CHAPTER 18

Royalty Calculation in a Restructured Gas Market

David E. Pierce*
Professor of Law
Washburn University School of Law
Topeka, Kansas

Of Counsel
Shughart, Thomson & Kilroy
Kansas City, Missouri

Synopsis

§ 18.01. Introduction.

The mere structure of a gas sales transaction can significantly impact the royalty due the producer's lessor.[1] In appropriate cases,

1. For example, the lease may require payment of 1/8th of the "proceeds" if gas is sold "at the well" and 1/8th of the "market value" if gas is sold at some point off the

courts have been willing to ignore the transaction structure created by the producer and the producer's gas purchaser when that structure adversely impacted the lessor's royalty rights under the oil and gas lease.[2] Since about 1985, fundamental regulatory changes have caused a restructuring of the natural gas industry and created previously unknown marketing opportunities for gas producers.[3] With new marketing options, a myriad of uniquely structured sales transactions, having an equally unique impact on a lessee's royalty obligations, are occurring. These new marketing opportunities create new royalty calculation issues under the oil and gas lease.

This Chapter examines the pre-restructuring jurisprudence developed to interpret common forms of royalty clauses and suggests how this law might be applied to post-restructuring transactions. The issues include determining how production will be valued to calculate royalty[4] and identifying expenses the lessee can properly deduct before calculating the lessor's royalty.[5] Each issue can be impacted by judicial treatment of the implied covenant to market and the degree to which the implied marketing covenant is circumscribed by the express terms of the royalty clause.

This Chapter also introduces a new concept for the oil and gas bar to consider: an implied covenant to *sell* production as opposed to an implied covenant to *market*. In many instances, the lessee's implied "marketing" obligations begin, and end, once oil or gas is sold. The terms of the initial sale, or subsequent resales, may be irrelevant to the royalty calculation when the royalty clause is tied

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leased premises. *See generally* Waechter v. Amoco Prod. Co., 537 P.2d 228 (Kan. 1975).

2. *See, e.g.,* Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 233 (5th Cir. 1984) ("reference in the lease to 'sold at the well' need not be controlled by the point at which title passes in the sale contract.").

3. Instead of recounting the now familiar history of restructuring, I refer you to what has become perhaps the most-cited work chronicling this event. *See generally* R.J. Pierce, Jr., "Reconstituting the Natural Gas Industry from Wellhead to Burnertip," 9 *Energy L. J.* 1 (1988).

4. Calculation of *gross* royalty values.

5. Calculation of *net* royalty values.

to market value or proceeds at the well. This may help to simplify royalty calculations and protect the interests of all parties concerned, when gas is sold into the restructured gas market.[6]

§ 18.02. The Restructured Gas Market.

Royalty calculation problems arise when dealing with gas largely because the lessor is not a party to contracts that can impact the lessor's interests. The lessor and lessee define their relationships through the oil and gas lease[1] and, in some instances, a division order.[2] However, to effectively maintain its lease rights, the lessee is required to enter into various contracts with third parties to market gas produced from the leased land. Even the simple sale of gas to a purchaser in the vicinity where the gas is produced can trigger extensive litigation and the transfer of hundreds of millions of dollars in damages from lessees to lessors.[3] Therefore, it is certain that lessors will be scrutinizing the more complex contemporary transactions in an attempt to maximize their return under the oil and gas lease. Lessees will be scrutinizing contemporary transactions to try and obtain the best deal possible for their gas while ensuring the lessor shares only in income properly classified as "royalty" under the oil and gas lease. The lessee will also be concerned that the lessor "pays its way" when the lessee's marketing efforts extend beyond the traditional wellhead sale.

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6. It also offers the lessor and lessee a baseline for negotiation when entering into longer-term transactions for which each party may desire to have royalty valuation tied to prices specified in a gas contract.

1. *See generally* D.E. Pierce, "Rethinking the Oil and Gas Lease," 22 *Tulsa L. J.* 445 (1987).

2. *See generally* D.E. Pierce, "Resolving Division Order Disputes: A Conceptual Approach," 35 *Rocky Mtn. Min. L. Inst.* § 16.03[3] (1989).

3. *See, e.g.*, Lightcap v. Mobil Oil Corp., 562 P.2d 1 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977), *reh'g denied*, 440 U.S. 931 (1979); Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968).

[1]—Traditional Marketing Scenario.

Under most forms of royalty clause, the lessee takes title to 100% of the gas production.[4] The lessor does not own any of the produced gas, having only a contractual right to receive payment for a fractional share of the gas sold.[5] Therefore, lessees need not, and typically do not, consult lessors when making arrangements for the sale of gas. Lessors often prefer this approach since it permits them to come forward after-the-fact to assert that, depending on the circumstances, the marketing choices made by the lessee are not binding upon them or, if binding, were imprudent when made.[6]

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4. For example, a common form of royalty clause states:

> The royalties to be paid by lessee are:
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> (a) on oil . . . one-eighth of that produced and saved from said land . . . (b) on gas . . . produced from said land and sold or used off the premises or in the manufacture of gasoline . . . the *market value* at the mouth of the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the *amount realized* from such sale.

Instead of taking title to a fractional share of production, as is the case for oil, the gas portion of the royalty clause entitles the lessor only to a money payment. In this particular clause, the money payment is calculated either as a share of the "market value" of the gas or the "amount realized" from the sale, depending upon whether the actual sale is made at the wellhead or at some point beyond the leased premises.

5. Greenshields v. Warren Petroleum Corp., 248 F.2d 61, 67 (10th Cir. 1957), *cert. denied*, 355 U.S. 907 (1957). In *Greenshields*, the lessee contracted with a gas purchaser to sell gas produced from the lease. The lessor asserted the purchaser was liable for conversion when it took the gas into its pipeline without the lessor's consent. The court rejected this claim, stating:

> Whether or not title passes upon the occurrence of production must be determined from the language of the lease . . . . In the Producers 88 lease here under consideration, it is provided that the lessor shall receive a portion of the gross *proceeds* at the market rate of all gas, contrasting with the provision for his receipt of one-eighth *part of all oil produced.* 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 thereafter 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.

248 F.2d at 67 (emphasis in original).

6. The market value royalty cases are an excellent example of lessors asserting that, after they had knowledge that the market value for gas was a better deal than the lessee's contract price, they were not bound by the lessee's marketing contracts. *E.g.*, Exxon Corp.

Lessees seem to abhor the idea of consulting lessors after they have obtained their signature on the oil and gas lease. Even oil and gas commentators routinely recommend convoluted legal maneuvering instead of simply raising the issue with the lessor and seeking express agreement to resolve the matter.[7] Traditionally, lessees have turned to more clandestine means such as tendering division orders containing "clarifying" language or language designed to change the royalty provisions of the oil and gas lease to try and resolve royalty calculation issues with lessors.[8]

Since the lessor is not a necessary party to the lessee's gas marketing contracts, the structure of these transactions are defined by the lessee and the gas purchaser. The traditional structure has included the following five elements:

(1) Commitment of the leased property to a specific contract and purchaser;

(2) Long-term contract obligations ranging from ten to thirty years, or for so long as the leased land is capable of producing gas;

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v. Middleton, 613 S.W.2d 240 (Tex. 1981). For an example of lessors attempting to reap the benefits of the lessee's marketing contracts, while at the same time challenging the prudence of the lessee's marketing decisions, see *Robbins v. Chevron U.S.A., Inc.*, 785 P.2d 1012 (Kan. 1990).

7. If the lessee is unable to come to an agreement with their lessor, the lessee can then weigh that fact in deciding the course of action to be taken. Attempting to nail the issue down before acting should not diminish either party's rights if the issue is ultimately litigated. However, by opening negotiations with the lessor, the lessee will be identifying the issue and inviting lessor scrutiny. In most situations, the potential gain from having the issue resolved should outweigh any negative impact from alerting the lessor to the issue.

8. This has worked to a limited extent in some jurisdictions; it has failed in others. Several state statutes now exist which effectively prevent using the division order to modify the terms of the underlying oil and gas lease. *See generally* Pierce, "Resolving Division Order Disputes: A Conceptual Approach," 35 *Rocky Mtn. Min. L. Inst.* § 16.03[3] (1989). Regardless of how courts treat the division order, from a business planning view it is too tenuous a document, the situation too coercive, and the process too unprofessional to accomplish the lessee's ultimate goal of defining royalty obligations effectively under varying marketing scenarios.

(3) Pricing provisions that, typically, do not reflect varying gas market values during the life of the contract;

(4) Lessee marketing obligations generally limited to delivering the gas to the purchaser at a particular point in the field where it is produced; and

(5) A requirement that the lessee supply only those volumes that the lease can efficiently produce (The purchaser may or may not have an obligation to take, or pay for, a minimum volume of gas produced from the lease.).

Most of the lessor issues that have arisen under this traditional marketing scenario concern (1) the lessee's initial inability to access a market and (2) when a market is accessed, whether the lessor's royalty will be valued using the pricing provisions of the lessee's gas sales contract.

Under the traditional marketing scenario, the lessee would seldom search for a market beyond the gas pipeline companies in the area—primarily because the lessee could not access available pipelines to transport gas to other markets. The jurisprudence to date demonstrates, however, that disputes concerning gas values and deductible costs often arise once the lessee ventures beyond a simple wellhead sale to a pipeline.[9] Currently, the opportunities for lessor/lessee disputes are magnified by the contemporary marketing opportunities lessees are pursuing to try to make the most out of their gas interests.[10]

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9. *E.g.*, First Nat'l Bank in Weatherford v. Exxon Corp., 622 S.W.2d 80 (Tex. 1981) (market value vs. proceeds basis for calculating royalty and whether market value should encompass the "legal" characteristics of the gas); Scott v. Steinberger, 213 P. 646 (Kan. 1923) (lessee constructed pipeline to sell gas directly to brick plant and oil refinery at $0.15/Mcf and deducted $0.07/Mcf as a transportation charge before calculating royalty).

10. The Interstate Natural Gas Association of America has reported that, in 1991, gas was delivered to U.S. markets through the following marketing outlets:

Pipeline Sales	16%
Contract Carriage	84%

"U.S. Gas Line Contract Carriage on the Rise," *Oil & Gas Journal*, May 18, 1992, at 22. The 84% contract carriage rate would reflect gas being moved through "contemporary

[2]—Contemporary Marketing Scenarios.

Contemporary marketing scenarios are characterized by the following five elements:

(1) The leased property is not committed to a specific contract and purchaser; the lessee merely agrees to sell and deliver "gas."

(2) Most gas volumes are being sold under thirty day contracts to entities other than gas pipeline companies.

(3) Pricing generally reflects the current market value of the gas at the time it is sold.

(4) The lessee may market its gas beyond the wellhead; the actual sale may occur hundreds of miles from the leased land after the value of the gas has been greatly enhanced by lessee's marketing efforts, the efforts of lessee's contractors, and transportation.

(5) The lessee's gas delivery obligations are not tied to what the lease can produce; the purchaser generally will not have an obligation to take, or pay for, a minimum volume of gas produced from the lease.

The attribute of the current marketing regime that offers the most challenge to the oil and gas bar is the variety of transactions that are possible.

