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Royalty Issues: Take-or-Pay Claims and Division Orders

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TULSA LAW JOURNAL

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ROYALTY ISSUES: TAKE-OR-PAY CLAIMS AND DIVISION ORDERS*

Ernest E. Smith**

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I. INTRODUCTION

Royalty issues, ranging from the method of calculation to the effect of division orders on claims for back royalty, have long been a source of dispute between lessors and producers. Two of the most recent additions to the list of royalty issues are: (1) claims by royalty owners to share in proceeds from take-or-pay clauses or in settlements of take-or-pay disputes between producers and pipeline purchasers, and (2) questions over the effect of split-stream connections and balancing agreements on the division of proceeds among royalty owners. A much older but still unsettled issue is the effect of division orders on claims by royalty owners to recover royalties which were allegedly underpaid in past years.

Part II of this paper discusses the viability of claims to royalty on take-or-pay related payments and the problem of calculating royalty when a lessee is participating in a pooling agreement which has given rise either to split-stream sales or underproduction by the lessee. Part III deals with recent decisions discussing the effect of other instruments, especially division orders, on the lessee's obligations under an oil and gas lease. Part IV attempts to assess how division orders affect the types of royalty claims discussed in Part II.

II. CURRENT ISSUES OVER THE RIGHT TO ROYALTY AND THE CALCULATION OF ROYALTY

A. *Payments Made Because of Take-or-Pay Obligations*

An issue increasingly in dispute between lessors and lessees is the right of royalty owners to share in proceeds which an operator has received under a take-or-pay clause. Such clauses, which are common in gas purchase contracts entered into in the last two decades, obligate the pipeline purchaser to take a specified percentage of a well's delivery capacity. The pipeline is required to pay for the prescribed amount of gas, even if it fails to take it. Under most contracts, however, the pipeline has a stipulated period, such as five years, in which it can "make up" by taking gas in excess of a current year's take requirements and crediting the excess take against the amount paid for the earlier deficiency.¹

1. Payments Made Pursuant to the Take-or-Pay Clause: Existing Case Law

Many lessors are now claiming they are owed royalty on payments made pursuant to the take-or-pay clause. The operators, by and large, have countered with the argument that no royalty is due until the gas is actually produced and delivered. Under the logic of this argument the lessor's right to royalty is deferred until the make-up option has been exercised. As thus formulated, the dispute is essentially over when the royalty is due: at the time the payment is made or as gas allocable to the payment is taken by the purchaser.

To date, there have been only a few cases dealing with this issue, and they have been resolved in favor of the producer. Recently the Fifth Circuit in *Diamond Shamrock Exploration Co. v. Hodel*² rendered its decision on conflicting holdings from the Western and Eastern Districts of Louisiana, which had been consolidated on appeal. In the litigation involving Diamond Shamrock, the United States, as lessor, asserted a right to unpaid royalties and accumulated interest on take-or-pay proceeds received by its lessee on gas production from federal lands. In an opinion which was not reported in the advance sheets, the federal judge

1. For a discussion of the issues which may be involved in a dispute between a producer and a pipeline over a take-or-pay contract, see Medina, *The Take-or-Pay Wars: A Further Status Report*, 41 OKLA. L. REV. 381 (1988); Medina, McKenzie & Daniel, *Take or Litigate: Enforcing the Plain Meaning of the Take-or-Pay Clause in Natural Gas Contracts*, 40 ARK. L. REV. 185 (1986); Roland, *Take-or-Pay Provisions: Major Problems for the Natural Gas Industry*, 18 ST. MARY'S L.J. 251 (1986).

2. 853 F.2d 1159 (5th Cir. 1988).

for the Eastern District of Louisiana had held that royalty was due on such proceeds since they were part of the revenue gained from exercising the right to drill for, remove, and dispose of oil and gas which had been granted to the lessee.³

The opposite result was reached by the judge for the Western District on almost identical facts. In *Mesa Petroleum Co. v. United States Department of Interior*,⁴ the United States had executed an oil and gas lease that required the lessee "[t]o pay the Lessor a royalty of 16 2/3 percent in amount or value of production saved, removed, or sold from the leased area."⁵ Mesa, the lessee, had received payments from Tennessee Pipeline Company ("Tennessee") under a take-or-pay clause contained in a natural gas purchase contract between the two companies. In rejecting the government's claim for royalties on payments for gas not yet taken, the court relied on the meaning of "royalty" as commonly understood in the oil and gas industry: a right to share in production as production is obtained.⁶ According to the court, "production" refers to the removal or actual severance of oil and gas from the ground.⁷ Since the payments made by Tennessee were "in lieu of taking production," Mesa was not required to remit royalties on such payments.⁸

The Fifth Circuit's decision favored the producers. It agreed with the reasoning of the lower court in *Mesa* that "production," when used in the context of the royalty clause, means "the actual physical severance of minerals from the formation."⁹ Further, it pointed out that payments made pursuant to take-or-pay clauses were not made for the sale of gas, but for the failure to take the gas.¹⁰ The producer has fixed charges, such as service on its indebtedness, maintenance costs, and its initial capital investment, which must be met. The purpose of the take-or-pay provision is to give the producer a continuous, stable, assured source of revenue which will cover these financial commitments.

An identical result was reached by the Wyoming Supreme Court in *State v. Pennzoil Co.*¹¹ Wyoming had executed an oil and gas lease providing that on gas "produced from said land saved and sold or used off

3. *Id.* at 1163.

4. 647 F.Supp. 1350 (W.D. La. 1986).

5. *Id.* at 1352.

6. *Id.* at 1354.

7. *Id.* at 1353-54.

8. *Id.*

9. *Diamond Shamrock Exploration Co. v. Hodel*, 853 F.2d 1159, 1168, (5th Cir. 1988).

10. *Id.* at 1167.

11. 752 P.2d 975 (Wyo. 1988).

the premises”¹² the lessee would pay a royalty “of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale.”¹³ The state asserted that this royalty language entitled it to royalties on take-or-pay payments made by the pipeline buying gas from the lessees under gas purchase contracts. The Wyoming Supreme Court’s analysis of the lease terms, which it found to be unambiguous, was similar to that of the Fifth Circuit. The court reasoned that the lease language which required the payment of royalty on the twentieth day of the month “following the month of production and removal and sale of oil and gas from said land,” clearly used the term “production” to mean the physical extraction of gas from the ground.¹⁴ Since the “sale” takes place after severance, the lease did not require the payment of royalties on monies received for unproduced gas.¹⁵

2. Effect of Lease Language

As the decisions in *Diamond Shamrock* and *Pennzoil* indicate, a determination of the lessor’s right to royalty on take-or-pay payments turns in large part upon a construction of the royalty and related clauses in the oil and gas lease. Hence, the decisions are no guarantee that similar disputes will be resolved in favor of the producer. Differences in lease language may possibly lead to different results, even for lessors pooled into the same gas well unit. In some instances courts may conclude that royalty language is ambiguous and allow the admission of extrinsic evidence to determine the parties’ intent with respect to take-or-pay payments. In others, federal or state regulations may modify or define terms used in the lease.¹⁶ In other instances, the presence or absence of key terminology and prior judicial definitions of that terminology will determine the rights of the parties to the lease.¹⁷

12. *Id.* at 976.

13. *Id.*

14. *Id.* at 979.

15. *Id.* at 980.

16. For example, in *Diamond Shamrock Exploration Corp. v. Hodel*, 853 F.2d 1159 (5th Cir. 1988), the Fifth Circuit was essentially resolving conflicting interpretations of the impact of the Outer Continental Shelf Lands Act on the calculation of royalty under offshore oil and gas leases. *Id.* at 1163, 1166.

17. For example, a prior judicial definition of the terms “proceeds” or “market value” may determine whether royalty is due.

a. *When Is Gas "Produced"?*

In the litigated disputes the leases apparently limited the lessor's royalty to gas produced and saved. The conclusion in *Diamond Shamrock* and *Pennzoil* that "production" clearly means severance is fully consistent with a common sense interpretation and industry usage of the word. It is not, however, the universally applied meaning of the term when used in an oil and gas lease. For example, courts in some states, when determining if a lease has been held past the primary term by the production of oil and gas, have not required the physical severance of the substances from the ground.¹⁸ As Professor Eugene Kuntz has pointed out in summarizing the holdings construing the requirement of "production" to extend a lease past the primary term:

[T]hree rules have been developed. According to one rule, the discovery of either oil or gas will satisfy the habendum clause. According to a second rule, gas and oil are distinguished because oil may be extracted and stored economically without marketing, whereas gas cannot be economically stored above ground. Under such rule, the discovery of gas is sufficient, but if oil is discovered, the oil must be actually extracted in order to satisfy the habendum clause. According to the third rule, mere discovery of oil or gas will not satisfy the habendum clause, but in both instances the product must be actually extracted. In the instance of gas, this necessarily involves marketing. As a matter of generality, each jurisdiction which has decided the point has adopted one of such rules.¹⁹

The same term does not have to be given the same meaning wherever used in an oil and gas lease. As Professor Kuntz notes, some states, in construing the habendum clause, have interpreted production to mean different things for different substances.²⁰ Thus oil is produced only if extracted, whereas gas is produced if discovered in paying quantities.²¹ Arguably, "production" may not require severance when used in the royalty clause, regardless of its meaning when used in the habendum clause.

These arguments are not entirely convincing, however. The jurisdictions that have given the term "production" an artificial meaning in the context of the habendum clause have done so largely to protect a

18. See, e.g., *McVicker v. Horn, Robinson & Nathan*, 322 P.2d 410 (Okla. 1958).

19. 2 E. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 26.6, at 343 (1989). See also, E. KUNTZ, J. LOWE, O. ANDERSON, E. SMITH, CASES AND MATERIALS ON OIL AND GAS LAW 169-70 (1986).

20. 2 E. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 26.6, *supra* at 341.

