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ROYALTY INTEREST IN THE UNITED STATES: NOT CUT FROM THE SAME CLOTH

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I. INTRODUCTION

If you ask any lawyer familiar with oil and gas law what a royalty is, the response will be reasonably uniform whether the lawyer is located in Colorado, Texas, Kansas, Louisiana, Oklahoma or New Mexico. Most lawyers agree with the basic definition given of a royalty interest by Williams & Meyers. They define a royalty as:

> (1) The landowner's share of production, free of expenses of production.
> (2) A share of production, free of expenses of production . . . .[1]

Thus we know that a royalty interest is not a cost-bearing or profit-sharing interest. We also know that it is solely a share of production and does not include any of the remaining constituent elements of a mineral estate. The royalty interest therefore would not be a possessory estate and would likewise not have any easement to use or occupy the surface.

But when you take a closer look at many of the underlying issues which affect royalty interests, you will not find universal agreement among the states. In fact you will find an amazing diversity of opinion on several basic issues relating to defining, measuring and valuing royalty interests. In this article I will explore a number of those areas where there is a split of authority, especially where the differences relate to the valuation of the royalty interest.[2]

II. THE NATURE OF THE ROYALTY INTEREST

A. *The Stand Alone Royalty Interest*

The royalty interest is a constituent or component part of the mineral estate.[3] As stated above, the owner of a royalty interest has a right to a fractional share of production, free of any exploration and production costs.[4] A royalty owner does not possess any of the other

1. 8 HOWARD WILLIAMS & CHARLES MEYERS, OIL AND GAS LAW 1087 (1992) [hereinafter WILLIAMS & MEYERS].

2. Royalty interests have recently been the subject of a host of articles. *See, e.g.*, David Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 E. MIN. L. FOUNDATION 18-1 (1992); Richard Maxwell, *Oil and Gas Royalties - A Percentage of What?*, 34 ROCKY MTN. MIN. L. INST. 15-1 (1989).

3. *See, e.g.*, Altman v. Blake, 712 S.W.2d 117 (Tex. 1986). Williams and Meyers define a royalty interest as: "The property interest created in oil and gas after a severance by royalty deed." 8 WILLIAMS & MEYERS, *supra* note 1, at 1094.

4. *See, e.g.*, Duval v. Stone, 213 P.2d 212 (N.M. 1949); Meeks v. Harmon, 250 P.2d 2038 (Okla. 1952); Watkins v. Slaughter, 189 S.W.2d 699 (Tex. 1945).

constituent elements of a mineral interest such as the right to explore and/or develop, the executive power to lease or the right to receive bonus or delay rental payments.[5] The duration of a royalty interest may be limited to any of the common law estates in land, and in addition may be limited by use of the so-called defeasible term interest which measures the interest by a fixed term for years, followed by an indefinite period usually requiring the continuation of production.[6]

While the above statements are generally correct, even in the basic definition of a royalty interest there is a divergence of views. For example, most states clearly allow the owner of the mineral estate to segregate the royalty interest and transfer it to another party in fee simple absolute. Yet in Kansas the attempted transfer of a perpetual royalty interest has been found to violate the Rule Against Perpetuities.[7] The problem began in *Miller v. Sooy*,[8] where the court in dicta opined that an attempt to transfer a royalty interest that would affect future leases for an indefinite period would violate the Rule.[9] But it was *Lathrop v. Eyestone*,[10] that firmly entrenched the Rule as a bar to the transfer of a perpetual royalty interest. In *Lathrop*, the lessor purported to transfer a fractional share of royalty under an existing lease and a fractional share of royalty and bonus under any future leases.

5. *See, e.g.*, Continental Oil Co. v. Landry, 41 So. 2d 73 (La. 1948); Schlittler v. Smith, 101 S.W.2d 543 (Tex. 1937). But even as to this basic proposition there are states which treat a royalty interest differently. For example, West Virginia, relying on the 500 year old Coke's Rule, had apparently concluded that a freestanding royalty interest could not be created. Toothman v. Courtney, 58 S.E. 915 (W.Va. 1907). Fortunately, *Toothman* was limited in a subsequent case. Davis v. Hardman, 133 S.E.2d 77 (W.Va. 1963). Likewise several California cases appear to give the owner of a royalty interest the right to enter and drill if no lease is outstanding. Dabney-Johnston Oil Corp. v. Walden, 52 P.2d 237 (Cal. 1935); Callahan v. Martin, 43 P.2d 788 (Cal. 1935).

6. For an example of a fixed term royalty interest, see Lively v. Fed. Land Bank of Louisville, 176 S.W.2d 264 (Ky. 1943); Katz v. Bakke, 265 S.W.2d 686 (Tex. Ct. App. 1954).

7. *See generally* David Pierce, Kansas Oil and Gas Handbook 4.15-.16 (1986).

8. 242 P. 140 (Kan. 1926).

9. Without criticizing the Kansas approach, it is best to remember that the Rule only applies to two types of future interests: contingent remainders and executory interests. If you treat the royalty interest as a constituent element of the mineral estate, a transfer of a royalty interest is the transfer of part of a fee simple absolute. Or if the transfer is of a royalty interest where the existing mineral estate is under lease, the transferor is essentially conveying a part of her possibility of reverter. Possibilities of reverter are, for historic reasons, not subject to invalidation under the Rule. While Oklahoma has in part accepted the proposition that where there is no outstanding lease, there is not a royalty interest to be transferred, Pease v. Dolezal, 246 P.2d 757 (Okla. 1952), it has not found that the Rule invalidates such transfers. Pauly v. Pauly, 176 P.2d 491 (Okla. 1946). For other articles criticizing the application of the Rule to oil and gas conveyances in general, see Joseph Morris, *Future Interests in Oil and Gas Law*, 3 Rocky Mtn. Min. L. Inst. 579 (1957); Eugene Kuntz, *The Rule Against Perpetuities and Mineral Interests*, 8 Okla. L. Rev. 183 (1955).

10. 227 P.2d 136 (Kan. 1951).

The lessor, however, retained the executive power. The plaintiff acquired the lessor's interest and after the extant lease expired brought a quiet title action seeking to terminate the grantee's interest as a violation of the Rule. The court based its holding on the proposition that a royalty interest does not vest until it is created by a lease. Thus the transfer of a present possessory mineral estate is perfectly valid since it vests immediately, and Kansas courts will construe an ambiguous instrument so as to create a valid mineral interest rather than an invalid royalty interest.[11] While *Lathrop* has been questioned, it has never been overruled, and it would be a foolhardy lawyer who drafted a royalty deed that was not of a limited duration in Kansas.[12] With the possible exceptions of California[13] and Colorado,[14] however, the Kansas adoption of the Rule has been appropriately ignored.[15] In fact, in several states where the issue has arisen since the *Lathrop* decision, the courts have rejected its application to the transfer of a royalty interest.[16]

Another area of divergence that arises when a stand alone royalty interest is created affects the duty owed to a royalty owner by the owner of the executive power to lease.[17] For example, an early Louisiana case, *Gardner v. Boagni*,[18] found that there was no duty owed at all between the executive and non-executive except that duty which was expressly created by a written instrument. This position, however, was reversed with the adoption of Article 109 of the Mineral Code in

11. Drach v. Ely, 703 P.2d 746 (Kan. 1985).

12. For cases avoiding Rule problems where ostensibly *Lathrop* should apply, see Froelich v. United Royalty Co., 290 P.2d 93 (Kan. 1955), *reh'g granted*, 297 P.2d 1106 (Kan. 1956); Howell v. Cooperative Refinery Assoc., 271 P.2d 271 (Kan. 1954).

13. Dallapi v. Campbell, 114 P.2d 646 (Cal. Ct. App. 1941).

14. Corlett v. Cox, 333 P.2d 619 (Colo. 1958).

15. *See, e.g.*, Arkansas Valley Royalty Co. v. Arkansas-Oklahoma Gas Co., 258 S.W.2d 51 (Ark. 1953); Texas Gulf Producing Co. v. Griffith, 65 So. 2d 447, 452 (Miss. 1953); Rist v. Toole County, 159 P.2d 340 (Mont. 1945); Duval v. Stone, 213 P.2d 212 (N.M. 1949); Doss Oil Royalty Co. v. Lahman, 302 P.2d 157 (Okla. 1956); Harriss v. Ritter, 279 S.W.2d 845 (Tex. 1955); Denver Joint Stock Land Bank v. Dixon, 122 P.2d 842 (Wyo. 1942).

16. *See, e.g.*, Dauphin Island Property Owners Assoc. v. Callon Institutional Royalty Investors I, 519 So. 2d 948 (Ala. 1988); Hanson v. Ware, 274 S.W.2d 359 (Ark. 1955); Terry v. Conway Land, Inc., 508 So. 2d 401 (Fla. Dist. Ct. App. 1987), *aff'd.*, 542 So. 2d 362 (Fla. 1989).

17. Not all of these cases deal with royalty interests, but the analysis is not affected by whether the outstanding interest is a nonparticipating mineral interest or a royalty interest. The one exception is where the stand alone royalty interest is stated as a fractional share of production and not a fractional share of royalty. An owner of a 1/16th royalty is unaffected by the leasehold royalty provision. An owner of a 1/2 of royalty interest is obviously affected by the amount of royalty reserved in the lease. An excellent review of the basic doctrines and cases can be found in Ernest E. Smith, *Implications of a Fiduciary Standard of Conduct for the Holder of the Executive Right*, 64 TEX. L. REV. 371 (1985).

18. 209 So. 2d 11 (La. 1968).

1975, which required the executive owner to act in good faith and as a reasonably prudent operator. Thus the Mineral Code imposed both a subjective and objective standard of care on the executive owner.

Many jurisdictions have adopted an "utmost fair dealing" standard.[19] But defining what is utmost fair dealing under any particular factual situation has proved to be elusive. While it is generally conceded to be an intermediate standard of care, lying somewhere between good faith and fiduciary, the parameters of the standard have never been carefully laid out. In fact, some courts refer to the standard as one of utmost good faith and fair dealing, combining both an objective and subjective test, although never fully explaining the differences between the two.[20] Other courts have used the standard of "utmost fair dealing and diligence."[21]

Yet other courts have found higher duties owed by the executive. In *Hollister Co. v. Cal-L Exploration Corp.*,[22] the court analogized the relationship between the executive and non-executive as similar to that of a trustee and beneficiary. That immediately raises the specter of imposing a fiduciary obligation on the owner of the executive right. In fact, such language was used in *Manges v. Guerra*,[23] although later Texas courts eschewed finding a fiduciary relationship.[24] Thus, even within a single state there has been difficulty in agreeing on the basic issue of the relationship between a stand alone royalty interest owner and the owner of the executive power.