For example, assume a lessee has acquired leases covering three different tracts of land, each owned by a different mineral owner. In June of 1992, the lessee enters into three different gas contracts. None of the contracts commit any reserves from the leased land. Instead, the lessee agrees to deliver to each purchaser a stated volume of gas. The lessee plans to obtain the volumes to perform the gas sales contracts from the three leases, leases it might acquire in the future, and by purchasing gas from other

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marketing scenarios."

producers in the area. The three contracts have the following terms:

Contract #1. Two-year term, fixed price of $2.10/Mcf, and a daily delivery obligation of between 500 and 750 Mcf per day.

Contract #2. Six-month term, variable price of 15% above a designated published field (spot) price, and a daily delivery obligation of between 500 and 750 Mcf per day.

Contract #3. Thirty-day term, price agreed upon five days before the month of delivery, volumes not to exceed 10,000 Mcf per day.

Assume further that the parties agree upon $0.90/Mcf as the price for deliveries accepted during the month of July; that, for all the gas contracts, the sales point is at the same designated point on an interstate pipeline. The lessee measures all the gas produced from each lease at the wellhead. The gas from the lessee's leases is commingled in a gathering system that serves several other leases in the area. From the gathering system, the gas is delivered to the interstate pipeline where it is transported to the sales point designated in the lessee's three gas sales contracts. The lessee also purchases other gas along the pipeline to meet its contract needs.

Assuming each of the lessee's leases provides for a 1/8th royalty, which lessor gets 1/8th of $2.10/Mcf? Which lessor gets 1/8th of $0.90/Mcf? Which lessors have their wells shut in when the lessee's purchasers fail to take gas under their contracts?[11] Can the lessee choose to declare a "pool" of gas from which it

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11. Note that lessors may complain, not only when their gas is shut in, but also when it is *not* shut in. For example, if the well is not shut in while the spot price is low, the lessor may argue the lessee could have obtained more royalty income on the gas had it not been sold when spot prices were, for example, below $1.00/Mcf. Suppose the lessee also owns a processing plant. This lessee may have an independent incentive to sell at "low" spot prices because lower gas prices improves the lessee's processing margins on its natural gas liquids. If the lessor does not share in the liquids sales, they may object to the practice. *See generally* "Sagging Spot Market Prices Spawn U.S. Gas Flow Curtailments," *Oil & Gas Journal*, February 3, 1992, at 28.

markets and then pay royalties based upon the "weighted average price of gas"—the "WAPOG"? Suppose the lessee pays in excess of $1.00/Mcf to acquire third-party gas to meet its gas sales obligations, can the lessee credit the $2.10/Mcf contract to it's third party gas? This series of questions demonstrates a few of the problems associated with the lessee's new marketing freedom. Courts grappling with these problems must initially look to traditional gas royalty valuation jurisprudence in an attempt to resolve issues arising in a very non-traditional gas market.

§ 18.03. Royalty Valuation Jurisprudence.

Royalty clauses generally value production based either upon what the lessee receives from a sale of the production,[1] or the market value[2] of the production. In determining the meaning of market value, some courts have used the value at the time the lessee entered into a gas contract.[3] Other courts interpret market value, instead, to mean the market value *when the gas is actually produced.*[4] These conflicting views reflect the varying willingness of courts to consider gas marketing realities when interpreting royalty obligations.

[1]—Courts That Consider Gas Marketing Realities.

The Oklahoma Supreme Court, in *Tara Petroleum Corp. v. Hughey*,[5] attempted to account for the "realities" confronting the

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1. Commonly referred to as the "proceeds" received by the lessee in a sale to a third party.

2. In this Chapter, market value and market price are used interchangeably. Although a few courts have tried to draw distinctions between the two concepts, the distinctions had little meaning then and no meaning now.

3. Hillard v. Stephens, 637 S.W.2d 581 (Ark. 1982); Henry v. Ballard & Cordell Corp., 418 So.2d 1334 (La. 1982); Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981).

4. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); Holmes v. Kewanee Oil Co., 664 P.2d 1335 (Kan. 1983); Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978); Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968).

5. 630 P.2d 1269 (Okla. 1981).

lessee when marketing gas. The lessee, Wilcoy Petroleum Company,[6] entered into a two-year gas sales contract with Jarrett Oil Company. The contract provided for a gas price of $0.32/Mcf the first year and $0.33/Mcf the second year. Five months after the gas contract was made, the Federal Power Commission (FPC) raised ceiling prices to $1.30/Mcf.[7] The lessors, the Hughey heirs, asserted they were entitled to royalties calculated using the higher FPC price instead of the Wilcoy/Jarrett contract price.[8]

The royalty clause of the lease provided:

> "[L]essee . . . agrees . . . [t]o pay lessor for gas . . . produced and sold or used off the premises, or used in the manufacture of any products therefrom, one-eighth (1/8) *at the market price at the well* for the gas sold, used off the premises, or in the manufacture of products therefrom . . . .[9]

The court held that, when a lessee enters into an "arm's-length, good faith gas purchase contract with the best price and term available to the producer at the time, that price is the "market price" and will discharge the producer's gas royalty obligation under a market price royalty clause.[10]

The court used an end-result analysis to arrive at its market-price-equals-contract-price conclusion—any other approach would "not be fair to the producers."[11] However, to make its end-result analysis more legal-like, the court justified its conclusion by

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6. Wilcoy was a successor in interest to the original lessee, Tara Petroleum Corporation. *Tara*, 630 P.2d at 1271.

7. *Id.*

8. Jarrett Oil Company actually resold the gas to El Paso Natural Gas and received the FPC ceiling price. The lessors argued their royalty should be calculated using the Jarrett/El Paso contract price instead of the Wilcoy/Jarrett price. The court noted that the lessors had not demonstrated any impropriety in the contract between Wilcoy and Jarrett. *Id.* at 1275.

9. *Id.* at 1272 (emphasis by the court).

10. *Id.* at 1273.

11. *Id.*

finding that, when the oil and gas lease was entered into, the lessors must have contemplated that lessees would enter into long-term contracts that might not keep pace with current gas prices.[12]

The court bolstered its producer-fairness conclusion by analyzing the realities of gas marketing:

> Once a producing well is drilled, a producer has a duty to market the gas. In order to market gas it is usually necessary to enter into a gas purchase contract—frequently a long-term one . . . . We have recognized this necessity of the market, and we believe that lessors and lessees know and consider it when they negotiate oil and gas leases.[13]

This "market-reality" rationale has been adopted by the courts of Arkansas and Louisiana to arrive at conclusions similar to that of the Oklahoma Supreme Court in *Tara*.[14]

The Arkansas Supreme Court, in *Hillard v. Stephens*,[15] had to interpret a gas royalty clause providing for a royalty of "one-eighth (1/8) of the value of such gas calculated at the rate of '~~five cents~~' *Prevailing Market Price at Well* per thousand cubic feet . . . ."[16] The lessee entered into a long-term[17] gas contract containing a pricing formula that eventually failed to keep pace with the market value of gas being sold in the area.[18] The court

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12. *Id.* at 1273, 1274. It is doubtful that the lessors, when entering into the lease, ever thought about the lessee's gas marketing problems. However, if the lessors had thought about the problem, they probably would have included some sort of language to protect their interests, e.g., the market price royalty provision dealt with in *Tara*.

13. *Id.* at 1273.

14. Hillard v. Stephens, 637 S.W.2d 581, 583-84 (Ark. 1982); Henry v. Ballard & Cordell Corp., 418 So.2d 1334, 1338 (La. 1982).

15. 637 S.W.2d 581 (Ark. 1982).

16. *Id.* at 582 (emphasis by court).

17. The contract would run so long as gas could be produced from the leased land; this was a "life-of-lease" contract.

18. *Hillard*, 637 S.W.2d at 584. For example, the lessee would receive the contract price of $0.33/Mcf and have a royalty obligation, applying then current market values, of 1/8th x $2.40/Mcf or $0.30/Mcf. This would reduce the lessee's cost-bearing revenue

ultimately held that the "prevailing market price at well" language in the royalty clause should be limited to the contract price paid by the gas purchaser under its long-term contract with the lessee.[19]

The Arkansas Supreme Court's reasoning, in many respects, paralleled that of the Oklahoma Supreme Court in *Tara*. The court noted that a current market value approach would be unfair to the lessee.[20] With regard to the marketing realities of the situation, the court observed:

> Once the lessee-producer drills a well resulting in the commercial production of natural gas on the leased premises, the lessee-producer has the immediate duty to market the gas. In order to market such gas effectively, it is the custom in the industry and is usually necessary for the lessee-producer to sell the gas under a long-term gas purchase contract.[21]

The court also stated: "[T]he law should not penalize Stephens [the lessee] who was forced into the gas purchase contracts in a large measure by its duty to the Hillards [the lessors] to market the gas efficiently and effectively.[22] So long as the contracts entered into by the lessee were reasonable at the time they were made, the contract price will be deemed the "prevailing market price."[23]

The Louisiana Supreme Court, in *Henry v. Ballard & Cordell Corp.*,[24] also considered marketing realities by holding that "market value" equaled the proceeds received by the lessees under their long-term gas contracts.[25] In *Henry*, the lessees entered into

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interest from $0.29/Mcf to $0.03/Mcf; the lessor's cost-free revenue interest would increase from $0.04/Mcf to $0.30/Mcf.

19. *Id.* at 585.

20. *Id.*

21. *Id.* at 583-84.

22. *Id.* at 585.

23. *Id.*

24. 418 So.2d 1334 (La. 1982).

25. *Id.* at 1340.

gas contracts that would run for twenty years beginning in 1961.[26] By 1976, the prices provided for in the 1961 contracts were not keeping pace with current gas market prices.[27]

The court adopted the Oklahoma Supreme Court's *Tara* approach stating: "Like the Oklahoma court in *Tara*, we believe that ambiguity in royalty provisions such as those at issue in this litigation cannot be resolved without consideration of the necessary realities of the oil and gas industry."[28] The realities noted by the court included:

(1) At the time the leases were entered into, "the known obligation of the lessee to market discovered gas reserves, and the accepted universal practice of marketing such reserves under long-term gas sales contracts provide the background against which these leases were executed."

(2) The sole gas purchaser in the area would agree to purchase the gas only under a twenty year sales contract.[29]

(3) The price and terms obtained by the lessees in the 1961 contracts were the best available in the relevant market area at that time.[30]

However, like the Arkansas and Oklahoma courts, the court in *Henry* held that in the royalty clause was ambiguous as to whether market value meant *current* market value.[31] The ambiguity was resolved in the lessee's favor since it would be "unfair" to do otherwise.[32]

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26. *Id.* at 1336.

27. *Id.*

28. *Id.* at 1339.

29. *Id.* at 1340.

30. *Id.*

31. *Id.* at 1337.

