Chapter 12
Market Value Royalties—Yesterday, Today and Tomorrow
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§ 12.01. Why this Topic? Aren’t the Issues Behind Us?

During the pre-NGPA era of gas sales pursuant to long-term contract dedications and bifurcated markets with unregulated intrastate prices frequently at substantial premiums over Natural Gas Act\(^1\) regulated interstate prices, disputes arose over whether royalties under market value royalty leases were to be governed by the terms of the lessee’s long-term gas sales contract with prices substantially below current market prices or, by some higher value, representative of the current market. This resulted in a split among jurisdictions on that issue.

Subsequent to the gas market structure that existed at the time of these decisions, natural gas markets and natural gas marketing changed substantially. The former paradigm no longer exists. The Natural Gas Policy Act in 1978\(^2\) ushered in a hodgepodge of multi-tiered pricing, and in some cases, free market pricing. There followed an early-on substantial fly-up in unregulated prices and to a lesser extent, in regulated prices, to be succeeded by a free-fall of gas prices in the mid-1980s, and the complete deregulation of gas prices effective January 1, 1993.\(^3\) In the meantime initiatives of the FERC, pursuant to FERC Order 436 in 1985 and Order 636 in 1992, and a policy fostering the spin-down and spin-off of gas gathering systems previously owned and regulated as a part of interstate pipeline facilities completely restructured the natural gas market. This resulted in the prevalence of spot market and short-term gas sales, price indices and the pricing of gas based thereon. Further, the marketing of gas at locations distant from the wellhead as a response to FERC’s open access and unbundling initiatives has revealed previously invisible post-wellhead costs that enhance the value of the gas—costs that producers quite naturally assert should not be royalty bearing, thus adding another

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dimension to market value determinations. This chapter begins with the
issues that arose and the case law decisions made under a gas marketing
structure from a different era, and considers whether and to what extent
those same decisions are applicable today in the new market environment.
Further, that new market environment presents other issues that did not
previously exist.

§ 12.02. Some Basics.


This chapter is concerned with a species of royalty clause that is found
in the oil and gas lease.

It does not deal with the so-called stand-alone royalty interest.

4 Market value and market value royalty clauses have been addressed in a number of
papers over the years, usually as a part of a broader discussion about royalty issues. A
representative, but by no means exhaustive, list is: Robert B. Allen, “Royalty
Administration in Volatile Energy Markets,” 23 Energy & Min. L. Inst. ch. 7 (2002);
Owen L. Anderson, “Royalty Valuation: Should Royalty Obligations be Determined
Intrinsically, Theoretically, or Realistically, Part 2,” 37 Nat. Resources J. 611 (1997);
Ashabranner, “The Oil and Gas Lease Royalty Clause – One-Eighth of What?,” 20 Rocky
Mt. Min. L. Inst. 163 (1975); Earl A. Brown, “Royalty Clauses in Oil and Gas Leases:
Their Nature, Construction and Remedies for Breach Thereof,” 16 Oil & Gas Inst.
(Sw. Legal Fdn. 1965); Fischl, “Ascertaining the Value or Price of Gas for Purposes of
the Royalty Clause,” 21 Okla. L. Rev. 22 (1968); Hardwick and Hayes, “Gas Royalty
Issues Arising From Direct Gas Marketing,” 43 Oil & Gas Inst. ch. 11 (Sw. Legal Fdn.
1992); Hardwick and Hayes, “Gas Marketing Royalty Issues in the 1990’s, Paper No. 2,”
Special Institute on Oil & Gas Royalties on Non-Federal Lands (Rocky Mt. Min. L. Fdn.
1993); Bruce Kramer, “Interpreting the Royalty Obligation by Looking at the Express
Interest In the United States: Not Cut From the Same Cloth,” 29 Tulsa L.J. 449 (1994);
John S. Lowe, “Defining the Royalty Obligation,” 49 SMU L. Rev. 223 (1996); Richard
C. Maxwell, “Oil and Gas Royalties – A Percentage of What?,” 34 Rocky Mt. Min. L.
Inst. ch. 15 (1988); Daniel M. McClure, “Royalty Valuation and Payment Issues: Where
Are We and Where Are We Headed?,” 48 Rocky Mt. Min. L. Inst. ch. 11 (2002); Joseph
(Sw. Legal Fdn. 1974); David E. Pierce, “Royalty Calculation in a Restructured Gas
Market,” 13 Eastern Min. L. Inst. ch. 18 (1992); Kevin L. Sykes, “The Royalty Clause, A
Guide for the Commoner,” 11 Eastern Min. L. Inst. ch. 22 (1990). See also, Kramer and
Martin, Williams & Meyers Oil & Gas Law § 650.2; E. Kuntz, The Law of Oil and Gas,
§ 40.4 (1989).
It is commonly said that the lessee’s royalty obligation will be governed largely by the royalty clause of the underlying oil and gas lease, although as we shall see, in some jurisdictions and in some contexts, the “plain meaning” of the royalty clause has been downplayed to other considerations. Royalty clauses commonly encountered contain wide differences in language. However, for purposes of this chapter, royalty clauses will be divided into two types: dependent or compensation-based clauses; that is, clauses under which the lessee’s royalty obligation is expressed in terms of the compensation which the lessee receives in marketing the gas. Such clauses are typically framed in terms of a fraction or percentage of the proceeds the lessee receives from the sale of production.


It is said that under a proceeds clause the basis for accounting is clear, the clause is not ambiguous, there is no room for construction and “. . . proceeds ordinarily refer to the money obtained by an actual sale” with the result that, under a one-eighth (1/8) royalty clause, “for every dollar the lessor receives, the lessee receives seven.” Waechter v. Amoco Prod. Co., 537 P.2d 228 (Kan. 1975). Of course, such statements do not address the issue of the effect on proper royalty payments under a proceeds royalty clause when the sale is made at a location other than at the well and post-production costs are incurred by the lessee in making the sale.
The second type is independent or value-based clauses; that is, clauses under which the lessee’s royalty obligation is based upon a value determined independently of the compensation received by the lessee for the sale of gas. The most frequently encountered are those requiring that the lessee pay lessor a stipulated fraction or percentage of the market value of the gas and those stipulating a fraction or percentage of the market price of the gas. A variant of the market value clause is the so-called two-pronged clause under which the lessor’s royalty is stipulated to be a fraction or percentage of proceeds when the gas is sold at the well, but if the gas is not sold at the well, then a fraction or percentage of the market value at the well when the gas is marketed off the lease.8


It is important to note the fundamental difference between royalties on oil and royalties on gas as pertains to the lessor’s ownership rights in the product itself. Under the typical oil royalty clause—requiring lessee to deliver to the lessor a stipulated share of oil produced and saved—the lessor has actual ownership of the stipulated share of oil produced as personal property.9 In sharp contrast with the oil royalty clause, the gas royalty clause typically provides for “payment to the lessor” of a share of proceeds of the gas produced and sold or of the market value or market price of the gas produced. As a consequence, the lessor has fundamentally different rights with respect to the produced gas:

It is well settled that the provision concerning the payment for gas operates to divest the lessor of his right to obtain title in himself by reduction to possession and that therefore his claim must be based upon the contract with the one to whom he has granted that right. His claim can only be for a payment in money and not for the product itself.10

8 Id.
This important distinction between the ownership in-kind of royalty on oil and a mere right to a money payment for royalty on gas is ignored in simple definitions which define royalty as “the landowner’s share of production, free of expenses of production.”11 A landowner owns no share of gas production under the typical gas royalty clause. As will later be asserted, the failure to recognize the fundamental difference between royalty on oil and royalty on gas and that the lessor’s right is simply one to payment of money has contributed to some courts’ improper interpretation of the requirements of the royalty clause and the proper calculation of the lessor’s royalty on gas sold at distant markets.


