

ROYALTY GAS VALUATION IN THE NEW GAS MARKET – THE LESSORS’ PERSPECTIVE

A. Gas Royalty Payment In The Historical Gas Market

By definition, royalty on oil and gas is an interest in production (or measured by production) which is free of all costs of drilling, completing and operating the well from which it is produced. Beyond that seemingly clear definition lay myriad exceptions and qualifications which multiply when applied to gas (as opposed to oil) production. Oil royalty has traditionally been paid either in cash or in kind. If taken in kind, oil is delivered to the lessor in identified facilities at the surface. Due to the nature of gas production and problems of delivery and storage, gas royalty is typically paid only in cash. Inherent in this fact is potential for conflict between lessor and lessee since, effectively, the lessee is contracting to sell gas in which the lessor has an interest and the lessor rarely has any say in the sale. Further complicating the conflict is the fact that the lessee's sale and receipt of proceeds is governed by a gas contract between the producer and a purchaser. However, the lessor/lessee relationship regarding valuation and payment of royalty is governed by another contract - the oil and gas lease.¹ Market factors which in turn drive gas purchase contract terms have often created difficulties for producers in satisfying their royalty obligations under the terms of the oil and gas lease. In turn lease terms have developed over time to accommodate the problems experienced.

Most of the lease forms in use over the last fifty years provide for two types of gas sales, and consequently, two means of calculating and paying gas royalties.

¹Producers and purchasers have often sought to reconcile acknowledged variance between royalty obligations arising under oil and gas leases and realities of the sales transactions in division orders which authorize the accounting basis necessitated by the contract. See Exxon Corp. v. Middleton, 613 S.W.2d 240, (Tex. 1981). A lessee's ability to alter royalty obligations by contrary provisions in division orders has been circumscribed in recent years. Tex. Nat. Res. Code Ann. §§91.401 et seq. (Vernon 1991).

These lease forms are reflective of the gas market existing at the time the forms were generated, generally involving commitment by the producer to sell to a specific purchaser (or under a specific contract) full wellstream production from leases for a long term, or for the life of the lease at a fixed price. The gas was usually delivered or made available to the purchaser at the wellhead or at some designated point in the vicinity. In rare instances a producer could access a market other than at the wellhead in which a different payment standard was needed. Thus, leases generated during this period provided for one standard for sales at the wellhead and another for sales or use off the lease. If gas is sold "on the lease" or "at the mouth of the well" the royalty has been generally based upon the proceeds received from the sale of that gas at the point of sale. In the case of a true wellhead sale, there is rarely any issue of whether or what post-production expenses may be borne by the royalty--there should be few, if any, such expenses.² In such case the royalty should bear only its share of taxes charged on production.

The second type of sale is an "off premises" sale. If gas is "sold or used off the premises," the royalty has been measured by the "market value at the well" of the gas so sold or used. Market value relates to the time at which the gas is actually produced and sold, and is determined by reference to sales of gas which are comparable in time, quality, quantity and availability of marketing outlets and is based upon gas which is "free and available for sale."³ The general definition of 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

²Skaggs v. Heard, 172 F.Supp. 813, 817 (S.D. Tex. 1959) (because sales took place on lease premises after compression lessor bears no compression costs).

³Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981); *see also*, Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 872 (Tex. 1968). Under this rule, the lessees' sale price does not govern the amount owed the royalty owners, which is instead governed by an objective standard for a larger area. However, this rule may have been changed by the Texas Division Order Statute, Tex. Nat. Res. Code Ann. §§ 91.401 et seq. (Vernon 1991), for instruments executed after 1991.

necessity of buying it."⁴ The Court in Exxon Corp. v. Middleton further defined the relevant inquiry as follows:

"Market value may be calculated using comparable sales. Comparable sales of gas are those comparable in time, quality, quantity and availability of marketing outlets. Vela, supra.

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. Quality also involves legal characteristics of gas; that is, whether it is sold in a regulated or unregulated market, or in one particular category of a regulated market (footnote omitted). 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. Gas from fields with outlets to interstate markets only, for instance, would not be comparable to gas from a field with outlets only to the intrastate market."⁵

Among the characteristics to be considered in identifying "comparable" sales are legal characteristics (such as regulated vs. unregulated) of the gas.⁶ The determination of what constitutes a "comparable" sale for purposes of determining "market value" is often a contested issue. In litigation involving market value royalties, the comparability issue for valuation is inherently fact-intensive.

Because the valuation point is a point of sale off the lease, the lessee is allowed to deduct the cost of getting the gas to the valuation/sales point in

⁴Exxon Corp. v. Middleton, supra, at 246 (citing Polk County v. Tenneco, Inc., 554 S.W.2d 918 (Tex. 1977)).

⁵Id. at 246-47.

⁶First National Bank v. Exxon Corp., 622 S.W.2d 80 (Tex. 1981). The Court's opinion in this case, while very terse, reaffirms the premise that regulated sales which can only go into interstate markets are not comparable to gas which can be sold in intrastate markets. Id. at 83 (citing Exxon Corp. v. Middleton).

determining the equivalent value "at the well."⁷ During most of the history of gas production, most gas sales have fairly neatly fit within one of these two categories.

In either type of sale, the valuation point is at the well. In reviewing valuation issues as to specific gas sales, "at the well" means, at minimum, on the lease, though it may include sales which do not physically occur at the wellhead itself. For example in Skaggs v. Heard⁸ a sale at a separator on the lease some 330 feet from the wellhead was held to be a sale at the well. Conversely, the Court in Exxon Corp. v. Middleton expressly disapproved the holding in Butler v. Exxon Corp.,⁹ that a sale off the leased premises, but within the field of production could be a sale "at the well."

There have been at least two common approaches to determining market value at the well. The first is to consider the sale at the sales point as being reflective of the market and then working back to the wellhead, deducting the reasonable costs of making the gas marketable (e.g., costs associated with transportation to the sales point, processing, dehydrating, etc.). This approach has been used when no comparable sales are found in the field¹⁰ and may or may not reflect a true market value at the well, depending upon the producer's success at marketing, and is really more akin to trying to approximate "proceeds" at the well. A second approach is a "comparable sales" approach -- tying the value to values demonstrated by other sales in the relevant market for sales of gas of like kind, quality and quantity. This is the approach considered and approved by the Court in

⁷Phillips Petroleum Co. v. Johnson, 155 F.2d 185 (5th Cir. 1946) (lessor required to bear proportionate share of transportation cost when gas sold off the premises).