32. *Id.* at 1340. The court stated its fairness reasoning as follows:

> We do not propose to penalize defendants' [lessees'] good faith compliance with their lease obligations by requiring them to pay royalties based on a current,

The Louisiana Supreme Court, however, adopted a more tentative market-value-equals-contract-price rule, stating:

> Had plaintiffs shown that the purpose of the market value royalty clause was to provide them with protection as to price, regardless of what disposition is made of the gas by lessee and regardless of what price was received, then we would arrive at a different conclusion.[33]

This suggests that, in Louisiana, the issue will be addressed on a case-by-case basis by inquiring into the parties' actual intent at the time of leasing. The burden of proof will be on the lessor.[34]

Another concept, introduced somewhat obliquely by the court in *Henry*, concerns the "cooperative venture" created by the oil and gas lease.[35] Under this cooperative venture, the lessee is obligated to market gas and, because this traditionally necessitates a long-term gas contract, the lessor should not be allowed to be "uncooperative" and demand a royalty measured by some standard other than the long-term contract to which the lessee is bound.[36] In essence, the lessor is forced to "come along for the ride" under the lessee's gas contract. It will be interesting to see if this lessor/lessee cooperation continues when the lessee obtains take-or-pay payments or settlements under the gas contract.[37]

As the foregoing discussion demonstrates, the Arkansas, Louisiana, and Oklahoma courts adopting the market-value-equals-

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> fluctuating, day-to-day market value of gas several times higher than the price received by them in a sales contract admittedly in the best interest of both lessors and lessees.

Id.

33. *Id.* at 1340.

34. *Id.*

35. *Id.* at 1338.

36. *Id.*

37. *See generally* D.E. Pierce, "Developments in Nonregulatory Oil and Gas Law: Relationships, Contracts, Torts, and the Basics," 41 *Inst. on Oil & Gas L. & Tax'n* § 1.07[1] (1990).

contract-price rule have done so because they believe that equating market value to *current* market values would be unfair to lessees. The unfairness arises out of lessees being forced, by the implied covenant to market, to sell their gas at the time of production into markets where the terms have traditionally been dictated by a few pipeline purchasers. The most common term traditionally dictated by pipeline purchasers has been commitment of the gas from a particular lease for a relatively long duration, such as twenty years or longer. The obvious issue, in a restructured gas market, is whether the market-value-equals-contract-price rule will be applied when the marketing realities have changed and the lessee is no longer forced to sell gas under long-term contracts.[38]

[2]—Courts that Do Not Consider Gas Marketing Realities.

The Texas Supreme Court, in *Texas Oil & Gas Corp. v. Vela*,[39] interpreted a royalty clause requiring the lessee to "pay to lessor, as royalty for gas from each well where gas only is found, while the same is being sold or used off of the premises, one-eighth of the market price at the well of the amount so sold or used."[40] The lease was signed in 1933. In 1935, the lessee obtained production from the land and entered into a gas sales contract in which the purchaser agreed to pay lessee $0.023/Mcf; the contract would continue "for the life of the lease."[41] The purchaser, United, was the only commercial purchaser of gas in the field and the terms were the best available in the field.[42]

Although the court noted the difficulties confronting a lessee marketing gas,[43] it refused to alter what it viewed as the unam-

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38. See text *infra*, at § 18.03[3].

39. 429 S.W.2d 866 (Tex. 1968).

40. *Id.* at 868.

41. *Id.*

42. *Id.* at 870.

43. The court noted that:

> When the . . . contracts were made . . . United was the only commercial purchaser of gas in the field. The operators could market their gas only on a 'life

biguous terms of the oil and gas lease. The court found that "[t]he royalties to which . . . [the lessors] are entitled must be determined from the provisions of the oil and gas lease, which was executed prior to and is wholly independent of the gas sales contracts."[44] The court concluded that the "plain terms" of the oil and gas lease required the lessee to pay royalty based upon the "prevailing market price at the time of the sale or use."[45] The sale in this case did not occur "at the time the contracts were made but at the time of the delivery to the purchaser."[46] Therefore, the contract price received by the lessee is not necessarily the market price required by the royalty clause.[47] The net effect of the *Vela* court's holding required the lessee to pay the lessor, as royalty, over 50% of the amount received by the lessee under its long-term contract.[48]

In *Exxon Corp. v. Middleton*,[49] the Texas Supreme Court reaffirmed the holding in *Vela*, interpreting a lease providing for royalty:

[O]n gas . . . sold or used off the premises or in the manufacture of

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> of the lease' basis, and the price stipulated is the only price that could be obtained at that time. Respondents also point out that gas is not sold on a day-to-day basis, and that any substantial volume can be marketed only under a long-term contract that fixes the price to be paid throughout its term. The trial court found that the contracts in this case were made in good faith . . . . Petitioners argue that in these circumstances, the market price of gas within the meaning of the lease is the price contracted for in good faith by the lessee in pursuance of its duty to market gas from the premises. We do not agree.

Id.

44. *Id.* The court also noted that none of the royalty owners ever agreed to accept royalties calculated using the contract price.

45. *Id.* at 871.

46. *Id.*

47. *Id.*

48. The trial court found that during one four year period at issue, the market price was $0.13047/Mcf instead of the $0.023/Mcf actually received by the lessee. The supreme court held that the evidence supported the trial court's market price finding. *Vela*, 429 S.W.2d at 874.

49. 613 S.W.2d 240 (Tex. 1981).

> gasoline . . . the market value at the well of one-eighth of the gas so sold or used, provided that on gas so sold at the wells the royalties shall be one-eighth of the amount realized from such sale.[50]

After finding the gas had been sold or used off the leased premises and that the proper measure for royalty was one-eighth of the "market value at the well," the court held that the gas should be valued when it was actually produced and delivered.[51]

Rejecting Exxon's plea to consider "the practicalities of the natural gas industry," the court stated:

> We are not unmindful of the realities of the gas industry; however, our resolution of this problem is based upon the recognition of two separate and distinct transactions, the lease agreement and the gas contract. . . . Exxon's royalty obligations are determined from lease agreements which were executed prior to and wholly independent of the gas contracts.[52]

The court concluded: "Exxon's royalty obligations are fixed and unaffected by its gas contracts."[53] Rejecting the producer-equity approach followed by the Arkansas, Louisiana, and Oklahoma courts, the Texas court observed:

> When Exxon negotiated the gas contracts, it took the risk that the revenue therefrom would be sufficient to satisfy its royalty obligations. That subsequent increases in market value have made these obligations financially burdensome is not reason to compel this Court to disregard the plain and unambiguous terms of the royalty clause . . . .[54]

The Kansas Supreme Court, in *Holmes v. Kewanee Oil Co.*,[55] considered the effect of gas contracts that were entered into in

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50. *Id.* at 241.

51. *Id.* at 243, 244.

52. *Id.* at 245.

53. *Id.*

54. *Id.*

55. 664 P.2d 1335 (Kan. 1983).

1929 and leases that provided for a royalty of "one-eighth (1/8) of the gross proceeds at the prevailing market rate . . . ."[56] The court found this was a market value lease and that market value "refers to value or price at the current rate prevailing when the gas is delivered rather than the proceeds or amount realized under a gas purchase contract."[57] The court also held that market value would equal the "price which would be paid by a willing buyer to a willing seller in a free market."[58] Like the Texas Supreme Court in *Exxon* and *Vela*, the Kansas Supreme Court was cognizant of the "realities" of the gas market,[59] yet it felt constrained, as had the Texas Supreme Court, to give effect to the plain meaning of the royalty clause.[60]

In *Piney Woods Country Life School v. Shell Oil Co.*,[61] the court evaluated the rationale underlying the *Tara* approach:

> The most important rationale underlying the *Tara* rule is the concern that it is unfair to require the lessee to pay increasing royalties out of a constant stream of revenues. The reasoning is as follows: the lessee has a duty to market the gas; gas is customarily sold in long-term contracts; the lessee is thus forced by his duty to the lessor to enter into a long-term contract but then sees his profits whittled away as the market price of gas rises.[62]

Rejecting this rationale, the court noted that the lessee is

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56. *Id.* at 1338.

57. *Id.* at 1339.

58. *Id.* at 1341 (*quoting* Lightcap v. Mobil Oil Corp., 562 P.2d 1, 2, Syl. 4 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977)).

59. *Holmes*, 664 P.2d at 1338-39.

60. In *Montana Power Co. v. Kravik*, 586 P.2d 298 (Mont. 1978), the Montana Supreme Court held that a royalty clause providing for payment of 1/8th of the "market price . . . at the well" required payment of "the *current* market price being paid for gas at the well where it is produced." *Id.* at 302 (emphasis by the court). The court noted: "The price to be paid is not to be an arbitrary price fixed by the lessee but the price actually given in current market dealings." *Id.*.

61. 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

62. *Piney Woods*, 726 F.2d at 236.

merely a "middleman" that failed to limit its potential royalty exposure when entering into agreements with its gas purchasers.[63] The court held that the *Tara* approach would be unfair to *lessors* because it destroys their expectation under the lease that royalties would be calculated using the *current* market value of gas.[64]

The courts in Kansas, Montana, Texas, and the Fifth Circuit in *Piney Woods*, all were cognizant of the realities under which the lessee operated in contracting for the sale of natural gas. However, these courts refused to incorporate the marketing realities into their analysis and resolution of the market value royalty issue. Instead, they gave effect to what they perceived to be the express terms of the royalty clause: market value equals *current* market value. These courts reasoned that, although their interpretation may create "unfair" results for lessees as gas prices escalate beyond contract prices, it would be equally unfair to deprive lessors of royalty based upon current market values.

[3]—The Old Market Value Rules Under New Marketing Realities.

In Arkansas, Louisiana, and Oklahoma, courts have held that it was not clear whether the term "market value" in the oil and gas lease meant "current" market value or the value established when entering into a long-term gas contract.[65] In Kansas, Montana, and Texas, the courts have held that the term "market value" had a clear meaning, "current" market value. Therefore, in Kansas, Montana, and Texas, there was no need to "interpret" the phrase and, in the process, adjust the equities created by the situation.[66] However, in Arkansas, Louisiana, and Oklahoma, because the meaning was not "clear," courts took the opportunity to "interpret" the clause to ascertain its meaning. As part of the interpretive

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63. *Id.* at 237.

64. *Id.* at 237-38.

65. *See* text, *supra*, at § 18.03[1].

66. *See* text, *supra*, at § 18.03[2].

process, these courts attempted to account for the "realities" of gas marketing and the "unfair" burdens they could place on the lessee.

The realities of gas marketing at the time required lessees to commit production from their lease to a long-term contract.[67] The marketing realities are much different today. First, lessee, in most instances, is not *required* to enter into long-term contracts. Instead, it has the *option* to sell under thirty day or longer term contracts. Also, in many instances, the lessee will not commit individual leases to a contract but, instead, will merely agree to deliver a stated volume of gas to a purchaser at a stated sales point.[68]

Since the lessee has the power to control the nature of its commitment, there is no longer any need for courts to intervene with benevolent interpretations of the royalty clause. The underlying premise for the *Tara* market-price-equals-contract-price rule is gone. Because the marketing realities have changed, it is no longer "unfair" to require lessees to pay royalty based upon *current* market values. Since the underlying premise for the *Tara* approach is gone, it is unlikely that those courts that had adopted the market-price-equals-contract-price rule will apply it to contemporary marketing scenarios.[69] Instead, they should apply the market value

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67. Hillard v. Stephens, 637 S.W.2d 581, 583-84 (Ark. 1982); Henry v. Ballard & Cordell Corp., 418 So.2d 1334, 1338 (La. 1982); Tara Petroleum Corp. v. Hughey, 630 P.2d 1269, 1273 (Okla. 1981).

68. *See* text, *supra*, at § 18.02[2].

