production, not low quality production. Crude oil, for example, has an ideal weight—or “gravity.”²⁴⁸ Heavier-weight crude oil is generally less desirable, and more expensive to process, than lower-weight crude oil.²⁴⁹ Thus, if a producer is selling heavier-weight crude oil, the parties may agree to a gravity adjustment in the index price to reflect that the oil is lower quality production. At the leasing stage, however, the parties often can only guess as to whether any oil or gas that the lessee ultimately produces from the lease will be of high quality or low quality. A royalty clause tied to a downstream index price may overvalue oil or gas production that turns out to be of low quality.
- Fourth, the fact that a royalty clause ties royalty payments to a downstream index price is no guarantee against litigation over the meaning of the royalty clause. Courts in first marketable product states that have found the historical term “at the well” to be ambiguous are equally as likely to have trouble interpreting royalty clauses that are tied to index prices, especially if those royalty

²⁴⁷ Arguably, a lessee could try to eliminate this problem by insisting on a lower royalty fraction in lieu of using a modifier—for example, by agreeing to pay “20% of the Platts Oilgram WTI Price per barrel” instead of “25% of the Platts Oilgram WTI Price minus \$1.50 per barrel.” Of course, a lessee could do that even under a lease that does not tie the amount of royalties to a downstream index price—for example, by agreeing to pay “20% of the amount realized at the point of sale” instead of “25% of the market value at the well.” Regardless, relying on a lower royalty fraction to reflect the difference between the upstream and downstream value of oil or gas is no less dependent on guesswork than using a modifier to adjust a downstream index price. A five percent reduction in the royalty fraction that is appropriate in 2017 may be inappropriate in 2022 if market conditions dramatically increase transportation or other post-production costs.

²⁴⁸ See Conine, *supra* note 23, at 18–27.

²⁴⁹ *Id.*

clauses contain complex pricing modifiers or gravity adjustments.²⁵⁰

From a lessee's perspective, a better solution may simply be to draft a royalty clause that plainly and unambiguously permits it to use a workback methodology to calculate its royalty payments. The case law, both in historical rule states and in first marketable product states, provides ample guidance for drafting such a clause. The following language may serve as a model of the terms that a lessee might consider in drafting such a clause:

For any oil, gas, or other minerals that Lessee produces from the lease, including casinghead gas, condensate, distillate, natural gas, or any other gaseous or liquid substance or mineral that may exist in the oil or gas stream as produced at the wellhead, Lessee shall pay Lessor royalties on such oil or gas in an amount equal to 25% of the market value of the oil or gas at the "wellhead"—that is, the location where Lessee extracts the oil or gas from the ground.

It is the express intent of the parties that Lessor's royalties shall be based on the market value of Lessee's production in the form and condition of Lessee's raw and unimproved production as it is extracted from the ground at the wellhead. The parties expressly disclaim any intent that Lessor shall receive any royalties on any refined or improved products, including any natural gas liquids that Lessee may generate or manufacture from Lessee's oil or gas production downstream of the wellhead.

Lessee may, at its own option and discretion, calculate the market value of its oil or gas production at the wellhead in one of three ways:

- a. Lessee may determine the market value of the oil or gas on the basis of the actual price, if any, that Lessee receives on selling the oil or gas in an arm's length transaction at or near the wellhead; *or*
- b. Lessee may determine the market value of the oil or gas on the basis of the price that Lessee could have

²⁵⁰ See *supra* text accompanying notes 105–141.

received on selling the oil or gas in an arm's length transaction at or near the wellhead, as determined either (i) by comparable prices that other producers are receiving for wellhead sales of oil or gas production in the same field of production,²⁵¹ or (ii) by an index price, posted price, or other formula mutually agreed to in writing between Lessee and Lessor; *or*

c. Lessee may use a "workback" methodology to calculate the market value of the oil or gas at the wellhead.

In the event that Lessee elects to calculate the market value of its oil or gas production under a "workback" methodology, then Lessor's royalties will be an amount equal to 25% of the price that Lessee—or any of Lessee's affiliates, if Lessee sells its oil or gas production to an affiliate at or near the wellhead²⁵²—receives on selling the oil or gas in an arm's length transaction at a downstream sales location, minus 25% of all post-production costs that Lessee and/or its affiliates may incur from the wellhead to the downstream sales location, including but not limited to any gathering, separating, storing, dehydrating, compressing, transporting, treating, marketing, and delivering costs that Lessee and/or its affiliates may incur in connection with the sale of the oil or gas.²⁵³

²⁵¹Obviously, the parties may define what constitutes a "comparable" sale. See *supra* text accompanying notes 76–77. In this example, comparable sales are wellhead sales in the same field of production. The parties may use different definitions—e.g., wellhead sales "in the same county," or wellhead sales "within a ten mile radius around the Lease."