B. *The Landowner's or Leasehold Royalty*

The landowner's royalty is the percentage of production retained by the lessor who has granted the privilege to explore and produce to the lessee. The royalty has been firmly entrenched in the oil and gas business since its inception. For example, while it was labelled a rental, a copy of the Drake lease retained for the benefit of the lessor,

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19. *See, e.g.*, Welles v. Berry, 434 So. 2d 982 (Fla. Dist. Ct. App. 1983); Schroeder v. Schroeder, 479 N.E.2d 391 (Ill. App. Ct. 1985); Murdock v. Pure-Lively Energy 1981-A Ltd., 775 P.2d 1292 (N.M. 1989); J.M. Huber Corp. v. Square Enterprises, Inc., 645 S.W.2d 410 (Tenn. Ct. App. 1982); Schlittler v. Smith, 101 S.W.2d 543, 545 (Tex. 1937). The term "utmost fair dealing" derives in part from an early article which argued against the imposition of a fiduciary standard. Lee Jones Jr., *Non-Participating Royalty*, 26 TEX. L. REV. 569 (1948).

20. *See, e.g.*, Hudgins v. Lincoln Nat'l Life Ins. Co., 144 F. Supp. 192 (E.D. Tex. 1956); Archer County v. Webb, 338 S.W.2d 435 (Tex. 1960).

21. Federal Land Bank of Houston v. United States, 168 F. Supp. 788 (Ct. Cl. 1958).

22. 102 Cal. Rptr. 919 (Cal. 1972).

23. 673 S.W.2d 180 (Tex. 1984); *see also* Donahue v. Bills, 305 S.E.2d 311 (W. Va. 1983).

24. *See, e.g.*, Mims v. Beall, 810 S.W.2d 876 (Tex. Ct. App. 1991); Pickens v. Hope, 764 S.W.2d 256 (Tex. Ct. App. 1988).

"one-eighth of all oil as collected from the springs in barrels."[25] This is an example of a royalty clause requiring the lessee to make an "in kind" payment of the oil. Neither the lessor nor the lessee have the option to make payment except in kind.[26]

There is no standard royalty clause. There are substantial variations in length, coverage and types depending on the state or region in which the lease is executed. The following examples are not meant to be exhaustive but to generally suggest the various types of clauses that can be found. Royalty clauses have historically differed regarding the production of oil versus the production of gas. This difference can be traced to the earlier view of natural gas as a waste product and the difficulties in above ground storage of gas. It is also true that royalty clauses are more varied when it comes to gas than when it comes to oil.

1. Oil Royalty Clauses

> Lessee shall pay royalties to Lessor as follows: (a) one-eighth (1/8th) of the Oil produced and saved from said land to be delivered at the wells or to the credit of Lessor into the pipeline to which the well may be connected: Lessee may, at any time or times, purchase any royalty oil, paying the market value in the field on the day it is run to the storage tanks or pipeline.[27]

The above provision requires payment in kind either at the well or in the pipeline. It does, however, favor the lessee by giving the lessee the power, but not the duty, to take the royalty oil and pay the prevailing market value on the day the oil is run to the storage tanks.

> A royalty clause which is more favorable to the lessor is as follows: (a) on oil, one-eighth (1/8) of that produced from said land the same to be delivered free of cost to Lessor into the nearest available pipeline to which the oil produced from this lease may be delivered . . . .[28]

This clause makes it clear that the expense of delivering the oil to the pipeline is borne solely by the lessee. In addition, the obligation is to

25. RICHARD MAXWELL ET AL., CASES ON MATERIALS ON OIL AND GAS LAW 355 (6th ed. 1992) [hereinafter CASES].
26. One of the earliest Texas oil and gas leases reserved to the lessor, ". . . the one twelfth part of all products of said lands in the way of minerals or oil that may hereafter be saved, procured or found . . . ." *Id.* at 356.
27. AAPL Form 681 - Colorado Oil and Gas Lease.
28. 8 WILLIAMS & MEYERS, *supra* note 1, at 501.

deliver it to the nearest available pipeline. Finally, the lessee is not authorized to take the lessor's royalty oil and pay for it.

The principal variations in oil royalty clauses relate to the fraction of royalty reserved, whether it must be taken in kind, and if it is not taken in kind, whether the royalty owner is to receive the market price or market value of the oil, the expenses which may be deducted from the royalty and how it is to be measured, sampled and/or adjusted. Obviously, the lengthier the oil royalty clause the more you can deal with the above variables. While earlier leases were silent on treatment or transportation issues, most leases today specify a point of delivery as either a storage tank or the nearest common carrier pipeline, so that expenses incurred prior to the point of delivery are borne solely by the lessee.

2. Gas Royalty Clauses

Unlike oil royalty clauses, gas royalty clauses have normally been longer and more complex. After the initial period in which a flat fee per well or no royalty at all was standard, gas royalty clauses have gradually evolved into drafter's nightmares. The options are typically more numerous and the products more varied. A typical gas royalty clause will have to deal with the production of liquids or condensate or casinghead gas, the ability to take in kind, the right to have the royalty measured by market value, market price, net proceeds or gross proceeds, the place of valuation, and the problem of measuring, sampling and post-production expenses. It is also common for there to be multiple measures depending upon the place of sale or disposal of the product or upon its ultimate use. The following gas royalty clause is typical of many standard lease forms:

> . . . on gas, including casinghead gas or other gaseous substances, 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[s] . . . .[29]

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29. Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 228 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985). The leases being litigated in *Piney Woods* also had the following type of royalty clause:

> [T]o pay lessor on gas and casinghead gas produced from said land (1) sold by lessee, one-eighth of the amount realized by lessee, computed at the mouth of the well or (2) when used by lessee off said land or in the manufacture of gasoline or other products, the market value at the mouth of the well . . . .

Id. at 228.

This clause provides for two different valuation methodologies. For gas that is sold or used the lessor is to receive a royalty based on the market value of the gas as determined at the wellhead. For gas that is sold at the well, however, the royalty is based on the amount realized or the proceeds received by the lessee from that sale. It is this type of bifurcated royalty clause which led to an onslaught of litigation starting in the 1960's.

3. Realty or Personalty

A landowner's royalty interest in hydrocarbons which have already been produced is universally found to be personalty.[30] However, there is a split of authority over whether the landowner's royalty interest in unaccrued production is realty or personalty. Several states including Kansas, Ohio and Illinois find that it is personalty.[31] The remaining states all classify it as an incorporeal real property interest; although in those states which treat the lease as an incorporeal interest, it is doctrinally incorrect to carve out an incorporeal estate out of another incorporeal estate.[32] It is clear that because of common law restrictions on assignability of choses in action, courts in states treating leases as incorporeal estates ignored the common law rule in order to avoid substantial injury to the oil and gas business.

C. *The Overriding Royalty Interest*

This term has evolved over the years from describing a royalty interest created by the lease in excess of the typical 1/8th royalty to one that describes a royalty interest carved out of an existing working interest.[33] The former usage has all but disappeared with the disappearance of the "standard" 1/8th royalty. Instead the term is used to describe the type of interest retained by an assignor of the working interest.[34] It can also be used to describe an interest conveyed by the

30. *See, e.g.*, Kentucky Trust & Bank Co. v. Ashland Oil & Transp. Co., 310 S.W.2d 287 (Ky. 1958); Lone Star Gas Co. v. Murchison, 353 S.W.2d 870 (Tex. Ct. App. 1962).

31. *See, e.g.*, Hardy v. Greathouse, 94 N.E.2d 134 (Ill. 1950); Lathrop v. Eyestone, 227 P.2d 136 (Kan. 1951); Pure Oil Co. v. Kindall, 156 N.E. 119 (Ohio 1927).

32. *See generally* RICHARD HEMINGWAY, THE LAW OF OIL AND GAS 59-60 (3rd ed. 1991).

33. 8 WILLIAMS & MEYERS, *supra* note 1, at 859-61. In Walter v. Sohio Petroleum Co., 83 N.E.2d 346 (Ill. 1948), the court broke down a 1/6th royalty reserved in a lease into a 1/8th royalty and a 1/24th overriding royalty.

34. *See, e.g.*, Tidelands Royalty B Corp. v. Gulf Oil Corp., 804 F.2d 1344 (5th Cir. 1986).

working interest owner to a person who provides goods and/or services to the owner during the exploration or production process.[35]

The overriding royalty interest owner for the most part possesses all of the qualities of a stand alone or landowner's royalty. It is "first and foremost" a royalty interest.[36] For most purposes it is treated as any other royalty interest would be in answering questions relating to valuation.[37] The major difference between an overriding royalty and a stand alone royalty is that its duration is limited to the continued existence of the lease out of which it was created. This limitation is only logical, since one cannot create an estate of greater duration than one owns. The overriding royalty interest is created out of the leasehold estate. Its duration cannot be greater than the leasehold estate, but can be shorter.[38] The parties, however, can by written agreement extend the life of the override to lease renewals or extensions.[39]

One area where there is a significant split of authority in dealing with the override is whether or not the override owner is entitled to receive the benefits of the leasehold implied covenants. If one applied traditional real covenant theory, the owner of an override carved out of the working interest would not be able to enforce the benefits of the real covenant. Only the assignee of the lessor who was the covenantee could sue to enforce the implied covenants. An early Oklahoma case took that position when the owner of the override sought to enforce the implied covenant to prevent drainage.[40] But

35. *See, e.g.*, Crothers v. General Petroleum Corp., 280 P.2d 182 (Cal. Ct. App. 1955); Leonard v. Prater, 36 S.W.2d 216 (Tex. Civ. App. 1931).

36. Cities Serv. Oil Co. v. Pubco Petroleum Corp., 497 P.2d 1368, 1372 (Wyo. 1972). *See also* Alamo Nat'l Bank of San Antonio v. Hurd, 485 S.W.2d 335, 339 (Tex. Ct. App. 1972).

37. Martin v. Glass, 571 F. Supp. 1406, 1409 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984).

38. *See, e.g.*, Henderson Co. v. Murphy, 70 S.W.2d 1036 (Ark. 1934); K & E Drilling, Inc. v. Warren, 340 P.2d 919 (Kan. 1959); La Laguna Ranch Co. v. Dodge, 114 P.2d 351 (Kan. 1941); Fontenot v. Sun Oil Co., 243 So. 2d 783 (La. 1971); Sunac Petroleum, Inc. v. Parkes, 416 S.W.2d 798 (Tex. 1967).

39. Likewise the lessor and the assignee cannot intentionally seek to wash out the override by terminating the active lease and then negotiating a new lease. *Sunac Petroleum*, 416 S.W.2d at 802. *See generally* 8 WILLIAMS & MEYERS, *supra* note 1, at 420.2. For two recent cases dealing with the problem of lease termination and its impact on the override, see GHR Energy v. TransAmerican Natural Gas, 972 F.2d 96 (5th Cir. 1992), *reh'g denied*, 979 F.2d 40 (5th Cir. 1992), *cert. denied*, 113 S. Ct. 1879 (1992); The Exploration Co. v. Vega Oil & Gas Co., 843 S.W.2d 123 (Tex. Ct. App. 1992).