69. *Taylor v. Arkansas La. Gas Co.*, 793 F.2d 189 (8th Cir 1986), suggests that the Arkansas approach to the market value royalty issue may not depend on whether the lessee is locked into a long-term gas contract. In *Taylor*, the leasehold interest was owned by Stephens and Arkla. Stephens entered into a long-term gas contract with Arkla. With regard to the portion of the leasehold interest Arkla owned, Arkla took the gas into its pipeline system without a contract but paid royalty as though it was sold under terms identical to the Stephens/Arkla gas contract. *Id.* at 191. As between Stephens and Taylor, the court applied the *Hillard* rule and held the royalty clause requiring payment at the "prevailing market price" was satisfied by paying Taylor 1/8th of the proceeds received by Stephens under the Stephens/Arkla gas sales contract. *Id.* at 191-92. However, the court also had to determine how Arkla's royalty obligations should be calculated when Arkla, as a lessee, was never bound to a gas contract. The court decided to apply the *Hillard* rule to Arkla's royalty obligation.

analysis, adopted by the Kansas, Montana, and Texas courts, which equates market value with *current* market value.[70] However, it is doubtful that there will be a groundswell of litigation by royalty owners to overturn the *Tara* rule since the current market value of gas, in most instances, is *less* than long-term gas contract prices.[71]

If we determine that market value means *current* market value,

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The court recognized that the *Hillard* reasoning "is not directly applicable to leases where the producer has not executed a long-term contract to sell to a buyer under a fixed price." *Id.* at 192. Nevertheless, the court applied the *Hillard* analysis to Arkla as though Arkla had entered into the same sort of gas sales contract as Stephens. *Id.* The court offered five, equally unconvincing, reasons for applying the *Hillard* rule to Arkla:

(1) *Hillard* dictated the legal standard that must be used to measure prevailing market price;

(2) The leases were executed with Arkla and Stephens as co-lessees and nothing in the record indicated they should be treated differently for payment of royalty;

(3) In Arkansas, the execution of an oil and gas lease constitutes a present sale of all the gas in place at the time the lease is executed;

(4) The lessors failed to sustain their burden of proof to show that the contract price was not a fair price—when all else fails, blame it on the attorneys; since no gas sales contract existed, it is understandable that counsel for the royalty owners would not spend much effort attacking Stephens' contract to establish Arkla's royalty obligations; and

(5) "[I]t would be highly incongruous to apply different measures of royalty value to the same contract term within the same lease agreement based solely on the use of the gas by its producer." *Id.* at 193.

This cost was probably the main reason for the court's holding. The court does not offer any independent basis for its holding once it is conceded that the marketing realities do not require application of the *Tara* rule to protect the lessee from an unfair situation.

70. In jurisdictions that have never addressed the market value royalty issue, there is still considerable debate over the proper interpretation of the royalty clause. When the lease provides for payment of a share of "proceeds" when sold at the well and a share of the "market value" when sold off the leased premises, it is arguable that the term "market value" was used to permit the lessee to deduct marketing costs from its sales proceeds in calculating a wellhead-equivalent sales price. Under this approach the lessee would argue that market value will always be something *less than* the proceeds it receives. *See* Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 235 (5th Cir. 1984) (rejecting the argument as posed by various commentators).

71. Instead, the issue will probably be decided when royalty owners discover that their lessees are no longer paying them a share of contract proceeds but rather a share of current market value. In these situations the royalty owners will attempt to perpetuate the *Tara* rule; a rule that just a decade ago was viewed by royalty owners with disdain. It is amazing what shifts in the market for a commodity can do to one's perspective.

the next problem is determining how to ascertain that current market value.

[4]—Defining Market Value.

[a]—Traditional Approaches.

"Market value" of gas has been defined by courts to equal "the price that a willing purchaser would be willing to pay a willing seller for gas delivered in comparable quantities and under like conditions."[72] Market value is a question of fact[73] that can be ascertained by considering "any competent evidence."[74] For example, in *Matzen v. Cities Service Oil Co.*,[75] the court held that "any competent evidence" included "evidence of actual sales of the gas produced, evidence of comparable sales, and expert opinion based on the sale price of comparable fuels and on econometric model projections."[76] However, courts have generally based their market value conclusions on evidence of "comparable sales."[77]

"Comparable sales" includes "sales of gas comparable in time,

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72. United Fuel Gas Co. v. Columbian Fuel Corp., 165 F.2d 746, 750 (4th Cir. 1948). *See also* Matzen v. Cities Service Oil Co., 667 P.2d 337, 343-44 (Kan. 1983) (market value "is that price which would be paid by a willing buyer to a willing seller in a free market"); Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981) (market value is "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") (emphasis by the court).

73. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 238 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

74. Matzen v. Cities Service Oil Co., 667 P.2d 337, 342 (Kan. 1983); Holmes v. Kewanee Oil Co., 664 P.2d 1335, 1341 (Kan. 1983).

75. 667 P.2d 337 (Kan. 1983).

76. *Id.* at 343.

77. *E.g.*, Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 239 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); Shell Oil Co. v. Williams, Inc., 428 So.2d 798, 802 (La. 1983) (this case concerned lease in which parties *agreed* it required payment of royalty based upon current market values); Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981); Montana Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978).

quality and availability to marketing outlets."[78] In *Montana Power Co. v. Kravik*,[79] the court defined the "criteria of comparability" to include leases that are "comparable to lessor's well in quantity, quality, and availability to marketing."[80] The Texas Supreme Court noted, in *Exxon Corp. v. Middleton*:[81]

> 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 properties such as sweet, sour, or casinghead gas. . . . 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 marketing outlets similar to the gas in question.[82]

The types of physical factors courts consider were enumerated by the United States Court of Claims in *Hugoton Production Co. v. United States*[83] and include the following:

> (a) The volume available for sale. Generally the greater the volume or reserves, the greater the price the seller could command.
>
> (b) The location of the leases or acreage involved, whether in a solid block or scattered, and their proximity to prospective buyers' pipelines.
>
> (c) Quality of the gas as to freedom from hydrogen sulphide in excess of 1 grain per 100 cubic feet.
>
> (d) Delivery point.
>
> (e) Heating value of the gas.

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78. Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 872 (Tex. 1968). The court in *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 246 (Tex. 1981), adds to the *Vela* list the "quantity" of gas being offered for sale.

79. 586 P.2d 298, 303 (Mont. 1978).

80. Montana Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978) ("The question is . . . what is being paid in recent, substantial, and comparable sales of similar gas whose availability to marketing is reasonably similar to lessor's gas.").

81. 613 S.W.2d 240 (Tex. 1981).

82. Exxon Corp. v. Middleton, 613 S.W.2d 240, 246-47 (Tex. 1981).

83. 315 F.2d 868, 894-95 (Ct. Cl. 1963).

(f) Deliverability of the wells. The larger the volume that could be delivered from a reserve, the greater the price the seller could command.

(g) Delivery or rock pressure. The higher the pressure, the less compression for transportation is required.[84]

Courts have been able to deal effectively with the comparability of physical factors. Where wellhead sales have not been comparable, courts have followed the gas upstream to the point of first sale and then worked back to a calculated wellhead price by deducting marketing costs incurred in making the upstream sale.[85] However, courts have had considerable difficulty in defining the non-physical gas qualities they will consider in identifying comparable sales.

The issue is whether sales of gas subject to federal regulation are "comparable" to unregulated sales. Another way of stating the issue is whether the "quality" component of the comparable sales equation includes the *legal* quality of the gas. For example, in *Shell Oil Co. v. Williams, Inc.*,[86] the court considered the legal quality of the gas in issue and held that:

> [M]arket value must be determined by comparable sales in quality which also involve the legal characteristics of the gas, that is, whether it is sold on a regulated or unregulated market. Intrastate and interstate gas are not comparable in quality. They are conceptually and legally different.[87]

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84. *Id.* at 894-95.

85. In *Montana Power Co. v. Kravik*, 586 P.2d 298, 303 (Mont. 1978), the court defined this "alternative test" as follows:

> Where no market exists in the field, in the absence of unlawful combination or suppression of price, royalty may be computed upon receipts from the marketing outlet for the products, less the costs and expenses of marketing and transportation.

See also Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 238-39, 240 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

86. 428 S.2d 798 (La. 1983).

87. *Id.* at 802.

The court concluded that Shell had properly discharged its royalty obligations when it paid its lessors the highest price allowed by the FPC for the particular category of gas sold.[88] The court also concluded that the court of appeals had erred when it required the trial court to consider prices paid in intrastate sales.[89] The Texas Supreme Court also considers the "legal" quality of the gas and has held that gas sales in the intrastate market are not "comparable sales" for the purpose of determining the value of gas dedicated to the interstate market.[90]

The opposite approach is demonstrated by the Kansas Supreme Court's holding in *Matzen v. Cities Service Oil Co.*:[91]

> The age of the well or the contract of sale matters not to the landowner whose gas is being produced and whose reserves are being reduced, or to the producer or the consumer, who are concerned only with quality and quantity, not origin. . . .
>
> We disagree with the *Williams* rationale . . . and hold that quality, as that term is used in defining comparable sales, does not include the "legal characteristics" of the gas resulting from "vintaging." Quality consists of the inherent properties of the gas—BTU content, pressure, and the like.[92]

In Kansas, therefore, market value royalty calculations for gas are not limited by the legal classification of the well from which it is produced.[93] However, the distinction between the Louisiana/Texas and Kansas approaches will decline as federal regulation runs its course and contemporary marketing scenarios take hold.

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88. *Id.*

89. *Id.*

90. First Nat'l Bank in Weatherford v. Exxon Corp., 622 S.W.2d 80, 82 (Tex. 1981).

91. 667 P.2d 337 (Kan. 1983).

92. *Id.* at 344-45.

93. However, the court can consider the overall impact of regulation on the market for gas. *Matzen*, 667 P.2d at 345.

[b]—Market Value in the Restructured Gas Market.

It is doubtful that the *Tara* approach to the market value royalty issue will survive as producers enter into new contracts in an era of gas marketing options.[94] Therefore, courts will employ a *Vela* approach, where they must ascertain the *current* market value to calculate the royalty due. As gas marketing becomes more like the sale of other readily deliverable commodities, courts should apply the Kansas approach to define comparable sales. Under this approach, the court considers only the physical characteristics of the gas without regard to its "legal" or "regulatory" status.[95] This concept becomes even more important for the time period between phased deregulation under the Natural Gas Policy Act[96] (NGPA) and final price deregulation under the Natural Gas Wellhead Decontrol Act.[97]

For example, under the Texas approach to comparable sales, which factors in the regulatory status of the gas,[98] a lessor may assert that the market value royalty should be calculated using only its regulated price as determined under the NGPA. Assume under the NGPA (and the existing gas contract) the gas is priced at $3.19 for July 1992.[99] However, no purchaser would *currently* pay $3.19 for the gas if they were buying it today. Instead, the price would be closer to $1.42, the average spot price for July 1992 as reported by the Natural Gas Clearinghouse.[100] The *value* which elevates

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94. *See* text *supra*, at § 18.03[3].

95. Matzen v. Cities Service Oil Co., 667 P.2d 337, 344-45 (Kan. 1983). As producers used to lament during the heyday of gas regulation: "gas-is-gas" and its intrinsic commodity value should not vary depending upon when a well was drilled or the interstate or intrastate nature of the pipeline carrying the gas to market.

96. 15 U.S.C. §§ 3301 to 3432 (1988).