⁸172 F.Supp. 813 (D.C. Tex 1959) (cited with approval in Exxon Corp. v. Middleton, *supra*, 613 S.W.2d at 244).

⁹559 S.W.2d 410 (Tex. Civ. App. -- El Paso 1977 writ ref'd n.r.e.).

¹⁰See Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 238-40 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); Montana Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978).

Exxon Corp. v. Middleton.¹¹ While this approach is more subjective (due to the need to decide what is "comparable") it should be more reflective of a true market value.¹²

Either approach can result in benefits to either the lessor or lessee. For instance, in Exxon Corp. v. Middleton, the Texas Supreme Court concluded that under a royalty clause calling for market value royalties for sales off the lease, a lessee could face liability for royalties based upon the market value of gas which is "free and available for sale" in the area, notwithstanding its receipt of a far lower price for the gas because of an existing contractual obligation. This finding was fully consistent with the Court's prior ruling in Texas Oil & Gas Co. v. Vela. In such cases the comparable approach is highly beneficial to the royalty owner.¹³ Under the Court's ruling in Exxon Corp. v. Middleton, using the net back to the well approach would be improper since under the Court's findings the contract price would not equate to a current market price. However, it is not hard to conceive of a circumstance in which gas could be dedicated to a contract that calls for a higher price than the current market value. Under Middleton and Vela and their progeny, the lessee's royalty obligation may then be tied to the current market value irrespective of the price received by the lessee. While no Texas appellate court has yet directly decided the issue, this result would be very beneficial to the lessee and result in the lessor being paid on a gas value less than the actual sales price.¹⁴ Both approaches leave considerable room for controversy between lessors and lessees.

Beyond these generalities about the types of sales, one must determine how specific royalties must be accounted for. In general, the language in the gas royalty

¹¹613 S.W.2d at 246.

¹² See Texas Oil & Gas Co. v. Vela, 429 S.W.2d 866 (Tex. 1967); Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225,239 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

¹³In any event the question of whether such a sale could be reflective of the market is not conclusively resolved by the existing body of Texas case law.

¹⁴See Piney Woods Country Life School v. Shell Oil Co., 726 F.2d at 236 n.14 (dicta).

clause of the lease will control the manner in which gas royalty is calculated and paid. If the lease royalty clause specifically provides for a means of valuation or delivery of royalty, that clause will govern, irrespective of whether it is advantageous or disadvantageous to the lessor.¹⁵ As with other lease obligations, royalty obligations are primarily a matter of contract, and the express contractual provisions will govern the parties' rights. In addition, however, Texas courts have long implied lease covenants imposing upon lessees a “duty to reasonably market” gas production.¹⁶ In 1981, the Texas Supreme Court adopted Professor Richard Hemingway’s analysis of the implied covenants in oil and gas leases, stating that the implied covenant to manage and administer the lease has four components: (1) to produce and market; (2) to operate with reasonable care; (3) to use successful, modern methods of production and development; and (4) to seek favorable administrative action.¹⁷ The lessee should be held to a “reasonably prudent operator” standard for its performance of implied covenants.¹⁸ What is referred to as the marketing covenant is the first element of the covenant to manage and administer. The marketing covenant is not displaced by express provisions in the lease on royalty valuation; but, instead it establishes the standard of conduct by the lessee in performance of its marketing obligations.¹⁹

¹⁵See Magnolia Petroleum Co. v. Connellee, 11 S.W.2d 158 (Tex. Comm'n. App. 1928, judgment adopted) (enforcing fixed rate royalty clause as written); Schlipf v. Exxon Corp., 626 S.W.2d 741 (Tex. Civ. App. -- Houston [14th Dist.] 1981), *aff'd*, 644 S.W.2d 453 (Tex. 1982) (upholding settlement based upon fixed rate royalty against allegation of unjust enrichment of lessee).

¹⁶See, e.g., Cole Petroleum Co. v. United States Gas & Oil Co., 41 S.W.2d 414, 416 (Tex. 1931)(discussing the implied covenant for development, and stating that, absent “an express covenant for reasonable diligence in marketing the output of gas in paying quantities from wells on [the lease premises], still such covenant would be implied”).

¹⁷Amoco v. Alexander, 622 S.W.2d 563, 567, n.1 (Tex. 1981).

¹⁸Id. at 567-68.

¹⁹No reported cases discuss this implied covenant under leases where the lessee's actual marketing duties are expressly spelled out; however, by analogy to other leases covenants, one might expect that the express covenants would then control over inconsistent implied covenants. Cf. Dallas Power & Light Co. v. Cleghorn, 623 S.W.2d 310 (Tex. 1981).

In many instances, the royalty owner and the lessee share a common goal: to realize the maximum amount possible from gas production. In such a situation, a gas marketing strategy which benefits the lessee should also benefit the royalty owner. However, there are often situations when the lessee has concerns other than those directly associated with maximizing the wellhead value of its gas production under a specific lease. When the interests of the parties diverge, Texas courts require the lessee to exercise good faith in marketing gas production. In Le Cuno Oil Co. v. Smith,²⁰ the Texas Supreme Court dealt with a lessee who sold gas to a third party pipeline operator. In dicta, the court noted that the lessee also owned a pipeline and that, if he had acted as both lessee and purchaser, then he would be required to exercise “the highest good faith” in any contract for the sale of gas.²¹ More recently, the Texas Supreme Court upheld a decision holding the lessee to a good faith standard (not a “highest” good faith standard) in its gas marketing practices.²² The Texarkana Court of Appeals, in 1984, sought to elevate the duty significantly and held that the lessee owed the royalty owner a duty of “highest good faith” in marketing gas; however, the judgment was later set aside by the Texas Supreme Court.²³ A settlement in the case precludes use of the Supreme Court's opinion as precedent and limits its usefulness in establishing any bedrock legal principles. However, the opinion was a bellwether that the standard of conduct is more in the nature of commercial reasonableness than any type of

²⁰306 S.W.2d 190 (Tex. Civ. App. - Texarkana 1967, writ ref'd n.r.e.), *cert. denied*, 356 U.S. 974, 78 S. Ct. 1137, 2 L.Ed. 2d 1147 (1968).