40. Kile v. Amerada Petroleum Corp., 247 P. 681 (Okla. 1925). In drainage cases it is clear that the owner of the override is being damaged by the loss of recoverable hydrocarbons. Nonetheless, the Oklahoma Supreme Court held that the assignor could not sue to enforce the lessor's covenant. For other cases reaching a similar result on traditional covenant theory, see Campbell v. Nako Corp., 424 P.2d 586 (Kan. 1967); Ebberts v. Carpenter Prod. Co., 256 S.W.2d 601 (Tex. Ct. App. 1953). *See generally* Maurice H. Merrill, *Implied Covenants Between Others Than Lessors and Lessees*, 27 WASH. U. L.Q. 155 (1942).

many courts refused to get bogged down in what they perceived to be arcane and ancient real covenant law and looked at the underlying purposes of implying covenants. By focusing on the reasons for implying such covenants, several courts reached the conclusion that the override owner was in a similar position to that of the lessor so as to justify the implication of certain of the leasehold covenants.

A leading case finding that the override owner could sue the working interest owner for breaching the implied covenant to prevent drainage is *Bolton v. Coats*.[41] Bolton was the assignor of a lease who retained an overriding royalty upon the assignment. Coats was the operator of the lease as well as the operator of several adjacent leases. Bolton claimed that oil from the acreage covered by his assignment was being drained to adjacent leases. The court concluded: "Unless the assignment provides to the contrary, the assignee of an oil and gas lease impliedly covenants to protect the premises against drainage when the assignor reserves an overriding royalty.... [The assignor] is entitled to the benefit of the implied covenant under his assignments ...."[42]

It is unclear whether the court is implying a new covenant between assignor or assignee or treating the assignor as a fictional successor in interest to the original lessor/covenantee. This latter approach was taken in *Cook v. El Paso Natural Gas Co.*,[43] where the court allowed a federal oil and gas lessee to sue her assignee for breach of the drainage covenant. The better reasoned approach, however, is for the court to treat the assignment instrument as creating a new implied covenant where the assignor/override owner is treated as the covenantee.[44]

On the other hand several courts have found that no implied covenants exist between the override owner and the operator of the lease. For example, in *McNeill v. Peaker*,[45] the Arkansas Supreme Court summarily dismissed a claim by the assignor/override owner that the working interest owner had breached both the implied covenant to

41. 533 S.W.2d 914 (Tex. 1975).
42. *Id.* at 916-17.
43. 560 F.2d 978 (10th Cir. 1977).
44. *See also* Phillips Petroleum Co. v. Taylor, 116 F.2d 994 (5th Cir. 1941), *cert. denied*, 313 U.S. 565 (1941); United States Steel Corp. v. Whitley, 636 S.W.2d 465 (Tex. Ct. App. 1982). *See generally* Ernest E. Smith III, *Duties and Obligations Owed by an Operator to Nonoperators, Investors and Other Interest Owners*, 32 Rocky Mtn. Min. L. Inst. 12-1 (1986); Michael D. Salim, *Implied Covenants Between Assignors and Assignees of Oil and Gas Leases: Policy and Precedent*, 31 Sw. L.J. 905 (1977).
45. 488 S.W.2d 706 (Ark. 1973).

develop and the implied covenant to prevent drainage. The court relied on the traditional freedom of contract argument against implying terms to agreements where the parties are knowledgeable about the subject matter and are in an equal bargaining position. The assignor could have included express covenants to protect her interest in the agreement, and the court was loath to rewrite that agreement in order to rescue the assignor.[46]

III. Some Basic Valuation Principles — Market Value/Market Price

Royalty is not a share of the lessee's profits, but is a share of the lessee's production. In the case of a landowner's royalty the calculation of the amount of royalty owed should depend upon the express language of the leasehold royalty clause. As we shall see,[47] courts sometimes ignore the express language in order to reach results that are deemed to serve other public purposes than freedom of contract.

In theory there should be a distinction between the terms market price and market value. Market price seemingly refers to an actual sale of the gas in exchange for a cash consideration. Thus without a sale there is no market price. Market value, however, may exist in the absence of any actual sale because it is based on a hypothetical standard.[48] In fact, a number of courts have made that distinction.[49] But the vast majority of courts have treated market price and market value royalty clauses as functional equivalents.[50]

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46. *See also* Tidelands Royalty B Corp. v. Gulf Oil Corp., 804 F.2d 1344 (5th Cir. 1986); Henderson Co. v. Murphy, 70 S.W.2d 1036 (Ark. 1934); Phoenix Oil Co. v. Mid-Continent Petroleum Corp., 60 P.2d 1054 (Okla. 1936).

47. *See infra* Section IV.

48. Hemingway, *supra* note 32, at 376.

49. *See, e.g.*, Hugoton Prod. Co. v. United States, 315 F.2d 868, 874 (Ct. Cl. 1963), *modified*, 349 F.2d 418 (Ct. Cl. 1965) where the court said:

> [A]lthough 'market value' and 'market price' have often been used interchangeably,the two have different meanings. It would be consistent with the difference between these terms to hold that although the *market value* of gas at the wellhead is the amount that could be obtained for it under a new contract at any given time, the *representative price* is the price which is in fact being obtained under all existing comparable contracts.

See also Swain v. Santa Fe Pacific R.R., 538 P.2d 1150 (Ariz. Ct. App. 1975).

50. *See, e.g.*, Arkansas Natural Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935), *cert. denied*, 296 U.S. 656 (1936); Sartor v. United Gas Pub. Serv. Co., 173 So. 103 (La. 1937); Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978).

An initial problem in dealing with royalty calculation under a market value/price royalty clause is determining the point of valuation.[51] In fact many gas royalty clauses have different valuation criteria depending on whether the gas is sold or used on or off the premises.[52] Where possible, the parties to the lease should specify the point of valuation because without a clear point of reference valuation issues become very difficult.[53]

Any determination of market value normally starts with the generally accepted proposition that value is determined by what a willing buyer would pay to a willing seller where neither party is compelled to enter into the transaction.[54] It is also reasonably well settled that evidence of market value may be received from any witness who has facts or opinions relating to market value.[55]

A hierarchy of methodologies has been created that influence a court's determination of market value. Where possible, the best evidence of market value is the price at which the commodity is sold in an arms' length transaction at the point of valuation.[56] The sale must also be contemporaneous with the time of valuation, a point that was disputed in the market value litigation of the 1970's and early 1980's. If there is no actual sale at the time and point of valuation, the next best valuation methodology is the use of comparable sales.[57] The

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51. *See generally* Maxwell, *supra* note 2, at 15-4 to 15-6 (1989).

52. Most of the cases discussed that relate to the problem of market value leases and long term gas purchase contracts have those kind of bifurcated clauses. In both Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984) and Exxon Co. v. Middleton, 613 S.W.2d 240 (Tex. 1981), the issue was critical to the courts' ultimate findings because only if the gas was sold off of the leasehold or off of the premises was the royalty owner entitled to market value royalties.

53. For a general criticism about the inadequacy of many royalty clauses, see Joseph T. Sneed, *Value of Lessor's Share of Production Where Gas Only is Produced*, 25 TEX. L. REV. 641 (1947).

54. Ashland Oil, Inc. v. Phillips Petroleum Co., 463 F. Supp. 619, 626 (N.D. Okla. 1978); Lightcap v. Mobil Oil Corp., 562 P.2d 1, 3 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977), *reh'g denied*, 440 U.S. 931 (1979); Exxon Corp. v. Jefferson Land Co., 573 S.W.2d 829, 830 (Tex. Ct. App. 1978).

55. *Piney Woods*, 726 F.2d at 238; J.M. Huber Corp. v. Denman, 367 F.2d 104 (5th. Cir. 1966); Arkansas Natural Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935), *cert. denied*, 296 U.S. 656 (1936); Butler v. Exxon Corp., 559 S.W.2d 410 (Tex. Ct. App. 1977).

56. Phillips Petroleum Co. v. Bynum, 155 F.2d 196, 201 (5th Cir. 1946), *cert. denied*, 329 U.S. 714 (1946); Phillips Petroleum Co. v. Ochsner, 146 F.2d 138, 141 (5th Cir. 1944); Cabot Corp. v. Brown, 754 S.W.2d 104 (Tex. 1987).

57. *See, e.g.*, Ashland Oil, Inc. v. Phillips Petroleum Co., 554 F.2d 381, 387 (10th Cir. 1975); Hugoton Prod. Co. v. United States, 315 F.2d 868 (Ct. Cl. 1963); Arkansas Natural Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935), *cert. denied*, 296 U.S. 656 (1936); Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981); Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968).

third and "least desirable" methodology,[58] is the net-back or work-back method whereby value at the point of valuation is determined by taking the downstream sales price and deducting from it the costs incurred by the working interest owner to move the gas from the point of valuation to the actual point of sale. The basis for using the work-back method is that merely because there is a lack of an available market at the point of valuation does not mean that the product lacks any value.[59] The procedure has been described as follows: "it is commonly understood that 'market price at the well' is often determined by working back from the price at the point of the sale, deducting the cost of processing and transportation . . . [from] the wellhead, to determine the 'market value at the wellhead.' "[60] The work-back system of valuation has been most often used in cases involving gas royalty clauses requiring the lessee to pay the market value or market price of the gas at the wellhead, but the actual sale of the gas was downstream of that point.[61]

While there is near-universal agreement about these general principles, there has been disagreement about how to deal with the regulated versus unregulated gas market when measuring comparable

58. Montana Power Co. v. Kravik, 586 P.2d 298, 303-04 (Mont. 1978) (cited with approval in Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 239). *See also Ashland Oil*, 554 F.2d at 381.

59. Scott Paper Co. v. Taslog, Inc., 638 F.2d 790, 799 (5th Cir. 1981).

60. Atlantic Richfield Co. v. State, 262 Cal.Rptr. 683, 688 (1989). For other cases applying the work-back methodology see, *Piney Woods*, 776 F.2d at 238; *Ashland Oil*, 554 F.2d at 381; Freeland v. Sun Oil Co., 277 F.2d 154 (5th Cir. 1960), *cert. denied*, 364 U.S. 826 (1960); Old Kent Bank & Trust Co. v. Amoco Prod. Co., 679 F. Supp. 1435 (W.D. Mich. 1988); Matzen v. Hugoton Prod. Co., 321 P.2d 576 (Kan. 1958); Reed v. Hackworth, 287 S.W.2d 912 (Ky. 1956); Clear Creek Oil & Gas Co. v. Bushmaier, 264 S.W. 830 (Ark. 1924). In a case involving valuation of helium a court described the work-back method as follows:

> Effective application of this [work-back] method requires selection of an appropriate starting value in the form of a processing state whose product possesses a value certain; accurate assessment of the costs accruing between the known stage and the one in question is also essential. In developing a resource from a raw material into a finished product, each production stage will add economic value to what was initially only the value of the raw material. The value added at each stage of production is essentially the cost of resources used in taking the material through that stage of production. The work-back method essentially establishes at each production stage the value of the product at that point. By subtracting out all production costs, the value of the raw material is revealed.