97. Pub. L. No. 101-60, 103 Stat. 157 (amending portions of the NGPA) (1989).

98. *See, e.g.*, First Nat'l Bank of Weatherford v. Exxon Corp., 622 S.W.2d 80, 82 (Tex. 1981).

99. Using the § 104 Post-1974 gas price. II *FERC Stat. & Reg.* 14,183 (1992).

100. "Natural Gas Clearinghouse Spot Price Estimates for July 1992 Drop from Previous Month," *Foster Natural Gas Rep.*, July 2, 1992, at 20. The Clearinghouse

the price to $3.19, as opposed to $1.42, is attributed to the producer's gas *contract*, not to the *gas*. If market value means *current* market value, then the comparable sales should be *current* sales. However, lessors will argue that unregulated spot sales are not comparable to regulated sales. Although an accurate observation, rather than suggesting that unregulated spot sales should be ignored, it suggests that regulated sales are a remnant of a prior era and not representative of *current* gas values. Instead of arguing over what are "comparable sales," the parties should return to the basic charge of the courts in this area that market value can be established by "any competent evidence" which establishes the price "which would be paid by a willing buyer to a willing seller in a free market."[101]

Determining current market value under contemporary marketing scenarios should be relatively simple as the infrastructure for making and reporting current sales develops. If the lease calls for a royalty based upon the market value of gas "at the well," the lessee will consider the traditional physical qualities of the gas and the location of the well. "Location" means what it will cost to move the gas to a marketing point. If the gas must be gathered, compressed, processed, and transported to a marketing point, it will have a lower wellhead value than gas that requires minimal handling before being marketed. If wellhead sales are not made in the area, a workback formula must be employed that values the gas at a marketing point and then deducts the cost of getting the gas from the wellhead to the marketing point. Location will also play a major role when the lessee is at the mercy of a third party in control of a gathering system.

Determining the "spot" price in an area is merely the beginning of the process. If the lease calls for market value at the well, the spot price at the designated sales point must be reduced by the

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estimates are based on prices quoted by industrial end users and local distribution companies.

101. Matzen v. Cities Service Oil Co., 667 P.2d 337, 343 (Kan. 1983).

amount it will cost to get the gas from the wellhead to the sales point. This process accounts for the "location" criteria that plays a major role in determining market value.

The primary benefit of a "spot" price basis for calculating market value is that market forces and reporting services perform the valuations previously performed by expert witnesses in lengthy trials.[102] The spot price basis is a much more accurate representation of the value currently placed on gas at a particular sales point. It also has the benefit of focusing exclusively on the *current value of the gas commodity* without any adjustment for the value of the *contractual relations* between the producer and purchaser.

The primary virtue of using quality and location-adjusted spot prices to calculate market value royalty is that they come the closest to giving the lessor what was contracted for under the oil and gas lease. As the court noted in *Piney Woods*, "the market value clause serves in part to protect the lessor from bad bargains by the lessee."[103] The lessor's royalty, under a market value royalty clause, is based upon what is now becoming a very objective standard—a standard insulated from the lessee's manipulation and good faith, albeit poor, business judgments.

As with any limitation on risk, there is a price to pay. Under a market value royalty clause, the lessor gives up any claim to benefits the lessee may receive when the lessee assumes market risks by entering into longer-term contracts or sales transactions beyond the initial marketing point. As the *Vela* line of cases demonstrates, the lessee's market value risk can be substantial in a gas market of escalating prices. However, in a gas market of de-escalating prices, the lessee should be able to reap the full benefit of its contract risk assumption. For example, if the lessee has a

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102. For example, in *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 245 (Tex. 1981), the Middletons' expert reviewed over 30,000 monthly gas purchaser tax reports to arrive at an opinion concerning market value.

103. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 236, n.15 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

contract authorizing collection of NGPA prices of $3.19/Mcf, the lessee should be able to pay, under a market value royalty clause, royalty calculated from a properly adjusted spot price. For example, using the July 1992 spot price for sales at a designated sales point on Texas Eastern's pipeline, the price for royalty valuation should not exceed $1.45.[104] This would seem to be the correct approach in states following the *Vela* approach to market value royalty.

However, courts following the *Tara* approach may be reluctant to abandon the "market-value-equals-contract-price" rule on contracts that were entered into under the traditional marketing regime. Even though the underlying basis for the *Tara* approach no longer exists, the courts may find it "unfair" to now make lessors bear the burdens of the market after they were prevented from enjoying its benefits when market prices exceeded contract prices.

The market value royalty clause is uniquely suited for the new marketing scenarios that have developed to eliminate much of the commodity price risk in gas sales transactions. By moving to open price indexes, shorter-term transactions, and away from reserve commitments, shifts in the commodity price of gas are shared by all parties instead of being hung, by contract, on the unfortunate producer or purchaser. The market value royalty clause, in light of today's gas marketing realities, permits the lessor to share in the risk associated with changes in the commodity price of gas.

The commodity price "risk" associated with a market value royalty clause can be illustrated by considering the spot prices

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104. "Natural Gas Clearinghouse Spot Price Estimates for July 1992 Drop from Previous Month," *Foster Natural Gas Rep.*, July 2, 1992, at 20. If the lease provides for market value "at the well," the spot price would have to be adjusted downward to account for the cost of moving the gas from the wellhead to the sales point where the spot price is reported.

offered for natural gas during one six month period from January through June 1992:[105]

Jan.	Feb.	Mar.	Apr.	May	June
$1.61	$1.00	$1.17	$1.33	$1.48	$1.61

The average spot price for gas during this six month time frame *decreased* over 62% during one thirty day period, January to February 1992. Comparing the February price with the June price, the average spot price *increased* by 61%. The market value royalty clause, applying the *Vela* approach, would distribute these downward and upward shifts in price equally among the lessor and lessee.

If the lessee decided to enter into a long-term contract, the lessee would assume the risk, and should reap the benefits, of these price fluctuations. For example, assume the parties have entered into an oil and gas lease providing for 3/16ths of the market value of gas as a royalty. The lessee completes a well that produces 1,000 Mcf/month and enters into a six month contract to market gas from the well at a fixed price of $1.45/Mcf. The contract begins on January 1, 1992 and will terminate on June 30, 1992. Using the average spot prices for this time frame as the unadjusted market value for gas produced from the well, the lessee's royalty obligations, using the *Vela* approach, would be as follows:[106]

Jan.	Feb.	Mar.	Apr.	May	June
$301.88	187.50	219.38	249.38	277.50	301.88

For each month the lessee would realize, from the sale of the royalty owner's 3/16ths share of production, $271.88 which equals

105. "Natural Gas Clearinghouse Spot Price Estimates for July 1992 Drop from Previous Month," *Foster Natural Gas Rep.*, July 2, 1992, at 20. All prices are reported based on $/MMBtu. 1 MMBtu = 1 Mcf of gas having a Btu content of 1,000 Btu/cubic foot of gas.

106. Each calculation is made by taking the royalty owner's 3/16ths share of production, 1000 Mcf x 3/16 = 187.5 Mcf, and multiplying it by the reported spot price for the month of production.

187.5 Mcf[107] x the contract price of $1.45. The "risk" assumed by the lessee, and its attendant costs and rewards, is represented by the following chart:

Jan.	Feb.	Mar.	Apr.	May	June
$301.88	187.50	219.38	249.37	277.50	301.88
- 271.88	271.88	271.88	271.88	271.88	271.88
($30.00)	84.38	52.50	22.51	(5.62)	(30.00)

The net effect, if the lessee pays royalty based upon the current market value instead of proceeds received, is a profit of $93.77 on the 3/16ths share of gas attributed to the royalty owner. In this situation, the additional risk paid off for the lessee. However, had the fixed price been a few cents lower, the lessee would have lost money with regard to the 3/16ths share of production attributed to the lessor.

As the lessee extends the term of its contract, and assumes more risk, the current market price versus contract price disparities can be greater. For example, suppose the lessee entered into a five year contract at a fixed price of $3.00/Mcf. The lessee's reward for taking this "risk" during one six month 1992 time frame under the contract is represented by the following chart:

Jan.	Feb.	Mar.	Apr.	May	June
$301.88	187.50	219.38	249.37	277.50	301.88
$562.50	562.50	562.50	562.50	562.50	562.50
$260.62	375.00	343.12	313.13	285.00	260.62

The lessee will reap a $1,843.49 profit from the sale of the 3/16ths share of gas attributed to the royalty owner.[108] However, royalty owners under this scenario would probably claim an entitlement to royalties based upon the lessee's contract proceeds instead of the current market value.

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107. 1000 Mcf x 3/16 = 187.5 Mcf.

108. If spot prices rise above $3.00 during the life of the contract, the lessee would be caught in the more familiar market value royalty pinch.

Under the *Vela* approach, the lessors have no claim to amounts the lessee receives in excess of the current market value.[109] In *Piney Woods*, the court commented on the *Vela* approach as follows: "If the price of gas declines, a market value royalty clause would benefit a lessee who has contracted to sell gas at a favorable price."[110] Although the statement in *Piney Woods* was dicta, the Kansas Supreme Court addressed the issue directly in *Holmes v. Kewanee Oil Co.*[111] In *Holmes*, the Supreme Court affirmed that portion of the trial court's judgment awarding mineral owners "increased royalty payments" of $272,391.68.[112] The leases provided for payment of royalty based upon the "prevailing market rate" which the court held required payment of the price at the current rate prevailing when the gas is delivered rather than the proceeds or amount realized under a gas purchase contract.[113] The gas contracts had been entered into in 1929 and the gas prices in the contracts failed to keep pace with the current market value of the gas, resulting in the $272,391.68 liability.

The trial court also granted the royalty owners "prospective relief based on the section 108 price for the duration of regulation and thereafter the highest price paid for natural gas in Barber County."[114] The Supreme Court held that the trial court had erred in granting prospective relief because it would have unlawfully amended the lease, which provided for payment of royalty based upon *current* market values.[115] The Supreme Court explained its position stating: "The Okmar Contract and the section 108 price are the evidence of market price *in this case*. They are factual in nature

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109. This assumes their lease provides for payment of royalty based upon market value.

110. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 236, n.14 (5th Cir. 1984), *cert. denied*, 417 U.S. 1005 (1985).

111. 664 P.2d 1335 (Kan. 1983).

112. Holmes v. Kewanee Oil Co., 664 P.2d 1335, 1338 (Kan. 1983).

113. *Id.* at 1338, 1342.

114. *Id.* at 1342

115. *Id.*

and not controlling on future cases *because the market price might fluctuate*."[116] Since the court rejected the calculation of royalty applying "the highest price," the only way the market price could "fluctuate" would be a decrease in price. *Holmes*, therefore, supports the proposition that a market value royalty clause permits the lessee to retain any amount attributed to the royalty share of gas that is in excess of current market values. The only instance in which this could legitimately occur would be where the lessee sells the gas under a contract providing for a price greater than the current market value. The additional "value" realized by the lessee would not be attributable to the gas but to the lessee's contract.

Under the *Tara* approach, if the contract were entered into after real marketing options became available to lessees, the court should equate "market value" with "current market value," similar to the *Vela* approach. However, if the contract was entered into under the "old" gas marketing regime, where the lessee had no real marketing options, the court may be inclined to equate market value to the contract proceeds since the lessor, under the *Tara* approach, had to suffer any downside risk. Because gas marketing realities have changed, courts that traditionally followed the *Tara* approach should be inclined to abandon it for contemporary marketing scenario contracts in favor of the *Vela* approach.[117]

Where the royalty clause requires payment based on the "amount realized" or the "proceeds" received by the lessee, the lessor will share in the commodity price risks, and in any resulting rewards.[118]

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116. *Id.* (emphasis added).