21. See, e.g., *Christian v. A.A. Oil Corp.*, 161 Mont. 420, 506 P.2d 1369 (1973).

lessee against loss of a proven lease on which the lessee has spent considerable sums of money in high risk exploration and drilling. Much different factors are involved with take-or-pay proceeds. Moreover, courts in many states, including Texas, have not adopted this definition. They have held that oil and gas must actually be extracted to hold the lease past the primary term.²² In these states, "production," wherever used in the oil and gas lease, has been construed as referring to physical severance of oil or gas from the ground. It seems unlikely that the parties could have intended for it to mean something different when used in the royalty clause.

b. When Is Gas "Sold"?

The meaning of "sold" is also relevant to a claim to royalties on take-or-pay proceeds. In "proceeds" clauses, royalties are based on gas "sold." Most require that the gas be produced as well as sold, but some forms of leases which provide for royalties on gas "marketed" or "sold" do not specifically require that it be "produced." For example, a form lease widely used in Kansas and Oklahoma, and occasionally encountered in Texas, provides that "the lessee shall monthly pay lessor as royalty on gas marketed from each well where gas only is found, one-eighth (1/8) of the proceeds if sold at the well, or if marketed by lessee off the leased premises, one-eighth (1/8) of its market value at the well."²³ Production may also not be required in specially drafted provisions included in a lease to provide a landowner with an additional royalty.

Under such provisions the jurisdiction's position on the market-value issue may be especially relevant in determining when gas is "sold" and thus whether royalties are due on take-or-pay proceeds.²⁴ In states like Texas, which hold that gas is sold "at the time of the delivery to the purchaser,"²⁵ payments for gas which is still unproduced and undelivered should not logically be subject to the landowner's claim to royalty. In jurisdictions like Oklahoma, which have rejected this view and treat the gas' value as determined when the gas purchase contract is entered

22. *Stanolind Oil & Gas Co. v. Barnhill*, 107 S.W.2d 746, 749 (Tex. Civ. App.—Amarillo 1937, writ ref'd).

23. C Oil and Gas Lease, Form 88 Producers 1957, rev. 1974; P & M Printing Company, reproduced in *Form Supplement*, 1987 ROCKY MTN. MIN. L. FOUND. (Short Course).

24. See Kramer, *Royalty Obligations Under the Gun—The Effect of Take-or-Pay Clauses on the Duty to Make Royalty Payments*, 39 INST. ON OIL & GAS L. & TAX'N 5-1 (1988).

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

into,²⁶ take-or-pay payments could well be treated as part of the consideration for all of the gas purchased. In that event royalty would be owed on such proceeds. The Wyoming Supreme Court touched on this issue in its opinion in *State v. Pennzoil Co.*²⁷ when it concluded that a "sale" requires the passage of title and that under Wyoming law, which deems an oil and gas lease to create a profit à prendre rather than passing title to oil and gas in place, title to the gas can not be transferred until it is produced and severed from the ground.²⁸

3. Lease Benefits and the Implied Marketing Covenant

The interpretations of royalty clause language, such as "produced" and "sold," which are most favorable to a lessor's claim to share in take-or-pay payments, draw little support from case law in most states. This does not mean, of course, that the issue is resolved. Leases with unusual royalty language may clearly entitle the lessor to share in such payments. Additionally, some arguments in favor of lessor claims can be fashioned which do not depend upon the specific wording of individual royalty clauses.

A further argument in favor of the lessor's claim to proceeds for gas still in the ground might be derived from the courts' long-standing position that the payment of royalty is the principal consideration for an oil and gas lease.²⁹ Such economic benefits, rather than production per se, have prompted the landowner to transfer exploration and development rights to the oil company. A lessor might argue that a royalty is owed on such benefits, even in the absence of actual severance of gas from the reservoir.

Professor John Lowe has suggested a further refinement of this argument, basing it on the implied marketing covenant. In *Current Lease and Royalty Problems in the Gas Industry*,³⁰ he makes the following observation:

[T]here are many cases in which courts, in interpreting oil and gas leases, have looked beyond the literal terms of the lease to focus upon the broader general intent of the parties. The basic agreement of the oil and gas lease is that the owner of mineral rights, who does not generally have the equipment, the capital, or the expertise to develop

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

27. 752 P.2d 975 (Wyo. 1988).

28. *Id.* at 980.

29. *See, e.g., Brewster v. Lanyon Zinc Co.*, 140 F. 801, 809-10 (8th Cir. 1905); *Consumers' Gas Trust Co. v. Littler*, 162 Ind. 320, 323, 70 N.E. 363, 365 (1904).

30. 23 TULSA L.J. 547 (1988).

them, transfers the right to drill and produce to an oil company that supposedly does have the equipment, capital, and expertise to develop. From that tacit understanding of the parties a variety of implied covenants arise, including an implied promise of the lessee to market within a reasonable period of time and for the best price available. From recognition of an implied promise to market on the best available terms to recognition of a right of a royalty owner to share in whatever benefits are provided by the lessee's marketing efforts is but a step.³¹

The strength of these arguments is difficult to assess. They are based upon extrapolations from cases involving quite different fact patterns. Thus, although royalties are clearly the principal consideration for an oil and gas lease, they are royalties on oil or gas produced. The cases emphasizing the importance of royalties usually do so in the context of a lessor's claim that wells should have been drilled so that production can be obtained.³² The marketing covenant cases, such as *Amoco Production Co. v. First Baptist Church*³³ and *Texas Oil and Gas Corp. v. Hagen*³⁴ are close in point, but still distinguishable. Such cases commonly involve claims that the lessee has bargained for benefits for itself at the expense of the lessor. As indicated previously, the logic of the lessees' position in disputes over take-or-pay proceeds does not deny the lessors' claims to royalty but merely postpones payment until the time when gas is made up. This was, in fact, the practice of most lessees involved in the Fifth Circuit case.³⁵

4. Effect of Failure to Make Up Gas Paid For

A conclusion that the lessor has no current right to share in take-or-pay proceeds does not entirely dispose of the problem. Where the purchaser exercises its make-up rights in full, take-or-pay proceeds clearly constitute prepayments for gas later produced, and the lessor should be entitled to royalties on the take-or-pay proceeds as the gas allocable to such proceeds are later taken by the pipeline. In other instances, however, the purchaser may not be able or willing to exercise its make-up rights. If the producer is contractually obligated to return take-or-pay

31. *Id.* at 563 (footnotes omitted).

32. See, e.g., *Brewster*, 140 F. at 809-10 (Lessor sought to avoid lease on the ground that lessee breached an implied covenant of due diligence in failing to drill.): *Consumers' Gas Trust*, 162 Ind. at 322, 70 N.E. at 364 (Lessor sued to quiet title in lands against oil and gas contract for nonperformance of drilling obligations.).

33. 579 S.W.2d 280 (Tex. Civ. App.—El Paso 1979), writ ref'd per curiam n.r.e., 611 S.W.2d 610 (Tex. 1980).

34. 32 Tex. Sup. Ct. J. 140, *withdrawn*, 760 S.W.2d 960 (Tex. 1988) (case settled).

35. *Diamond Shamrock Exploration Co. v. Hodel*, 853 F.2d 1159 (5th Cir. 1988).

proceeds allocable to gas never received, the lessor would seem to have no basis for a claim to share in such proceeds or, to the extent they were received, would be similarly obligated to refund them to the purchaser. Conversely, if the gas purchase contract entitles the producer to retain take-or-pay proceeds, even though the pipeline never makes up the gas paid for, such proceeds have had the practical effect of increasing the price paid for gas actually produced. In such a situation, the lessor should be entitled to a share of royalties once the make-up right has terminated.

5. Royalty Claims on Settlements of Take-or-Pay Disputes

The previous discussion presupposes that payments were made in accordance with the take-or-pay clause of the gas purchase contract. In many instances, however, the pipeline purchaser's obligation to make such a payment will be in dispute. Payments made in settlement of such disputes give rise to a somewhat different problem.

a. *The Unshared Benefit/Implied Covenant Argument*

Professor Richard Pierce has argued that lump-sum payments made to settle past take-or-pay claims should be distinguished from routine payments made in accordance with the contractual provision.³⁶ He argues that if the settlement terminates the pipeline's right to make up gas not taken during the period covered by the settlement, the royalty owner will have no later opportunity to claim part of the settlement as gas is produced.³⁷ Indeed, once the gas is produced, it will almost invariably be sold under a new contract which establishes a price significantly lower than the price provided for in the disputed take-or-pay clause. As he points out, "If producers are allowed to retain all of one part of the settlement (the lump-sum payment), but must share with royalty owners another part of the settlement (proceeds from future sales under the contract), producers have an artificial incentive to maximize the lump-sum settlement and minimize future prices."³⁸

Professor Kramer and Professor Lowe have independently reached the same conclusion, but by applying the implied covenant to market. They suggest that under the reasoning of *Amoco Production Co. v. First*

36. Pierce, *Lessor/Lessee Relations in a Turbulent Gas Market*, 38 INST. ON OIL & GAS L. & TAX'N, 8-1, 8-19 to 8-20 (1987).

37. *Id.*

38. *Id.* at 8-20.

*Baptist Church*³⁹ a violation of the implied covenant occurs if the lessee receives a substantial benefit which is not shared with the lessor and, indeed, deprives him of income that he otherwise would have received.⁴⁰

Even here, however, the objection may be raised that the gas to which the settlement money relates has not yet been produced. Hence the lessor has no right to royalty on the settlement proceeds until production occurs. This argument may have some force if the contract remains in force. In such a situation the settlement proceeds can be deemed to relate to gas produced during the remaining life of the contract and the lessor's share in the proceeds should be spread over that period. This method of allocation may result in some complicated accounting problems with the lessor, however, and is inappropriate if the contract terminates. If the contract is ended, there is no reasonable way to allocate settlement proceeds to gas produced under an entirely different contract with, perhaps, an entirely different purchaser. If the marketing covenant analysis entitles the lessor to share, the lessor's claim is immediate.

b. Multi-Lease Settlements

A far more difficult situation will arise if the payment for past take-or-pay violations relates to several different oil and gas leases held by the producer. If the dispute proceeds to litigation and a final jury verdict, there presumably will be evidence of the amount of gas for which the pipeline is liable and some basis for calculating how the award should be apportioned among the operator and the various lessors. Such evidence may not be present in a take-or-pay settlement. Such a settlement may cover dozens (or hundreds) of leases; and the settlement itself, while reciting the variety of controversies it governs, is unlikely to make an allocation to specific wells. Suppose, for example, a \$10,000,000 settlement which extinguishes a claim for \$25,000,000 relating to take-or-pay contracts covering twenty wells. In such an instance two questions are likely to arise with respect to a lessor's rights: Is the lessor entitled to a royalty on that portion of the settlement allocable to his lease? If so, how much of the settlement should be allocated thereto?

