The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners

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The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners

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** This Article is dedicated with the greatest fondness to the late K. Craig Shephard, who was heavily responsible for my interest in oil and gas law. What is true for his friends is true for the industry; both are far richer for Craig's involvement with them. Craig's untimely death deprived the industry of one of the leaders who was guiding it through the challenges and pitfalls of this deregulated era.
ABSTRACT

The oil and gas industry has developed a handful of implied covenants that regulate royalty owners’ rights. Yet the courts have not formally recognized any new covenants in recent years. In practice, however, courts frequently enforce a covenant that is perhaps more fundamental than the recognized covenants: the mutual benefit covenant that operators are to share benefits they receive with royalty owners and are not to take separate benefits from the revenue stream. This covenant can be found in application in areas as diverse as division order cases, affiliate pricing cases, and some drainage and interest-suspense cases. It is expressly recognized by the one code state, Louisiana. Adopting this principle formally should have prevented the current rule that royalty owners do not share in take-or-pay payments and might have prevented the oil posted-price problems and similar problems now...
coming to light in natural gas royalty payments. The mutual benefit covenant meets requirements for formal articulation; it tracks the parties' true understanding and is necessary to effectuate the purposes of the lease.

One of the best-settled rules in oil and gas law is that courts give royalty owners extra contract protection in order to equalize the balance of power between the royalty owner and the lessee, which usually is an operating oil and gas company. These protections are called implied covenants. Academics can dispute whether courts imply these extra protections as a matter of law because of the imbalance of power in most leases, or instead imply them "in fact" to round out the parties' subjective intent. But there is no disagreement that courts will imply a series of specific duties in every lease, even though the duties are not in writing, and give these duties equal weight to the written terms.

Courts traditionally imply one general standard of reasonable prudence and five particular covenants. They also, however, routinely enforce but fail to formally recognize a substantive principle that goes more directly to the heart of the lease: the lessee cannot take separate benefits from or otherwise reduce the royalty interest, and it must share all benefits it derives from the lease with royalty owners.

The process of common-law iteration has not yet added this mutual benefit covenant to the canon of oil and gas law. The wisdom of the common law supposedly lies in its process of deciding only concrete cases and building principles outward from particulars. Over time, small steps build the larger body of law. In the classical view, this evolutionary process

1. Royalty owners (often called lessors) and lessees are two of the main actors in the development of oil and gas law under the standard American legal structure. The royalty owner is a landowner who executes a deed (the lease) that transfers its mineral interest to a lessee, but ordinarily retains a share of production free of expenses. See HOWARD WILLIAMS & CHARLES MEYERS, MANUAL OF OIL AND GAS TERMS [MANUAL] 1087-90 (8th ed. 1991). The lessee is the party that receives the royalty owner's mineral interest. See id. at 651. Ordinarily it is an operating oil company.

2. See infra notes 228-34 and accompanying text.

3. Courts imply these covenants in every lease, but at least some of them can be disclaimed if the lease addresses the issue with an express clause. For the problem of disclaimers and implied covenants, see generally Jacqueline Weaver, When Express Clauses Bar Implied Covenants, Especially in Natural Gas Marketing Scenarios, 37 NAT. RESOURCES J. 491 (1997); see also Freeport Sulphur Co. v. American Sulphur Royalty Co., 6 S.W.2d 1039, 1043 (Tex. 1928) (no implied covenant of general development where contract specified development via one plant); Stoddard v. Emery, 18 A. 339, 442 (Pa. 1889) (when number of wells is expressed, "there is no room for any implication that there should be some other number").

4. See Brewster v. Lanyon Zinc Co., 140 F. 801, 812 (8th Cir. 1905) (It is a "well-established rule that a covenant arising by necessary implication is as much a part of the contract—is as effectually one of its terms—as if it had been plainly expressed.").
served to unveil a legal corpus that was fixed and external; it was law that
courts claimed to discover, reveal, expose, or find. Yet even for those with
more Realist leanings, the revelation of principles embedded in a growing
mass of cases is a part of the elaboration and articulation of the law.\(^5\) Indeed, it can be more important for Realists to extract the principles hidden
in the pattern of cases. The more law is a series of social choices, the more
important it is to make those choices apparent. Transparency of legal
thinking is the foundation for legitimacy in a just system of law.

The oilfield's mutual benefit covenant presents one of these
subterranean principles that courts routinely apply, but have yet to bring
to full consciousness. Courts do not honor this covenant as openly as the
other implied covenants, yet it is closer to the essence of the lease than, say,
the covenants to protect the lease, to explore, or to develop. Bringing the
mutual benefit covenant to the fore will improve the quality of oilfield
jurisprudence and refine a basic principle courts already enforce.