117. *See* text *supra*, at § 18.03[3].

118. In *Imperial Colliery Co. v. OXY USA, Inc.*, 912 F.2d 696 (4th Cir. 1990), the court noted the difference between "market value" and "proceeds" royalty clauses stating:

> In oil and gas practice, there are two generally used lease clauses dictating the amount of royalties due under a lease: the 'market value' clause and the 'proceeds' clause. Under a market value clause, royalties are paid based upon the market value of the gas; under a proceeds royalty clause, upon the amount of money received by the lessee upon its sales of gas.

In these cases the primary focus will be upon the reasonableness of the contract price negotiated by the lessee. The reasonableness of the contract price will be tested under the implied covenant to market the lessor's production.[119]

§ 18.04. Defining Deductible Costs.

[1]—Pre-Restructuring Approaches.

Where the oil and gas lease clearly identifies the point at which "market value" or "proceeds" are to be determined, the lease terms will control. For example, if the lease provides for payment of the market value or proceeds "at the well" or "at the mouth of the well," and the actual sale of production takes place at some point beyond the wellhead, reasonable costs incurred by the lessee beyond the wellhead will be deductible in calculating royalty.[1]

Courts have held the phrases "at the well" and "at the mouth of the well," mean any place "on the lease."[2] Although the express terms of the lease do not refer to "anywhere on the leased premises," courts have generally given the phrase a broader effect to encompass the entire leased area instead of merely the wellhead location.[3] In *Exxon Corp. v. Middleton* the lease specifically

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Id. at 700.

119. See text, *infra*, at § 18.05.

1. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 240 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985). In *Piney Woods* the court noted:

> We emphasize, however, that processing costs are chargeable only because, under these leases, the royalties are based on value or price at the well. Processing costs may be deducted only from valuations or proceeds that reflect the value added by processing. Thus, processing costs may not be deducted from royalties for gas 'sold at the well,', because the price of such gas is based on its value before processing.

See generally 3 H. Williams, *Oil & Gas Law* § 645 at 595, 598-609 (1992)

2. Schupbach v. Continental Oil Co., 394 P.2d 1, 2 (Kan. 1964) (lease provided for royalty of "1/8th of the proceeds of the sale thereof at the mouth of the well."); Gilmore v. Superior Oil Co., 388 P.2d 602, 605 (Kan. 1964) (lease provided for royalty of "1/8 of the proceeds of the sale thereof at the mouth of the well.").

3. *See also* Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 228,

referred to gas "sold or used off the *premises* . . .."[4] The court in *Middleton*, relying upon the express terms of the royalty clause, equated "premises" to "the land described in the lease agreement."[5]

In *Piney Woods*, the court departed from a literal interpretation of the lease in favor of an interpretation it believed gave effect to the underlying purpose of the clause. The leases in *Piney Woods* provided for a royalty:[6]

> [O]n gas . . . produced from said land and sold or used, the market value at the well of one-eighth (1/8) of the gas so sold or used, provided that on gas sold at the well the royalty shall be one-eighth (1/8) of the amount realized from such sale . . ..[7]

Although Shell and its purchasers had structured a sale, and passage of title, "at the wells," the court found that the actual sale took place further downstream, off the leased premises. Therefore the proper royalty measure would be one-eighth of the "market value" instead of the "amount realized."[8] In discussing when a sale takes place "at the well," the court stated:

> [T]he purpose is to distinguish between gas sold in the form in which it emerges from the well, and gas to which value is added by transportation away from the well or by processing after the gas is produced. The royalty compensates the lessor for the value of the gas at the well: that is, the value of the gas after the lessee fulfills its obligation under the lease to produce gas at the surface, but before the lessee adds to the value of this gas by processing or transporting it. When the gas is sold at the well, the parties to the

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231 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) (leases provided for payment of 1/8th of the "market value at the well" and on gas sold "at the well . . . one eighth (1/8) of the amount realized from such sale . . ..").

4. Exxon Corp. v. Middleton, 613 S.W.2d 240, 241-2 (Tex. 1981).

5. *Id.* at 243.

6. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

7. *Id.* at 228.

8. *Id.* at 229.

> lease accept a good-faith sale price as the measure of value at the well. But when the gas is sold for a price that reflects value added to the gas after production, the sale price will not necessarily reflect the market value of the gas at the well. Accordingly, the lease bases royalty for this gas not on actual proceeds but on market value.[9]

Concluding its analysis, the court held: "'At the well' therefore describes not only location but quality as well."[10] Under this analysis, market value "at the well" means "market value before processing and transportation" as reflected by a price paid to the lessee for the gas as it is produced, "at the well."

If "at the well" means anywhere on the leased premises, this could narrow the scope of costs a lessee can deduct in calculating royalty. For example, if compressors, dehydrators, and an extensive gathering system are physically located on the leased premises, the lessors may argue that expenses associated with these facilities are not deductible since they are associated with operations "at the well." In *Gilmore v. Superior Oil Co.*,[11] the lessee, Superior, installed a large compressor on Gilmore's leased land to compress gas so it could be sold to a purchaser. The lease provided for a gas royalty of "1/8 of the proceeds of the sale thereof at the mouth of the well." The court equated "at the well" with anywhere "on the lease" and held that the gas was being compressed and delivered to the purchasing pipeline "on the lease." The court held the lessee's compression costs would not be deductible in calculating royalty noting: "The only purpose for the compressing station was to put enough force behind the gas to enable it to enter the pipeline *on the lease*. This made the gas marketable and was in satisfaction of the duties of the lessee so to do."[12]

A further narrowing of deductible costs could occur under this analysis when the lease provides for calculation of royalty "at the

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9. *Id.* at 231.

10. *Id.*

11. 388 P.2d 602 (Kan. 1964).

12. *Id.* at 606 (emphasis by the court).

pipeline." For example, in *Scott v. Steinberger*,[13] the royalty clause provided:

> [Lessee] shall deliver to the credit of . . . [lessor] free of cost in the pipe lines to which he may connect his wells one-eighth of all oil produced and saved on said premises, and shall pay the market price for same in cash if . . . [lessor] shall so desire; *and shall pay to . . . [lessor] one-eighth of all gas produced and marketed.*[14]

The lessee was unable to find a local market for its gas so it built a pipeline and sold the gas to a brick plant and an oil refinery at $0.15/Mcf. The lessee paid royalty to the lessor calculated at 1/8 x $0.08/Mcf, which reflected a $0.07/Mcf transportation charge to move the gas from the well to the end users. The lessor objected and asserted a right to be paid a royalty on the full $0.15/Mcf.

Holding that the lessee was authorized to deduct the transportation charge, the court stated:

> We think the parties contemplated . . . that gas, if produced would be measured and the price determined at the place where the wells were connected with pipe lines, and not at some distant market that might be found at the end of a pipe line remote from the field and where the cost of transportation might equal or exceed the value of the gas produced.[15]

Although the gas portion of the royalty clause merely stated the lessee "shall pay . . . lessor one-eighth of all gas produced and marketed," the court "borrowed" from the oil portion of the royalty clause which stated the lessee would deliver lessor's oil "free of cost in the pipe lines to which he may connect his wells . . .." The lessee would arguably be obligated to bear all costs of getting the gas to the pipeline.

Often the royalty clause is silent concerning at what point in the marketing process market value or proceeds should be cal-

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13. 213 P. 646 (Kan. 1923).

14. *Id.* at 646 (emphasis added).

15. *Id.* at 647.

culated. If the lease merely provides for payment of one-eighth of the proceeds from the sale of production, or one-eighth of the market value, disputes are likely to occur concerning where proceeds or market value should be determined. If proceeds or market value are determined at the wellhead, the lessor will bear a proportionate share of costs when the gas is marketed downstream from the wellhead. If proceeds or market value are based upon a sale downstream from the wellhead, the lessee will end up bearing all the costs associated with getting the gas from the wellhead to the sales point.

A series of Kentucky cases suggest that when the lease is silent concerning where in the marketing process market value or proceeds should be calculated, the lease should be interpreted to require payment calculated "at the well."[16] For example, in *Warfield Natural Gas Co. v. Allen*,[17] the lease provided for a royalty equal to "one eighth of proceeds received [by lessee] from the sale . . . [of gas]."[18] However, the lease was assigned by the original lessee to Warfield Natural Gas Co. which was also a gas pipeline company and local distribution company. Warfield took the gas from the field and ultimately sold it to customers in its service area. Warfield paid Allen royalties based upon the prevailing field price for gas, $0.12/Mcf. Allen demanded "one eighth of the proceeds received" by Warfield, which would have been the

16. La Fitte Co. v. United Fuel Gas Co., 284 F.2d 845, 847, n.4 (6th Cir. 1960) (lessor entitled to a royalty of "one-eighth (1/8) of the gross income received by the Lessee from the sale or disposition . . . of gas produced and sold or marketed in its natural or reduced state . . .."); Reed v. Hackworth, 287 S.W.2d 912, 913 (Ky. 1956) (lessor entitled to "deliver[y] to the credit of lessor, free of cost, in the pipe line to which he may connect his wells, the equal one-eighth part of all oil (and gas) produced and saved from the leased premises."); Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989, 990 (Ky. 1935) (lessor entitled to "the sum of one eighth of proceeds received [by lessee] from the sale . . . [of gas]."); Rains v. Kentucky Oil Co., 255 S.W. 121, 122 (Ky. 1923) (as royalty on gas "[lessee] to pay fifty or 1/8 dollars each year for the product of each well while the same is being used off the premises . . ..").

17. 88 S.W.2d 989 (Ky. 1935).

18. *Warfield*, 88 S.W. 2d at 990.

proceeds received from consumers after it had been transported from the wellhead to Warfield's service area.[19]

The court held that, when the lease is silent regarding where marketing must take place, "it is usually held to be the place of production."[20] The court found that, since the gas was measured at the well and the lessee took the gas at the well, the lessee should be required to pay a royalty based on the wellhead value, not on the value for which it was ultimately sold in a downstream transaction.[21]

The West Virginia Supreme Court arrived at a contrary result in *Cotiga Development Co. v. United Fuel Gas Co.*[22] In *Cotiga*, the lease required the lessee to pay the lessor "one-eighth (1/8) of the gas produced from each gas well . . . from which the gas is marketed . . . *at the rate received by Lessee for such gas* . . .."[23] As in the *Warfield* case, the lessee was a public utility that produced the gas and then transported it to customers served by its pipeline. United paid royalties based on the prevailing wellhead market price in the area covered by the lease.[24] Cotiga argued:

> [T]he proper basis for computation of royalties is not the wellhead price, but rather that such royalties should be computed on the basis of the price received by United Fuel for such gas when sold after having been commingled with gas from other sources and trans-

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19. *Id.* at 991-92.

20. *Id.* at 991. However, the court also noted: "Proceeds of a sale, unless there is something in the context showing to the contrary, means total proceeds." *Id.*

21. *Warfield*, 88 S.W.2d at 991. The court concluded, stating:

> Nothing was said in the lease about a sale elsewhere and this lease must be held to mean one-eighth of the gross proceeds of a sale of the gas at the well side, *and that is all for which defendant must account even though it may market the gas elsewhere and get a much greater sum for it.*

Id. at 992 (emphasis added).