Ashland Oil, Inc. v. Phillips Petroleum Co., 463 F. Supp. 619, 620 (N.D. Okla. 1978). A recent Texas case apparently rejects the use of the work-back method where other alternatives were being used by the lessee which may not have been as accurate as the work-back. Carter v. Exxon Corp., 842 S.W.2d 393 (Tex. Ct. App. 1992).

61. Danciger Oil & Refineries v. Hamill Drilling Co., 171 S.W.2d 321 (Tex. 1943); Wall v. United Gas Pub. Serv. Co., 152 So. 561 (La. 1934).

sales. It is usually stated that the comparable sales must be comparable in time, quantity, quality and availability to marketing outlets.[62] In litigation during the 1960's and 1970's royalty owners sought to admit evidence of the price of gas not regulated under the Natural Gas Act even though the gas from their well was dedicated to interstate commerce. In *Lightcap v. Mobil Oil Corp.*,[63] the Kansas Supreme Court clearly held that even though the gas being produced was committed to the interstate market and therefore price-regulated, the royalty owner could submit evidence of the higher intrastate unregulated prices. Comparability did not include the existence of partial federal price regulation. This approach, however, did not receive widespread support outside of Kansas.[64]

Texas and the federal courts reached a different result. The Texas Supreme Court described the comparability methodology as follows:

> Market value may be calculated by using comparable sales. Comparable sales of gas are those comparable in time, quality, quantity, and availability of marketing outlets . . . . Sales comparable in time occur under contracts executed contemporaneously with the sale of the gas in question. Sales comparable in quality are those of similar physical properties such as sweet, sour, or casinghead gas. Quality also involves the legal characteristics of the gas; that is, whether it is sold in a regulated or unregulated market, or in one particular category of a regulated market. Sales comparable in quantity are those

62. Phillips Petroleum Co. v. Ochsner, 146 F.2d 138 (5th Cir. 1944); Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981). In looking at the physical comparability characteristics one court listed the following as relevant:

> (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.
>
> (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.

Hugoton Prod. Co. v. United States, 315 F.2d 868, 894-95 (Ct. Cl. 1963).

63. 562 P.2d 1 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977), *reh'g denied*, 440 U.S. 931 (1979).

64. In Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978), the gas in question was sold in the intrastate market. The court suggested, however, that even if the gas had been committed to interstate commerce, only intrastate comparable sales would be admissible to determine market value.

of similar volumes .... To be comparable, the sales must be made from an area with marketing outlets similar to the gas in question.[65]

IV. Market Value Versus Proceeds Gas Royalty Clauses

Under pre-1990's gas marketing realities, most gas produced in the United States was sold pursuant to a long-term gas purchase contract. In the 1970's, however, a divergence occurred between the typical price escalation features of these long-term contracts and the current market value of the gas.[66] As the divergence became greater, royalty owners who had market value royalty clauses instituted litigation when the working interest owners continued to determine their royalty as a percentage of their contract proceeds and not as a percentage of the current market value of the gas. In resolving what seemingly is a contract interpretation issue, a divergence of opinion arose as to how to determine the market value or market price of gas that was sold pursuant to a long term contract.

In three cases, state supreme courts interpreted gas royalty clauses which required the lessee to make payments based on either market price or market value as being satisfied if the lessee tendered royalty based on the proceeds received under a long term gas purchase contract. The earliest decided case was *Tara Petroleum Corp. v. Hughey*.[67] The royalty owner claimed that his royalty share should be based on the FPC ceiling price of $ 1.30/MCF rather than the contract price of $ 0.33/MCF. The contract had been executed five months prior to the increase in the FPC ceiling price.[68]

The court's rationale for interpreting a market price royalty clause as being the functional equivalent of a proceeds or amount realized clause was that any other approach would "not be fair to the producers."[69] Since the parties were free to negotiate a proceeds or amount realized royalty clause, I do not particularly see the unfairness

65. Exxon Corp. v. Middleton, 613 S.W.2d 240, 246-47 (Tex. 1981). For cases comparable to *Middleton*, see Kingery v. Continental Oil Co., 626 F.2d 1261 (5th Cir. 1980), *reh'g denied*, 654 F.2d 721 (5th Cir. 1981), *cert. denied*, 454 U.S. 1148 (1982); Weymouth v. Colorado Interstate Gas Co., 367 F.2d 84 (5th Cir. 1966); First Nat'l Bank in Weatherford v. Exxon Corp., 622 S.W.2d 80 (Tex. 1981).

66. *See generally* David Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 E. Min. L. Foundation 18-1 (1992); Richard Pierce, *Lessor/Lessee Relations in a Turbulent Gas Market*, 38 Inst. on Oil & Gas L. & Tax'n 8-1 (1987).

67. 630 P.2d 1269 (Okla. 1981).

68. *Id.* at 1271.

69. *Id.* at 1273. The court's fairness rationale is weakened by the fact that the gas purchase contract was executed in 1976, at a time when almost all of the extant decisions had reached a contrary result.

that the Oklahoma Supreme Court did. The court looked to the expectations of the parties when they executed the lease, rather than the language they chose to include in the lease.[70]

Tara was followed by *Hillard v. Stephens.*[71] Again a market price royalty clause was being interpreted. The lessee had entered into a life-of-the-lease gas purchase contract whose pricing mechanism lagged substantially behind the current market price. As with *Tara* the court relied on market realities and unfairness to the lessee as justifications for changing the clause to a proceeds clause. It did so by concluding that the term "prevailing market price at the well" does not mean current market price, but the price as set by the long term contract.[72] The court was particularly influenced by the claim that if the current market price of $ 2.40/MCF was used the lessee would owe the royalty owner $ .30/MCF while the lessee was only receiving $ .33/MCF from the purchaser. While this scenario looks bleak from the producer's standpoint, it is a condition brought about by the lessee's own inability to negotiate a lease whereby it would not bear the risk of a rising value gas market. The court also emphasized the producer's duty under the implied marketing covenant to market the gas. Again that argument misses the point. There is a duty to market, but that is independent of the express royalty clause. The agreement executed between the producer and the purchaser cannot vary the terms of the lease signed between the producer and the lessor. While the marketing duty may be met by entering into a contract which is fair when executed, it cannot preempt the application of the royalty clause.

Finally, the Louisiana Supreme Court in *Henry v. Ballard & Cordell Corp.*,[73] became the highest court of the third state to ignore the express leasehold language. Here the lease contained a market value royalty clause. A long term gas purchase contract was executed in 1961, whose pricing scheme was lagging well behind the current

70. The court presumed that the lessor expected the lessee to enter into a long term gas purchase contract which would limit the lessee's income stream to increases in the gas purchase contract. The court, however, ignored the opposite side of the value/proceeds coin, because if the contract price was higher than the current market price or value, under a price or value royalty clause the lessor would only be entitled to receive a percentage of the current value and not a percentage of the proceeds. *See generally* David Pierce, *supra* note 66, at 18-9 to 18-11.

71. 637 S.W.2d 581 (Ark. 1982).

72. *Id.* at 585.

73. 418 So. 2d 1334 (La. 1982).

market value at the time the litigation was begun in 1976.[74] The Louisiana Supreme Court was clear in stating that its decision in this matter had to be resolved by looking at the "necessary realities of the oil and gas industry."[75] Those realities included the general industry practice of executing long term gas purchase contracts, the unforeseeable rise in gas prices and the limited marketing options available because of pipeline monopolies.

While the Arkansas and Oklahoma courts seemingly determined as a matter of law that leases containing market price royalty clauses mean contract price, the Louisiana court found the term market value was ambiguous in that it could mean current market value or market value at the time of the execution of the gas purchase contract. The ambiguity was then resolved in the lessee's favor because of the lessee's difficult position even though the normal canon of construction is to interpret ambiguous provisions against the lessee who normally is the scrivener of the instrument.[76]

Before "marketing realities" were an influence on the interpretational process for royalty clauses, most of the cases that were decided indicated that under a market value royalty clause, the value was to be determined at the time of delivery and not at the time that the gas purchase contract was executed. The first important case was *Foster v. Atlantic Refining Co.*[77] The gas royalty clause required a 1/8th royalty "the same to be delivered to the credit of the Lessor into the pipe line and to be sold at the market price therefor prevailing for the field where produced when run."[78] The lessee entered into a 20 year gas purchase contract in 1950, but by 1957, the field price exceeded the contract price. The lessee made all of the same arguments made in *Tara*, *Hillard* and *Henry*. He alleged that it was impossible to sell gas with an escalator clause that would have kept pace with the unexpected rise in gas prices. The court responded with this somewhat harsh, but realistic view of the lessee's lack of business acumen:

> The inability of Atlantic to make a gas sales contract with [appropriate] escalation provisions is beside the point. The obligation of Atlantic to pay royalties is fixed and unambiguous. It made the gas

74. *Id.* at 1336.
75. *Id.* at 1339.
76. For an exhaustive analysis of canons of construction for mineral deeds and leases in Texas, see Bruce M. Kramer, *The Sisphyean Task of Interpreting Mineral Deeds and Leases: An Encyclopedia of Canons of Construction*, 24 TEX. TECH L. REV. 1 (1993).
77. 329 F.2d 485 (5th Cir. 1964).
78. *Id.* at 488.

> sales contract with full knowledge of this obligation .... The fact that its purchaser would not agree to pay the market price prevailing at the time of delivery does not destroy the lease obligation ....[79]

The agreement between the lessee and the gas purchaser, could not, and should not affect the lessee's leasehold obligations to the lessor. *Foster* clearly values the gas at the time of delivery leaving the lessee with the risk that its royalty obligation will not be covered by its long term gas purchase contract.