The answer to the first question depends primarily upon the strength

39. 579 S.W.2d 280 (Tex. Civ. App.—El Paso 1979, writ ref'd per curiam n.r.e., 611 S.W.2d 610 (Tex. 1980).

40. Kramer, *Royalty Obligations Under the Gun—the Effect of Take-or-Pay Clauses on the Duty to Make Royalty Payments*, 39 INST. ON OIL & GAS L. & TAX'N 5-1 (1988); Lowe, *Current Lease and Royalty Problems in the Gas Industry*, 23 TULSA L.J. 547, 563 (1988).

of the argument based upon the implied marketing covenant. An affirmative answer leads to the second, equally difficult question. A full discussion of this problem is outside the scope of this paper, but the general outlines of three possible arguments may be as follow: First, the lessor may argue that the burden of proof on this issue should lie with the operator. By failing to stipulate what portions of the settlement are allocable to each gas lease covered by the settlement, the operator has, in a sense, "commingled" all parts of the settlement, including the operator's own and that of all the royalty owners. The operator thus has the burden of establishing what percentage of the settlement belongs to the operator and what to each royalty owner. If the operator is unable to establish these percentages, a lessor may be entitled to treat the settlement as including a payment in full of the entire take-or-pay claim allocable to the lessor's lease.⁴¹

A second approach, which is less harsh to the lessee, would be to apportion the settlement among the various leases on a percentage basis. The apportionment would be in accordance with the ratio that the amount in dispute from a lease bore to the total amount in dispute.

Thirdly, the operator may well take the position that the burden of proof lies entirely with the royalty owners. Since the settlement does not relate to actual production, each lessor should have the burden of showing the extent to which the settlement related to the gas purchase contract binding the gas from his lease. There are, of course, other alternative solutions, and the facts of each settlement will suggest other approaches.

B. *Delayed Marketing and Gas Imbalances*

A much different set of royalty issues is likely to arise whenever two or more tracts are pooled into a single gas unit. If the leases on the pooled tracts are owned by different working interest owners and if there is any difference in the identity of royalty owners, method of calculating royalty, or size of royalty in the tracts, a dispute over rights to royalty is likely. However, the most serious royalty problem arises when gas is being produced from the unit, but one of the lessees who has pooled its tract into the unit is not marketing its share of the gas. Its lessors will almost certainly insist that they are owed royalty, although the lessee is

41. Cf. *Humble Oil & Refining Co. v. West*, 508 S.W.2d 812 (Tex. 1974), cert. denied, 434 U.S. 875 (1977).

receiving no income from the well and the price upon which the royalty should be calculated may be far from clear.

When tracts are pooled the working interest owners' rights in the gas production are governed by their operating agreement. Most operating agreements are similar—or identical to—the Form 610-Model Form Operating Agreement promulgated by the American Association of Petroleum Landmen (AAPL) in that they specifically authorize each party “to take in kind or separately dispose of its proportionate share” of the gas produced from the contract area.⁴² Sales of production in exact proportion to ownership are unlikely, however. Some working interest owners may be selling gas to pipelines or end-users while others, either unable to obtain contracts or unwilling to sell at current prices, are neither taking nor disposing of their share of the gas. Even if all working interest owners in the unit are marketing gas, disproportionate takes are almost inevitable if more than one pipeline has connections to the well.⁴³ The problems resulting from these gas imbalances are likely to be exacerbated by the different prices received under the different gas purchase contracts.

In many instances these problems will be addressed in a gas balancing agreement that has been attached to the operating agreement.⁴⁴ In others, the parties will be left to work out their rights from the rather sparse language of the operating agreement.⁴⁵ These instruments are not likely to be binding on the royalty owners, however. The primary source of their rights to share in the income from production is the oil and gas lease. The typical oil and gas lease provides for pooling, but makes no mention of delayed sales from a producing well or rights of an underproduced party to make up in kind or in cash from an overproduced party. The lease is almost invariably worded, based on the assumption that the lessee will produce and sell all of the gas. Hence in many, perhaps most, situations where a lessee in a pooled unit has delayed marketing its share of gas or is selling at a different price than another working interest owner, the lessor's claim to royalty will be determined by lease language that was not drafted with such situations in mind.

42. 1982 Model Form Art. VI.C.; 1977 Model Form Art. VI.C.; 1956 Model Form ¶ 13.

43. See Note, *Oil and Gas: Production Imbalance in Split Stream Gas Wells—Getting Your Fair Share*, 30 OKLA. L. REV. 955 (1977).

44. See R. Grable, *Selected Problems in Split-Stream Production*, (presented at Advanced Oil, Gas and Mineral Law Course, Paper C, State Bar of Texas, Sept. 17, 1987).

45. See Smith, *Gas Marketing by Co-Owners: Disproportionate Sales, Gas Imbalances and Lessors' Claims to Royalty*, 39 BAYLOR L. REV. 365 (1987).

1. Methods of Allocating Production Among Tracts in a Pooled Unit

Two principal legal theories have been used in resolving the royalty issues created by gas imbalances and differing sales prices. The two approaches are best exemplified by cases in Oklahoma and Louisiana. Oklahoma's approach is set out in *Shell Oil Co. v. Oklahoma Corporation Commission*,⁴⁶ commonly referred to as the *Blanchard* decision. It calls for payments to be made to all royalty owners within the unit, regardless of whether their lessees are selling gas, and provides that the royalty payments are to be based on the "weighted-average" of the prices received by the sellers. This holding is based upon the Oklahoma Supreme Court's construction of an Oklahoma statute⁴⁷ providing that each lessor should share proportionately in one eighth of all production from the unit.

The alternative "tract allocation" theory, which has been followed in Louisiana, also has a statutory basis in a forced-pooling statute.⁴⁸ Under this approach each tract within a pooled unit is treated as if it actually produced the oil or gas which has been allocated to it under a surface acre formula. Thus each lessor is entitled to a royalty based upon the price actually received by his own lessee; if lessee is not marketing gas, the lessee may be obligated to account to the lessor out of its own monies.⁴⁹

The Oklahoma and Louisiana cases rely heavily upon the language of each jurisdiction's forced-pooling statute. Hence the language of a state's forced-pooling statute should be of special significance in indicating which rule will ultimately be adopted in a state which has not yet judicially opted for an allocation rule. However in states like Texas, where pooling is typically accomplished voluntarily, rather than through forced-pooling, a standard resolution of the royalty issues posed by gas imbalances and differing sales prices may be impossible. The method of allocation may depend primarily upon the language of individual leases.

a. Allocation Under Texas Case Law and Texas Leases

The only Texas case directly deciding these issues is *Puckett v. First*

46. 389 P.2d 951 (Okla. 1963).

47. OKLA. STAT. tit. 52, § 87.1(d) (1961).

48. See *Arkansas Louisiana Gas Co. v. Southwest Natural Prod. Co.*, 221 La. 608, 60 So. 2d 9 (1952).

49. See Upchurch, *Split-Stream Gas Sales and the Gas Storage and Balancing Agreement*, 24 ROCKY MTN. MIN. L. INST. 665, 669-70 (1978).

City National Bank,⁵⁰ which involved royalty computation on a split-stream sale. The lessor's land had been pooled, and the gas produced from the well on the pooled unit was being sold to different purchasers at different prices. The court rejected the argument that all lessors whose land was included in the unit should receive a royalty based upon the weighted-average price of all the gas sold. Instead, it adopted the tract allocation method and concluded that each lessor's royalty should be based upon the price received by his lessee for the gas which it sold. The court's reasoning was primarily grounded in the language of the oil and gas lease and the division order signed by the lessors. According to the court, the lease royalty clause, which provided that the lessee would make payments based on "the market value of the gas so sold or used," required the lessors to look to the sales of gas by their own lessee and did not authorize a claim to royalty based on sales by other lessees that had joined in the pooled unit.⁵¹ The pooling clause, which stipulated that the lessor would receive "on production from a unit so pooled only such portion of the royalty stipulated herein as the amount of his acreage placed in the unit . . . on an acreage basis bears to the total acreage so pooled in the particular unit," did not expand the right to royalty to include a proportionate share of the proceeds from the sale of all unit production.⁵²

The royalty language relied on by the *Puckett* court does not point particularly strongly toward the court's conclusion. The clause—or at least that portion quoted in the opinion—provided for royalties calculated on the basis of market value; hence, the lease royalties were not necessarily tied to any price received by lessee. If such language clearly indicates a tract allocation method of awarding royalty, as the court held, it is difficult to imagine many lease forms which would be construed differently. Royalty language providing for payments based directly upon sale proceeds is far more susceptible to the court's argument than the market value language of the clause in the case. Indeed, some royalty clauses are even explicit about the identity of funds. For example, one form provides for a royalty

on gas . . . produced from said land and sold or used beyond the well . . . an amount equal to one-eighth of the net amount realized by Lessee computed at the wellhead from the sale of such substances. On

50. 702 S.W.2d 232 (Tex. Ct. App.—Eastland 1985, writ ref'd n.r.e.).

51. *Id.* at 235-36.

52. *Id.*

gas sold at the well, the royalty shall be one-eighth of the amount realized by Lessee from such sale.⁵³

Such language could hardly be construed as basing royalty on any price other than that actually received by the lessee.