22. 128 S.E.2d 626 (W. Va. 1962).

23. *Id.* at 630 (emphasis added).

24. *Id.* at 633.

ported to the various points of sale.[25]

The court agreed with Cotiga and held that United was obligated to pay to Cotiga one-eighth of the proceeds United received when it sold the gas to its first purchasers, its retail gas customers.[26]

The North Dakota Supreme Court took a somewhat similar approach in *West v. Alpar Resources, Inc.*[27] interpreting a lease providing for a royalty equal to "one-eighth of the proceeds from the sale of the gas . . .."[28] The gas, when produced, was "sour," so the lessee installed an amine plant on the leased premises to remove the hydrogen sulfide.[29] After the gas was treated, it was sold to a gas utility. In calculating the lessor's royalty, the lessee deducted a charge for removing the hydrogen sulfide. The lessor objected.

The court first found that the royalty clause was ambiguous because it merely referred to "proceeds" without indicating whether it should be gross proceeds or net proceeds. The court resolved the ambiguity against the lessee holding: "[T]he Wests are entitled to royalty payments based upon a percentage of the total proceeds received by Alpar [lessee] from the sale of gas without deduction for the cost of extracting hydrogen sulfide and without deduction for any other cost incurred by Alpar."[30]

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25. *Id.*

26. The court noted:

> It may very well be that a determination of 'the rate received' by United Fuel will be difficult in view of the commingling of Cotiga's gas with other gas and in view of the fact that United Fuel occupies the status of a public service corporation; but any difficulty or hardship of this nature cannot serve to alter the plain provisions of the lease.

Id. at 634.

27. 298 N.W.2d 484 (N.D. 1980).

28. *Id.* at 486.

29. *Id.* at 487.

30. *Id.* at 491.

The *West* approach would seem to prohibit the lessee from deducting any costs from the gross proceeds for royalty purposes. This could cause the lessee to forego otherwise lucrative marketing opportunities because of the greater royalty burden. With such a royalty clause, the lessee may decide to sell gas at the wellhead when it could otherwise treat the gas and obtain a better price for all parties involved.

For example, suppose the untreated gas could be sold at the wellhead for $1.45/Mcf, but, if treated, would sell for $1.90; it would cost the lessee $0.40/Mcf to treat the gas. If the lessee can deduct the cost of treating the gas to calculate the lessor's share, the lessee will build the plant and net $0.05/Mcf more on all the gas for the benefit of both lessor and lessee. However, if the lessee must bear all the cost of treating the gas, it will elect to sell its gas at the wellhead and the lessor and lessee will each be worse off.[31] The mathematical calculations supporting the lessee's decisions are as follows:

Able to deduct costs:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$1.90	$0.40	$0.19	$1.31

Not able to deduct costs:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$1.90	$0.40	$0.24	$1.26

Wellhead sale without treatment:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$1.45	$0.00	$0.18	$1.27

31. The lessor's royalty would be about $0.01/Mcf less and the lessee's net revenue interest would be about $0.04/Mcf less, but still $0.01/Mcf more than if it treated the gas but was unable to deduct treatment costs attributable to the royalty owner's share.

In *Reed v. Hackworth*,[32] the court addressed the point-of-sale issue under a market value lease. The lease required the lessee: "To deliver to the credit of lessor, free of cost, in the pipe line to which he may connect his wells, the equal one-eighth part of all oil (and gas) produced and saved from the leased premises."[33] Although this clause appears to entitle the lessor to take its share of production in kind, the lessee marketed all the gas from the property by transporting it two and one-half miles and selling it to a public utility for $0.25/Mcf.[34] The purchaser advanced the cost of building the pipeline to the lessee who agreed to permit the purchaser to withhold $0.10/Mcf to recoup the pipeline costs. The lessee paid royalty based upon a gas value of $0.15/Mcf.[35]

The lessee argued that, since the lease was silent with regard to where market value should be determined, royalty should be calculated applying the fair market value of gas at the well.[36] The court agreed stating: "We conclude that where, as here, the lease is silent concerning the place of market and the price, the royalty should be applied to the fair market value of gas at the well."[37] Expert testimony established the fair market value of gas at the well to be between $0.12 to $0.15/Mcf. The court approved the lessee's payment of royalty on $0.15/Mcf.[38]

As the foregoing cases demonstrate, when the lease fails to designate a specific point in the marketing process for calculating proceeds or market value, courts have taken varying approaches.

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32. 287 S.W.2d 912 (Ky. 1956).

33. *Id.* at 913.

34. *Id.*

35. *Id.*

36. *Id.*

37. *Id.* at 913-14.

38. *Id.* at 914. With regard to the ten cent pipeline fee, the court stated: "Since the additional ten cents obviously was intended to compensate for the cost of piping, the appellee [lessor] is not entitled to any portion of that amount, or any interest in the pipe line, which will belong to Reed [lessee] when its cost is paid in full." *Id.*

However, contemporary marketing scenarios seem to shift the equities in the dispute in favor of the lessee. Contemporary marketing scenarios also offer the lessee a number of options for structuring sales to avoid disputes. These matters are discussed in the next section.

[2]—Impact of Restructuring.

The major impact of restructuring on the deductible cost issue is further, and arguably complete, divorcement of the production function from the marketing function. Marketing is now recognized as a separate business. Marketing services will often constitute a significant cost in selling gas. A major issue is whether the lessee can properly deduct marketing costs in calculating royalty under the various royalty clause forms. The outcome may depend on whether the lessee is deducting (1) the value of its own internal marketing staff, (2) a fee paid to an affiliated marketing company, or (3) a fee paid to unaffiliated marketers.

The issue may be avoided when the lease provides for a market value royalty, calculated at the well. In these situations, at least under the *Vela* approach, the value of the gas will be determined without regard to the lessee's particular marketing arrangements.[39] However, the issue could become relevant in trying to work back from a reported spot price at a major sales point to the location of a particular well. Then, the market value at the well may be reduced to reflect the administrative cost of moving gas from the wellhead to the sales point selected as a market value reference. This marketing cost, if appropriate in calculating market value at the well, would be deductible regardless of what the lessee does.

The issue becomes more difficult under a "proceeds" royalty clause. If the clause provides for payment of proceeds "at the well,"

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39. This would also eliminate problems associated with lessees selling to their marketing affiliates since market value for royalty purposes would be determined without regard to the price or terms provided for in the affiliate transaction.

the lessee will be able to deduct costs paid to generate the proceeds. This would seem to limit the deductible costs to those actually paid to other entities and restrict the lessee's ability to make a charge for its internal marketing staff services. However, affiliate transactions should be recognized, particularly when there are non-affiliated entities providing similar services by which to test the reasonableness of affiliate charges.

If the lease does not designate the sales point for calculating market value or proceeds, cost deduction will depend on whether the court will resolve the ambiguity in favor of a transaction "at the well" or at some point downstream from the wellhead where the exchange of cash for gas actually takes place. Courts, under contemporary marketing scenarios, may be more inclined to resolve the issue in favor of lessees and establish the sales point "at the well." Under contemporary marketing scenarios, applying the "cash-for-gas" approach could produce some very inequitable results and cause lessees to pursue marketing options that are economically prudent but leave lessor and lessee both worse off. For example, if "proceeds" under a proceeds lease equals the cash actually paid by the purchaser to the producer for the gas,[40] the lessee would have to bear all the costs of moving the gas from the wellhead to the ultimate sales point and then pay royalty on the total "proceeds" received.

The potential inequity to the lessee, and the economic perversion caused by such a rule, is demonstrated by the following contemporary marketing scenario:

The mineral owner leases land to Acme Oil Company. The lease provides for a royalty of "1/8th of the proceeds from the sale of gas." Acme has entered into a contract to sell gas to BallPark Cards in Pittsburgh, Pennsylvania. BallPark has agreed to pay $2.75/Mcf for the gas at a delivery point in Pittsburgh. Acme produces the gas, runs it through a gathering system owned and

40. The cash-for-gas approach.

operated by Major Oil Company, then into Interstate Pipeline Company's pipeline. Interstate transports the gas to Pittsburgh where it is moved through a distribution line owned by a local distribution company (LDC), and delivered to BallPark's manufacturing plant.

Mineral owner obtains a royalty check showing the following calculations:

Volumes: 1 Mcf
Gross Proceeds: $2.75/Mcf (paid by BallPark to Acme)
Deductions:
Gathering: $0.50/Mcf (paid to Major)
Transportation: $0.80/Mcf (paid to Interstate)
Transportation: $0.20/Mcf (paid to LDC)
Net Value for Royalty Calculation: $1.25/Mcf

If Acme is able to deduct the marketing costs to calculate the mineral owner's royalty, the royalty owner will receive $0.16/Mcf and Acme's net revenue interest will be $1.09/Mcf. However, if Acme must pay royalty on the total proceeds without deducting marketing costs, the royalty owner will receive $0.34/Mcf and Acme's net revenue interest will be $0.91/Mcf. If Acme could merely sell the gas at the wellhead for $1.05/Mcf, without carrying any marketing costs, the lessee would net $0.92/Mcf after paying a 1/8th royalty.[41] However, if the lessee tried to obtain a better price for the gas by seeking marketing alternatives, it would only net $0.91/Mcf after paying a 1/8th royalty on $2.75 ($0.34) and carrying the entire $1.50/Mcf in marketing expenses. The additional time and effort netted the lessee $0.01/Mcf *less* than merely selling at the wellhead.

However, if the costs are allocated proportionately between lessee and lessor, each would be better off: the lessor by $0.03/Mcf and the lessee by $0.17/Mcf. The share of each party is enhanced and the economic incentive for the lessee to market the gas actively

41. The lessor's royalty on $1.05 would be $0.13.

is preserved. The mathematical calculations supporting the lessee's decisions are as follows:

Able to deduct costs:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$2.75	$1.50	$0.16	$1.09

Not able to deduct costs:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$2.75	$1.50	$0.34	$0.91

Wellhead sale without treatment:

Sales Price	Costs	Lessor's Royalty	Lessee's Net Revenue Interest
$1.05	$0.00	$0.13	$0.92

If the marketing costs could be deducted before calculating the royalty, the lessee would be encouraged, and under the implied marketing covenant perhaps required, to seek out such marketing opportunities.

This example demonstrates how the deductible cost issue can become magnified by contemporary marketing scenarios in which the lessee may spend $1.00/Mcf or more to generate the gas sale "proceeds." This should tend to make courts less likely to adopt royalty clause interpretations that place the entire cost burden on the lessee. It will also promote the separation of the marketing and production functions. Because of these developments, courts, and royalty owners, are likely to shift their focus from deductible costs to the lessee's implied marketing covenant obligations.

§ 18.05. The Lessee's Implied Covenant to Produce and *Sell* Gas.

Cases defining the implied covenant to "market" under the traditional marketing scenario could take on a distorted meaning when applied to contemporary marketing scenarios. Under the traditional marketing scenario, the act of "marketing" meant to sell the gas to a pipeline at or near the field where it was produced.

Courts defined the lessee's duty as being simply to "market the product once it is discovered" and to act as a prudent operator to obtain the best price for the gas when arranging a sale.[1] However, the lessee has never been obligated to expend large sums of money to build pipelines or seek distant markets.[2] In reality, the traditional implied covenant to market has been nothing more than an implied covenant to *sell* gas produced from the property at an acceptable price.