²¹*Id.* at 192.

²²Amoco Production Co. v. First Baptist Church of Pyote, 579 S.W.2d 280, 287 (Tex. Civ. App. - El Paso 1979), *aff'd per curiam*, 611 S.W.2d 610 (Tex. 1980). There the lessee was liable to its royalty owners under a "proceeds" types lease clause, because the lessee accepted a below market gas price for that lease in order to increase its gas prices for other, older leases in the area. The Supreme Court upheld that finding but reserved judgment on how the marketing covenant might affect "market value" lease clauses.

²³Texas Oil & Gas Corp. v. Hagen, 683 S.W.2d 24, 29 (Tex. App. - Texarkana 1984), *set aside and dismissed*, 760 S.W.2d 960 (Tex. 1988). The Supreme Court had written a broad opinion in this case, but it was vacated after the parties settled.

fiduciary obligation. The San Antonio Court of Appeals in Hurd Enter. Ltd. v. Bruni²⁴ recently reaffirmed that, in general, the duty owed by the lessee to the lessor in performance of all of its implied covenants is based upon the “reasonably prudent operator” standard.²⁵

The duty to market as a reasonably prudent operator has two prongs: the lessee must market the gas with due diligence, and must obtain the best price reasonably possible.²⁶ The duty generally requires the lessee to actively market gas production and, in doing so, to take into account the lessor’s interests. Accordingly, transactions which involve the potential for self-dealing by the lessee are subject to higher scrutiny by the courts.²⁷ Nonetheless, such an arrangement is not *per se* improper, and can be approved if other facts negate the inference of improper self-dealing.²⁸

In addition to determining whether a lessee has acted as a reasonably prudent operator in discharging its duty to market gas, courts are often called upon to decide what marketing expenses, if any, should be borne by the royalty owner.

²⁴ 828 S.W.2d 101 (Tex. App. -- San Antonio 1992, writ denied).

²⁵Id. at 106. The Court examined the Supreme Court's opinion in Amoco v. First Baptist Church of Pyote, 579 S.W.2d 280 (Tex. Civ. App. -- El Paso 1979), *writ ref'd n.r.e.*, 611 S.W.2d 610 (Tex. 1980) and noted that the Supreme Court in its withdrawn opinion in Texas Oil & Gas Corp. v. Hagen, 31 Tex. Sup. Ct. Jour. 140, 142 n.2 (December 16, 1987) had disapproved elevation of the duty owed by the lessee to the lessor, as regards marketing, to a fiduciary duty. The Court of Appeals considered the Opinion in Amoco Production Co. v. Alexander, 622 S.W.2d 563 (Tex. 1981), which came down after the Amoco v. First Baptist Church opinion (in 1980) and which held the reasonably prudent operator standard applicable to all implied covenant cases to be the latest pronouncement by the Supreme Court. The Hurd Court also noted that, because the reasonably prudent operator standard required the lessee to "act in good faith, with competence and with due regard to the interest of the lessor," the higher good faith standard suggested in Amoco v. First Baptist Church may be no more than is ordinarily required under the ordinary reasonably prudent operator standard. Hurd, 828 S.W.2d at 109 n. 10.

²⁶Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987).

²⁷Le Cuno, *supra*, at 192; Parker v. TXO Prod. Corp., 716 S.W.2d 644, 646 (Tex. App. - Corpus Christi 1986, no writ)(describing a gas purchase contract between a lessee and its subsidiary, a gas pipeline operator, as “inherently suspect”).

²⁸Id. at 647. The recently filed case alleging that the State of Texas was underpaid on its oil royalties due to self-dealing within several major oil companies may eventually define these standards more clearly.

While drilling, completing and operating costs are unquestionably the responsibility of the lessee,²⁹ the lessee often finds that there is no market for gas at the wellhead or that a sale at an off-lease delivery point yields a better net price. In that situation, the gas must (or should) be transported and treated before it can be sold. As a general proposition, Texas law has long held that the royalty owner can properly be charged with its proportionate share of costs which are incurred solely for the purpose of making the gas marketable.³⁰ Courts have analogized the benefits attendant these costs to "services" provided by the lessee which add value to the gas.³¹ Depending on the actual language of the lease, the royalty owner may be required to share the burden of other expenses as well.³² While there may be issues regarding whether a cost is more properly associated with the production or marketing function, the point at which gas is produced at the wellhead has consistently been used as the touchstone for determining which costs may be charged to royalty.

²⁹See, e.g., Danciger Oil & Refineries, Inc. v. Hamill Drilling Co., 171 S.W.2d 321 (Tex. 1943).

³⁰See, e.g., Le Cuno, *supra* (compression, transportation, gathering); Martin v. Glass, 571 F.Supp. 1406 (N.D. Tex. 1983)(compression); Hagen, *supra* (transportation). These factors are elements in determining the market value of the gas at the well.

³¹See Piney Woods Country Life School v. Shell Oil Co., 539 F. Supp. 957, 970-71, *aff'd in part, rev'd and remanded in part*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

³²See, e.g., J. M. Huber Corp. v. Santa Fe Energy Resources, 871 S.W.2d 842 (Tex. App. - Houston [14th Dist.] 1994, writ denied)(windfall profits tax). Texas Courts' allowance of these costs is at odds with the law of many jurisdictions, which require the lessee at its own expense to make gas ready for sale or use. For a thorough discussion and critical review of the history of this issue see Marla J. Williams, Brent B. Moore, Richard A. Paschal, Patricia A. Patton and Steven P. Williams, Determining the Lessor's Royalty Share of Post-Production Costs : Is the Implied Covenant to Market the Appropriate Analytical Framework, 41 ROCKY MTN. MIN. LAW INST. (1995).