As mentioned, market-based royalty clauses are of two general types, market value and market price. Although some cases and commentators have treated “market price” and “market value” as functionally the same, other cases have recognized a difference. This writer believes the difference is still relevant in some situations and should be followed.12

“Market price” means . . . the price actually given in current market dealings . . . The actual price at which a given commodity is currently sold, or has recently been sold, in the open market, that is, not in a forced sale, but in the usual and ordinary course of trade and competition, between the sellers and buyers equally free to bargain, as established by records of late sales.13

“Market value” on the other hand:

. . . is defined as the price property would bring when it is offered for sale by one who desires, but is not obligated to sell, and is bought by one who is under no necessity of buying it . . . To

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11 8 Williams & Meyers, Oil and Gas Law.
12 I read Professor Kramer as recognizing a distinction. See discussion, Kramer, supra, note 5, Part IV, 35 Tex. Tech. L. Rev. at 241-245.
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determine the market value of gas, the gas should be valued as though it is free and available for sale. 14

Other cases have distinguished market price from market value. Market price is the price that is actually paid by buyers for the same commodity in the same market. It is not necessarily the same as “market value” or “fair market value” or “reasonable worth”. Price can only be proved by actual transactions. Value or worth, which is often resorted to when there is no market price provable, may be a matter of opinion. There may be wide difference between them. The first inquiry here must be whether there was a market price. All the witnesses say that gas like this was bought at the mouth of the well continually in this field. A market price therefore existed and was admittedly proven by actual sales. Opinions and estimates, and particularly consideration of what the buyers could have paid or should have paid, are entirely irrelevant. 15

Professor Hemingway argues for a distinction between “market price” and “market value.” 16 Hemingway states of “market price”:

Price can only be proved by actual transactions, if such exist. It is not based upon market value, fair market value, or reasonable worth. Price relates to actual sales; value or worth relates to opinion. 17

Of “market value,” Professor Hemingway states:

[V]alue is distinguishable from price. The price of a product may or may not reflect the intrinsic value of it. It also may be that a

15 Shamrock Oil & Gas Corp. v. Coffee, 140 F.2d 409, 410-411 (5th Cir. 1944), cert. den’d, 323 U.S. 737 (1944).
17 Hemingway, supra note 16 § 7.4(B) at 376.
product may have different values for differing uses, but only one market. Generally, value is established by opinion evidence concerned with comparable sales and intrinsic uses of the product or like products.  

If, as asserted by the above authorities, market price can only be proven by actual sales, then how is royalty to be determined if there are no actual third party arm’s-length sales? In those cases, courts have fallen back on market value as a substitute. The fallback to market value allows the introduction of opinion evidence to establish that value, evidence that would not be allowed if there were actual sales from which a market price could be determined.


Market value is a question of fact usually proved by the testimony of experts and other evidence presented at trial. It is said that market value—the price a willing buyer would pay a willing seller—may be proven by any competent evidence. In determining market value, “the law looks not to the particular transaction, but to the theoretical one between the supposed free seller vis-à-vis the contemporary free buyer dealing freely at arm’s-length supposedly in relation to property which neither will ever own, buy or sell.”

Professor Kramer suggests a three-tiered hierarchy of methodologies to determine market value:

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18 Hemingway, supra note 16 § 7.4(C) at 378.
19 See Cimarron Utilities Co. v. Safranko, 101 P.2d 258 (Okla. 1940); Arkansas Natural Gas Co. v. Sartor, 78 F.2d 924 (5th Cir. 1935). See also, Shamrock, 140 F.2d, at 411 n.1.
20 The purpose of this chapter is served by recognizing the potential difference between market value and market price royalty clauses. It is not its purpose to dwell in depth on those issues, but to serve as a segue to market value issues today. The reader is referred to Professor Kramer’s detailed analysis of market value, market price and amount realized in his discussion cited above at note 5.
The best evidence of market value is the price at which the commodity is sold in an arm’s-length transaction at the point of valuation. These sales must be contemporaneous with the time of valuation. This presented points of litigation and market value litigation prior to deregulation of a gas market.

If there is no actual sale at the time and point of valuation, the next best valuation methodology is the use of comparable sales.

Where there are no comparable sales sufficient to determine market value, the third methodology—described as the least desirable—is the net-back or work-back method whereby the value at the point of valuation is determined by taking the down-stream sales price and deducting from it costs incurred by the lessee to move the gas from the point of valuation to the point of sale.

However, case authorities generally state only two. The first, the use of comparable sales. The second, the work-back method, with work-back to be utilized only when there are no or insufficient comparable sales to determine market value. The writer believes the two-tiered categorization is the correct one. However, in this debate we must not lose sight of the goal—to determine what a willing buyer would pay a willing seller. “In determining market value at the well, the point is to determine the price a reasonable buyer would have paid for the gas at the well when produced.”

Comparable sales are merely evidence bearing on that question. Comparable sales are not themselves the goal. My concern about Professor Kramer’s three-tiered approach is that it might (depending on how it is applied) exclude other sales occurring somewhere other than “at the point of valuation.” As I later explain, in today’s restructured gas market other sales (often represented by index pricing) can evidence what a willing buyer would pay a willing seller.

24 Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 238-239 (5th Cir. 1984); on remand, 905 F.2d 840 (5th Cir. 1990).
25 In laying the groundwork for today’s market value issues, the author’s analysis of market value and determining market value in the historical context does not purport to
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[5] — What Are Comparable Sales?

Historically, comparable sales played a major role in determining the market value of natural gas. However, authorities did not completely agree on what constituted comparable sales. Kansas stated simply that:

To be comparable the sales must be of similar or under substantially similar conditions. Comparability is a question of fact which will most often be proven by expert testimony.26

Market value litigation prior to the NGPA saw disputes over whether the price of gas not regulated under the Natural Gas Act could be used to establish the market value for gas that had been committed to the interstate market and was therefore price regulated. The view in Kansas was that the royalty owner could offer evidence of the higher intrastate unregulated price to establish the market value of price regulated interstate committed gas.27

Texas stated comparability more narrowly than Kansas:

Comparable sales of gas are those comparable in time, quality, and availability of marketing outlets . . .

Sales comparable in time occur under contracts executed contemporaneously with the sale of the gas in question. Sales comparable in quality are those of similar physical property, such as sweet, sour or casinghead gas. Quality also involves the legal characteristics of the gas; that is, whether it is sold in a regulated or unregulated market, or in one particular category of a regulated market. Sales comparable in quantity are those of similar volumes to the gas in question. To be comparable, the sales must be made from an area with market outlets similar to the gas in question.

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26 See Holmes v. Kewanee Oil Co., 664 P.2d at 1341-42.
Gas from fields with outlets to interstate markets only, for instance, would not be comparable to gas with a field with outlets only to the intrastate market.\(^{28}\)

Thus, unlike Kansas, which rejected the legal characteristics of the gas (whether sold in a regulated or unregulated market and the distinction between interstate and intrastate sales) as a comparability factor, Texas reached a different result, holding gas sales in the intrastate market were not comparable to those in the interstate market.\(^ {29}\)

\section*{\S~12.03. The Effect of Long-Term Contracts on Market Value or Market Price.}

Historically (pre-1980s), natural gas was most commonly sold at the well to interstate or intrastate pipelines under long-term (15-year, 20-year or life-of-lease) contracts. Regulations applicable to interstate gas sales prohibited favored nations, price renegotiation, price redetermination, and other indefinite pricing clauses that would have permitted prices to track currently obtainable market prices.\(^ {30}\) As a result, contract prices in regulated sales escalated in small increments which, with the rapid price increases that occurred in the non-regulated intrastate market in the 1960s and 1970s, resulted in contract prices for regulated gas considerably below prices currently obtainable for non-regulated gas. Litigation ensued over whether royalty under market value and market price leases was payable on contract price or the higher current market price. Two views developed.