The scope of the *implied* covenant becomes even narrower when the lease provides for market value royalty in a jurisdiction applying a *Vela* approach to market value. Arguably, the *implied* covenant, with regard to price, never operates because an *express* covenant, the royalty clause, states the basis for payment—current market value. Therefore, the implied marketing covenant consists of the obligation to *sell* gas produced from the property.[3] Using current market value for royalty calculation avoids disputes between the lessor and lessee as to whether the lessee prudently shopped all marketing options before selecting a sales option.[4]

However, where the lease requires royalty calculated on a proceeds basis, the price element of the implied covenant will be the lessor's primary focus. When a proceeds lease is involved, the implied covenant analysis consists of two components: (1) Did the lessee obtain the best price currently available for the gas under the circumstances? and (2) Are the other terms of the sales transaction prudent with regard to the dual interests of the lessor and lessee? If the interests of the lessor and lessee coincide, the chance for

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1. *See generally* Amoco Prod. Co. v. First Baptist Church of Pyote, 579 S.W.2d 280, 285 (Tex. Int. App. Ct. 1979), writ ref'd n.r.e.

2. *See, e.g.,* Reed v. Hackworth, 287 S.W.2d 912, 913 (Ky. 1956).

3. Even this portion of the implied covenant may be modified by express lease clauses, such as a properly drafted shut-in royalty clause.

4. This would be particularly helpful where the lessee sells to an affiliate, conducts its own processing operations, or engages in other activities which may cause the lessee to select a marketing option for some reason other than the highest current sales price.

dispute is reduced.[5] The major problem with contemporary marketing scenarios concerns the requirement to obtain the best price available. Under the traditional marketing scenario, this consisted of contacting the one, two, or perhaps three, pipeline purchasers in the area and negotiating for a long-term contract under the best terms currently being offered. Under contemporary marketing scenarios, the lessor might argue that the lessee should have arranged for transportation of the gas from the wellhead in West Virginia to an end user in New York. This imposes a much greater burden on the lessee and, unless the lessee has an in-house marketing staff, may require the lessee to contract with independent marketers to search out the best deal available.[6]

It is doubtful that the parties to the lease ever contemplated the lessee being responsible for extensive marketing services. Contemporary marketing scenarios have divorced the production function from the marketing function, treating them as separate business enterprises. Courts should therefore limit the lessee's implied marketing obligation to obtaining a sale of production, upon reasonable terms, at or near the field where produced.[7] Where the lease provides for a market value royalty, the nature of the terms of the sale simply do not matter since the lessor will be entitled to royalty based upon the current market values. Where the lease provides for a proceeds royalty, the terms must be reasonable and, arguably, the best terms currently available at or near the wellhead, or beyond the wellhead, *at the election of the lessee*. However, when a proceeds lease is involved, and the lessee's interests

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5. But not eliminated. As time goes on the lessor may try to hindsight the lessee when what seemed like a great deal five years ago does not look so good today. *See, e.g.*, Robbins v. Chevron U.S.A., Inc., 785 P.2d 1010 (Kan. 1990).

6. This also raises the issue whether the lessee's marketing expenses would be deductible in calculating royalty. If they are not, and the lessee's net revenue interest would be greater under a wellhead sale, a "prudent operator" would most likely opt for the wellhead sale even though it may net the lessor a lower royalty.

7. If a market is not available at or near the field where produced, the lessee should be obligated to search out the next closest available market.

conflict with those of the lessor, the courts may examine the lessee's marketing choices more closely to ensure that the lessee is not obtaining benefits for itself at the lessor's expense.[8]

§ 18.06. Lessor and Lessee Strategies.

[1]—Lessor Strategies.

Under existing oil and gas leases, the lessor should be vigilant concerning the basis on which their royalty is being calculated. If the lease provides for royalty based upon market value, the lessor should track spot prices in their area to ascertain whether they are being properly paid. In states following the *Tara* market value approach, the lessor should determine whether the lessee is marketing under a gas contract which provides for higher prices than current market values. If so, the lessor can argue entitlement to royalties based on the higher contract prices—at least where the contract was entered into before marketing options became available in the area.

For leases valuing royalty on a proceeds basis, the lessor should ascertain how the gas is being marketed and determine whether the contract represents the best price and terms available at the time it was made. The lessor should also determine what costs, if any, are being deducted before calculating the royalty due.

When the lease is silent regarding deductible costs, the lessor's best approach may be to argue that the lessee has an implied covenant to make the gas "marketable." Under contemporary marketing scenarios, the lessor would argue that "marketable" includes all costs associated with moving the gas to the first marketing point where willing buyers can interact with willing sellers. In many instances, this would impose on the lessee all costs of producing, gathering, compressing, treating, and transporting to the first available marketing point on a pipeline.

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8. *See generally* Amoco Prod. Co. v. First Baptist Church of Pyote, 579 S.W.2d 280, 285 (Tex. Int. App. Ct. 1979), writ ref'd n.r.e.

Courts and commentators have generally evaluated expenses by defining where the production process ends and the post-production process begins. The lessee would be solely responsible for costs incurred in the production process. However, post-production costs would be deducted from total revenues before calculating the lessor's royalty. The problem, however, is that courts and commentators differ regarding where the processes begin and end. For example, Professor Maxwell would declare the production process at an end once the gas is brought to the surface.[1] Professor Merrill, on the other hand, would hold that the production process is not completed until the lessee has produced a marketable product.[2] Building on Professor Merrill's analysis, in light of present day marketing realities, the lessor could argue that the product is not "marketable" until it is brought to a marketing point where willing buyers and sellers can meet and conclude a sale. However, to the extent there is an active market at the wellhead, the wellhead may be the relevant point for making this determination.[3]

With regard to new leases, what should the royalty clause look like? From an analysis of the *Tara* and *Vela* line of cases, it would be beneficial for the lessor to have the royalty calculated on the basis of "current market value of the gas or the gross proceeds received by the lessee, *whichever results in the largest current payment of royalty to the lessor.*" The lease should define the costs that can be deducted prior to calculating the royalty due. The lease should also specify the lessee's marketing obligations. For example, will the lessee be obligated to market the gas for the best price possible, making full use of all marketing outlets available to it?

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1. Maxwell, "Oil and Gas Royalties—A Percentage of What?," 34 *Rocky Mtn. Min. L. Inst.* § 15.03[1] (1989).

2. M. Merrill, *Covenants Implied in Oil and Gas Leases* § 85, pp. 214-15 (2d ed. 1940 and Supp. 1964).

3. This may often be the case where a third party owns the gathering system and is buying gas at the wellhead.

[2]—Lessee Strategies.

Probably the most desirable form of royalty clause for the lessee today is a market value royalty clause which requires payment of royalty based upon current market values. If interpreted by courts in light of present marketing realities, a current market value royalty calculation provides the lessee with the maximum flexibility to market the gas to or through affiliates, through marketing pools, or any other arrangement. It is also imminently fair to the royalty owner, who will receive, with the emerging spot-pricing network, the market value the lease requires regardless of what the lessee does with the gas.

If the lease calls for payment of royalty based upon the proceeds received by the lessee, the lessee should be talking with the lessor to try and define how "proceeds" will be calculated. When gas is aggregated from several leases to create a marketing "pool" of gas, and sales are made to several buyers at different prices, it is impossible to say who purchased the gas from a particular lease. Since wells are seldom dedicated to a contract under contemporary marketing scenarios, it is not feasible to allocate production to a particular sale.

Many producers have responded to this pooled-sale problem by calculating the lessor's royalty based upon the "weighted average price of gas"[4] sold from the pool during the month. However, lessors with a proceeds lease may not be willing to settle for the WAPOG price when they can identify distinct sales transactions from the pool that individually exceed the WAPOG. They might also argue that, if lessors having market value leases are being paid a WAPOG price greater than the current market value, the WAPOG is not a fair indicator of proceeds since some of the value of the proceeds transactions is being improperly paid to the market value royalty owners.

Perhaps the best way to deal with this situation is to try and

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4. The "WAPOG."

negotiate an amendment to the proceeds leases to provide for payment of current market value or on an agreed WAPOG formula. Another option for some operators might be to structure their sales as net-back transactions where the proceeds are represented, each month, by a formula instead of a price. For example, the lessee may agree to accept 85% of the amount received by a marketing entity. The marketing entity might gather, compress, treat, process, transport, and market the gas for which it receives proceeds from a buyer, deducts its marketing expenses, and pays the balance to the lessee. Lessors will probably test these types of arrangements under the implied marketing covenant. However, in most instances the arrangement will be prudent and, in many instances, the only market available.[5]

It is likely that courts, and royalty owners, will begin to "test" proceeds transactions with a current market value reference. Particularly if sales from the marketing pool are less than current market values. This could occur, for example, when some of the gas the lessee is selling from the pool is priced under longer-term contracts that are not keeping pace with current market values. In this situation, the lessors being paid at the WAPOG are subsidizing a bad deal made by the lessee. If the WAPOG falls below the current market value, certainly lessors with market value royalty clauses will object—a classic *Vela* situation for the 90s. The proceeds royalty owners will retort with: "that's not *my* contract" and demand that they not be required to subsidize the lessee's separate marketing business.

For new leases, a market value royalty clause, requiring current market values based upon location, quality, and adjusted spot prices, would seem to be the most workable approach. The calculation should be made "at the wellhead." The drafter may

5. For example, when the marketing entity owns the gathering system connecting the well to the only major pipeline in the area. In some of these situations, the lessee may have an implied obligation to seek administrative relief to force open access to the gathering system at reasonable rates and terms.

want to define wellhead to mean the precise well site instead of the "leased premises." The major issue regarding market value will be determining how to work back from a recognized sales point to the well location.

Lessees desiring to enter into longer term gas sales should not forget the teachings of *Vela* and the other market value royalty cases. The best way to approach this problem is to go to the lessor, at the time the deal is proposed, and ask if the lessor will amend the lease to accept royalties under the contract.[6] If the contract price is a good one, the lessor will probably agree to amend the lease. If the lessor refuses to amend the lease, the next step would be to negotiate an excess royalty clause with the gas purchaser, or an option to release the royalty share of gas in the event current royalty values exceed the contract price by a stated margin.

§ 18.07. Conclusions.

Lessees face new challenges as they attempt to adjust their operations to account for new opportunities created by the restructured gas market. Lessors will be challenged as they attempt to monitor the lessee's actions to ensure that new marketing opportunities are not being pursued at the expense of the lessor's rights under the oil and gas lease. However, both parties should be aided by the development of a recognized market value for gas based on spot prices for current gas sales. For the first time, the market value of gas can be determined without regard to the trappings of long-term contracts where few sales were truly "comparable" or representative of the current commodity value of the product being sold.

As the gas marketing system matures, the sale of gas will become similar to the sale of oil where lessors, almost uniformly, are paid royalty based upon the market value of the commodity at

6. The amendment should also clarify the lessor's status as a third party beneficiary of the gas contract and the lessor's right to share in any of the benefits provided for in the gas contract.

the time it is sold. Nevertheless, long-term gas sales will continue to play a major role in gas marketing and all parties will need to carefully consider the lessee's royalty obligations when entering longer term sales.