B. “The Changes”

In recent years the gas market has undergone stunning transformation and expansion. The natural gas market has had a long history of federal regulation beginning with the Natural Gas Act of 1938³³ and proceeding through the Natural Gas Policy Act of 1978.³⁴ In general, the NGA and NGPA together with the comprehensive regulatory scheme implementing these acts sought to establish stability of markets, price and supply in what was considered to be a highly volatile environment. The price controls effectively isolated the natural gas market from the effects of market forces and it can be argued that the effect was exactly the opposite of what was intended by Congress. This extensive system of regulatory control began winding down with the Wellhead Decontrol Act of 1989,³⁵ (which occurred in phases the last of which became effective as of Jan. 1, 1993) that has now resulted in near complete deregulation of gas as to price.

At the same time as Congress was deregulating the natural gas industry, FERC began making its own substantial impression on the gas market, beginning in 1985 with FERC Order 436 which was later replaced (in 1987) by FERC Order 500. The intended effect of these orders was to encourage open access to transportation services on a non-discriminatory basis -- to allow new players into the marketing business. One actual effect was to begin to provide producers the opportunity to directly market their gas to end users and to start removing the gas “merchant” function from the sole province of the gas pipeline companies. The FERC’s reordering of the industry reached its natural conclusion with the entry of

³³15 U.S.C. §§717-717z (1982). This NGA was extended to producer sales of gas in the 1954 decision in Phillips v. Wisconsin, 347 U.S. 672, 74 S.Ct. 794, 98 L. Ed. 1035 (1954).

³⁴15 U.S.C. §§ 3301 et seq. (1982).

³⁵P.L. 101-60, 103 Stat. 158 (1989).

FERC Order 636 which tore down the remaining barriers to "open access to transportation" to producers.

All of these changes in the pipeline industry, coupled with the resultant active spot market, increased end user marketing by producers, and unbundling of pipeline transportation services, have radically changed the options available for marketing gas production and have superimposed a new level of complexity on the royalty valuation and payment issues. Unlike the prior days of gas marketing, dedication of reserves from a single lease to a single purchaser are the exception rather than the rule. New contracts are generally shorter term, or subject to regular price redetermination and do not entail the dedication of specific reserves to contracts.

A significant consequence of these changes over the last ten years has been the combination (or some would say confusion) of the producer, marketer and merchant functions of the oil and gas industry. Now it is not at all uncommon for producers to have affiliated entities which provide functions of transporting, treating and/or marketing gas produced from a lease. In instances where the valuation issue may be based upon point of sale and proceeds received, the inter-relations among affiliated entities and, particularly, confusion regarding the producer's merchant function, raises a whole new set of potential conflicts between lessors and lessees. The usually concordant interests of lessor and lessee to maximize the value for their mutual benefit no longer necessarily apply since unilateral benefits may be derived by the lessee, albeit by benefits realized by an affiliated entity. It is in this new market and regulatory framework that the expressed and implied covenants of the oil and gas lease are called upon to operate.

When evaluating the royalty payment obligation under an existing lease in today's gas market, attorneys must compare the factual circumstances involved in a

current sale to the marketing arrangements in effect when the present case law governing royalty payment obligations was decided. However, evaluating how to value production for royalty payments under existing leases is only half the problem. Attorneys representing lessors negotiating leases must also be aware of the potential for confusion and the realities of the market place.³⁶ Under the Texas Supreme Court's opinion in Sun Oil Co. v. Madeley,³⁷ it is assumed that parties and, in particular, parties represented by attorneys, were aware of the underlying regulatory and practical circumstances of the oil and gas industry at the time they entered into contracts, and that they contracted with reference to those issues.³⁸ Thus, if an existing common marketing issue adversely affects a lessor and it is not specifically dealt with in the lease, courts may assume that the omission was intentional and that the lessor and lessee intended the common practice to prevail notwithstanding its effect on the lessor. Only when leases directly or implicitly address these consequences will it be assumed that the parties intended to address them.

An attorney cannot use a royalty clause which does not contemplate the issues of pooled or aggregated sales, deferred sales, exchange transaction or storage and be certain of the manner in which a court might enforce the clause as to the issues of royalty valuation and payment. In effect, attorneys today are in a similar circumstance to attorneys drafting "market value" leases in a regulated gas market before Vela and Middleton were decided. Despite the shortcomings of the existing

³⁶Attorneys often prepare lease clauses designed to counteract the last problems experienced in the industry, rather than the issues presented by current conditions. For example, many of today's lease forms address problems presented by the "energy crisis" of the 1970's, which in turn resulted from lease clauses designed to address problems which arose in the 1930's, when only a few pipelines controlled most gas markets. We are similar to the generals who are now prepared to "fight the last war."

³⁷626 S.W.2d 726 (Tex. 1981).

³⁸Id. at 727; *see also* Amarillo Oil Co. v. Energy-Agri Prod., 794 S.W.2d 20, 21 (Tex. 1990); REO Industries, Inc. v. Natural Gas Pipeline Co. of America, 932 F.2d 447, 454 (5th Cir. 1991).

body of caselaw in analyzing royalty payment obligations in the modern market, it must still be regarded as controlling; and, in fact, it still provides a useful framework for evaluating these obligations. The intentions of the parties and the meanings of terms in existing leases will be determined with reference to the law in effect at the time the leases were drafted. While the rules must be applied by analogy and based upon intent, they can be applied.

C. Applying The Old Rules To The New Game

1. Post-Production Costs Under the Implied Covenant to Market

Texas law has generally allowed the lessee to charge the lessor's royalty with its proportionate part of the expenses incurred in making gas marketable, but the evaluation rests upon lease language and the particular conditions involved. For instance, lease compression used as an element of the production function has traditionally not been held to be an expense to which the lessor's royalty may be subjected,³⁹ whereas compression needed to boost produced gas to pipeline pressures or otherwise to make the gas marketable, may be deducted to determine market value.⁴⁰ The lessor has generally been required to bear a portion of the cost of separating, dehydrating or treating gas.⁴¹

The new marketing arrangements available to producers should not alter the basic rules regarding what expenses may properly be charged to royalty. They may simply magnify the implications. For instance, under new marketing arrangements, gas deliveries may occur at a hub or a location miles away from the lease implicating transportation and compressor costs; and further, different treatment may be required to make gas "marketable." The related expenses should

³⁹Parker v. TXO Prod. Corp., 716 S.W.2d 644 (Tex. App. -- Corpus Christi 1986, no writ).

⁴⁰Martin v. Glass, 571 F. Supp. 1406, 1415 (N.D. Tex 1983).