The decision in *Puckett* does not rest entirely upon the lease language; the court also relies upon the terms of the division orders. They provided for "[s]ettlement . . . on the basis of the proceeds derived from sales of such production and upon the volume computations made by the purchaser(s) thereof."⁵⁴ Since the division orders were addressed to the lessee, the court concluded that the sales referred to in the order necessarily meant sales by the lessee.⁵⁵

The division orders, like the royalty clause, are not crystal clear in specifying which sales are referred to. However, these facts probably strengthen rather than weaken the precedential weight of the decision. If rather vaguely worded instruments can be construed as unambiguously evidencing an intent to use the tract allocation method of royalty computation, it seems doubtful that many printed lease or division order forms employ language pointing toward price averaging.

A somewhat earlier case, *TXO Production Corp. v. Prickette*,⁵⁶ also discussed royalty issues, but in the context of deciding a dispute over venue. The *Prickette* case involved delayed marketing by a lessee, and the issue was whether the lessor was entitled to his royalty from the date of first production from the gas unit with which his land had been pooled or whether his right to royalty arose when his lessee first sold its share of gas.

The court in *Prickette* also looked primarily to the language of the lease in deciding the controversy. The lease clause it focused on was the pooling clause rather than the royalty provision. The pooling clause contained standard language providing that production from any part of the pooled unit should be considered as if it had been produced from the leased acreage and that royalties should be computed on the portion of the production allocated to the leased acreage "just as though such production were from such land."⁵⁷ Since the court did not quote the royalty language, its conclusion that the lease unequivocally entitled the

53. E. KUNTZ, J. LOWE, O. ANDERSON, E. SMITH, OIL AND GAS FORMS MANUAL, Form 7, 63, 66 (1987).

54. *Puckett*, 702 S.W.2d at 235.

55. *Id.* at 236.

56. 653 S.W.2d 642 (Tex. Ct. App.—Waco 1983).

57. *Id.* at 644.

lessor to a royalty from the time production first commenced is somewhat difficult to evaluate. A royalty based on "the amount realized by Lessee from such sale" or a proceeds royalty making no reference to "gas produced from said land" would at least interject some element of uncertainty. If, however, the royalty clause contained the more common language simply referring to the sale of gas produced from the leased land, the court's analysis is difficult to fault.

Because the *Prickette* court suggests that the lessor can recover a royalty based upon sales of gas made by a party other than his own lessee,⁵⁸ the case is occasionally cited as support for the "weighted average" method of royalty computation and as a countervailing authority to *Puckett*. Such a use of the decision is misleading. Both decisions are based primarily upon the language of the leases involved in the individual controversies. Neither purports to articulate a standard rule to be used in all such controversies. Moreover, both the reasoning and the result reached in *Puckett* are consistent with a tract allocation theory. The court treats the portion of unit production to which the lessor's land is entitled as having come from the lessor's land, and a conclusion that a nonmarketing lessee must pay royalties to its own lessor out of its own funds is entirely consistent with the accepted statement of the tract allocation theory. The tract-allocation and weighted-average theories reach divergent results where there are several gas purchasers or split-stream sales.⁵⁹

The main support for the weighted-average method of royalty computation does not come from the *Prickette* case, but from the traditional Texas theory of pooling and unitization. In *Veal v. Thomason*⁶⁰ the Texas Supreme Court held that a unitization agreement constituted a cross-conveyance of mineral interests among the tracts contributed to the unit.⁶¹ Each lessor's agreement to the plan of unitization had the effect of conveying a part of his royalty interest to the lessor of every other tract within the unit. Thus every lessor received a proportionate royalty interest in every tract.

The cross-conveyances theory has been applied to pooled units

58. *Id.* at 645.

59. See generally Upchurch, *supra* note 49; 6 H. WILLIAMS & C. MEYERS, OIL AND GAS LAW § 951, 702-706.2 (1988).

60. 138 Tex. 341, 159 S.W.2d 472 (1942).

61. *Id.* at 349, 159 S.W.2d at 476.

formed under oil and gas lease pooling clauses⁶² as well as to unit agreements and joint and community leases. It points toward the weighted-average method of calculating royalties on a split-stream sale. If pooling gives each lessor a pro rata interest in every tract in the unit, each lessor no longer has a single lessee. Through cross-conveyancing, each owner of a working interest within the unit becomes the lessee of every lessor. Thus every lessor can claim his proportionate share of the royalty from each sale made by each working interest owner.

It seems doubtful that any Texas court will use this analysis when dealing with royalty computation. The cross-conveyancing theory, which has been strongly criticized in other contexts,⁶³ was not mentioned in the *Prickett* decision and was specifically rejected by the court in *Puckett v. First City National Bank*.⁶⁴ That court distinguished *Veal v. Thomason* on the ground that the issue involved in *Veal*, i.e., a determination of necessary parties to the litigation, was purely procedural.⁶⁵ Perhaps most importantly, the cross-conveyancing theory is at odds with standard pooling clause language. The language of the AAPL Form 675 is typical. It provides:

For the purpose of computing the royalties to which owners of royalties and payments out of production and each of them shall be entitled upon production of oil and gas, or either of them from the pooled unit, there shall be allocated to the land covered by this Lease and included in said unit a pro rata portion of the oil and gas, or either of them, produced from the pooled unit after deducting that used for operations on the pooled unit. Such allocation shall be on an acreage basis, that is to say, there shall be allocated to the acreage covered by this Lease and included in the pooled unit that pro rata portion of the oil and gas, or either of them, produced from the pooled unit which the number of surface acres covered by this Lease and included in the pooled unit bears to the total number of surface acres included in the pooled unit. Royalties hereunder shall be computed on the portion of such production, whether it be oil or gas or either of them, so allocated to the land covered by this Lease and included in the unit just as though such production were from such land. The production from an oil well will be considered as production from the Lease or oil pooled unit from which it is producing and not as production from a gas pooled unit; and production from a gas well will be considered as production from

62. *Renwar Oil Corp. v. Lancaster*, 154 Tex. 311, 313-14, 276 S.W.2d 774, 775 (1955); *Texaco, Inc. v. Lettermann*, 343 S.W.2d 726 (Tex. Civ. App.—Amarillo 1961, writ ref'd n.r.e.).

63. See, e.g., French & Elliott, *The Legal Effect of Voluntary Pooling and Unitization: Theories and Party Practice*, 35 TEX. L. REV. 401 (1957).

64. 702 S.W.2d 232, 237 (Tex. Ct. App.—Eastland 1985, writ ref'd n.r.e.).

65. *Id.*

the Lease or gas pooled unit from which it is producing and not from the oil pooled unit.⁶⁶

Even apart from the repeated use of "allocated," the clause clearly contemplates that proportionate shares of production will be treated as if they came from the individual tracts which make up the pooled unit. There is no suggestion that the pooled unit should be treated as a tenancy in common for the purposes of computing royalty or—what may amount to the same thing—that all royalty owners share equally in all sales of gas produced from the unit. Although variations in lease language may occasionally lead to different results, most controversies over calculating royalties on split-stream sales in Texas should thus be resolved by using the tract allocation method. If the lease calls for a proceeds royalty, each lessor will receive a share of the sales price obtained by his own lessee.

b. Allocation Under Forced Pooling in Texas

A similar analysis has been made of tracts pooled under the Texas forced-pooling statutes.⁶⁷ Section 102.051 stipulates:

For the purpose of determining the portions of production owned by the persons owning interests in the pooled unit, the production shall be allocated to the respective tracts within the unit in the proportion that the number of surface acres included within each tract bears to the number of surface acres included in the entire unit.⁶⁸

The court in *Puckett v. First City National Bank*⁶⁹ pointed out that this language strongly suggests the tract allocation approach. Moreover, the cross-conveyancing doctrine, which provides some theoretical support for the weighted-average method of calculating royalties in voluntarily pooled units, is almost certainly inapplicable to forced-pooled units. Texas courts have repeatedly held that Railroad Commission orders "cannot effect a change or transfer of property rights."⁷⁰ Thus a forced-pooling order could not effectuate a transfer of royalty among lessors within a forced-pooled unit.⁷¹

66. E. KUNTZ, J. LOWE, O. ANDERSON, E. SMITH, OIL AND GAS FORMS MANUAL, Form 5 at 19, 21 (1987).

67. TEX. NAT. RES. CODE ANN. §§ 102.001 - 102.112 (Vernon 1978).

68. TEX. NAT. RES. CODE ANN. § 102.051(a) (Vernon 1978).

69. 702 S.W.2d 232, 237 (Tex. Ct. App.—Eastland 1985, writ ref'd n.r.e.).

70. *Nale v. Carroll*, 155 Tex. 555, 559, 289 S.W.2d 743, 745 (1956). See also *Dorchester Gas Producing Co. v. Harlow Corp.*, 743 S.W.2d 243, 252 (Tex. Ct. App.—Amarillo 1987) (citing *Railroad Commission v. City of Austin*, 524 S.W.2d 262, 267-68 (Tex. 1975)).

71. See Smith, *The Texas Compulsory Pooling Act* (pt. 2), 44 TEX. L. REV. 387, 414-16 (1966).

2. Disparity Between Voluntarily Pooled Units and Regulatory Units

Although tract allocation is the most commonly used method for allocating production among tracts in a pooled unit, there are situations which it does not clearly fit. The most serious of these occurs where a unit pooled under the authority granted in the oil and gas lease is larger than the drilling or proration units established by the state's regulatory agency. Thus four tracts, each a 160-acre quarter section and each subject to an oil and gas lease authorizing pooling into a 640-acre unit, may all be pooled into a single unit as authorized by the leases. The regulatory commission, however, may adopt 320-acre drilling units. If the drilling units are designated on a north half/south half basis, there is an obvious problem as to whether production from each well is allocated only between the two tracts making up the drilling unit or among all four tracts under the contractual pooling accomplished under the terms of the leases. If the wells produce different volumes and are subject to split-stream sales at different prices, disputes about royalty computation are assured.⁷²

There is no easy solution to this problem. The language of the lease, which speaks in terms of the contractually pooled unit rather than proration or drilling units, suggests that for purposes of calculating royalty the production from each well should be allocated on a surface acreage basis among all four tracts, i.e., twenty-five percent of the production from each well is allocated to each tract. This solution is not likely to satisfy the lessors of the two tracts assigned to the 320-acre unit of the more productive well, and if the pooling clause permits modifications of the pooled unit, they may well argue that their lessors are under an implied duty to reduce the size of the units pooled under the lease to conform with the drilling or proration units.