Parts I and II show that this mutual benefit covenant, though not
yet formalized, is central to oil and gas law. Part I analyzes *Amoco Production Company v. First Baptist of Pyote*,\(^6\) a case that crops up repeatedly
for the principle that a lessee cannot gain a special benefit at the expense of
its royalty owners. Practicing oil and gas lawyers are used to seeing *First Baptist* cited as a separate, substantive principle. Moreover, the *First Baptist*
principle is the same principle that courts honor when they refuse to let
division orders amend the lease if the change unjustly enriches the lessee,
and when they refuse to let lessees use affiliates as an excuse to levy added
charges against the royalty interest. Part II discusses the mutual benefit
principle in division order and affiliate cases, in three prominent oilfield
cases, and in Louisiana's Mineral Code.

Part III explains why courts should acknowledge the mutual
benefit covenant formally. If the principle is as clear as part II suggests, it
is natural to ask why formal recognition matters. The last decade has
produced at least three perfect illustrations of the answer to this question:
the take-or-pay royalty cases, the practices unearthed in the oil posted price
cases, and the efforts of natural gas producers to use deregulation to reduce
their royalty obligations.

In perhaps the worst exploitation, traditional royalty law proved
impotent when a majority of courts let lessees pocket royalty-related
proceeds from take-or-pay prepayments and settlements. In contrast, the

\(^5\) Even Benjamin Cardozo, though writing to expand the range of legitimate common
law reasoning, would claim that "adherence to precedent must then be the rule rather than
the exception," and described a precedential system as one in which "the sordid controversies
of litigants are the stuff out of which great and shining truths will be shaped." *Benjamin

\(^6\) 579 S.W.2d 280 (Tex. App. 1979), writ ref'd n.r.e., 611 S.W.2d 610 (Tex. 1980).
two jurisdictions that do require lessees to share these payments have done so on the substantive principle proposed here, namely, that the lessee cannot take a separate benefit or advantage at the expense of its lessors. In a second problem area, the oil posted price cases unearthed the unsavory fact that oil companies for years underpaid their royalty owners as an ordinary business practice. The industry’s most-recognized names engaged in sham trades with each other to make the posted price appear legitimate, all while collecting a better price when they sold their own production in true, third-party sales. A series of pending gas price and cost cases concerning the marketing practices of gas buyers in the deregulated gas market are raising similar challenges to natural gas and natural gas liquids (NGL) prices and costs.

Part IV pulls this discussion together to show that a mutual benefit covenant satisfies the standard framework for implying an implied covenant’s extra-contract protection and will improve oilfield jurisprudence from several perspectives. Oil and gas law will be much clearer, and the legitimate rights of royalty owners much better protected, when courts finally acknowledge the mutual benefit covenant that they already extend, but too often sub silentio. Given the link between oil and gas law and the larger law of mining from which oil and gas principles spring, this clarification will benefit many other areas in natural resources law as well.

I. THE FIRST BAPTIST RULE: LESSEES CANNOT APPROPRIATE BENEFITS AT THE EXPENSE OF ROYALTY OWNERS

First Baptist is an unusual case, a sleeper whose significance was not obvious when it was decided. It is one of the most influential oil and gas cases, yet unlike most lead cases, the key opinion comes from an intermediate appellate court.

The dispute arose from leases Amoco pooled in Ward County, Texas. Amoco committed these leases to a very low-priced, long-term (20-
year) contract in 1969, only to see market prices rise. The 1969 gas purchase agreement paid only 17 cents per thousand cubic feet (mcf) for five years, and then increased the price haltingly by one cent every five years. In 1970, Amoco committed more leases to the contract. By 1975, however, when Amoco and its lessees were getting just 18 cents per mcf, the market price had climbed to over a dollar and was heading north to two dollars.\(^8\)

Ignoring the high and rising market, in June 1975 Amoco added the plaintiffs' leases to the underpriced gas sales contract. Amoco took this seemingly irrational step only because it received a payoff; the buyer agreed to raise the price for all gas under the 1969 contract to 70 cents per mcf, effective August 1, 1974, and promised to raise this price one cent a year, not just once every five years.

With this amendment, Amoco and its old lessors won a substantial increase in their gas price. That bounty, however, came at the expense of royalty owners in the new leases, who could have sold their gas for more than twice as much. And this was only the beginning of the last oil boom, so we now know that the loss was even greater. In essence, Amoco discounted the new royalty gas in order to improve its old, below-market gas contract.

Amoco's leases were "amount realized" leases, and the case was postured as a dispute over Amoco's duty to market under such leases. The standard lessee defense under amount-realized terms is that the lease is satisfied as long as the lessee pays royalty on whatever it gets. The lessors argued, in contrast, that Amoco had a duty to get them the best price possible, which it indisputably did not do. The trial court agreed and found that Amoco had breached its duty to market.\(^9\)

The court of appeals affirmed in a discussion whose structure somewhat obscured the future significance of the holding. This is partly because the court pigeonholed the legal issue under the heading "Marketing Duty." Thus the mutual-benefit covenant came dressed in a traditional implied covenant, the duty to market.\(^10\) In retrospect, though,

\(^8\) See First Baptist, 579 S.W.2d at 282.