²⁵²Notwithstanding the Fifth Circuit opinion in *Potts*, it would seem prudent for a lessee to address specifically the possibility that it may sell its production to an affiliate at the wellhead. Otherwise, the lessee risks litigation over whether it complied with its implied covenant to market. See *supra* text accompanying notes 167–173.

²⁵³The list of post-production costs in this example does not include *processing costs*. If a lessee uses the downstream price that it receives for its residue gas as the basis for calculating the market value of its gas production at the wellhead, then it arguably cannot subtract any of its *processing costs* from its workback calculation: the lessee presumably should not "charge" the lessor any share of the processing costs that the lessee incurs to generate NGLs that benefit only the lessee and do not form the basis for any part of the lessee's workback calculation.

If, on the other hand, the parties expressly agree that the lessor will receive royalties on NGLs, then under a workback method of calculating royalties on NGLs, the lessee would be

Lessee has no duty to pay royalties on, and Lessor will not receive royalties on, any oil or gas that Lessee produces but does not sell from the lease, such as any oil or gas that Lessee may use on the leased premises.

Even in a first marketable product state, such language is probably sufficient to permit a lessee to use a workback methodology to calculate its royalty payments on the basis of the value of its oil or gas production at the wellhead.

VII. CONCLUSION

Royalty accounting rules vary from state to state. Some states continue to follow the historical rule, which holds that under a “market value at the well” royalty clause, the lessee may calculate its royalty payments on the basis of the value of its oil and gas production at the wellhead.²⁵⁴ Other states follow various forms of the first marketable product doctrine, which generally holds that a lessee should calculate its royalty payments on the basis of the value of its oil and gas production at the location where it first acquires a marketable product.²⁵⁵

Each of these rules is effectively just a rule of contract construction. Both the historical rule and the first marketable product doctrine seek to instruct the parties to an oil and gas lease on how to interpret common provisions in a royalty clause. But as with any rules of contract construction, the parties to an oil and gas lease may disclaim these rules and contract for a different result.²⁵⁶ Even in a historical rule state, the parties may agree to a downstream royalty valuation point; and even in a first marketable product state, the parties may agree to a wellhead royalty valuation point.

The trick, of course, is to draft a royalty clause that leaves no doubt about the parties’ contractual intent. It is not easy to disclaim either the historical rule or the first marketable product doctrine. An “anti-deductions” clause may not be effective, at least in and of itself, to disclaim the

entitled to subtract the lessor’s proportional share of all of the lessee’s post-production costs, including the lessee’s processing costs, from the price that the lessee receives for the NGLs. In that event, the lessee would want to include *processing costs* in the list of post-production costs that it may subtract from its workback calculation of the value of its production at the wellhead.

²⁵⁴ See *supra* text accompanying notes 73–96.

²⁵⁵ See *supra* text accompanying notes 97–141.

²⁵⁶ See *supra* text accompanying notes 96 & 104.

historical rule in historical rule states.²⁵⁷ Language stating that the lessee may calculate its royalty payments “at the well” may not be effective, at least in and of itself, to disclaim the first marketable product doctrine in first marketable product states.²⁵⁸

The parties to an oil and gas lease must be aware not only of the existence of the historical rule and the first marketable product rule, but also of the case law discussing the boundaries of these rules. The case law discussing these rules may raise interpretational “dilemmas”—such as the *Heritage* dilemma or the *Patterson* dilemma—for lessors and lessees negotiating and drafting an oil and gas royalty clause.²⁵⁹ The key is for the parties to take care to ensure that their lease expressly says what they intend it to mean.

²⁵⁷ See *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 123 (Tex. 1996); see also *supra* text accompanying notes 154–166.

²⁵⁸ See *Estate of Tawney v. Columbia Nat. Res., L.L.C.*, 633 S.E.2d 22, 28 (W. Va. 2006); see also *supra* text accompanying notes 133–134.

²⁵⁹ See *supra* text accompanying notes 154–225.