3. Applicability of the Shut-In Royalty Clause

In many instances gas is being sold from the unit well, but an individual lessee is not marketing its share of the gas. Can the lessee treat the gas well as shut-in and tender payments based on the shut-in royalty clause, or must the lessee pay royalty on its proportionate share of production, even though it is neither using nor selling it? The traditional function of the shut-in royalty provision has been to provide the lessee

72. See R. Grable, Selected Problems in Split-Stream Production, (presented at Advanced Oil, Gas and Mineral Law Course, Paper C, State Bar of Texas Sept. 17, 1987).

with a means for maintaining the lease at a time when it is unable to market the gas.⁷³ Looked at from this general perspective, the shut-in clause would appear to be applicable. In specific instances, however, the answer depends upon the language of the lease, and most leases probably require a payment based on production.

The shut-in provision is not likely to have been drafted to cover this situation. Many leases use language authorizing the payment of shut-in royalties, such as: "If, at any time or times after the expiration of the primary term, all such wells are shut-in for a period of ninety consecutive days, and during such time there are no operations on said land"⁷⁴ If the gas well in question is producing, this type of clause will obviously not apply.

The same is probably true of a shut-in royalty clause like that used in the AAPL Form 675 oil and gas lease, which provides for a shut-in royalty "[w]hile there is a gas well on this Lease, on an acreage pooled therewith, but gas is not being sold or used."⁷⁵ Such a clause can be interpreted to permit the payment of shut-in royalty only by implying the phrase "by the lessee" after the reference to gas "not being sold or used." Whether a court would do so is open to question. The phrase was implied in the operations clause in *Hughes v. Cantwell*⁷⁶ where leases to different companies had been executed by co-owners of land. The court held that drilling operations by one lessee did not excuse the payment of delay rentals by the other lessee. It should be noted, however, that in *Hughes* the implied language benefitted the lessor, rather than the lessee, and that in most other instances analogous disputes are resolved in accordance with the precise language of the lease.⁷⁷

There are additional arguments against permitting the nonmarketing lessee to invoke the shut-in royalty clause. The payment of shut-in royalties in this situation is almost certainly contrary to the intent and expectation of the lessor. The traditional purpose of shut-in clauses was to permit the maintenance of a lease past its primary term if a well could not be produced because of the lack of pipeline connections for gas production. Here actual production and marketing are taking place. Although loss of royalty on production as a result of drainage to adjacent

73. Lowe, *Shut-in Royalty Problems*, 5 EASTERN MIN. L. INST. 18-1, 18-24 (1984).

74. Producers 88 (7-69) Oil, Gas and Mineral Lease; Pound Printing & Stationery Co. (copy on file with TULSA LAW JOURNAL).

75. E. KUNTZ, J. LOWE, O. ANDERSON, E. SMITH, OIL AND GAS FORMS MANUAL, Form 5, at 20 (1987).

76. 540 S.W.2d 742 (Tex. Civ. App.—El Paso 1976, writ ref'd n.r.e.).

77. See H. WILLIAMS & C. MEYERS, OIL AND GAS LAW § 503.1.

tracts is possible if a well is shut in, the loss of the economic benefit from royalties on production is even more acute where other lessees in the pooled unit are selling gas specifically attributable to the lessor's property.

Perhaps the most serious problem with relying on the shut-in royalty clause is that in most leases the languages of the pooling clause precludes its use. The royalty and pooling clauses typically require the payment of a royalty on production whenever production takes place. As indicated previously, most pooling clauses "allocate" unit production to each tract within a pooled unit. They may not only make such an allocation, but go on to provide: "the production so allocated shall be considered for all purposes, including payment or delivery of royalty . . . to be the entire production of unitized minerals from the land to which allocated in the same manner as though produced therefrom under the terms of this lease."⁷⁸ The royalty clause, in turn, requires a payment to the lessor whenever gas is produced from the land and sold.

4. Calculation of Royalty: The Underproduced Lessee

Even though a lessee is not marketing gas, most leases will probably require a payment of royalty on the production which the pooling clause allocates to a tract. In this situation the royalty will come entirely or in part from the lessee's own pocket, depending on the terms of the operating agreement. However, the *amount* of the royalty may be subject to dispute. If the lease requires the royalty to be based upon market value, the parties may sharply disagree over what the market value is or how it should be ascertained. A similar problem will arise under a proceeds royalty: Since the lessee is not receiving "proceeds," how should the royalty be calculated?

Few, if any, printed form leases are drafted with this precise problem in mind. The term "proceeds" is rarely defined. For example, the royalty provision of the AAPL Form 675 simply provides "on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale."⁷⁹ Read literally, such language requires the lessee to pay a royalty based upon the sales price received by the lessees in the unit that are marketing gas. If only the operator is selling gas, the royalty is based upon the sales price it received. If several parties are selling gas, the

78. Producers 88 (7-69) Oil, Gas and Mineral Lease: Pound Printing & Stationery Co. (copy on file with TULSA LAW JOURNAL).

79. E. KUNTZ, J. LOWE, O. ANDERSON, E. SMITH, OIL AND GAS FORMS MANUAL, Form 5, at 20 (1987).

royalty is presumably based upon an average price, adjusted in accordance with the proportion of gas marketed under each separate contract.

As an underproduced party, the nonmarketing lessee will at some future time have a right to be brought into balance with the other working interest owners in the pooled unit. If the lessees and working interest owners in the pooled unit have entered into a gas balancing agreement, its terms will usually control⁸⁰ and will govern the mechanism and time for bringing the underproduced party back into balance.⁸¹ If there is no such agreement, the rights of the working interest owners will be decided under the provisions of their operating agreement⁸² or in some instances by statute⁸³ or by common law.⁸⁴

If the balancing is in kind, the lessee will have a temporary right to sell a disproportionate amount of gas. During this period the lessee should not owe royalty on that part of the proceeds attributable to the increase in the lessee's fractional share of production. Royalty has already been paid on this gas. In some respects the lessee is in a position analogous to that of a pipeline exercising its make-up rights under a take-or-pay contract. The make-up clause typically allows a pipeline to take gas that it has already paid for in earlier years. The nonmarketing lessee, which has been required to pay the lessor a royalty on gas which the

80. See Art. II of the 1977 and 1982 versions of the AAPL Model Form Operating Agreement. In some jurisdictions, however, statutes provide for types of gas balancing between marketing and nonmarketing parties which may override the terms of the gas balancing agreement. See, e.g., OKLA. STAT. tit. 52, §§ 541-547 (Supp. 1987) and Comment, *A New Dimension in the Ratable Taking of Natural Gas in Oklahoma: Enrolled House Bill 1221*, 20 TULSA L. J. 77 (1984). The constitutionality of the Oklahoma statute was upheld in *Seal v. Corporation Comm'n*, 725 P.2d 278 (Okla. 1986), *appeal dismissed*, *Amerada Hess Corp. v. Corp. Comm'n*, 479 U.S. 1073 (1987).

81. For suggestions for drafting gas balancing agreements, see B. Campbell, *Gas Balancing Agreements, Oil and Gas Agreements*, Paper No. 9 presented at Rocky Mtn. Min. L. Found. May 13, 1983); Upchurch, *Split Stream Gas Sales and the Gas Storage and Balancing Agreement*, 24 ROCKY MTN. MIN. L. INST. 665 (1978); J. Walker, *Gas Balancing Agreements*, (presented at Advanced Oil, Gas and Mineral Law Course, Paper E, State Bar of Texas Oct. 3, 1985); R. Grable, *Selected Problems in Split-Stream Production*, (presented at Advanced Oil, Gas and Mineral Law Course, Paper C, State Bar of Texas Sept. 17, 1987).

82. See Smith, *Duties and Obligations Owed by an Operator to Nonoperators, Investors and Other Interest Owners*, 32 ROCKY MTN. MIN. L. INST. 12-1 (1986).

83. See Smith, *Gas Marketing by Co-owners: Disproportionate Sales, Gas Imbalances and Lessors' Claims to Royalty*, 39 BAYLOR L. REV. 365, 399-402 (1987).

84. In some situations the provisions of the operating agreement may have the effect of simply referring the parties to their rights at common law. If the operator is selling all unit gas production and neither buys the nonoperators' share of gas for resale nor markets it on their behalf, the parties may be treated as cotenants, with each entitled to receive a proportionate share of the net profits received by the operator. For a discussion of the arguments for and against this position, see Smith, *Gas Marketing by co-owners: Disproportionate Sales, Gas Imbalances and Lessors' Claims to Royalty*, 39 BAYLOR L. REV. 365, 382-84 (1987). Common law principles will almost certainly apply if the operating agreement was prepared as if a gas balancing agreement had been attached, but no balancing agreement has ever been attached.

lessee neither used nor sold, should not be required to pay royalty when it later sells an amount of gas equivalent to that on which its earlier royalty payments were based.

Balancing in kind may not be feasible. The gas contract obtained by the underproduced lessee may not permit a temporary increase in the amount of gas sold.⁸⁵ Even if there is no contractual obstacle to balancing in kind, other impediments may exist. The reservoir may be too depleted to permit gas balancing, or agency regulations may restrict production or sales to assure ratable taking or to compensate for past production that exceeded a well's allowable. In such situations other alternatives for balancing the underproduced party must be considered.