⁴¹*See, e.g.,* LeCuno, *supra* (gathering, transportation and processing); Phillips Petroleum Co. v. Johnson, 155 F.2d 185 (5th Cir. 1946) (transportation, separation); Holbein v. Austral Oil Co., 609 F.2d 206 (5th Cir. 1980) (dehydration).

still be subject to the same analysis, but the amount of the deductions may be significantly increased. Again, consistency being the key, it seems unlikely that a simple change in the point of sale with concurrent increase in financial implications should impact the analysis (subject to compliance with the implied marketing covenant). Drilling and production costs will be borne solely by the lessees. In contrast, if the expense is attributable to the marketing function (and absent an express lease provision to the contrary) the lessors' royalty should bear its share of the cost. The more confusing issues involve the identification of the time and place of sales and the amount of costs which should be borne by the royalty owner.

The growth of producer marketing affiliates is another factor which increases the implications of post-production costs. Many producers market gas, in the first instance to an affiliated marketing entity which in turn, markets the gas to end users and other markets. Royalties are often based upon the price paid (or the market value of the gas) on a Btu-adjusted basis when and where the produced gas is sold to the affiliate. Questions necessarily are raised by this type of transaction. If the marketing affiliate immediately delivers the gas for processing and realizes a higher value on liquids, should the lessor share in that incremental value? Arguably, the producer or affiliate has itself done nothing to increase the value of the gas and the availability of processing and gas quality that make processing possible would seem to impact the "market value" of the gas when and where sold. If the lease specifically requires payment of royalties on liquids, does the affiliate sale prevent the royalty owner from being paid on the higher incremental liquid value? Recall the implied covenant cases which require the lessee to contract with regard to the interests of the lessor and to obtain the best price reasonably available.⁴² Has the lessee satisfied this obligation in selling at a market-clearing

⁴²See authorities cited in Notes 21-23 *supra*.

price to an affiliate if that affiliate immediately processes the gas and realizes substantial profit? This issue becomes even more complicated when there is an existing relationship (affiliate or otherwise) between the producing/marketing affiliate and the processor.

2. Effect of Time and Place Dislocation and Loss of Identity of Gas

Because most royalty clauses address royalty valuation issues at either a point in time or a place where gas is sold or valued for royalty purposes, the sales point has always been an important factor. As noted in previous sections, the point of sale may determine whether any transportation or treatment expenses are deductible at all. However, in today's market the point of sale and the point of transfer may not be the same. Similarly the point in time at which a sale takes place versus the point in time when possession or custody is transferred may not coincide. Finally the point in time or point of sale may be divorced entirely from the production aspect such as in instances where gas is produced for storage and sale at a later date. The dislocation of time and place of sale create serious valuation issues.

Another (and probably the most common) issue is loss of identity, where gas is aggregated before being sold. In the ordinary case of this kind, gas from numerous leases is aggregated by the producer at a hub and the undifferentiated mass of commingled gas is delivered/sold to various purchasers. It is impossible to tie specific lease production volumes from the pooled value to specific sales for valuation purposes. Some producers have attempted to avoid the implications of these issues by simply denominating all sales as wellhead sales and valuing production for royalty purposes on an MMBtu basis at the wellhead based upon a pooled price net of transportation costs. Whatever legitimacy this approach may have from a practical standpoint, it may result in an improper determination of

value for several reasons. First, if the true point of sale is downstream from the wellhead, at a point of transfer of custody and control, then the gas is being valued at the wrong point under the terms of the lease. Particularly, if the downstream point is the valuation point, this may deprive the lessor of some royalty -- the proper measure should be "market value at the well." Second, as discussed above, if the lease provides for payment of separate royalties on liquids, payment on an MMBtu basis at the wellhead may deprive the lessor of the incremental value of entrained liquids in the gas stream which were removed by processing.⁴³ Finally, this approach confuses what, if any, post production expenses may or should be deducted. If, for instance, the sale is denominated as one at the wellhead, but royalty is based upon a price delivered at a distant location less a transportation cost, a lessor whose lease prohibits deduction of any transportation costs would be disadvantaged by this type of sale. All of these circumstances also enhance the potential for self dealing by the lessee. Logically and legally, royalty settlements should be based to the extent possible on accurate depiction of the point of sale/point of valuation based upon the realities of the transaction.

A more objective standard such as a market value based upon overall competitive conditions in the area should provide a more complete standard for calculating royalties, but it raises another set of issues concerning what factors should be used in determining that value, and the post production costs remain a

⁴³There has been substantial confusion regarding payment of royalties on liquids removed from the gas stream, with the recent reported cases favoring the view that royalties based upon liquids removed and sold (as opposed to market value of the gas with entrained liquids) are not due. See Carter v. Exxon Corp., 842 S.W.2d 393 (Tex. App. -- Eastland 1992, writ denied); Sowell v. Natural Gas Pipeline Co. of America, 789 F.2d 1151, 1157 (5th Cir. 1986). These opinions deal with clauses calling for payment of royalty based upon the market value on gas used for the manufacture of liquid products and not specifically calling for payment of royalties on liquids. These cases did not discuss the early opinions holding that the markets for processing gas are not comparable to those for gas sales, so a different measure of market value should apply. See, e.g., Phillips Petroleum Co. v. Ochsner, 146 F.2d 183, 141 (5th Cir. 1944). A relatively simple re-write of the royalty clause takes royalty valuation on processed gas and resultant liquids outside the ambit of Carter & Sowell.

center of controversy.⁴⁴ Further, few if any producers have accounting systems that are designed to account for royalties on any basis other than net proceeds credited back to the lease for financial reporting purposes, and they are not set up to accommodate varying lease clauses. Thus, these issues are likely to remain controversial.