Four years after *Foster*, the Texas Supreme Court in *Texas Oil & Gas Corp. v. Vela*,[80] likewise treated the lessee's argument about practical difficulties with indifference. Again the lease called for "market price" based royalties while the lessee was paying on the basis of actual proceeds. The difference was substantial in that market price was determined to be 13.047 cents/MCF while the "life of the lease" gas purchase contract had a price of only 2.36 cents/MCF. It gave support for the position that value is determined at the time of delivery and not at the time the gas purchase contract was executed. It also placed the risk of loss should the price escalation features of the gas purchase contract fall behind market price clearly on the lessee. The court agreed with the *Foster* court that the contract's terms cannot vary the leasehold language requiring market price royalties. Finally, the court rejected the "marketing realities" defense when it concluded:

> It is clear that the parties knew how to and did provide for royalties payable in kind, based upon market price or market value, and based upon the proceeds derived by the lessee from the sale of the gas. They might have agreed that the royalty on gas from a gas well would be a fractional part of the amount realized .... Instead of doing so, however, they stipulated in plain terms that the lessee would pay one eighth of the market price .... The lease obligations may prove financially burdensome to a lessee who has made a long-term contract without protecting itself against increases in market price.[81]

The Texas Supreme Court reiterated its rejection of the "market realities" defense in *Exxon Corp. v. Middleton*.[82] It also reaffirmed the *Vela* holding that as between the lessor and the lessee the gas is sold

79. *Id.* at 489.
80. 429 S.W.2d 866 (Tex. 1968).
81. *Id.* at 871.
82. 613 S.W.2d 240 (Tex. 1981); *see also* Exxon Corp. v. Jefferson Land Co., 618 S.W.2d 529 (Tex. 1980).

when produced and delivered and not when the gas purchase contract is executed. The court stated:

> Although as between Exxon and its customers, the gas may have been sold when the contracts became effective, there is no basis in the royalty clause for applying such a definition to the lease agreements . . . . When Exxon negotiated the gas contracts, it took the risk that the revenue therefrom would be insufficient to satisfy its royalty obligations . . . .[83]

Finally, the Fifth Circuit in *Piney Woods* in a scholarly opinion followed the *Foster/Vela* approach both as to the time the gas is sold and with regard to the difference in market value or price royalty clauses and proceeds royalty clauses. The Fifth Circuit relied in part on the principles contained in the Uniform Commercial Code to buttress the argument that the gas is sold when delivered and not when the contract is executed.[84] It concluded that the gas purchase contract is executory in nature until the gas is actually delivered. It also rejected the *Tara* assimilation of market value and market price royalty clauses into a proceeds royalty clause when the lessee should have been aware that there is a difference between those types of clauses.[85]

The court further rejected Shell's claim that market value is basically always determined by proceeds less post-production costs. Again that would render the clear differences between proceeds and value based royalties meaningless when the parties intended otherwise. Further support for the court's decision was found in the canon of construction that mineral leases are construed against the lessee and in favor of the lessor. Finally, the court merely interpreted a written document so that royalties were to be based on market value, not amount realized or proceeds. The court rejected Shell's request to "rewrite the lease to [its] satisfaction."[86]

This final point is the key to the difference between the *Vela* and *Tara* rules. The reasonably simple task of a court in determining what a royalty owner is entitled to, is to interpret the express language of the royalty clause. There is a difference between language giving the

83. Exxon Corp. v. Middleton, 613 S.W.2d 240, 245 (Tex. 1981).

84. Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 233-34 (5th Cir. 1984).

85. *Id.* The court noted that up until *Tara* all of the courts had followed the *Foster/Vela* rule. *See, e.g.*, Lightcap v. Mobil Oil Corp., 561 P.2d 1 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977); Wall v. United Gas Pub. Serv. Co., 152 So. 561 (La. 1934); Montana Power v. Kravik, 586 P.2d 298 (Mont. 1978); Exxon Corp. v. Middleton, 613 S.W.2d 240, 245 (Tex. 1981).

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

royalty owner a share of the market value of the produced hydrocarbons and the amount realized or proceeds from the sale of the hydrocarbons. The *Vela* rule is truer to the language of the instrument, while the *Tara* rule rewrites the contract because of "market realities."

Several states have enacted royalty payment statutes in the past few years.[87] These statutes sometimes call for the royalty owner to share in the proceeds of production. In *Hillard*, one of the arguments made by a royalty owner of a fixed price gas royalty clause was that the Arkansas statute transformed the lessee's royalty obligation into a proceeds, rather than a fixed price, obligation. The court rejected that argument, concluding that the statute did not alter the contractual agreement between the parties which set forth the nature of the royalty payment.

Similar arguments could be made regarding the recently enacted Oklahoma Production Revenue Standards Act,[88] which provides in part that "each royalty interest owner shall share in all proceeds derived from the sale of gas production from a well to the extent of such owner's interest in the well without regard to the identity of the producing owners."[89] The statutory language should not be construed to change leasehold market value clauses into proceeds clauses. The leasehold language should control and determine the appropriate method of valuing royalties.

V. Production Versus Post-Production Expenses

As shown above in Section II, most royalty clauses require that the royalty be free of the costs of production. The parties are free in the lease or deed to expand or contract the royalty owner's freedom from costs. A typical clause shifts the burden of paying taxes from the royalty owner to the working interest owner.[90] Likewise the parties may expressly allocate the burden of certain expenses which may be anticipated should oil or gas be produced. For example, the following

87. *See, e.g.*, Ark. Code Ann. §§ 15-74-601-15-74-704 (Michie Supp. 1993); N.M. Stat. Ann. §§ 70-10-1-70-10-6 (Michie Supp. 1993); Tex. Nat. Res. Code Ann. § 91.402 (West 1993).

88. Okla. Stat. tit. 52, §§ 570.1-570.15 (West Supp. 1992).

89. *Id.* § 570.4(A).

90. For an example of a tax shifting clause, see Tenneco West, Inc. v. Marathon Oil Co., 756 F.2d 769, 770-71 (9th Cir. 1985), *cert. denied*, 474 U.S. 845 (1985). The clause required the lessee to pay "any and all taxes . . . upon or referable to any operations or acts of [the lessee] . . . including . . . the drilling or operation of any well or wells, the production, extraction, severance or removal of any oil, . . . the processes, refining, storage and use thereof, [and] the sale . . . or the transportation thereof away from the demised premises." *Id.* The Ninth Circuit concluded that this clause did not shift to the lessee the burden of paying the lessor's windfall profits tax. For a contrary view, see Santa Fe Energy Co. v. Baxter, 783 S.W.2d 643 (Tex. Ct. App. 1989).

clause clearly places the burden of certain oil processing costs on the lessor:

> Where it is necessary to treat oil in order to meet pipeline specifications or to render it merchantable, said oil may be treated or dehydrated at lessee's option, and as agreed compensation for treating or dehydrating such oil, lessor shall be charged at the rate of five cents per barrel on lessor's royalty oil which lessee may currently deduct from any payments or settlements due lessor.[91]

Where the parties have not specified how to allocate certain costs, it is up to the courts to determine what costs are non-deductible production costs and what costs are deductible post-production costs. Again, there is a lack of agreement between the states as to the categorization process.[92] The principle that a landowner's royalty is free of the costs of production also applies to the overriding royalty carved out of the working interest.[93]

The deductibility of certain expenses is obviously critical if the court is using the work-back methodology for valuing royalty. It may also be critical if the court is dealing with a net proceeds rather than a gross proceeds lease. Only those expenses which are to be shared by the royalty and working interest owners are to be deducted from the selling price. Since in most situations the point of valuation is the wellhead, expenses downstream of that point which add value may be deducted from the sales price.[94]

The *Piney Woods* decision is probably the best reasoned statement on the underlying basis for allowing the lessee to deduct certain post-production expenses.[95] There the lessee had constructed at great expense a processing plant needed to convert the sour gas produced

91. 3 WILLIAMS & MEYERS, *supra* note 1, at 509.

92. The best two authors who articulate the underlying doctrinal differences are George Siefkin, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provision*, 4 INST. ON OIL & GAS L. & TAX'N 803 (1953), who argues that all post-production expenses including transportation and processing are deductible and MAURICE H. MERILL, COVENANTS IMPLIED IN OIL AND GAS LEASES 85 (2d ed. 1940), who argues that the implied marketing covenant required the lessee, at her own expense, to make the raw product suitable for the marketplace.

93. Professor Masterson observed:

> An overriding royalty interest is a free interest carved out of the oil and gas leasehold estate, which estate is also called the working interest. Clearly an overriding royalty is free of the usual costs of drilling, operating, and marketing, which costs must be borne by the owner of the interest out of which the override was carved.

8 Oil & Gas Rep. (MB) 1226 (1958).

94. *See, e.g.*, Matzen v. Hugoton Prod. Co., 321 P.2d 576 (Kan. 1958).

95. Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 255 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

from the plaintiff's well into marketable sweet gas. Shell deducted from the royalty payment costs associated with the plant. The lessor argued that the royalty interest was free of the costs of production, and production included marketing. Without marketing in Mississippi, the lease would terminate if it was in the secondary term. The leases contained both market value and proceeds gas royalty clauses, but the key factor was that value was determined at the well and the proceeds were likewise to be computed at the mouth of the well.[96] The gas was sold, according to the court, not at the wellhead, but at the tailgate of the gas processing plant or even further downstream. In describing why the court rejected the royalty owner's claim that all costs were non-deductible the court stated:

> [T]he royalty compensates the lessor for the value of the gas at the well; that is, the value of the gas after the lessee fulfills the obligation under the lease to produce gas at the surface, but before the lessee adds to the value of the gas by processing or transporting it.[97]

Where the parties have not specified to the contrary, and where the point of valuation is at the wellhead, it is only logical and equitable to assess the royalty owner with the costs incurred downstream of the point of valuation which add value to the product. It is not difficult to understand that the value of sour gas, which is basically unusable in its natural state, is less than the value of sweet gas. If the royalty clause requires payment based on wellhead value or proceeds at the wellhead, the royalty owner is only entitled to receive a fractional share of sour gas value. One type of clause that may operate to shift those expenses would be a "gross proceeds" clause although at least one court suggested that the language would have to been even more explicit before it would allow cost-shifting.[98] But typical royalty clauses, which are silent on the cost-shifting issue, are usually interpreted by courts in a manner consistent with the *Piney Woods* rationale.

It is usually conceded that the costs of geophysical surveys and other exploration costs, drilling costs, and costs associated with the completion or reworking of a well, including the cost of the measuring equipment, as well as secondary recovery costs are costs which are

96. *Id.* at 228-29. These issues are discussed in Maxwell, *supra* note 2, at 15-14 to 15-18.

97. *Piney Woods*, 726 F.2d at 241.