The relatively few cases which have dealt with the rights of an underproduced party who later begins marketing its gas have awarded an immediate cash balancing, based upon the price received by the marketing party.⁸⁶ Since in most instances the underproduced lessee will have already paid a royalty based on this price, it will owe no additional royalty to the lessor. If the payment exceeds the price on which the royalties were calculated, an additional royalty, based on the excess, will be payable. If the payment is based on a lower price, the lessee has a claim for reimbursement against the royalty owners. This result clearly follows under those leases which provide for royalty on sales "by the lessee." In the absence of such language the result, while less certain, should be the same. The tract allocation method of determining royalty which most leases explicitly or impliedly adopt limits the royalty to the sale price received by each lessor's own lessee.⁸⁷ The cash payment received to balance out the gas accounts retroactively establishes that price.⁸⁸

The same type of analysis should apply if cash balancing is delayed until reservoir depletion. The lessee should owe royalty on the money received only to the extent it exceeds the price used for calculating the royalties already paid.

85. See Hillyer, *Problems in Producing and Selling, By Split or Single Stream, Gas Allocable to Diverse Working Interest Ownerships*, 16 *INST. ON OIL & GAS L. & TAX'N* 243, 263 (1965).

86. *United Petroleum Exploration, Inc. v. Premier Resources, Ltd.*, 511 F. Supp. 127 (W.D. Okla. 1980). See also *Beren v. Harper Oil Co.*, 546 P.2d 1356 (Okla. Ct. App. 1975).

87. *Puckett v. First City Nat'l Bank*, 702 S.W.2d 232 (Tex. App.—Eastland 1985, writ ref'd n.r.e.).

88. A discussion of the various factors which should be considered in determining the price used for cash balancing can be found in E. KUNTZ, *A TREATISE ON THE LAW OF OIL AND GAS* § 77.3 (1978).

III. THE EFFECT OF OTHER INSTRUMENTS ON ROYALTY OBLIGATIONS OWED UNDER THE OIL AND GAS LEASE

The foregoing discussion of the lessee's royalty obligations focuses primarily upon the language of the oil and gas lease, especially the royalty, shut-in royalty, and pooling clauses. To what extent, however, may the royalty obligations imposed or affected by these clauses be modified by other instruments entered into by one or both the parties to the lease? Such instruments fall into two basic categories: contracts, such as the operating agreement, which have been entered into by the lessee and a third party; and agreements, such as the division order, entered into by the parties to the lease.

A. *Operating Agreements and Other Contracts Between the Lessee and Third Parties*

As a general proposition, it seems unlikely that the lessor's right to royalty established by the oil and gas lease can be altered by a contract entered into between the lessee and a third party. There are a few cases to the contrary, but they tend to turn on exceptional fact patterns. Thus in *Cook v. Thompkins*⁸⁹ the lessor had not been paid her share of royalties by the company to whom the lessee had sold her share of the oil because the oil purchaser, which was now bankrupt, did not have her address. In this instance Ms. Cook was effectively bound by the contract between her lessee and the oil purchaser because the lessee had acted as her agent in selling her proportionate share of it. Since she owned a stated fraction of production in kind and had failed to make arrangements for storing or marketing it, she had impliedly authorized the lessee to market it on her behalf.

Most other oil and gas cases which treat an agreement as affected by a subsequent contract entered into by only one of the parties involve oil and gas deeds. There are several cases which effectively treat the pooling clause of an oil and gas lease as modifying a deed creating a term mineral or royalty interest, even though only one party to the deed is a party to the oil and gas lease. These decisions hold that production from a pooled unit maintains the term interest, even though the well is located off the tract that is subject to the interest.⁹⁰ These cases are generally limited to

89. 713 S.W.2d 417 (Tex. Ct. App.—Eastland 1986).

90. See *Southland Royalty Co. v. Humble Oil & Refining Co.*, 151 Tex. 324, 249 S.W.2d 914 (1952); *Williamson v. Federal Land Bank*, 326 S.W.2d 560 (Tex. Civ. App.—Texarkana 1959, writ ref'd n.r.e.).

pooling, however, for the shut-in royalty provision does not have such an effect. The payment of shut-in royalty will not keep a term royalty or mineral interest in effect because "the language of the lease does not either expressly or by implication extend the term" of the deed.⁹¹

The cases involving payment of gas royalty based upon market value are closer in point, and they provide little or no support for treating the lease as modified by a separate contract to which the lessor is not a party. Unlike oil production, which is generally owned in kind by both the lessor and the lessee proportionately to their royalty and working interest shares, gas production is owned exclusively by the lessee. The lessor is entitled to a royalty calculated in cash. Several states have held that a lessor who is entitled to a royalty based on the market value of the gas produced and sold is not bound by the price established in a gas purchase contract entered into by the lessee. If the price is less than current market value, the lessor can insist upon having his royalty calculated on the basis of the higher value.⁹² In such states governmental price regulations may determine market value,⁹³ or at least be relevant to such a determination,⁹⁴ but the private contract between the producer and the pipeline purchaser does not automatically establish market value.

Logically, the operating agreement and gas balancing agreement should be similarly ineffective to modify the lessor's royalty rights. The Oklahoma Supreme Court has held that the operating agreement does not affect the habendum clause of the lease. In *Hininger v. Kaiser*⁹⁵ the court held that administrative expenses which the operating agreement imposed upon the lessee should not be taken into account in calculating whether a well was producing in paying quantities. Thus it seems unlikely that a nonmarketing lessee can successfully argue that it owes no royalty on gas production because the operating agreement gives the operator the right to market the operator's own share of gas, while refusing to buy or market the gas of a nonoperator who does not have a gas sales contract. The existence of a gas balancing agreement providing explicit

91. *Archer County v. Webb*, 161 Tex. 210, 338 S.W.2d 435 (1960).

92. *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); *Holmes v. Kewanee Oil Co.*, 233 Kan. 544, 664 P.2d 1335 (1983), *cert. denied*, 106 S. Ct. 322 (1985); *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866 (Tex. 1968).

93. *First Nat'l Bank v. Exxon Corp.*, 622 S.W.2d 80 (Tex. 1981); *Bowers v. Phillips Petroleum Co.*, 692 F.2d 1015 (5th Cir. 1982); *Flowers v. Diamond Shamrock Corp.*, 693 F.2d 1146 (5th Cir. 1982).

94. *Matzen v. Cities Service Oil Co.*, 233 Kan. 846, 667 P.2d 337 (1983), *cert. dismissed*, *Mobil Oil Corp. v. Batchelder*, 468 U.S. 1222 (1984).

95. 738 P.2d 137 (Okla. 1987).

guidance for make-up rights in kind or in cash would not seem to change the result.

B. *Division Orders*

Unlike the operating agreement, balancing agreement, or gas purchase contract, the division order is executed by the lessor. Thus there are far fewer conceptual problems in treating this instrument as affecting the lessor's rights. Just how it affects the lessor's rights is open to question, however. If the previous discussions suffered from a lack of case law to analyze, the division order cases present the opposite problem: There are too many cases saying too many things without clearly articulating the legal theories used.

The basic functions of the division order are to specify how funds from the sale of production should be distributed and to protect the distributor from liability for improper payment.⁹⁶ A division order executed by a lessor may occasionally serve other functions. For example, a cotenant who has not signed a lease may ratify it if the cotenant signs a division order containing an express ratification clause.⁹⁷ Even without a ratification clause a division order may have this effect if it clearly refers to the existing lease and the cotenant accepts royalty payments under it.⁹⁸ Usually, however, a division order will not be effective to accomplish a purpose outside the scope of the instrument. In *Bradley v. Avery*⁹⁹ a division order was ineffective to revive a lease. A well on the property in question had not produced for over two months when it was reworked and brought back into production. The court concluded that the cessation of production was not "temporary" and that the lease had terminated.¹⁰⁰ New division orders executed by the landowners did not revive the lease, for there was no clearly stated intent to do so. The division orders did not describe the land, contained no language of grant, and did not even refer to the terminated oil and gas lease.

1. Effect on a Lessor's Claim to Royalty

It is difficult to generalize too broadly about the effect of a division order upon a lessor's right to royalty. The nature of the division order is

96. See Hollimon, *Division Orders—A Primer*, 34 INST. ON OIL & GAS L. & TAX'N 313 (1983).

97. *Pope v. Pennzoil Producing Co.*, 288 Ark. 10, 701 S.W.2d 488 (1986).

98. See *Texas & Pacific Coal & Oil Co. v. Kirtley*, 288 S.W. 619 (Tex. Civ. App. 1926, writ ref'd).

99. 746 S.W.2d 341 (Tex. Civ. App.—Austin 1988).

100. *Id.* at 343.

unclear, and the principal natural gas producing states are divided on its effect. The Kansas courts have held that a division order is normally ineffective to change the method of calculating royalty specified in the underlying oil and gas lease. They have reasoned that since its purpose is primarily to protect the pipeline purchaser by directing it how to distribute payment for the gas, the division order should be viewed as part of the contract between the purchaser and producer, rather than as an amendment or modification of the lease.¹⁰¹ The result in Oklahoma seems less certain, although there is some authority that a lessor who executes a division order and accepts payments authorized by it is not estopped to challenge the basis upon which the payments have been calculated.¹⁰² The leading Texas case addressing the issue is *Exxon Corp. v. Middleton*,¹⁰³ which involved a claim by the lessee that the lessors' right to market-value royalties had been modified by division orders authorizing payments for royalties to be computed on the basis of gas sales. The court of appeals used a traditional contract analysis. It found that the lessors' agreement to accept royalties calculated on a basis different from that provided in the oil and gas lease was supported by consideration — the lessee's agreement (not expressly set out in the lease) to keep records available for inspection by the lessors at all times. Under this analysis the lessors were not only precluded from recovering for underpayment of back royalty, they should also be barred from seeking royalties based on market value in the future. They were bound by language in the division order agreement stating that it "shall remain in force during the life of the respective lease(s) under which payment is due . . ." ¹⁰⁴ According to the court, the effect of a division order depends upon its terms. "Routine division orders without . . . consideration" are revocable at will; if supported by consideration, they are irrevocable if the agreement so provided.¹⁰⁵

This holding was partially reversed by the Texas Supreme Court. It held the division orders binding, but only so long as the parties acted under them. The court reinstated the trial court's holding that they had been revoked when the lessors filed suit against their lessee. Hence the

101. *Holmes v. Kewanee Oil Co.*, 233 Kan. 544, 664 P.2d 1335 (1983), *cert. denied* 106 S. Ct. 322 (1985); *Maddox v. Gulf Oil Corp.*, 222 Kan. 733, 567 P.2d 1326 (1977), *cert. denied*, 434 U.S. 1065 (1978).