[1] — Majority View—Read the Words—They Mean What They Say!

Under the majority view, the courts ruled that market value and market price were to be determined independently of the contract price being paid to the lessee under the lessee’s gas sale contract. These states were

\begin{footnotesize}
\begin{enumerate}
\item See Exxon Corp. v. Middleton, 613 S.W.2d 246-7.
\item See Superior Oil Co. v. Federal Power Comm’n, 322 F.2d 601 (9th Cir. 1963).
\end{enumerate}
\end{footnotesize}
represented by Texas,\textsuperscript{31} Kansas,\textsuperscript{32} Montana,\textsuperscript{33} Mississippi\textsuperscript{34} and West Virginia.\textsuperscript{35} Thus, in each of these states gas producers, selling under long-term contracts at prices that with the passage of time did not keep pace with prices that could be currently obtained, were faced with paying an ever-increasing share of total revenues received in their gas sales to the royalty owner to comply with market value royalty obligations.


In a minority of states, the courts were sympathetic to the producer’s plight, caught between the market realities of purchasers’ insistence upon long term contracts and the likelihood that even with unregulated intrastate sales, pricing provisions would not keep pace with rapidly escalating gas prices. Oklahoma and Arkansas fell into this category, as did some, but not all, decisions in Louisiana.

[a] — Oklahoma.

In the context of marketing under a long-term gas sale contract, Oklahoma held that in certain circumstances “market price” would be determined by the price received under an arm’s-length contract between the royalty owner’s lessee and an unaffiliated purchaser, even though during the life of the contract, the contract price and the price the gas would bring on the open market free of that contract might diverge substantially. \textit{Tara Petroleum Corp. v. Hughey}\textsuperscript{36} involved a “market price” royalty clause. In \textit{Tara}, the court acknowledged that the lessee was under a duty to market the gas and (at least at the time of that decision) that duty “frequently” required gas be sold under a long-term contract. The court

\begin{itemize}
\item \textsuperscript{31} Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866; Exxon Corp. v. Middleton, 613 S.W.2d 246., note 6.
\item \textsuperscript{32} See Lightcap v. Mobil Oil Corp., 562 P.2d 1.
\item \textsuperscript{33} Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978).
\item \textsuperscript{34} See Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225.
\item \textsuperscript{35} Imperial Colliery Co. v. OXY USA INC., 912 F.2d 696 (4th Cir. 1990).
\item \textsuperscript{36} Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981).
\end{itemize}
reasoned that when lessor and lessee negotiated the lease, they recognized this marketplace necessity that then existed. Expressing a concern that an interpretation requiring royalty to be paid on a “current” price would result in the lessor taking an “ever larger and larger proportion of the producer’s revenues,”\textsuperscript{37} the court concluded, as a matter of interpretation, that the parties to the lease could not have contemplated such a result. From this, the court adopted the rule:

That when a producer’s lease calls for royalty on gas based on the market price at the well and the producer enters into an arm’s-length, good faith purchase contract with the best price and terms available to the producer at the time, that price is the “market price” and will discharge the producer’s gas royalty obligation.\textsuperscript{38}

The \textit{Tara} court placed two critical limitations on its holding. First, the contract must be at arm’s-length and, thus, the decision would not apply to the sales between affiliates. Second, the court expressly limited its decision to “market price” royalty clauses and excluded market value royalty clauses.\textsuperscript{39} However, this limitation seems to have become “lost” with the passage of time. In \textit{Wood v. TXO Prod. Corp.},\textsuperscript{40} the court stated that “in Oklahoma, we have equated the gas purchase contract price with the market value,” citing \textit{Tara}. However, \textit{Wood} did not deal with the issue quoted, but whether compression costs incurred by the lessee were deductible in determining the lessor’s royalty. Subsequently, in \textit{TXO Prod.}

\textsuperscript{37} \textit{Id.} at 1273.

\textsuperscript{38} \textit{Id.}

\textsuperscript{39} \textit{Id.} at 1272, fn. 3. Professor Kuntz recognized this limitation when he noted that \textit{Tara} was “restricted to the effect of a ‘market price’ royalty clause.” 3 Kuntz, \textit{The Law of Oil and Gas}, § 40.4. p. 331. The late Pete Woodruff, in his discussion notes of the \textit{Tara} decision in the \textit{Oil and Gas Reporter}, after stating that \textit{Tara} is welcome news, noted “however, that \textit{Tara} is expressly limited to ‘market price’ leases; and uncertainty still exists in Oklahoma with respect particularly to ‘market value’ leases, among others.” 71 \textit{O&GR} at 397-98. Finally, this limitation was recognized in \textit{Teel v. Public Service Co. of Oklahoma}, 767 P.2d 391 (Okla. 1985), where the court stated “\textit{Tara} was specifically limited to a market price gas royalty clause.” \textit{Id.} at 398.

\textsuperscript{40} \textit{Wood v. TXO Prod. Corp.}, 854 P.2d 880, 882 (Okla. 1992).
v. State, ex rel., Comm’rs of the Land Office, the court again made the same statement but merely quoted from its Wood decision. In TXO Prod., the issue was also deductibility of post-production costs in determining royalty. Finally, in Mittelstaedt v. Santa Fe Minerals, Inc., the court again stated that it had previously equated “market value” with the gas purchase contract price. Like Wood and TXO Prod., the issue in Mittelstaedt was deductibility of post-production costs. Thus, the Oklahoma Supreme Court has not, by an opinion directly addressing the issue and applying the same sort of rigorous analysis to the matter as it did in Tara, consciously lifted the self-imposed limitation on its Tara holding.

[b] — Arkansas.

In Hillard v. Stephens, the Arkansas court also followed Tara for a lease providing for royalty based on “prevailing market price.” In Hillard, the court reviewed and quoted at length from the reasoning of Tara and essentially adopted it as Arkansas law. As such, Hillard adds little to jurisprudence on the issue.


The Louisiana decisions are in conflict. In 1934, Wall v. United Gas Public Service Co. had indicated that market price was to be determined

43 One may speculate as to why the court expressly limited its holding to “market price” royalty clauses. Its footnote expressing the limitation cites to Professor Hemingway, supra, note 16, § 7.4(B). Professor Hemingway was an advocate for a distinction between market price and market value leases. Further basis may lie in the court’s citation to Fischl, “Ascertaining the Value or Price of Gas for Purposes of the Royalty Clause,” 21 Okla. L. Rev. 22, 29 (1968), wherein Fischl advocates an interpretation for market price royalty clauses (but not market value royalty clauses) almost word for word the rule subsequently adopted by the Tara court.
by current transactions. In *Henry v. Ballard & Cordell Corp.*,46 the court rejected *Vela* and held that “market value” was to be computed on the basis of the price received for the gas under a sales contract entered into before federal price regulation. It did so in view of “the accepted universal practice of marketing [gas] under long-term gas sale contracts” as the background against which the leases were executed. The court also relied upon the “custom of the industry” of paying royalty on amounts received under long-term contracts. However, subsequently in *Shell Oil Co. v. Williams, Inc.*,47 the court held that “market value” meant current market value. There the gas sold was subject to a federally regulated price. To determine marketability, the court adopted the view stated in *Middleton* that quality comparability involved the legal characteristics of the gas—whether it is sold in a regulated or unregulated market, or any particular category of a regulated market. Under *Shell*, intrastate markets and interstate markets were not comparable.48 Later, in *Louisiana Land & Exploration Co. v. Texaco*,49 Texaco was held to have properly paid royalties where payment was based upon the maximum lawful price for the highest NGPA category for the gas in question, and the leases at issue variously required royalties to be paid based upon “a fair and reasonable price at the well,” a “reasonable value” but no less than “market value” in the field, a “fair and reasonable value” but not less than the “highest selling price” under certain types of contracts in a stated geographic area, or upon “value at the well.” Subsequently, in *Texaco, Inc. v. Duhé*,50 the court concluded that “Louisiana law restricts the value of natural gas royalties to actual sale prices, even when federal price controls govern.”51