98. Ashland Oil Co. v. Jaeger, 650 P.2d 265 (Wyo. 1982) (dealing with the allocation of severance and ad valorem taxes).

borne solely by the working interest owner.[99] Again, the parties are free to change this apportionment formula so that for example, an override owner can be contractually obligated to share in the expenses of "operating the lease."[100]

There is agreement that where the point of valuation is at the well or on the premises, the lessor and lessee share in the cost of physically transporting the hydrocarbons from the wellhead to the point of sale. For example, in *Kretni Development Co. v. Consolidated Oil Corp.*,[101] the lessee constructed a 90 mile pipeline in order to market the gas being produced from the well. The court allowed the lessee to charge back to the royalty owner her proportionate share of the cost of constructing that pipeline where the point of valuation under the royalty clause was the wellhead. The court did note that the lessee was under an implied covenant to market the product but that covenant does not impose the duty to construct at the lessee's own expense, such a lengthy pipeline.[102] Even in Kansas which as a general rule does not allow the deduction of other post-production costs, the courts have allowed the lessee to charge the lessor for the costs of transportation.[103] These costs can be deducted in situations where the royalty clause is a net proceeds clause and the sale takes place off of the leasehold after being transported on lessee installed pipelines.[104]

Where there has been a conflict on cost deductibility is in the area of compression and other processing costs which physically take place away from the wellhead. As discussed earlier in the context of *Piney Woods*,[105] the prevailing or majority view is that such costs are deductible from royalty in the absence of leasehold or deed language to the

99. Kingwood Oil Co. v. Bell, 136 F. Supp. 229 (E.D. Ill. 1955), *aff'd*, 244 F.2d 115 (7th Cir. 1957) (stating that secondary recovery costs were not apportionable between working and royalty owners).

100. Leonard v. Prater, 36 S.W.2d 216 (Tex. Civ. App. 1931).

101. 74 F.2d 497 (10th Cir. 1934), *cert. denied*, 295 U.S. 750 (1935).

102. *See* Bruce M. Kramer & Chris Pearson, *The Implied Marketing Covenant in Oil and Gas Leases: Some Needed Changes for the 80's*, 46 LA. L. REV. 787 (1986).

103. Molter v. Lewis, 134 P.2d 404 (Kan. 1943); Scott v. Steinberger, 213 P. 646 (Kan. 1923). For other cases that hold transportation costs deductible, see Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); Ashland Oil & Refining Co. v. Staats, Inc., 271 F. Supp. 571 (D. Kan. 1971); Phillips Petroleum Co. v. Johnson, 155 F.2d 1854 (5th Cir. 1946), *cert. denied*, 329 U.S. 730 (1946); Parnell, Inc. v. Giller, 372 S.W.2d 627 (Ark. 1963); Reed v. Hackworth, 287 S.W.2d 912 (Ky. 1956); Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970); Le Cuno Oil Co. v. Smith, 306 S.W.2d 190 (Tex. Ct. App. 1957), *cert. denied*, 356 U.S. 974 (1958).

104. Phillips Petroleum Co. v. Johnson, 155 F.2d 185 (5th Cir. 1946), *cert. denied*, 329 U.S. 730 (1946).

105. *See supra* text accompanying notes 94-97.

contrary. In Kansas, Oklahoma, North Dakota and Arkansas, however, a different approach with a different rationale has been used to deny the working interest owner the right to deduct what would be considered "downstream" or post-production expenses.

The underlying basis for the Kansas/Oklahoma approach is that the implied marketing obligation of the lessee includes the obligation to place the raw product in such a form that it is capable of being marketed. Professors Merrill and Kuntz and the leading proponents of that position.[106]

The Kansas Supreme Court has been a long time exponent of the non-deductibility rule. The two leading cases decided in 1964 both found that compression costs clearly incurred downstream from the well were to be borne solely by the lessee, unless the lessee put language in the lease that made it a joint cost feature.[107] The court relied on the implied marketing duty to put the gas into a marketable condition which then placed the burden on the lessee to put into the lease express language to counteract the application of the implied covenant.[108]

Recently, the Oklahoma Supreme Court was squarely faced with this issue as it responded to the following certified question: "Is an oil and gas lessee/operator who is obligated to pay the lessor '3/16 at the market price at the well for the gas sold', entitled to deduct the cost of gas compression from the lessor's royalty interest?"[109] In *Fox Wood*

106. 3 EUGENE KUNTZ, THE LAW OF OIL AND GAS 351 (1989) provides some ambivalent support for the non-deductibility of certain post-production expenses. Professor Kuntz would have the lessee deduct incurred costs if there was a market for the raw gas and the costs were used to further improve the quality. He would not, however, allow downstream costs to be deducted in order to make the raw gas stream marketable since that would be subsumed within the lessee's implied marketing obligation. *Id.* Professor Merrill was even more strident in concluding that the implied marketing covenant required the lessee to bear all of the downstream costs to make the raw product marketable. MAURICE H. MERRILL, COVENANTS IMPLIED IN OIL AND GAS LEASES 84-89 (2d ed. 1940). For criticism of the Merrill/Kuntz approach, see George Siefkin, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provisions*, 4 INST. OF OIL & GAS L. & TAX'N 181 (1953).

107. Schupbach v. Continental Oil Co., 394 P.2d 1 (Kan. 1964); Gilmore v. Superior Oil Co., 388 P.2d 602 (Kan. 1964). These cases are criticized in Richard B. Altman & Charles S. Lindberg, *Oil and Gas: Non-Operating Oil and Gas Interests' Liability for Post-Production Costs and Expenses*, 25 OKLA. L. REV. 363 (1972).

108. In Hanna Oil & Gas Co. v. Taylor, 759 S.W.2d 563 (Ark. 1988), the court interpreted a proceeds-at-the-well royalty clause to impose upon the lessee the sold burden of paying downstream compression costs. In addition to the marketing covenant argument, the Arkansas Supreme Court applied the traditional canon of construction that construes leasehold language most strongly against the lessee. Furthermore, the lessee had initially not attempted to deduct such costs, which buttressed the court's conclusion that the parties to the lease did not intend such costs to be borne by both the lessor and lessee.

109. Fox Wood III v. TXO Prod. Co., 854 P.2d 880 (Okla. 1992).

III v. TXO Production Co.,[110] the Oklahoma Supreme Court in a 5-4 decision sided with the Kansas approach and found that the compression costs were not deductible.

In *Fox Wood* the lessee had constructed compressors on the leased premises in order to boost the pressure of the gas into the receiving pipelines. The lessee was required under his gas purchase contract to provide the gas at a specified minimum pressure. While Oklahoma had previously allowed transportation costs to be deducted from the royalty interest,[111] the court treated compression differently than transportation. It followed the marketing duty rationale of *Schupbach*, although the court's opinion was influenced by the fact that the compressor units were on the leased premises. The duty to get the raw gas into a marketable condition meant getting the gas to the point of sale. That would suggest that transportation costs would likewise not be deductible if the point of sale was off of the leasehold. But the court did not overrule *Johnson v. Jernigan*. Instead it merely concluded that incurred costs designed to make the gas marketable which occur on the leasehold premises are to be borne solely by the lessee, unless there is express leasehold language to the contrary.[112]

The dissenting opinion emphasized the *Piney Woods* reasoning that the implied marketing duty stops with the production and that post-production costs which increase the value of the raw product are deductible from the amount owed the royalty owner. The dissent followed the view that the test is a physical one. Production costs are not deductible while post-production costs are deductible in the abscence of express leasehold language to the contrary.[113] Louisiana and Texas have adopted this view.[114] Essentially the majority view placed the burden on the lessee to put in express leasehold language to have

110. *Id.*

111. Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970).

112. The other case which denied the deductibility of downstream expenses is West v. Alpar Resources, Inc., 298 N.W.2d 484 (N.D. 1980). Under a proceeds royalty clause the lessee sought to deduct the allocable share of a gas processing plant needed to remove hydrogen sulfide from the raw gas stream. The court treated the royalty clause as ambiguous and then applied the canon that ambiguities should be resolved against the lessee. Under this approach probably all post-production or downstream expenses are not deductible.

113. Most federal oil and gas leases place the burden of most post-production expenses on the lessee under the so-called "marketable condition rule." *See* 30 C.F.R. 206.152(h),(i) (1993); Mesa Operating Ltd. Partnership v. Dep't of the Interior, 931 F.2d 318 (5th Cir. 1991), *cert. denied*, 112 S. Ct. 934 (1992); Shoshone Indian Tribe v. Hodel, 903 F.2d 784 (10th Cir. 1990); Davis Exploration, 112 Int'l Board of Land Appeals 254, (Dec. 28, 1989).

114. *See, e.g.*, Martin v. Glass, 571 F. Supp. 1406 (N.D. Tex. 1983), *aff'd without opinion*, 736 F.2d 1524 (5th Cir. 1984); Merritt v. Southwestern Elec. Power Co., 499 So. 2d 210 (La. App. 1986); Parker v. TXO Prod. Corp., 716 S.W.2d 644 (Tex. Ct. App. 1986).

cost-sharing while the dissenting view placed that burden on the lessor.[115]

VI. Royalty On Take or Pay or Settlement Payments

I have elsewhere argued that royalty should be paid on some parts of take or pay or settlement payments made by a gas purchaser to a lessee.[116] While it should be important, most courts have ignored the issue of breaking down a settlement agreement into its component parts in order to determine whether a royalty payment is owed. A recent article divided up take or pay settlements into four component parts:

> 1. Payments to settle past pricing disputes attributable to prior production.
> 2. Payments to settle past take-or-pay obligations not attributable to past production. This component can further be subdivided into payments which are recoupable from future production and payments which are not recoupable.
> 3. Contract buydown payments whereby the producer receives a lump sum payment to amend the contract to reduce the price on future gas purchases and, in some cases, to also reduce the purchaser's required takes.
> 4. Contract buydown payments whereby the producer receives a lump sum payment to terminate the contract. As a result, the gas is freed of any obligation to the purchaser and thus will be sold to different purchasers.[117]

An initial issue in dealing with gas purchase contract settlement agreements is whether the royalty owner is entitled to discover the contents of the agreement for purposes of determining whether royalty is owed. To the extent that settlement monies relate to prior production, it is clear that the royalty owner is entitled to recover. Up until recently, however, the courts which have decided this issue have interpreted the standard gas royalty clause as not entitling the lessor

115. In compression cases, a factual issue may arise as to whether the compression is part of the production or post-production process. To the extent that the compressors are used to boost production, rather than increase pressure as the gas is moved into the pipeline, the courts generally find that the compression costs are not deductible. *Martin*, 571 F. Supp. at 1411-12; *Parker*, 716 S.W.2d at 648.

116. Bruce M. Kramer, *Royalty Obligations For Take or Pay and Settlement Payments: Lessees Under the Gun*, 39 Inst. on Oil & Gas L. & Tax'n 5-1 (1988).

117. James C.T. Hardwick & J. Kevin Hayes, *Gas Marketing Royalty Issues in the 1990's*, Special Institute on Oil & Gas Royalties on Non-Federal Lands 2-1, 2-79 to 2-80 (Rocky Mountain Mineral Law Foundation 1993).

to royalty payments.[118] In *Killam Oil Co. v. Bruni*,[119] the lease provided for royalties to be paid on gas "produced from said land and sold or used off the premises." The lessees had entered into a gas purchase contract with United Texas Transmission Co. ("UTTCO"). In order to settle take or pay claims UTTCO agreed to pay the lessees nearly $ 7.0 million.