102. *Craig v. Champlin Petroleum Co.*, 300 F. Supp. 119 (W.D. Okla. 1969), *rev'd on other grounds*, 435 F.2d 933 (10th Cir. 1971).

103. 613 S.W.2d 240 (Tex. 1981).

104. *Id.* at 251.

105. *Id.*

lessors' claim for royalties based on a market value higher than the price provided in the sales contract was valid, but was limited to the period after revocation.

The Texas Supreme Court rejected the appellate court's contract analysis. It did not articulate a clear alternative theory, but used language strongly suggesting accord and satisfaction. It quoted at length a Fifth Circuit case, *Phillips Petroleum Co. v. Williams*,¹⁰⁶ suggesting that division orders are a method of settling a dispute over what the market value of the gas actually is. Although not directly discussed by the court, estoppel is an alternative theory on which the court might have rested its decision.

There are problems with all three possible approaches. Under a contract analysis division orders are binding if there is consideration. Barring special circumstances, such as fraud or misrepresentation, there is no apparent reason why division orders cannot be made to bind the lessor for the duration of the underlying oil and gas lease. Finding consideration may not always be easy, however. Although future division orders can undoubtedly be drafted to provide for new duties, the existence of consideration in existing division orders may well be a matter of considerable dispute. The appellate court recognized that "routine division orders" are not given for consideration,¹⁰⁷ and the presence of consideration in the division orders in the case is at least questionable. The duty to make available the records upon which royalties were calculated—which the appellate court relied on—may arguably have been implicit in the oil and gas lease royalty provisions and hence inadequate to constitute new consideration supporting modification of the royalty obligations. If there is no consideration, then there is no enforceable contract. The division orders cannot modify the royalty obligations contained in the lease nor bar the lessor from recovering for back underpaid royalties. Other doctrines, such as estoppel, waiver, and the statute of limitations, may constitute barriers to recovery, but they must be pled and proved.

A theory of division orders based upon accord and satisfaction presents at least two problems. One is identical to that posed by a contract analysis. If the division order is treated as settling the issue of market value for all payments under the lease, it should be binding as to all payments made at all times under the lease. The accord and satisfaction

106. 158 F.2d 723 (5th Cir. 1946).

107. *Exxon Corp.*, 613 S.W.2d at 250-51.

concept is consistent with the result reached by the Texas Supreme Court only if the acceptance of each payment made under the division order is deemed a separate transaction. By revoking the division order, the lessor rejects its effect as to future transactions. Such an arrangement is perfectly feasible but is not readily apparent from the language used in the division orders in *Middleton*.

The second problem is inherent in the assumption that the parties have agreed to settle a dispute. Most division orders are signed shortly after gas is first produced and sold, when the sale price and market price are likely to be identical. It is highly unlikely that most lessors sign them to resolve the meaning of "market value." Indeed, in most market value royalty cases the lessors were apparently unaware until shortly before filing suit that there was any meaningful difference in the royalty language of the lease and the terms of the division order. They did not knowingly accept payments based on sales price in satisfaction of the lessee's obligation to tender larger royalties whose amount was uncertain. Such knowledge is normally essential to a valid accord and satisfaction. In *Flowers v. Diamond Shamrock Corp.*¹⁰⁸ the Fifth Circuit held that the endorsement of a check "issued in full settlement of the account stated" did not constitute an accord and satisfaction of the lessee's market value royalty obligations because there was no showing that the lessee was aware of any dispute over the amount owed.¹⁰⁹ As the court there stated:

The requirement of a bona fide dispute presupposes both parties' knowledge that there exists a particular issue as to a greater liability that is settled by the accord. . . . In the present instance, no evidence whatsoever shows that the Flowers had or should have had any knowledge, at the time, that negotiation of these checks would affect or settle a disagreement as to the market value of the gas on which royalties were based. Shamrock's position at all times was that plaintiffs were being paid in accordance with the lease, and there is no evidence in the record that any of the plaintiffs were aware of the incorrectness of that position under *Vela*.¹¹⁰

The execution of a division order is obviously different from the endorsement of a check. The theory of the effect of the two instruments is the same, however. Hence, it is difficult to see why the use of different types of instruments should lead to different legal outcomes.

A third theory, estoppel, is a possible alternative basis for explaining *Middleton*, but it also presents problems. On the facts as set forth by the

108. 693 F.2d 1146 (5th Cir. 1982).

109. *Id.* at 1152-53.

110. *Id.* at 1152.

court, it is difficult to find any traditional reliance by the lessee on the lessors' division orders. The long term gas contract entered into by Sun Oil Company predated the division orders executed by Sun's lessors¹¹¹ and so could not have been made in reliance upon the lessors' willingness to abide by a royalty calculation based on the contract price. Moreover, there is no suggestion in the case that Sun gave up a right or opportunity to renegotiate the contract because the lessors were accepting payments based on the contract price. The absence of such types of reliance may explain why the court does not advance estoppel as a basis for its holding.

The absence of a clearly stated legal theory justifying the effect given division orders has not noticeably weakened the Texas Supreme Court's enthusiasm for its decision in *Middleton*. The court has repeatedly reaffirmed the holding. Thus it may be more helpful to describe the effect of division orders in recent cases involving various kinds of royalty disputes than attempt to find a legal theory explaining them.

2. Effect on the Implied Marketing Covenant

Under the *Middleton* holding a division order is binding until revoked. A lessor entitled to a market value calculation of royalty but paid on the basis of the gas' sales price is barred from seeking additional recovery for the period while the division orders were in effect. A more recent case indicates that the Texas Supreme Court has now extended the effect of division orders one step further. Until quite recently, it was widely assumed that division orders have no effect upon a lessee's potential liability for breach of implied covenants.¹¹² *Cabot Corp. v. Brown*¹¹³ strongly suggest that a division order not only bars a claim based on an express royalty clause, but also a claim based on breach of the implied covenant to market gas production.

In *Cabot Corp.* the lessee had dedicated gas to an interstate pipeline and thus subjected it to pricing regulation by the FPC under the Natural Gas Act. The division orders executed by the lessor obligated the lessee to pay royalties based on the price established by the FPC "if such sale be subject to the Federal Power Commission."¹¹⁴ One ground of complaint by the lessor was that she had not been paid royalties based on market

111. The gas purchase contract between Sun Oil Co. and Pan American Gas Co. was dated July 5, 1951, whereas the division orders were executed in 1952. *Exxon Corp.*, 613 S.W.2d at 249.

112. See, e.g., Hollimon, *supra* note 96, at 345-46.

113. 754 S.W.2d 104 (Tex. 1988).

114. *Id.* at 105.

value, as required by her lease. The court viewed this claim as clearly controlled by *Middleton*.¹¹⁵ It also treated *Middleton* as controlling her second ground of complaint, which was based on a much different theory. She alleged the lessee had breached its duty to seek an abandonment of the dedication to interstate commerce. If the abandonment request had been granted, the gas would have been free of FPC jurisdiction and available for marketing at the higher prices paid in the intrastate market. The Court did not discuss whether the lessee had any obligation to seek abandonment or if there was proof that such action by the lessee would have resulted in higher royalties to the lessor. Rather, treating the plaintiff's complaint as a claimed breach of the implied marketing covenant, it stated that the division orders barred a claim for higher back royalties based on implied lease provisions, just as they barred such a claim based on express lease provisions.¹¹⁶

As one commentator has pointed out,¹¹⁷ there is a potential inconsistency between the holding in *Cabot Corp.* and that in *Amoco Production Co. v. First Baptist Church*.¹¹⁸ The latter case permitted a lessor to recover damages based upon its lessee's failure to act in good faith when it entered into a gas sales contract providing for benefits that were not shared with the lessor. Arguments for permitting a lessor to claim royalty based upon take-or-pay settlements rely heavily upon it.¹¹⁹

The court in *Cabot Corp.* apparently recognized the tension between its two decisions and attempted to reconcile them on two grounds. It pointed out that the lease in *Amoco* called for a "proceeds" royalty rather than a royalty based on market value and that the division order in *Amoco* did not purport to change the net proceeds basis for calculating royalty provided by the lease.¹²⁰

The relevance of the first distinctions is not entirely clear. It is true that a "proceeds" lease may lead to a claimed breach of the implied marketing covenant on the ground that the contract price is too low; whereas such a contention is largely irrelevant in a market value lease because the lessor's royalty is not automatically based on the sales price of the gas.

115. *Id.* at 107.

116. *Id.*

117. M. Cockrell, *The Implied Marketing Obligation: Development and Current Implications*, (presented at the 14th Inst. on Oil, Gas & Min. L., co-sponsored by the Oil, Gas & Mineral Law Section of Texas and Texas Law School April 15, 1987).

118. 579 S.W.2d 280 (Tex Civ. App.—El Paso 1979), writ ref'd per curiam n.r.e., 611 S.W.2d 610 (Tex. 1980).

119. *See, e.g.,* Lowe, *supra* note 30, at 563.

120. *Cabot Corp.*, 754 S.W.2d at 107.

However, *Cabot Corp.* is one of the rare cases where breach of the implied marketing covenant can be claimed even though the lease contains a market value royalty clause. The lessor's marketing covenant argument is based on the lessee's alleged failure to get the gas released from FPC price regulation. The second distinction is not fully articulated by the court. It is possibly based on a conclusion that division orders in *Cabot Corp.* changed the terms of the royalty clause. Since the division order in *Cabot Corp.* recognized the possibility that the gas would be subject to FPC jurisdiction, the court may have reasoned that the lessor implicitly accepted sales of gas in interstate commerce as good faith marketing which complied with all implied marketing obligations.