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46 *Henry v. Ballard & Cordell Corp.*, 418 So. 2d 1334 (La. 1982).
47 *Shell Oil Co. v. Williams, Inc.*, 428 So. 2d 798 (La. 1983).
48 Professors Kramer and Martin would appear to reconcile these holdings on the basis that *Henry* dealt with older leases that predated the federal regulation of natural gas. Kramer & Martin, *Williams & Meyers Oil & Gas Law*, § 650.4, p. 650.23.
49 *Louisiana Land & Exploration Co. v. Texaco*, 491 So. 2d 363 (La. 1986).
50 *Texaco, Inc. v. Duhé*, 274 F.3d 911 (5th Cir. 2001).
51 *Id.* at 915.


When the historical model applied to gas marketing and interstate and large intrastate transmission pipelines operated as merchant pipelines, the producer’s sale was made on a bundled service basis. The pipeline laid its pipes to the well, took title there to the purchased gas and performed not only long-distance transportation, but also gathering, compression and often dehydration services. These discrete services were not apparent in the undifferentiated price the pipeline paid for the gas.

This historical model began to change in the mid-1980s as a result of actions by the FERC. In 1985, FERC Order 436 required that all pipelines provide open access transportation to all shippers on a nondiscriminatory basis. FERC Order 436 completely restructured the natural gas industry and began changing the role of pipelines from that of gas merchant to that of gas transporter. Subsequently, in 1992, FERC Order 636 mandated the “ unbundling ” of the pipelines’ various sales and transportation functions and other services and further implemented the open access transportation policies initiated by Order 436. At about the same time FERC was implementing unbundling, a series of FERC orders in the first half of the 1990s began permitting pipelines to divest of their gathering facilities. As a consequence, the divested facilities became free from

53 See United Distribution Cos. v. FERC, 88 F.3d 1105, 1122 (D.C. Cir. 1996).
55 See, e.g., Williams Natural Gas Co., 67 FERC ¶ 61, 252 (1994); Superior Offshore Pipeline Co., 67 FERC ¶ 61, 253 (1994); Amerada Hess Corp., 67 FERC ¶ 21,254 (1994);
regulation under the Natural Gas Act. Further, these gathering facilities, formerly constituting a part of an interstate pipeline’s seamless service from wellhead purchase to city gate delivery, became owned by separate business entities whose function was primarily to furnish gathering service and often related compression and dehydration.\(^{56}\) As a consequence of FERC initiatives, today producers with access to interstate and major intrastate pipelines may sell gas, ultimate users may purchase gas, and intermediaries may buy and resell gas at points of sale anywhere from the wellhead to burner tip. Further, transmission pipelines have ceased to be gas merchants and have become strictly transporters. A producer’s access to such a transmission pipeline will most commonly involve gathering by an entity performing unregulated gathering services.\(^{57}\) As a consequence of unbundling, there are different firms providing different services formerly offered by the pipeline’s bundled service, such as gathering, compression, dehydration, treating, processing and storage.

In this restructured gas market, wellhead sales continue, but often sales take place at market hubs or pipeline interconnects as offering a wider choice of markets and the benefits of aggregation.\(^{58}\) As a

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\(^{56}\) The divestiture of a pipeline’s gathering facilities to an entity related to the pipeline is commonly referred to as a “spin down.” A divestiture of facilities to an entity unrelated to the divesting pipeline is commonly referred to as a “spin off.”

\(^{57}\) Since gathering is free from FERC jurisdiction under § 1(b) of the Natural Gas Act, some states have enacted regulations to fill the void. See Okla. Stat. tit. 52, §§ 24.4-24.5; Kansas Stat. Ann. §§ 55-1,101-55-1,110 (2004); 16 Tex. Admin. Code § 7.7001 (West 2004).

\(^{58}\) Aggregation is the principle that by combining a producer’s reserves from multiple wells connected to a common gathering system and delivering the gas for sale at the gathering system’s connection with the transmission pipeline or market hub accessed by the gathering system, the producer can receive a better price for its gas than would be received for the volumes from any single well. This occurs because aggregation permits the producer to offer to the gas purchaser or consumer/end user greater volumes and a more assured gas supply. Further, by dedicating to the gatherer larger volumes from multiple wells, the producer may be able to negotiate a better gathering rate than would apply to gas volumes from an individual well on a stand alone basis.
consequence, post-production costs (gathering, compression, treating, mainline transmission, etc.) formerly invisible as a part of bundled service are now apparent as separate charges.

The location of a producer’s sale is not the only change in marketing. Long-term contracts of 10-year, 20-year or life-of-the-lease duration have all but disappeared. Today, a three (3)-year contract would be considered long-term. Further, those contracts will typically contain pricing terms that are tied to some indicator of the current market, such as a specified premium or discount to an appropriate index. However, the greatest number of sales today are made under short-term (30-day) contracts. These will be made for a given calendar month at prices agreed to during bid-week immediately preceding the sales month. Such sales have been facilitated by the appearance of electronic exchange platforms and bulletin boards through which buyers and sellers are brought together in nationwide markets. Electronic exchanges have also facilitated a growing market for next-day sales and balance-of-the-month sales, the former of one-day duration and the latter lasting through the balance of month of trade.59

The final link in the restructured gas market has been the appearance of published price indices intended to reflect prices at various pipeline index points for gas actually sold and delivered. These indices are compiled by various index publishers from information provided on a voluntary basis by various market participants about trades occurring at a number of trading locations. This information is verified, compiled and, in some cases, assessed and a price representing trading activity at each location is published.60 Commonly used indices are published by Platts and Natural Gas Intelligence. Both publish a report identifying first-of-the-month prices applicable to the month for numerous index points around the country for delivery of produced gas. Each also publishes indices of daily prices.61

60 Policy Statement on Natural Gas and Electric Price Indices, 104 FERC ¶ 61,121 at 61,404 (July 24, 2003).
61 See Craig Carver, “Natural Gas Indices: Do They Provide a Sound Basis for Sales and Royalty Payments?,” 42 Rocky Mt. Min. L. Inst. 10-1 (1996) for an in-depth discussion of gas price indices, the various types utilized and how they are compiled.
In 1996, Craig Carver noted industry surveys that concluded that published price indices were used thousands of times every day to establish the price for buying and selling natural gas, and that they were used far more than any other benchmark to establish the prices at which sales and trades are made and royalties calculated.\(^\text{62}\) Recently, FERC staff concluded from more recent surveys a high level of dependence upon natural gas indices as price references in contracts.\(^\text{63}\) The importance, however, with respect to market value royalty clauses is this availability of published price information reflecting prices paid at various pipeline index points for gas actually sold and delivered under contracts of one month or less duration.