3. Problems Involved In Pooling Or Aggregation Of Gas

The most ordinary type royalty clause calls for payment of royalties based upon the sale of gas "saved and sold" from the lease. This language presumes some tying of volumes actually produced from the lease to actual volumes sold. Pools or aggregations of gas by their nature entail commingling and loss of identity. In a true gas market pooling situation, individual lease volumes cannot be tied to specific sales. The typical approach to payment of royalties is based upon prices negotiated by the producer for a part of the entire commingled gas volume. The pool price is generally based upon a weighted average price for all sales or at least for some group of sales believed to be representative of a certain volume of gas. Typically, such sales will consist both of high and low price contract gas. Unless the producer is very fortunate indeed, he will not have all high priced contracts. The problem from the lessor's perspective is that it is often difficult to differentiate what constitutes a bona fide low priced third-party arms' length sale from a low priced sales contract that implicates other business issues unrelated to the value of the gas. Issues such as fiscal concerns, strategic objectives, goals and corporate relationships may affect the price of gas in some instances.

⁴⁴For example a common term in a "custom" lease form provides for royalties to be based upon market value at the well, but also prohibits deduction of transportation costs and other costs of making production ready for sale or use. It is unclear under this language whether transportation costs could properly be factored into determining market value at the well. See Middleton, *supra*. In such case, the most consistent approach may be to measure market value by comparable sales in the specific area of production.

The problem from the lessee's perspective is the loss of identity of the gas. A lessee who commingles gas by definition causes a "confusion of goods" as to its lessor - as a consequence of the commingling, it is not possible to tie specific produced gas to specific sales. In such instance, it is the lessee's burden to distinguish the sales as between lessors, and an inability to do so may enable the lessor to "select" the sales used for calculation of royalties.⁴⁵ Under the common law commingling rule, lessors may take the position that the producer is liable to them for royalties based upon the highest price sales sufficient to account for all lease volumes unless the producer can differentiate volumes. In most cases the producer would be unable to do this and could conceivably be responsible to all of his lessors for the highest priced contracts. This issue has not been resolved in any reported case and the pooling problem remains just that for the lessee producer.

Trying to attribute lease volumes and prices based upon lease language also entails problems. Assume a producer bundles gas from three leases and sells to six end users, and the contract prices to the six end users range from \$1.50 to \$3 (MMBtu) depending upon volumes, interruptability and other factors. Assume further that one lease has a provision calling for "20% of the market value of gas sold but, in no event less than the actual proceeds received by lessee (or any company affiliated with lessee) at the latter of the point of sale or the point at which possession and risk of loss pass to an unaffiliated third-party purchaser" and the royalty clause of the other two are typical Pound Printing and Stationery form royalty clauses. The producer then has a choice. He can either allocate high priced gas contracts to the lease with the more rigorous royalty clause and lower priced gas to the less rigorous clauses, or absorb the loss by overcompensating one royalty

⁴⁵Humble Oil & Refining Co. v. West, 508 S.W.2d 812 (Tex. 1974).

owner. The problem thus of trying to allocate on any preferred basis places the producer at risk of breach of covenant for favoring one lease over another.⁴⁶

The only entirely safe route for a lessee under these circumstances would be to value gas based upon its market value at the well rather than net back of proceeds. This approach is probably most reflective of the actual point of sale. Also the increasing availability of area indexes may create a gross barometer for evaluating the correctness of the market value at the well. However, even indexes are subject to questions. For instance, a large volume producer with established marketing clout should be able to beat most index rates. By contrast, for a very low capacity periodic seller, a market clearing price might be a "best-case" scenario. Thus an index while useful, will not necessarily end the inquiry.

4. The Gas Storage Issue

One of the historical reasons for treating valuation and sales of gas differently from those of oil is the problem of storing natural gas. For over 30 years pipeline companies have been storing gas in order to maintain a stable source of supply and to provide steady service to their customers. Now, thanks to the changes provided by FERC Order 636, the same options are available to large producers. This increasing ability to store gas creates a need for a new analysis. Storage raises the issue of when and where gas is "saved and sold" for purposes of royalty obligations. It creates a slightly different time and place dislocation issue. The sale ultimately does not take place at the same time or location as the production function.

In evaluating royalty payments in the case of storage several analogies present themselves based upon a central presumption. If a producer places gas in

⁴⁶Amoco v. Alexander, 622 S.W.2d 563, 566 (Tex. 1981); Shell Oil v. Stansbury, 401 S.W.2d 623 (Tex. Civ. App. -- Beaumont 1966, writ ref'd n.r.e.).

storage before it is sold, it may be reasonably assumed that the reason for the storage is to reap a more favorable price or market even in light of the additional transportation and storage costs. Gas produced in a "down" market is placed in storage before a sale in the hope that the gas can be delivered later at a more favorable price. The question is, should the royalty owner be entitled to participate in the higher later net price? How do these values relate to market value at the well?

The existing case law does not directly deal with gas storage valuation issues; and, by analog yields a confusing analytical framework of when a sale of stored gas takes place. In Middleton, Exxon's contention that a contractual dedication of reserves to a bona fide, long-term supply contract constitutes an immediate sale was rejected by the Texas Supreme Court. Instead, the Court held that for purposes of royalty valuation, gas is not sold until it has been produced and "sold or used."⁴⁷ Thus, valuation occurs when all of those conditions are met. This line of reasoning suggests the sale for valuation purposes occurs when the subsequent sale takes place and not merely when the production is severed. In like manner the Fourth Court of Appeals' opinion in Killam Oil Co. v. Bruni⁴⁸ reasoned that before a royalty payment obligation becomes due, there must be physical production as well as a sale of the production.⁴⁹ Thus no royalty obligation accrued based upon a purchaser's settlement (buyout) of its obligations under a take-or-pay contract since there is no production coupled with a sale. In the case of storage, a similar but opposite analysis results - there is production but no sale. The sale is deferred and only takes place when gas is removed from storage. Consistency suggests valuation would occur when both production and sales have transpired.

⁴⁷Middleton, *supra*, 613 S.W.2d at 244 (citing Monsanto Co. v. Tysell, 537 S.W.2d 135 (Tex. Civ. App. -- Houston 1976, writ ref'd n.r.e.).

⁴⁸806 S.W.2d 264 (Tex. App. -- San Antonio 1992, writ denied).

⁴⁹Id. at 167.