The Court of Appeals looked to the express terms of the royalty clause and focused on the term "produced." That term under prior law requires physical extraction as a condition precedent to recovery under the standard royalty clause.[120] Thus using a literal approach, consistent with the *Vela* literal approach to market value royalty clauses, the Texas courts rejected the lessor's claims to a share of the benefits that could not be tied to actual production.[121]

But in the past year two courts have disagreed with *Bruni* and by ignoring the express leasehold language and by emphasizing the broad nature of the "cooperative" nature of the relationship between lessor and lessee found the lessee liable for royalty payments on take or pay monies. In *Frey v. Amoco Production Co.*,[122] the Louisiana Supreme Court answered a certified question from the Fifth Circuit which concluded that royalty was due on take or pay payments. The relationship between *Frey* and *Henry* is important for the court. The *Frey* opinion, like the *Henry* opinion, moves away from the express language in the lease. *Bruni* relies on the production requirement in the royalty clause to deny any payments dues without production. *Frey* looks to extra-lease factors to divine the general intent of the parties to a lease. The court justifies its extra-lease interpretation because it finds that there can be no specific intent to either include or exclude such payments from the rather standard royalty clause language.

In looking beyond the language of the royalty clause the court relied on *Wemple v. Producers' Oil Co.*,[123] which talks in general terms about the relationship between a lessor and lessee. The court views the lease as a cooperative venture whereby the lessee contributes the capital and the expertise in exchange for the right to develop

118. *See, e.g.*, Diamond Shamrock Exploration Corp. v. Hodel, 853 F.2d 1159 (5th Cir. 1988); State v. Pennzoil, 752 P.2d 975 (Wyo. 1988).
119. 806 S.W.2d 264 (Tex. Ct. App. 1991).
120. *See, e.g.*, Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981); Monsanto Co. v. Tyrrell, 537 S.W.2d 135 (Tex. Ct. App. 1976).
121. *See also* Diamond Shamrock Exploration Corp. v. Hodel, 853 F.2d 1159 (5th Cir. 1988); Mandell v. Hamman Oil & Refining Co., 822 S.W.2d 153 (Tex. Ct. App. 1991).
122. 603 So. 2d 166 (La. 1992).
123. 83 So. 232 (La. 1919).

the lessor's minerals. The lessor expects a right to share in production and other benefits which flow from the exercise of the development right which has been transferred from the lessor to the lessee. Thus the lessee would not have received the benefits of the take or pay monies had they not received the right to produce from the lessor.

The court also relied on the *Henry* rule that the gas was sold at the time the gas purchase contract was executed. If the gas was sold, then under the terms of the leasehold royalty clause, payments were required. The take or pay monies were part of the "total" price paid by the pipeline for the gas. The amount realized by the producer included the take or pay monies received in settlement of the gas purchase contract dispute.

Yet another basis for finding royalty payments due on take or pay monies was set forth by the 8th Circuit in *Klein v. Jones*.[124] Although the facts are somewhat complex, in essence the royalty owners were suing to claim a share of the monies paid to Jones & McCoy by Arkla pursuant to various gas purchase contracts between those parties or their corporate affiliates. The royalty clauses involved were both value and proceeds type clauses.

The court initially rejected the lessor's claim that the lessees had violated their general duty of fair dealing owed to the lessors. The court found the actions of the lessees in liquidating their take or pay claims against the gas purchaser to be reasonable. Likewise the court rejected the lessors' claim that they were third party beneficiaries of the gas purchase contract. Neither the lessee nor the purchaser intended to give the royalty owner any direct benefit under the gas purchase contract.

The court, however, did find under a general "unjust enrichment" concept the right of the royalty owner to share in take or pay or settlement monies. Relying in large part on the *Frey* rationales that the lease relationship is a cooperative venture and that looking for specific intent to include or exclude such payments would be fruitless, the court concluded that such payments may be subject to the royalty owner's claims. The court viewed the potential payments to the royalty owners as being no more than a fair distribution of the monies received by the lessee who were carrying out their express or implied marketing duties under the lease.[125] Thus even without the unique

124. 980 F.2d 521 (8th Cir. 1992).
125. *Id.* at 529.

provisions of the Louisiana civil law system, a common law jurisdiction found that take or pay or settlement monies, to the extent they are non-recoupable, may be subject to a claim by the royalty owners.

VII. Royalties From Split-Stream Sales

Where there are multiple working interest and royalty owners within a pooled or unitized area and there is no pooling or unitization agreement covering all interest owners, a division of opinion has arisen regarding the rights of the individual royalty owners to share in the production and sale from one or more of the working interest owners.[126] The classic fact situation is represented by the actual facts in *Shell Oil Co. v. Corporation Commission*[127] (better known as the *Blanchard* case). Shell and Sun each contributed 320 acres to an Oklahoma drilling unit of 640 acres. The lessees entered into a joint operating agreement covering their expenses. Shell sold its gas at $ .15/MCF while Sun sold its gas at $ .17/MCF. Shell was selling the entire gas stream with the consent of Sun. Shell was paying its lessors on one-half of the gas sold at $ .15/MCF. Blanchard who was Sun's lessee was paid nothing.

The Corporation Commission issued an order at the request of Blanchard clarifying its original pooling order which had stated "[t]hat all royalty interests within any spacing unit shall be communitized and each royalty owner within any unit shall participate in the royalty from the well drilled thereon in the relation that the acreage owned by him bears to the total acreage in the unit."[128] The Commission adopted a tract allocation formula whereby each of the working interest owners owed to its royalty owner its allocated share of production, even though as in this case one of the two working interest owners was not taking any gas.[129] This method of allocation is commonly called "tract allocation."[130]

126. *See generally* Bruce M. Kramer & Patrick H. Martin, The Law of Pooling and Unitization 19.04[3] (1992); Richard Maxwell, *supra* note 2, at 15-44 to 15-49 (1989).

127. 389 P.2d 951 (Okla. 1963).

128. *Id.* at 952.

129. Lewis Mosburg described this method of division as a "fictional allocation" since it is not based on actual takes. Lewis Mosburg, *Practical Effect of the* 'Blanchard' *Case*, 35 Okla. B. J. 2331 (1964).

130. *See infra* notes 132-35 and accompanying text.

The Oklahoma Supreme Court reversed in part the Commission's order based on its interpretation of the appropriate statutory provision relating to the creation of drilling units and the sharing of royalty.[131] While the court interpreted the statute as applying a tract allocation formula for the working interest owners, it found that a weighted average approach was called for regarding the royalty owners. Each royalty owner was to share in 1/8th of production from the well in proportion that their acreage bore to the entire acreage of the unit. The result was that Shell had to pay a proportionally reduced 1/8th royalty to each of the royalty owners based on its sales price of $ .15/MCF. Likewise when Sun began to sell its gas it would have to pay a proportionally reduced 1/8th royalty to each of the royalty owners based on its sales price of $ .17/MCF. In effect, if both Sun and Shell take 50% the royalty owners will share 50% of the weighted average sales price or $ .16/MCF.

To contrast with the weighted average approach of *Blanchard*, several states have adopted a tract allocation approach. The first case that adopted tract allocation was *Arkansas Louisiana Gas Co. v. Southwest Natural Production Co.*[132] The royalty owners argued that a drilling unit order of the Commissioner of Conservation gave each royalty owner an interest in every MCF of gas produced. The court interpreted the Commissioner's order as only allocating to each tract its pro rata share of production.[133] Each royalty owner was owed royalty under its individual lease and not by virtue of the order. Under the tract allocation method each working interest owner is responsible to its own royalty owner. Unless the working interest owner actually takes production from the well, no royalty obligation exists.

In addition to Louisiana, a Texas case suggests that Texas will follow the tract allocation approach to deal with split-stream sales.[134] In *Puckett v. First City National Bank of Midland*,[135] the plaintiff's lessee

131. OKLA. STAT. ANN. tit. 52, § 87.1(d) (West 1963) as then worded is quoted at 389 P.2d at 953-54. The issue being one of statutory interpretation, the Oklahoma Legislature would be free to change the weighted average approach applied in *Blanchard* for a different one. Oklahoma has by statute modified the rules relating to allocation of royalty, most recently through the 1992 enactment of the Natural Gas Market Sharing Act which is located at OKLA. STAT. ANN. tit. 52, §§ 581.1-581.10 (West Supp. 1993).

132. 60 So. 2d 9 (La. 1952).

133. *Id.* at 10.

134. Puckett v. First City Nat'l Bank of Midland, 702 S.W.2d 232 (Tex. Ct. App. 1985). An earlier case could be interpreted as applying the weighted average approach. TXO Prod. Corp. v. Prickette, 653 S.W.2d 642 (Tex. Ct. App. 1983). *Prickette* was distinguished in *Puckett*. For a discussion of *Prickette*, see Maxwell, *supra* note 2, at 15-46 to 15-48.

135. 702 S.W.2d 232 (Tex. Ct. App. 1985).

pooled some acreage with another working interest owner. There were split-stream sales from the pooled tract with a significant difference in the prices received by each of the working interest owners because one was selling in the unregulated intrastate market. Expressly rejecting the weighted average approach, the court found no contractual or other obligation that would allow the royalty owners to be paid by someone other than their own lessee. The plaintiff would only be entitled to their royalty on the gas allocated on an acreage basis to their lessee. In addition the royalty would be based on their lessee's contract price, not on the higher price received by the pooled lessee.[136]

VIII. THE SULPHUR CLAUSE

Many standard oil and gas lease forms contain a royalty clause which has caused great consternation when courts have been asked to interpret and apply the clause. This clause ostensibly deals with the royalty that is to be paid on sulphur and is typically measured by a specified amount per long ton. The following two examples of form lease clauses are typical:

> If lessee mines and markets any other mineral the royalty to be paid lessor thereon shall be one-eighth either in kind or value at the well or mine at lessee's election except that on sulphur the royalty shall be 50 [cents] per long ton.[137]

And:

> As royalty, lessee covenants and agrees . . . (c) To pay lessor on all other minerals mined and marketed or utilized by lessee from said land, one-tenth either in kind or value at the well or mine at lessee's election, except that on sulphur mined and marketed the royalty shall be one dollar per long ton.[138]

Both the Fifth Circuit, ostensibly applying Alabama and Mississippi law, and the Texas Court of Appeals have struggled with similar clauses when confronted with the situation where the well produces

136. Mississippi apparently would follow the tract allocation approach since it rejects the idea that an operator owes any duty to the royalty owners of other lessees in the absence of an agreement to the contrary. Berard J.W. Bos & Co., Inc. v. Harkins & Co. and Transcontinental Gas Pipe Line Corp., 883 F.2d 379 (5th Cir. 1989).