[2] — The Intersection Between Market Value and Post-Production Costs: A Four-Car Collision?

The shifting of the producer’s point of sale away from the well in response to FERC’s open access and unbundling initiatives has also resulted in the appearance of post-production costs previously invisible when merchant pipelines purchased at the well. The result has been an explosion of litigation concerning the impact of these costs on the royalty to be paid. Post-production costs have often played a role in determining market value at the well when there were no comparable sales or other evidence from which market value at the well could be determined directly, that is, independently of the downstream price at which the gas was sold. In these cases the so-called “work back” method was applied as the only evidence of wellhead market value. Market value was viewed as the downstream sale price less post-production costs between the wellhead

\(^{62}\) Carver, supra note 61, § 10.01.

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point of valuation and the point of sale.64 However, the concern in this section of the chapter is not the use of the “work back” method to approximate market value, but whether there may be some conflict between a jurisdiction’s view of post-production cost sharing between lessee and lessor and the determination of wellhead market value. Whether post-production costs incurred prior to downstream sale points impact a determination of market value at the well presents issues dependent upon a jurisdiction’s view of the lessee’s obligation with respect to post-production costs.

[a] — Texas.

As expected, Texas’ strong “plain meaning” approach to market value royalty presents no conflict between traditional methods of determining market value at the well and the bearing of post-production costs. The general rule in Texas is that production ends at the well and all costs downstream of the well are post-production costs to be borne proportionately by lessor and lessee.65 As a result, the point of demarcation for assessing post-production costs to royalty owners and for determining market value coincide. It is not surprising, then, that market value may be determined without regard to post-production costs incurred. This is conformed by decisions holding that market value at the well means the value of the gas at the well before value is added by compression, transportation, and preparation for market.66 A consequence of the Texas concept of market value is that, absent a necessity to resort to the work-back method, post-production costs become irrelevant in determining that value. This is illustrated by Heritage Resources, Inc. v. Nationsbank,67 holding not only that market value means market value at the well but

64 The work-back method has been labeled the “least desirable method” of determining market price or market value. Montana Power Co. v. Kravik, 586 P.2d 298, 303-304 (Mont. 1978).
that it is unaffected by an express requirement that lessor bear no post-production costs.

[b] — Kansas.

In Kansas, there is a potential for conflict. In Kansas, market value is independent of the price actually obtained and is based upon the willing buyer/willing seller rule. On the other hand, there are Kansas decisions holding that the lessee’s implied duty to market requires the lessor to make the gas marketable at no cost to lessor. Gilmore v. Superior Oil Co. and Sternberger v. Marathon Oil Co. The issue is how Kansas will reconcile its rule that market value at the well is to be determined based upon what a willing buyer would pay a willing seller at the well for the gas, with the Gilmore holding when gas at the well is not marketable there.

The continued viability of the implied covenant approach to allocating post-production costs seems questionable after the Kansas Supreme Court’s recent decision in Smith v. Amoco Prod. Co., at least as respects

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71 In Sternberger, there was no market at the well but, nevertheless, the court found that the lessee’s implied covenant obligation regarding post-production costs was met. However, the court gave paramount importance to the plain meaning of the royalty clause holding “where royalties are based on market price at the well . . . the lessor must bear proportionate share of the expenses in transporting the gas or oil to a distant market.” Id. at 796. It is urged that a close reading of Sternberger reveals that the decision was grounded primarily upon an interpretation of the royalty clause and application of pre-Gilmore post-production cost decisions, and that the court’s marketable condition/implied covenant analysis was presented to show consistency with its primary analysis. Professor Pierce appears of the same view, labeling the second half of the Sternberger court’s opinion (which is its implied covenant analysis) as an attempt to “harmonize” Kansas, Oklahoma and Texas law to justify the court’s choice of law conclusion. David E. Pierce, “The Renaissance of Law in the Law of Oil and Gas: The Contract Dimension,” 42 Washburn L.J. 909, 928-930 (2004).

market value leases. In a case of first Kansas impression, *Smith* adopted the implied-in-fact approach as governing the implication of covenants and expressly rejected Professor Merrill and his implied-in-law approach. It was the statement of Professor Merrill in his treatise that the implied duty to market required the lessee to “bear the expense . . . necessary to make the gas marketable” that formed the basis of the court’s decision in *Gilmore*. Under the implied-in-fact approach as viewed by *Smith*, the implied obligation is “inferred from the facts and circumstances of the case . . . It is the product of agreement, although it is not expressed in words.” Further, “the obligation ‘was in the minds of the parties and became a part of the written contract’ . . . It is necessary to give effect to the actual intention of the parties, as reflected by the contract.” 73 A consequence of these principles underlying the implied-in-fact approach is the general rule that no implied covenant may arise where a lease or contract contains express provisions covering the same subject matter. 74 It is axiomatic then that no covenant may be implied that conflicts with an express provision. 75 Thus, if the “plain meaning” of market value at the well in Kansas is what a willing buyer would pay a willing seller for gas at that location in its wellhead condition, it is difficult to see how there can be implied an obligation to value the gas in some better condition or at some distant location at lessee’s sole cost. 76

[c] — *Oklahoma.*

Oklahoma has also adopted the implied covenant approach to determining whether royalty owners bear a share of post-production costs.

73 *Id.* at 265.
76 Professor Pierce has also recognized that, by reason of the Kansas Supreme Court’s adoption in *Smith* of the implied-in-fact approach to implied covenants, Kansas’ plain meaning approach to “market value” would seem to foreclose implication of any duty to make the gas marketable at lessee’s sole cost. Professor Pierce states that “the obligation to pay a royalty of one-eighth of the ‘market value’ needs no interpretation. There is nothing missing; there is no omitted term to be supplied by implication.” Pierce, note 71 *supra* at 923-924.
Wood v. TXO Prod. Corp.\textsuperscript{77} and Mittelstaedt v. Santa Fe Minerals, Inc.\textsuperscript{78} Wood involved the deductibility of on-lease compression and a “market price” royalty clause. However, the case did not present the issue of a conflict between determining market price at the well and deductibility of post-production costs for gas the court determined was not marketable at the well. Moreover, there is no indication in Wood that there were any actual sales in the area from which market price could have been determined had the court considered the meaning of the royalty clause to determine royalty payable. Instead, the parties framed the issues narrowly to the deductibility of post-production costs.

Another post-production cost case, TXO Prod. Corp. v. State ex rel. Comm’rs of the Land Office\textsuperscript{79} involved a state lease form under which the state had the option of receiving payment for the “market value” of the royalty share of production. However, before analyzing this case on the basis of its holding in Wood, the court first determined that under the express terms of the royalty clause, the “without cost into the pipeline” limitation applied to the payment in money alternative and as a matter of contract construction prohibited the deduction of the costs there at issue. Roye Realty & Devel., Inc. v. Watson\textsuperscript{80} demonstrates that where the effect of the royalty clause is placed squarely before the court, the court may give meaning to it and may find it controlling. In Roye the court ruled that lessors were not entitled to royalties on amounts received by the lessee under take-or-pay settlements because under the royalty clause, royalty was only due on oil and gas “produced, saved and sold.” In doing so, the court rejected the so-called Harrell rule that the lease was in the nature of a cooperative venture—a theory applied in Arkansas and Louisiana.\textsuperscript{81}

\textsuperscript{78} Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1203 (Okla. 1998).
\textsuperscript{80} Roye Realty & Devel., Inc. v. Watson, 2 P.3d 320 (Okla. 1996).
Amicus for the royalty owners argued for recovery under the implied covenant to market, but the court’s ruling implicitly rejected that theory. To date, no Oklahoma appellate decision since Tara and Wood has squarely faced whether a market value royalty clause will be given effect to determine royalty payable for gas sold at a distant market when there are other comparable sales from which market value can be determined. However, such a case is currently before the Oklahoma Supreme Court—Howell v. Texaco, Inc., an interlocutory appeal from a trial court decision finding that market value was determined by other arms’ length sales in the field, even though defendant did not sell gas at the well.