An argument can be made that the implied marketing covenant requires that a royalty owner would share in the benefit of the deferred sale based upon the deferred benefit received. The timing of production and gas sales is a right of the lessee. Placing gas in storage is roughly akin to either shutting-in a well or curtailing production. In the case of gas storage, the gas is actually being produced, but it is simply not then being sold. However, royalties are typically not owed until gas is sold,⁵⁰ in this case when removed from storage. To allow the lessee to remove the gas and pay market value or some other value at the time of production and then receive higher value at the time of sale allows the lessee to manipulate production and marketing to his benefit. In other words, in instances where the gas market is down, gas could be banked in storage and royalties paid on a relatively low market value when the gas is actually sold at a higher price. Even net of transportation and storage costs, the lessee would reap a benefit not shared by the lessor. This type of self dealing arguably, does not take into account the interests of the Lessor and may be discouraged by prior Texas case law.⁵¹

The lessee may have other reasons to store besides price and this fact may fuel yet another analysis. If the lessee's decision to store is not price but instead strategically driven (i.e., assuring firm supply to satisfy future contractual needs) a similar analysis should follow. In such instance, should the lessor be required to bear a lower price than market value and at which point in time would market value be determined, the time of production or the time of ultimate sale? The latter question is considerably more difficult to answer. In any event, however, it would seem that to comply with the implied marketing covenant the lessor should not be saddled with any reduction due to marketing arrangements intended to address considerations inuring only to the benefit of the lessee.

⁵⁰Killam Oil Co. v. Bruni, *supra*, 806 S.W.2d at 267-68.

⁵¹ See footnotes 20-24 *supra*.

One approach which bears consideration and could be included in a lease royalty clause is a provision similar to the Mineral Management Service negotiated rules regarding royalty accounting.⁵² These rules require periodic accountings based upon market value at the time and place of production removal and can be paid upon area index rates based upon published indices. The regulations also provide for periodic retroactive accounting when the price paid based upon indices is compared to actual proceeds received. If the lessee receives more than the redetermined price established in the accounting, it is required to make up the difference. The MMS would not share in any reduction, and while this limitation sounds unfair, it is actually fairly reasonable since the producer manages when and how gas is produced and takes the risks in making storage decisions.

5. Exchanges

Exchanges of gas on a volumetric or Btu basis bear similar analysis. In an exchange, gas produced from a lease is delivered to a "purchaser" who pays for the gas by delivering to (or for the benefit of) the producer a roughly equivalent gas volume at the location identified by the seller/producer. Assuming delivery at a hub or interconnect off the lease identified by the purchaser, the sale occurs at the point of delivery off the lease. In such instance, under a standard royalty clause which provides for either proceeds at the mouth of the well or market value for sales off the lease, the exchange would probably fall under the market value provision. If the royalty clause is a more recent "proceeds-type" or the delivery of the sales volume takes place at the wellhead and the proceeds of the sale are equivalent MMBtu values, the "proceeds" are probably based upon the market value of the

⁵²The rules, which recently entered their public comment period, were authorized by MMS in 59 Fed. Reg. 32,943 (1994) under the Federal Advisory Committee Act amendments to the Federal Administrative Procedures Act, 5 U.S.C. §553 (1992).

MMBtu equivalents received at the time and place they were received. The measures should likely be the same as market value in that instance.

There is some precedent for valuation of production for royalty purposes in the case of an exchange. In Cabot Corp. v. Brown,⁵³ Cabot was the lessee operator of the Kelln Gas Well No. 1 in Lipscomb County, Texas, and Brown was one of the royalty owners under the lease. Cabot and Transwestern Pipeline Company had entered into an exchange agreement in which Cabot delivered gas produced from its Kelln Lease through its pipeline to an interconnect in Roberts County, Texas, in Transwestern's interstate gas transmission system. Cabot received an equivalent volume of gas from Transwestern's pipeline which was delivered at its Skellytown plant until 1974 and later its Kingsmill plant in Pampa, Texas. The exchange gas was commingled with other gas produced or purchased by Cabot and the majority of the commingled gas remaining after processing was sold on the intrastate market. Cabot paid Transwestern \$.02 per Mcf for the exchange and transportation transaction. Cabot contended delivery of the gas to Transwestern's interstate pipeline constituted a deduction of the production to interstate commerce, and it paid royalties to Brown based upon regulated interstate prices - a price of \$.38 per Mcf from 1977 through 1980 and \$.80 per Mcf from October, 1980 through the time of trial. In fact, Cabot was selling the bulk of the exchange gas remaining after processing in the interstate market for approximately \$1.35 per Mcf. The Court of Appeals held that the exchange arrangement was "no more than a bailment of a fungible commodity and that simply because the gas flows through interstate pipelines does not mean the gas must be valued at interstate prices."⁵⁴ The

⁵³754 S.W.2d 104 (Tex. 1987).

⁵⁴ Cabot Corp. v. Brown, 716 S.W.2d 656, 659 (Tex. Civ. App. -- Corpus Christi 1986), *rev'd on other grounds*, 754 S.W.2d 104 (Tex. 1987) (citing Public Ser. Elec. & Gas Co. v. Federal Power Commission, 371 F.2d 1, 4 (3rd Cir. 1967), and Roeser & Pendleton v. Overlees, 34 S.W.2d 906 (Tex. 1931)). The Texas Supreme Court's reversal of this case is based primarily upon division orders executed by Brown which eliminated any claim of damages.

Appellate Court in Brown concluded that the exchange transaction was not intended to create a sale which would result in a dedication of the gas to interstate commerce and constitute a ceiling price. However, both the Court of Appeals and the Supreme Court recognized the exchange transaction ultimately resulted in a sale which implicated the implied covenant to reasonably market. From this analysis, it would appear that in the ordinary instance gas produced from a lease may be delivered in the exchange transaction, however, it is not sold until the exchange gas is sold. Under Brown in this analysis, gas delivered into a pipeline system under such circumstances, is simply transported in the custody of the other party and the exchange volumes constitute the equivalent volumes for purposes of calculating royalty. No sale of gas takes place until the exchange volumes are sold. This analysis brings back the issue of the place where gas is delivered. If the gas is delivered at a hub or other location off the lease, the issue would be the market value at the well of the volumes of gas produced. The usual analysis and review of comparable sales would apply. If the gas is delivered at the mouth of the well for exchange elsewhere, a proceeds standard would apply and the proceeds would be measured by either the proceeds received in the sale of the exchange gas or the market value of the exchange gas at the time and place of delivery.