137. 3 WILLIAMS & MEYERS, *supra* note 1, at 556.

138. Schwartz v. Prairie Producing Co., Inc., 833 S.W.2d 629, 631 (Tex. Ct. App. 1992).

hydrogen sulfide gas in the natural gas stream which is processed into elemental sulphur.[139]

The issue of whether a lessee must pay royalties based on the gas royalty clause or the sulphur royalty clause was analyzed in depth, but in dictum, in *Scott Paper Co. v. Taslog.*[140] Taslog was the successor in interest to royalty interests which had been conveyed during the existence of now-expired leases. Those leases had separate royalty provisions relating to "casinghead gas or other gaseous substance" and "sulphur produced and marketed from the land."[141] The royalty deeds did not specifically mention sulphur and the mineral owner claimed that the royalty deeds had not conveyed royalty to sulphur. This argument was based in part on the theory that had the original leases produced sour gas the royalty owners would only have been entitled to royalty based on the sulphur royalty clause and not the gas royalty clause.[142]

In this unusual context the Fifth Circuit concluded that had there been production from the now-expired leases which contained a hydrogen sulfide component, the lessee would have been obligated to pay royalty on the elemental sulphur removed at the gas royalty percentage. This conclusion was not supported by case law, there being none on point, but by the court's interpretation of the lease which provided for a 1/8th royalty on "gas including casinghead gas and other gaseous substance." In addition, the court found that the sulphur was not "produced" from said land, since it was part of the gas stream at the point of production. The sulphur was a processed product separated at a point downstream of the point of production. Finally, the trial court had accepted Taslog's uncontroverted evidence that it was common industry practice and custom to pay gas, not sulphur, royalties on elemental sulfur removed from a sour gas stream.[143]

The issue of whether royalty was owed on the royalty or sulphur clause was directly before the Fifth Circuit in *First National Bank of Jackson v. Pursue Energy Corp.*[144] The royalty clause provided for the

139. One Texas appellate justice concluded that such clauses have been used in form leases for at least "60 years" and a definitive ruling on how they should be interpreted was required. *Schwartz*, 833 S.W.2d at 633-34 (Cohen, J. dissenting on motion for rehearing).

140. 638 F.2d 790 (5th Cir. 1981).

141. *Id.* at 792. *See also* Maxwell, *supra* note 2, at 15-35 to 15-44.

142. *Scott Paper*, 638 F.2d at 795.

143. *Id.* at 795-96.

144. 784 F.2d 659 (5th Cir.), *vacated by,* 799 F.2d 149 (5th Cir.), *reh'g en banc denied,* 802 F.2d 455 (5th Cir. 1986). Although *Taslog* was ostensibly a case applying Alabama law while

payment of a 1/8th royalty on "gas and casinghead gas produced from said land." It further provided for a royalty of $ 1.00/long ton on "sulphur mined and marketed."[145] The trial court, based on *Taslog*, concluded that the lessee was required to make payments under the gas clause. As noted above, the issue in *Taslog* was different and ostensibly involved Alabama rules of deed interpretation. The Fifth Circuit in its initial opinion by Judge Jolly found that applying Mississippi canons of construction the royalty clause language was ambiguous so that extrinsic evidence could be admitted to ascertain the intent of the parties.[146] Judge Jolly distinguished *Taslog* on several grounds. First was the apparently broader language in the Taslog lease which covered "gaseous substance" rather than the Pursue lease which only covered "gas." The court further noted that Mississippi, not Alabama, law was to apply here. Finally the court found that the parties in *Taslog* had not controverted the evidence that industry practice and custom paid royalties on sulphur from hydrogen sulfide streams, while in *Pursue* there was evidence finding no such universal practice and custom.[147] The initial opinion thus reversed the grant of the motion for summary judgment and remanded for a trial so that extrinsic evidence could be admitted.

In a rare granting of a motion for rehearing, however, Judges Thornberry and Rubin in a per curiam decision reversed themselves and concluded that the language in the lease form unambiguously required the lessee to pay gas royalties on sulphur produced from the hydrogen sulfide contained in the natural gas stream.[148] The second opinion emphasizes that under the sulphur clause the sulphur must be mined in order to trigger its application. The sulphur is extracted from the gas stream at a point well downstream of the point of production. In addition the hydrogen sulfide gas is gas "produced" from said lands which would also trigger the gas royalty clause.

Pursue ostensibly applied Mississippi law, the 5th Circuit basically ignored any state-specific analysis for deed or lease interpretation issues. Perhaps Alabama and Mississippi law is the same, but different states often take different views on the role and importance of canons of construction and how easily courts will find language ambiguous so as to admit extrinsic evidence.

145. *Pursue*, 784 F.2d at 662.

146. *Id.* The court cites the traditional canons of construction, such as the four corners canon, the intent must be gleaned from the language used in the instrument canon and the specific controls over the general canon.

147. *Id.* at 659.

148. First Nat'l Bank of Jackson v. Pursue Energy Corp., 799 F.2d 149 (5th Cir. 1986).

As Dean Maxwell has aptly noted elsewhere,[149] it may be somewhat fruitless to try and parse the language of a form instrument insofar as the exact meaning of the boilerplate language, which was undoubtedly not read by either of the parties, is indeterminate. Judge Jolly, who dissented in the second opinion, attempted to make some fine distinctions between the terms "mined and marketed" and "produced and marketed" and "gas" and "gaseous substance."[150] In *Taslog* and *Pursue*, it is quite likely that neither party was cognizant of the specific language used in the gas or sulphur royalty clauses. Treating the language as ambiguous would allow "form" leases to be interpreted by the quality of the extrinsic evidence that a particular party could muster. This practice would likely result in the same lease form being interpreted in two different ways, a highly undesirable result. While somewhat arbitrary, the second *Pursue* opinion does settle the issue so that future drafters can be aware of the problem and draft a different result if that is desired, and transaction costs relating to future litigation of sulphur clauses can be minimized by discouraging such litigation.

The Fifth Circuit is not alone in having difficulty interpreting sulphur royalty clauses. In *Schwartz v. Prairie Producing Co.*,[151] a Texas court of appeals on two occasions struggled with the same issue leading to a split decision and substantial uncertainty. The disputed sulphur royalty clause stated: "(c). To pay lessor on all other minerals mined and marketed or utilized by lessee from said land, one-tenth either in kind or value . . . , except that on sulphur mined and marketed the royalty shall be one dollar ($1.00) per long ton."[152] The gas royalty clause used the term "gas and casinghead gas produced from said land." The lessor challenged the lessee's payment under the sulphur royalty clause for the elemental sulphur that was processed from the hydrogen sulfide contained in the sour gas.

The Court of Appeals in *Schwartz I* issued three separate and conflicting opinions. Justice Cohen, applying several canons of construction, including the harmonizing canon and construe-against-the-lessee canon, concluded that the form lease unambiguously required the lessee to pay royalty based on the gas clause. This opinion is consistent with the general Texas view that most written instruments are

149. Maxwell, *supra* note 2, at 15-39 to 15-41.
150. 799 F.2d at 154 (Jolly, J. dissenting).
151. 727 S.W.2d 289 (Tex. Ct. App. 1987), *reh'g denied*, 833 S.W.2d 629 (Tex. Ct. App. 1992).
152. *Id.* at 290.

legally unambiguous.[153] Justice Dunn concurred in the reversal of the trial court's granting of the lessee's motion for summary judgment, but on substantially different grounds. Justice Dunn believed that the leases are ambiguous as a matter of law and reversed so that both parties could proffer extrinsic evidence regarding the meaning of the gas and sulphur royalty clauses.[154]

Finally Justice Bass dissented concluding that the "mined and marketed" language of the sulphur clause was unambiguous and supported the trial court's finding that the royalty payments should have been made on the basis of the sulphur clause. Justice Bass also used the harmonizing and four corners canons to support his finding that the language was unambiguous on its face.[155]

After the Texas Supreme Court denied the writ, the case was sent back to the trial court. The trial court admitted extrinsic evidence but then issued a directed verdict for the lessees. In *Schwartz II*,[156] the same panel of justices again reversed and adopted the approach taken in the dissenting opinion in *Pursue*, namely that a jury will have to determine the meaning of the disparate royalty clauses and that the motion for instructed verdict was erroneously granted.

This time Justice Bass changed his mind from *Schwartz I* and sided with Justice Dunn in concluding that the lease language was ambiguous. Initially Justice Cohen concurred on the remand order but on a motion for rehearing, which was denied, Justice Cohen got to the heart of the problem and dissented. He returned to his original position that the lease unambiguously requires the lessee to pay gas royalties for the value of sulphur removed from a natural gas stream impregnated with hydrogen sulfide. In quoting from both parties' motions for a rehearing, Justice Cohen finds that a second trial will adduce any additional evidence on what the conflicting language means. He concludes:

> Let us have mercy on these parties. They have suffered enough. The public interest, as well as the private interest of the litigants, is best served by a decision on the merits because a finding that a lease is ambiguous sets no precedent. It will lead to litigation in many other cases.[157]

153. *See* Kramer, *supra* note 76, at 6-14.
154. *Id.* at 293 (Dunn, J. concurring).
155. *Id.* at 294 (Bass, J. dissenting).
156. Schwartz v. Prairie Producing Co., 833 S.W.2d 629 (Tex. Ct. App. 1992).
157. *Id.* at 633 (Cohen, J. dissenting on motion for rehearing).

The pratfalls of using form leases which contain clauses no one bothers to read are shown in the *Schwartz* and *Pursue* decisions. Six appellate court judges had substantial difficulty in interpreting a reasonably innocuous provision in a lease form. In Texas, continuing litigation regarding these clauses will undoubtedly continue so long as appellate courts treat the language as ambiguous. Disparate results in disparate trials may be inevitable given the nature of the jury system and the ability of the parties to hire sufficient numbers of experts to persuade each jury as to the correctness of their interpretation. While certainty is not always a virtue and justice and fairness considerations are always present, the Texas approach, as opposed to the Fifth Circuit approach, is more likely to be both uncertain and unjust.

IX. Conclusion

Disputes between royalty and working interest owners will undoubtedly continue. The issues will change with the times and the nature of the industry. It is likely that the responses to those issues will not be uniform throughout the United States. As with the market value/proceeds dispute and the royalty on take or pay dispute, the courts will be faced with competing public policy factors. Some courts will look to the language of the lease and the royalty clause to resolve the conflict. But other courts will go beyond the exact language and consider other factors, be they gas marketing realities or unjust enrichment, to resolve the conflict. It may not be easy to predict any particular state's outcome, since in some states the courts have remained true to the language of the agreement in some areas, while going outside of the language in others. It certainly makes for an interesting academic environment.