Pre-Tara Oklahoma decisions offer a basis for application of a traditional willing buyer-willing seller approach. See Cimarron Utilities Co. v. Safranko, holding rigid rules do not govern a determination of market value, use of the work-back method is not exclusive but “every factor throwing light on [market value] may be considered. It may be proved by the opinion of competent persons having knowledge of the facts, whether experts or not.” Johnson v. Jernigan stated:

Market rate means the rate at which the gas is commonly sold in the vicinity of the well. It is the market rate at the wellhead or in the field that determines the sale price, not the market rate at the purchaser’s location which may be some distance away from the lease premises. . . . Market rate implies the existence of a free and open market of supply and demand where there are willing sellers and buyers.

Oklahoma practitioners will have to await the decision in Howell before knowing, if then, whether the plain meaning of the words “market value at the well” have any remaining viability in Oklahoma.

82 Howell v. Texaco, Inc., 2004 WL 2823314 (Okla.) was decided by the Oklahoma Supreme Court December 7, 2004, too late for a review of that case and its impact on the issues herein discussed. In its opinion, the court addresses the payment of royalties on a market value basis when there is no arm’s-length sale at the wellhead. As of writing of this footnote, a Petition for Rehearing remains pending.
85 In other contexts, “market value” has a well-defined meaning in Oklahoma. See Jordan v. Peek, 268 P.2d 242, 244 (Okla. 1954) holding that “fair market value” means
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[d] — Colorado.

Rogers v. Westerman Farm Co.\(^86\) involved four different lease types, all of which stipulated that royalty was to be the determined “at the well” and one of which stipulated “market value thereof at the mouth of the well” for gas sold away from the well, and others stipulating “market price at the well.” The court refused to apply the “at the well” language to limit lessee’s obligation to pay royalty to gas based on its wellhead value holding that “at the well” did not establish the point of valuation and was silent as to the allocation of post-production costs including transportation and, instead, held the implied duty to market required not only that the gas be in marketable condition from a physical standpoint, but also in the location of a commercial market place such that it can be bought and sold in that place.

[e] — West Virginia.

Wellman v. Energy Resources, Inc.\(^87\) involved whether lessors under a lease stipulating royalty as a share of “proceeds from the sale of gas” were to bear a share of transportation costs to the point of sale. The court found the rationale in Garman v. Conoco, Inc.\(^88\) persuasive (which it also viewed as the rule in Oklahoma and Kansas) in resolving whether lessor or lessee should bear post-production costs. However, Wellman involved a proceeds lease and not a market value lease. Under Imperial Colliery Co. v. OXY USA, Inc.\(^89\) the court had upheld a trial court determination of market value based on a “willing buyer-willing seller” analysis. The court said “under this analysis, market value is computed

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\(^86\) Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001).


\(^89\) Imperial Colliery Co. v. OXY USA, Inc., 912 F.2d 696 (4th Cir. 1990)(applying West Virginia law).
by ascertaining the price that a willing buyer would pay a willing seller in a free market without regard to federal price regulation.” Assuming this analysis correctly represents West Virginia law, arguably if a market value lease were at issue and market value of the gas at the well could be determined from comparable sales, post-production costs and thus the rule of Wellman would not be implicated even though the gas were sold in a distant market and transportation costs were incurred. Wellman itself recognized that its holding might not apply “[w]here leases call for the payment of royalties based on the value of oil and gas produced . . . .”

[f] — Wyoming.

Wyoming has attempted to decide deductibility of post-production costs as a matter of legislative fiat. (Wyo. Stat. Ann. Sections 30-5-304 and –305). Under subsection 304, “royalty” is defined as “the mineral owner’s share of production, free of the costs of production.” The “lessor” is defined in terms of a person “who is entitled to the payment of a royalty on production, free and clear of the costs of production.” The “costs of production” are defined to include costs of gathering, compressing, dehydrating or transporting the gas “into the market pipeline.” Under Section 30-5-305, it is provided that “unless otherwise expressly provided for by specific language in an executed written agreement, ‘royalty’ and ‘overriding royalty’ are to be interpreted as defined in § 30-5-304.” In Cabot Oil & Gas Corp. v. Followill involving owners of overriding royalty interests, the court held that the term “gathering” as used in the statute means “to collect gas and move it to a point where it can be processed or transported to the user. All costs associated with that activity are nondeductible under Section 30-5-
304(a)(vi) and nondeductible from royalties.\textsuperscript{94} In so holding, the court embraced the holding of \textit{Wold v. Hunt},\textsuperscript{95} that under the statute, costs of production specifically exclude all charges between the wellhead and the market pipeline except those specifically otherwise excluded from the definition.

The implication of the Wyoming statute seems to be that proceeds received from the lessee’s first sale will govern the lessor’s right to royalty, even when the sale is distant from the well, and that permissible adjustments to sales proceeds for costs incurred by the lessee is the only question remaining in determining the payment amount. Issues of legislative wisdom and contractual impairment aside, the application of the Wyoming statute may be somewhat straightforward for proceeds royalty leases. Not so, however, for market value royalty leases, and for those leases, the statute seems both ill-suited and ill-drafted. In the context of gas dedicated under a long-term contract, Wyoming had not decided whether market value would be determined based on current market value, or would be based on contract price. However, \textit{Wyoming v. Davis Oil Co.},\textsuperscript{96} at a minimum, suggests that there is a difference in what the lessor receives under a royalty clause stipulating “market value at the well” and one stipulating “amount realized” on “gas sold at the wells.”\textsuperscript{97} Assuming a distinction between market value and proceeds leases, issues arising from application of the Wyoming statute to market value royalty leases may be illuminated by assuming a first sale by the lessee at a market

\textsuperscript{94} \textit{Id.} at 242. The court rejected the lessee’s assertion that transporting the gas from the locale of production to distant delivery points where it is sold is a deductible post-production function and that non-deductible costs under the statute are limited to those taking place on the lease or unit.


\textsuperscript{96} \textit{Wyoming v. Davis Oil Co.}, 728 P.2d 1107 (Wyo. 1986).

\textsuperscript{97} The precise issue addressed by the court in \textit{Davis Oil} was whether the sale was “at the well” for the purpose of determining which of the two royalty clauses applied. When title to the gas passed at the well to the purchaser who paid the lessee a percentage of proceeds received from residue gas sales and NGL recoveries at a processing plant, the court concluded that these were not sales “at the well.”
pipeline some distance from the well after the lessee has incurred gathering, compression and dehydration paid to a non-affiliated third-party gatherer. Further assume the lease specifies “market value at the well.”

The first issue is whether the royalty required under such a market value lease is “royalty” within the meaning of the statute. It may be appropriate to refer to the lessor’s royalty under a proceeds lease as a “share of production,” even though (absent the right to take in-kind) the lessor is only entitled to the payment of money. However, it seems inappropriate to refer to payments to a lessor as a “share of production” under a market value lease since the lessor owns no interest in the produced gas itself but only a right to the payment of money, and the amount of that payment is not based on proceeds received but what a willing buyer would pay a willing seller. Thus, there is no correlation between gas produced and amount due; conceptually, there is no “share.” However, to exclude market value leases from the statute would exclude from its operation a significant portion of the universe of royalty clauses and, arguably, such a result would be inconsistent with legislative intent.