D. Other Timing/Dislocation Issues

1. Prepayments In Contract Buyouts or Settlements

Recent court cases which dealt with prepayments in contract buyouts including take or pay payments have relatively uniformly held in the State of Texas that royalty owners do not participate in the contractual settlements.⁵⁵ The

⁵⁵Killam Oil Co. v. Bruni, *supra*, 806 S.W.2d 264; Hurd Enterprises Ltd. v. Bruni, *supra*, 828 S.W.2d 101; Mandell v. Hannon Oil & Refining Co., 822 S.W.2d 153 (Tex. App. -- Houston [1st Dist.] 1991, writ denied). In this regard, Texas courts have reached a contrary conclusion from the courts of two neighboring states and the Fourth Court of Appeals' conclusion in Hurd v. Bruni, was reached in the

rationale has been that these are contractual payments and not payments for gas "extracted from the land" and sold on which royalty would be due.⁵⁶ Thus, if the payment is made to compensate for production not taken and is non-recoupable, no royalty obligation arises. Depending on the nature of the sale or prepayment this may or may not be true. However, many royalty owners have begun to specifically contract for prepayments, contractual buyouts and contractual payments which are not based solely upon gas already saved and sold. While producers are somewhat reluctant to include this type of provision in a royalty clause, there is a strong incentive for the royalty owner to include it to maximize value and realize all benefits recognized by the lessee for actual or constructive sales and deliveries of gas. Again however, royalty owners are treading on unfamiliar ground. Take or pay settlements are waning as that generation of gas contracts dies out. The nature of future settlement, advance payment or contract buyout issues may have little resemblance to those arising under "take or pay" or "take and pay" contract provisions. One can imagine the range of possibilities for future contract liquidation provisions arising in a gas market that is increasingly directly related to future contracts and pure financial products. A royalty clause meant to include the royalty owners' interests in any such future transaction will necessarily require great breadth and careful drafting.

2. Variable Take Contracts

Some recent contracts call for variation in takes but for fixed payments during the contract term or for variable takes based upon a fixed price for a set volume provided under the contract. The result is that a price is paid for a volume

light of the Fifth Circuit Court's opinion on rehearing in Frey v. Amoco Prod. Co., 951 F.2d 67 (5th Cir. 1992); *See also*, Frey v. Amoco Prod. Co., 603 So.2d 166 (La. 1992) (opinion on question certified by Fifth Circuit Court of Appeals); Klein v. Jones, 980 F.2d 521 (8th Cir. 1992) (decided applying laws of Arkansas).

⁵⁶Killam Oil Co. v. Bruni, *supra*, at 267-68

of gas to be taken during a given month; and, if that volume is not taken during the month, the remaining volume can be taken during the following month based upon the prepaid price. A wide range of outcomes can result, ranging from delivery of gas in one month in which the set price is higher, to delivery in a later month for the prior month's set price when the contract price for the current month has increased. The question is then: when is production coupled with price for purposes of valuing gas for royalty calculations? The practical approach to valuation requires coupling the production function to specific proceeds relating to the sale of that production. If a payment is received for production to be taken in later months the delivery point of the production should govern. Under the cases previously cited, royalty would be due on the actual production sold. The delivery point will determine whether royalty of production is based upon market value or proceeds. If the proceeds cannot be tied to specific production volumes, it should be incumbent on the producer to pay royalties on the highest proceeds received. If not, it should be the lessee's responsibility to differentiate what, if any, gas should be accounted for at the lower price.

3. Futures Triggered Pricing/Hedging/Conversion Options

Many producers are now regularly hedging their prices by using commodities trading contracts such as hedges, options, puts, swaps and collars. Some of these transactions approach true financial transactions, not based upon actual commodity productions and sales. Although the producer's actual gas sales are a factor in the decision about how aggressively he should "play the market" these transactions do not generally require sales or dedications of specific volumes of gas. Instead they require cash payments to be made based upon changes in published index prices multiplied by a nominal volume of gas.

This is probably an area where the producer should be given the full benefit of transactions resulting in unilateral benefits to the lessee. There is no coupling of commodity value and sales to many of these transactions since the effect of a hedge is simply to "insure" receipt of a certain base level of revenue. Logically, those proceeds would not benefit the lessor since the lessor took none of the risk and the additional value is tied only tangentially to the commodity value. Arguably, a lessor (except for issues of financial strength) has the same ability as a producer to benefit by hedging transactions.

E. Implications of Lessor Take in Kind Provision

Many lessors have recently begun including within the royalty clause the right of the lessor to take gas in kind. In general this creates an option for the lessor which it does not otherwise have and which differs from the historical marketing arrangements for gas royalty. At least arguably under FERC Order 636, this type of lease clause places the lessor on the same footing as a producer since the take-in-kind royalty gas can be directly marketed by the lessor. As a practical matter, however, the take-in-kind provision may have very little value to a lessor unless he has a great deal of gas to market, resources to dedicate to gas marketing, and some expertise. For one thing the lessee may contend (absent a properly worded royalty clause) that lessee has been given the option to deliver in-kind gas in lieu of exercising its implied covenantal duties of good faith. If the lessee is not limited as to whether, when and how often it can deliver gas in kind, the lessor's options are limited. The lessor seldom has the marketing clout necessary to move, on short notice, its volumes of gas at favorable prices. Even more importantly, however, the lessor has no control over well operation or the volume of gas to be produced, has no ability to nominate volumes and no ability to control the flow of

gas to its purchaser. Without these abilities the lessor will almost certainly obtain a substandard price for its gas.

In the event the take-in-kind provision is desired, some care must be addressed to its drafting. For instance, lessor must be given the right to nominate volumes and to require the lessee to produce its volumes ratably. In addition, there must be a provision for gas balancing or make up in the event the lessor is unable to take its volumes of gas in any given month. Further, the right to take in kind should be just that, a right at the option of the lessor. It should not be an out for the lessee who does not wish to share a market with the lessor.

F. Conclusion

The complexities of the new gas market will result in a different analysis of the lessee's royalty obligation; however, the old rules still apply and can create a logical framework for determining the lessee's obligation under both the old form oil and gas lease royalty clauses and newer clauses. The attorney drafting royalty clauses or representing a lessor in a royalty dispute needs to have a clear understanding both of the modern market environment and the "rules of the road."