The conclusion suggested by the court's discussion in *Cabot Corp.* is that a division order will supplant the implied marketing covenant unless it specifically indicates that it does not change the method of payment called for by the lease.¹²¹ The court does not make clear why specific *lease* language indicating how a royalty will be calculated, e.g., "when sold by lessee, one-eighth of the amount realized by lessee," does not negate the implied covenant to market gas at a reasonable price, whereas specific *division order* language indicating the method of calculation has that effect.

In applying the division order holding in *Middleton* to an action based on breach of the implied marketing covenant, the Texas Supreme Court may well be mixing apples and oranges. An action for underpayment of a specific contract amount, such as was brought in *Middleton*, is conceptually different from an action for damages based upon failure to market reasonably or diligently. The distinction is clearer in a situation where the alleged breach is not based on the sale of gas for an unreasonably small amount, but on an unreasonable delay in seeking and obtaining a contract. The basis for the cause of action in such a situation is the same as in *Cabot Corp.*—breach of the implied covenant to market gas production—but it is difficult to understand why executing division orders once a contract is finally obtained should bar the lessor's claim for damages based on unreasonable delay in entering into that contract.

3. When Is a Lessor's Claim Not Barred?

Division orders do not preclude a successful suit for back royalties

121. The importance of the precise language used in the division order was also made clear in a recent Texas Supreme Court opinion which was withdrawn after the parties to the litigation entered into a settlement agreement. See *Texas Oil & Gas Corp. v. Hagen*, 32 Tex. Sup. Ct. J. 140, *withdrawn*, 760 S.W.2d 960 (Tex. 1988).

in all instances. Claims based on fraud are exempted from the holding in *Middleton*.¹²² *Gavenda v. Strata Energy, Inc.*¹²³ is the best known recent case refusing to find division orders a bar to a recovery of back royalties. It arguably falls into the "mathematical error" category, although that was not the ground relied on by the court in holding in favor of the royalty owners. The dispute arose because of the misreading of a fifteen-year term royalty which gave the plaintiffs an undivided one-half nonparticipating royalty in all oil and gas produced from the land conveyed. An oil and gas lease providing for a one-eighth royalty was later executed on the land subject to the term royalty. The lawyer who did the title examination for the lessee erroneously read the deed containing the term royalty as reserving one-half of the royalty in the plaintiffs. He thus concluded that they were entitled to one-sixteenth of the gross production under the oil and gas lease. The plaintiffs, who apparently read the reservation the same way initially, executed division orders prepared by the lessee reflecting a right to a one-sixteenth royalty. The lessee made payments of royalty on this basis until the royalty owners revoked the division order two days before the termination of the fifteen year term. They then filed suit for the \$2.4 million which they had been underpaid.

In rejecting the lessee's argument that the division orders were binding until revoked, the Texas Supreme Court distinguished *Middleton* and earlier cases on the ground that the defendants in such cases had not received a positive benefit from the mistake in division orders.¹²⁴ In *Chicago Corp. v. Wall*,¹²⁵ the operator had relied upon transfer orders in overpaying one set of royalty owners and underpaying another set and had not retained any royalty to which it was not entitled. In *Middleton*, where the lessors complained of payment on the basis of sales price rather than the higher market price, the operator also had not received any money which should have been remitted to the royalty owners. In *Gavenda*, however, the defendant operator had not only prepared the erroneous division orders itself, it had also affirmatively benefited from the error by retaining the seven-sixteenths of production owed the plaintiffs.

122. 613 S.W.2d 240, 251, n.8 (Tex. 1981).

123. 705 S.W.2d 690 (Tex. 1986).

124. *Id.* at 692.

125. 156 Tex. 217, 293 S.W.2d 844 (1956). On somewhat analogous facts, a Louisiana court held that the underpaid royalty owner was entitled to recover from the lessee and that the lessee was entitled to recover the amount of overpayment from the royalty owner who had received more than her share of the royalty. *Matthews v. Sun Exploration and Production Co.*, 521 So. 2d 1192 (La. Ct. App. 1988).

The court held that under such circumstances the division order did not prevent a claim for unpaid royalties for the period before revocation.

Gavenda clearly differs from *Chicago Corp. v. Wall*, where the mistake in the transfer orders was apparently made by the royalty owners themselves. The court's distinction of *Middleton* is open to question. In both cases the lessees had prepared the division orders; hence the only reason given for the difference in result was the presence or absence of benefit to the lessee from its own mistake. But a lessee that fails to make out-of-pocket payments owed to a royalty owner benefits from its mistake as fully as a lessee that keeps income that should have been paid to the royalty owner. The lessees in both instances are wealthier to the extent that the royalty owner has failed to receive moneys owed.

As questionable as the court's distinction may be, the express holding of *Gavenda*, which refuses to permit an operator to rely on division orders if it prepares the instruments understating the amount of royalty owed and benefits from its own mistake, does not seem to be either inequitable or unfair. The considerations are similar to those stated by the Kansas Supreme Court in *Maddox v. Gulf Oil Corp.*:

Where a division order prepared by the lessee of an oil and gas lease for the lessor's signature unilaterally attempts to amend the oil and gas leases to deprive the royalty owner of interest on royalties held in suspense, to which the royalty owner is otherwise entitled under the leasing contract, and the lessor signs the division order without consideration from the lessee, the provision waiving interest is null and void.¹²⁶

Nonetheless, the *Gavenda* holding further complicates the task of reconciling the division order cases under a single coherent legal theory or, more practically, of advising a client with a fact situation different from any heretofore litigated.

IV. THE EFFECT OF DIVISION ORDERS ON CURRENT ROYALTY ISSUES

Claims based on payments or settlements of take-or-pay obligations may have already supplanted market-value claims as the major source of royalty litigation. Disputes over royalty obligations owed by underproduced and overproduced lessees who have pooled their interests and have different marketing arrangements are likely to assume an equally

¹²⁶ *Maddox v. Gulf Oil Corp.*, 222 Kan. 733, 567 P.2d 1326 (1977), *cert. denied*, 434 U.S. 1065 (1978).

important role. To what extent will a division order preclude a successful assertion of such claims?

The difference in language of individual division orders, the absence of a clear theoretical basis for the holdings in the division order cases, and the uncertain validity of the royalty claims themselves make any answer highly speculative. As matters now stand, however, the following tentative conclusions can be suggested.

A lessor's right to royalty on payments made pursuant to a take-or-pay clause is far from settled, but existing case law and the language of most lease forms suggest that such claims will be unsuccessful. Thus the question of a division order's effect is likely to be limited to the somewhat more viable claims to share in settlements for past take-or-pay obligations, buy-outs and buy-downs. It is at least arguable that in Texas the division order constitutes a barrier to all such claims. The royalty owner is seeking relief analogous to that denied in *Middleton*: He is seeking to have his royalty recalculated on the basis of a price other than that received by his lessee for each unit of gas produced and accepted by him under his unrevoked division orders. That acceptance constituted an accord and satisfaction of the disputed right to royalty on take-or-pay payments and settlements. Further, under *Cabot Corp.* the division order negates the implied marketing covenant and also any implied duty which the lessee has to share benefits from gas marketing with the lessee.

Such an analysis would not be applicable to a state such as Kansas which normally treats the division order as having no effect on the lessor's claim to royalty. It may, indeed, overstate the effect of such instruments even in Texas. Claims to royalties on some types of settlements fall well outside the *Middleton* holding. In a buy-down, the gas purchaser is making a payment in exchange for lowering the contract price on future gas takes. The lessor should be entitled to share in this payment, if not when received, then at least when the gas to which it relates is produced. The typical division order calls for payment on the basis of proceeds, the terms of the lease, or the gas contract. If the royalty payments do not take the buy-down into account, the lessor has not been paid in accordance with the terms of the division order and the lessor's suit can be based on breach of that instrument, rather than the underlying lease. The same may also be true of "buy-outs" made in exchange for terminating future take-or-pay obligations.

The effect of division orders on royalty disputes arising from pooled leases is slightly clearer. As indicated previously, the tract allocation

doctrine, which most states and most lease pooling clauses have seemingly adopted, probably eliminates claims for back royalties based on split-stream sales by some other lessee which has pooled its working interest into the unit. A division order may serve to ratify this method of computation.¹²⁷ Logically a division order could also authorize this method of computation even though the lease is silent or provides for averaging. Similarly, a division order can determine the time when royalties must be paid by a lessee in a pooled unit.¹²⁸ A division order could make royalty obligations "subject to the terms of any applicable operating agreement or balancing agreement."¹²⁹ Such a division order will be revoked, of course, if its effect is to delay the lessor's royalty payments to a final in-cash payment on reservoir depletion.

V. CONCLUSION

A lawyer seeking to advise a client on any of the newer issues involving royalty rights has uncertain sign posts for guidance. There is little case law dealing with the types of royalty claims now being asserted. The extent, if any, to which division orders bar a lessor from successfully asserting such claims is conjectural. The division order cases are so numerous and so diverse that reconciling them is difficult, and generalizing about their effect is virtually impossible. Division orders, at least in Texas, are clearly controlling until revoked. They control some claims based on breach of the implied marketing covenant as well as claims to higher back royalties based on market value. Beyond that, exactly what they control remains uncertain.

127. *E.g.*, *Puckett v. First City Nat'l Bank*, 702 S.W.2d 232 (Tex. Ct. App.—Eastland 1985, writ ref'd n.r.e.).

128. *TXO Production Corp. v. Prickette*, 653 S.W.2d 642, 645 (Tex. Ct. App.—Waco 1983).

129. This language is used in the *Kraftbilt Oil and Gas Division Order form*. See E. KUNTZ, J. LOWE, O. ANDERSON & E. SMITH, *OIL AND GAS FORMS MANUAL*, Form 13 at 97.