Alternatively, it may be asserted that “market value at the well” is “specific language” “expressly provid[ing]” for “royalty calculated on a different basis within the meaning of Section 30-5-305(a), and thus, the express language of the royalty clause governs. Although this writer strongly urges that “market value at the well” is just such language, such a conclusion would have the same result of excluding from the statute’s operation a significant class of royalty clauses, arguably contrary to legislative intent. Possibly, it could be argued that the effect of the statute is to move the point of market valuation to the point of sale. However, notwithstanding the Rogers court’s unpersuasive ignoring of “at the

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98 Greenshields v. Warren Petroleum Corp., 248 F.2d 61, 67 (10th Cir. 1957); Kuntz, supra, note 10.
99 In neither Cabot nor Wold, both involving overriding royalties, was the operative language of the instrument revealed by the opinion or made an issue. From this, there may be some implication that the courts did not believe the language of the instrument mattered.
100 Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001).
well” language, such evisceration of the parties’ statement of a location with words even the most uninitiated can understand would seem to be a particularly blatant and offensive ignoring of the parties’ statement of their bargain. Must we then conclude that the effect of the statute is to convert “market value at the well” leases into “proceeds” leases? However, if “market value at the well” has any of its “plain meaning,” then rewriting the lease to change both the point of valuation and the basis for valuation is no less offensive that any other rewriting of the parties’ clearly stated bargain.

Thus, absent some subsequent judicial rationalization that “market value at the well” had always equated to “proceeds” in Wyoming, surely we must conclude that market value at the well is specific language expressly providing for royalty calculated on a different basis within the meaning of Section 30-5-305(a), and therefore, such royalty clauses should be excluded from the statute.

§ 12.05. “Reverse” Vela.

Ever since the Vela and Middleton decisions, the question has been posed whether a lessee with a market value royalty clause could pay royalty on the basis of a determinable current market value when the lessee actually receives a greater price for the gas sold. The question was hypothetical in the historical gas market, but has become reality with the advent of index pricing permitting the ready determination of market value in many instances. The question was answered in the affirmative in Yzaguirre v. KCS Resources, Inc. The court held that the “plain terms”

101 “[W]ords used in the contract are afforded the plain meaning that a reasonable person would give to them . . . . In the absence of any ambiguity, the contract will be enforced according to its terms because no construction is appropriate.” Double Eagle Petroleum & Mining Corp. v. Questar Exploration & Prod. Co., 78 P.3d 679, 681 (Wyo. 2003). The plain meaning rule has been applied in Wyoming in other oil and gas cases. See, Amoco Prod. Co. v. EM Nominee Partnership, 2 P.3d 534, 540 (Wyo. 2000); Wadi Petroleum, Inc. v. Ultra Resources, 65 P.3d 703, 708 (Wyo. 2003).

102 Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968).

103 Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981).

not only fix lessee’s duty to pay royalty, but also define the benefit the
lessee is entitled to receive. The court also held there was no breach of the
implied covenant to reasonably market by not paying royalties based on
proceeds received, reasoning that no such covenant can be implied
“because the lease provides an objective basis for calculating royalties
that is independent of the price the lessee actually obtains.”

§ 12.06. Determining Market Value Today.

A review of decisions from the historical era arising from pre-
deregulation facts illustrates the difficulties of establishing market value
as the gas industry was then structured. There were often limited markets
and limited outlets for the gas. That, coupled with the practice of marketing
under long-term contracts, frequently made market value determinations
based upon comparable sales very difficult as truly comparable sales were
often difficult to find. Frequently, there were no comparable sales and
less satisfactory evidence of value was resorted to in order to establish
market value. There were no index prices. One court, in struggling to
determine value from a 1935 vantage point, lamented:

In the nature of things, there could be no open market for natural
gas. It is admitted there are no exchange quotations or other
evidence to be obtained of open and notorious market prices at
which any one desiring gas could purchase it, as would be available
in the sale of other commodities. In this situation the modern rule
is that value may be shown by evidence of other sales, provided
the conditions are substantially similar, but not otherwise . . . It is
also well settled that value may be shown by the opinion of any
competent person having knowledge of the facts, whether an expert
or an ordinary witness.

“[T]he nature of things” has changed dramatically since 1935 and
Arkansas Natural. Today, there is index pricing reflecting the prices at
which gas is sold for the current month at various index points at a

105 Id. at 374.
106 Arkansas Natural Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935).
multitude of locations on transmission pipelines around the country. Also, today with open access, a producer with access to interstate and large intrastate pipelines generally finds it possible to move gas from any location in the country to most other locations nationwide. Thus, today many wells—almost all wells in historical gas producing areas accessed by market pipelines—have access to nationwide markets. With ubiquitous index pricing and market access, wellhead market value may more readily be determined by resorting to index prices at the appropriate index point and applying location differentials—that is, transportation and other costs between wellhead and index point—to reflect wellhead value. Thus, at least for the great majority of gas that is marketed under short-term contracts in areas with access to market pipelines, the difficulty of identifying comparable sales has been minimized. Applying the willing buyer-willing seller test to determine market value at the well for gas marketed under short-term contracts, it would appear that the index price at an index point accessible by an existing gathering line, reduced by gathering, transportation and other costs between wellhead and index point, would be indicative of market value.

This is not to suggest, however, that there are no problems in determining market value. Even where gas reserves have access to market pipelines, issues arise. There may be more than one gathering line with different gathering rates to access a given transmission line. Further, there may be more than one gathering rate applicable on any particular gathering line, dependent upon volumes dedicated and whether the gas is carried on an interruptible or dedicated basis. There may be multiple transmission lines and thus multiple index points through which the gas from a particular well can be marketed. Application of any of these combinations could yield a different answer to the question of what a willing buyer would pay a willing seller at the well for the gas depending upon assumptions as to how and where the gas would be marketed.

107 For producing areas with no access to market pipelines where the market for the gas is limited to local uses, the old rules developed during the historical era would seem to still apply.
These factual scenarios and the potential for producing different outcomes merely illuminate a dimension of market value not addressed in published decisions. Market value is not—or at least should not be considered to be—only a single number or value. Rather, it should be considered a range of values, as a range of values is consonant with the way gas markets function today. Market value should not be driven by the highest observed price for gas sold during a particular time period since in real world markets the absolute highest price likely is not available to all gas volumes but only for a limited volume. As a standard, this would result in market value being determined largely by chance rather than true market availability. More important, marketing transactions which are undertaken by willing buyers and willing sellers are not reducible to a single transaction. The nature of markets is that there will be a multiplicity of transactions for a given month at differing prices and volumes based upon the differing perceptions of the various buyers and sellers in the market, all of which involve legitimate and prudent business decisions. In today’s market, gas sales for a given month are typically made pursuant to transactions struck in the last few days of the preceding month. Thus they are made based upon each market participant’s judgment necessarily made before the delivery month of market conditions and of what the actual market prices during the month may be. Except in special situations, all of these transactions represent what a willing buyer would pay a willing seller and have a legitimate claim to represent market value.

§ 12.07. Will the Minority Rule Apply Today?

The so-called minority rule of Oklahoma and Arkansas was decided against a backdrop of the necessity of marketing gas under long-term contracts that did not and, in many instances, could not contain pricing provisions permitting the price to track current market prices. The question, then, is with the disappearance of long-term gas contracts and the prevalence of 30-day or other similar short-term sales, what validity does the so-called minority rule retain? Otherwise posed, will the price specified and paid pursuant to the contract by which the gas is marketed control the determination of royalty to be paid under a market value royalty clause, even when that price is different than market value determined on a willing buyer-willing seller basis?

*Tara*\(^{108}\) was decided against the court-acknowledged requirement that the lessee, to fulfill its duty to market obligation, would be required to enter into a long-term contract. In *Tara*, the court held as a matter of interpretation that the “market price” requirements of the royalty clause should be construed in light of market realities—the lessee’s duty to market and the requirements of the market at that time to enter into long-term contracts. These market realities no longer exist. With index pricing, short-term marketing contracts, and the common practice of relating contract prices to some appropriate index for longer term contracts, it can be argued that there is no longer a conflict between the royalty clause applied on a willing buyer-willing seller basis and fulfillment of the lessee’s duty to market. Further, if the lessee markets under short-term contracts, those contracts most likely represent market value—a current, accurate reflection of what a willing buyer would pay a willing seller. However, if the sale takes place at a location distant from the well, Oklahoma’s treatment of the lessee’s obligation to bear post-production costs can affect a calculated market value (as above earlier discussed). Finally, *Tara* has its own built-in limitations. In *Tara*, the court expressly stated its holding applied only to “market price” leases and excluded all others including market value leases. Moreover, the court limited its rule to “long-term gas purchase contracts” entered into at “arm’s-length” in good faith “with the best price and term available” at the time. Thus, by its own terms, the rule of *Tara* does not apply to “market value” leases or to sales between affiliates.

As noted above in Section 12.04[2][c] discussing the potential for conflict between the requirement to pay market value and to bear post-production costs, pre-*Tara* decisions, as well as decisions in non-natural gas cases, offer a basis for application of the traditional willing buyer/willing seller approach to market value leases. With the absence today of any lessee requirement to enter into long-term gas marketing contracts, the background context which—by the court’s own statement in *Tara* drove

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The basis for its decision—no longer exists, thus clearing the way for application of the traditional meaning of “market value.” The Oklahoma Supreme Court’s decision in *Howell v. Texaco*\(^{109}\) may well give us some guidance on these issues.

**[2] — Arkansas.**

*Hillard*\(^{110}\) contained no independent reasoning, but repeated verbatim the reasoning and holding of the Oklahoma Supreme Court in *Tara* as the basis for its holding. Arguably, the same limitations inherent in the *Tara* decision and the change in gas marketing practices permit the same arguments and conclusions as would apply to Oklahoma. However, *SEECO, Inc. v. Hales*,\(^{111}\) which applied *Hillard* to a long-term gas contract between affiliates (*Tara* held its rule only applied to arm’s-length contracts) and permitting that contract to establish “pre-vailing market price” may foretell the extension of *Hillard* beyond its facts and adopted reasoning.

**[3] — Louisiana.**

*Henry v. Ballard & Cordell Corp.*\(^{112}\) similarly was decided against “the accepted universal practice of marketing [gas] under long-term gas sale contracts, and the leases were executed against that background. The court also relied on “the custom of the industry”—which it found to be payment of royalty on amounts actually received on long-term contracts and the lessor’s acceptance of such payments to decide that, as a matter of interpretation, the parties intended that market value be computed on the base of the price received. Arguably, the disappearance of the practice of marketing under long-term gas sale contracts which the court found controlling would permit the application of traditional (willing buyer-willing seller) market value determinations to be applied. This would be consistent with Louisiana’s approach prior to the *Henry* decision. See


\(^{112}\) *Henry v. Ballard & Cordell Corp.*, 152 So. 561 (La. 1982).
(for example) Wall v. United Gas Public Util. Co. As troublesome as is the court’s statement in Texaco, Inc. v. Duhé that “Louisiana law restricts the value of natural gas royalties to actual sale prices,” hopefully that scantily supported statement would fall. Moreover, under Louisiana’s civil code system, precedent is (at least in theory) accorded much less, if any, weight.

§ 12.08. A Parting Shot: Ignoring the Basics Skews Royalty Clause Interpretation.

As first mentioned, under the typical gas royalty clause, the lessor has no ownership rights in the product itself, but only a right to payment in money. However, this concept is often ignored. But ignoring this concept improperly shifts the focus of proper royalty payment analysis from a determination of the amounts payable under the royalty clause to a dispute over what “share” of gas sale proceeds “belong” to the royalty owner. This is apparent in post-production cost cases in jurisdictions such as Colorado, Kansas, Oklahoma, West Virginia, and Wyoming when sales are made downstream of the well after the value of the gas has been enhanced by post-production costs. It surfaces in the very language commonly used in discussing post-production cost issues since attorneys, commentators, and courts commonly speak in terms of whether the royalty owner is required to “bear” certain post-production costs or those costs are to be “charged to” the royalty owner or the royalty interest.

In Wood, the court variously referred to a “deduction of compression costs from the royalty interest” or whether certain post-production costs were “chargeable to the lessors.” The court further

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113 Wall v. United Gas Public Serv. Co., 152 So. 561 (La. 1934).
114 Texaco, Inc. v. Duhé, 274 F.3d 911 (5th Cir. 2001).
116 Greenshields v. Warren Petroleum Corp., 248 F.2d 61, 67(10th Cir. 1957); Kuntz, supra, note 10.
commented that without express authority for sharing post-production costs, “royalty owners would be sharing the burdens of working interest ownership.”

The Mittelstaedt court framed the issue addressed as when “a royalty interest may bear post-production costs.” Wellman and Garman also address the issue in terms of costs that must be “borne” by the royalty owner. Sternberger discusses when certain costs “may be charged against nonworking interest owners.” Such terminology is often used as a shorthand means of discussing the issue. But in some decisions it appears to have gotten the court off-track, into a belief of gas ownership and away from the issue: determining a monetary sum—an amount payable only in money—which is to be paid to the royalty owner with respect to a commodity the royalty owner does not own. The gas royalty clause provides an objective standard—more precisely, a formula—for determining that amount. Where the proper royalty payment on produced gas is concerned, the relationship of lessee to royalty owner is purely that of debtor-creditor, not bailee-bailor or other relationship where the lessee holds property belonging to another. If in litigation determining royalties properly payable the court labors under the unstated assumption that it is dealing with a commodity owned by the lessor and sold by the lessee on lessor’s behalf, that assumption will skew the court’s analysis and thus its outcome. In such circumstances, the court will view the proceeds received for the sale of the gas, no matter how far distant from the well that sale may occur, as money received from the sale of something owned by the lessor, and thus money, at least, prima facie, belonging to the lessor. This incorrect view of the lessor’s ownership of the gas may explain why some decisions have placed on the lessee the burden to show why lessor is not entitled to the royalty fraction of the full amount received for the gas sold. Instead, the true task of the court is to

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118 Id. at 883.
calculate the amount of money due the lessor in accordance with the formula stated in the lease. When it is remembered that the lessor owns none of the product sold, then hopefully the court will return to the formula the parties have specified for calculating the amount of money owed the lessor.

This reminder of the background against which royalty payment analysis should be undertaken is applicable to both proceeds and market value leases. Even with proceeds leases, proceeds are merely a starting point in the formula to compute a monetary payment. Such leases do not alter the lessor’s non-ownership of the product itself. However, where market value and market price leases are concerned, failure to adhere to the basic principles governing the lessor/lessee relationship runs the high risk of skewing proper royalty clause analysis since, in such leases, the formula chosen by the parties to determine the amount owed the lessor employs a standard not connected to the sale price of the gas received by the lessee.