\(^9\) See id. at 284. The court in this bench trial found no duty-to-market violation for the gas committed in 1970, presumably because Amoco had gotten the best price it could at that time, and this finding was not appealed. See id.

\(^10\) Further confusing the issue, the opinion began with a technical discussion of executive rights cases and the general question of implied contract rights. Id. at 284-85. This beside-the-point diversion into executive rights cases addressed why courts can imply rights in a contract at all. The court then spent several pages establishing that an implied covenant to market does indeed exist. Id. at 285-87. The decision's future impact probably also was clouded because the court had to deal with the appropriate measure of market value, an issue on which the court held that prices others paid for gas from the same wells were appropriate evidence of market value, see id. at 287, and with whether division orders can amend a lease's price terms; see id. at 288, the latter a then-contentious issue under Texas law.
readers easily can extract the principle for which First Baptist has become best known. The opinion cited Williams and Meyers for the proposition that "where the interests of the [lessor and lessee] diverge and the lessee lacks incentive to market gas, closer supervision of his business judgment will be necessary."1 Under such circumstances, "where the interests of the lessee and lessor do not coincide, the lessee must be held to a stricter standard."2 When it explained what Amoco actually did wrong, the court focused on Amoco's taking a separate benefit for itself. The 1975 increase in price for Amoco's gas under the old contract "was obviously a substantial benefit for Amoco and its royalty owners under the previously dedicated leases."3 That gain came, however, at plaintiffs' expense because they sacrificed a higher gas price: "But it also meant that as to twelve of the leases involved in this case, the royalty owners would receive a payment for gas which was approximately one-half of the amount soon to be paid by Lone Star and Delhi....This was not a substantial benefit to them...."4

First Baptist can be read as a duty to market case with bad facts. Its issue can be stated in a narrow, technical way: Does a lessee under an amount-realized lease satisfy its duty to get the best price possible as long as it pays its royalty owners exactly what it receives?5 Yet the case more frequently gets cited for the broader principle that a lessee cannot appropriate a benefit at the expense of its lessors.6 In the way in which the

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1. Id. at 286 (quoting 5 HOWARD WILLIAMS & CHARLES MEYERS, OIL AND GAS LAW, § 856.3 (1977 ed.); see Garman v. Conoco, 886 P.2d 652, 661 n.28 (Colo. 1994) (citing with approval First Baptist for standard of higher scrutiny when lessee owns processing plant).
2. First Baptist, 579 S.W.2d at 286 (emphasis added).
3. Id. at 287.
4. Id. One aspect of this holding is the principle the Texas Supreme Court later enunciated in Amoco v. Alexander, 622 S.W.2d 563, 569 (Tex. 1981), namely, that the lessee has a duty to each lessor, not just to its lessors as a group. See generally infra notes 79-87 and accompanying text.
5. First Baptist sometimes gets cited for this narrow point or for its division order issue, rather than its no-separate-benefit rule. See, e.g., Cabot Corp. v. Brown, 754 S.W.2d 104, 106-07 (Tex. 1987).
6. See, e.g., Frey v. Amoco Prod. Co., 943 F.2d 578, 585 (5th Cir. 1991) (summarizing First Baptist principle as follows: "lessee who compromises volume gas price for benefits that did not accrue to lessors is accountable to lessors," and then enforcing Louisiana rule that lessee must share take-or-pay settlement with royalty owners); Hurd Enters. v. Bruni, 828 S.W.2d 101, 108, 112 (Tex. App. 1992) (describing as operative fact of First Baptist that "Amoco obtained for itself extra benefits in respect to other properties in which the appellees had no interest," in a case largely ignoring that principle when it held that lessee did not have to share take-or-pay settlement); El Paso Nat. Gas v. American Petrofina, 733 S.W.2d 541, 550 (Tex. App.1986) (First Baptist's duty to market is "based on the assumption that the operator is marketing something that belongs to the royalty owners, and retaining some benefit for itself that should rightfully be included in the benefit obtained for the royalty owners..."; but the court held that the duty did not extend to requiring the operator to get a high enough price to keep wells profitable); cf. Condra v. Quinco Petroleum, Inc., 954 S.W.2d 68, 73, 76
steady stream of disputes can separate an earlier decision from the

Although it did not describe First Baptist as a separate-benefit case, the court relied on it in that way in the affiliate case of Parker v. TXO Production Corp., 716 S.W.2d 644, 646 (Tex. App. 1986); see also infra notes 70-71.

Some have questioned First Baptist's vitality since the withdrawn supreme court opinion in Texas Oil & Gas Corp. v. Hagen, 31 Tex. Sup. Ct. J. 140, No. C-3768, 1987 WL 47847 (Tex. Dec. 16, 1987), opinion withdrawn, 760 S.W.2d 960 (Tex. 1988). The Hagen court of appeals had cited First Baptist as imposing a duty of the highest good faith on facts where the lessee was selling production to its affiliate and paying royalties on a below-market price. See generally infra notes 49-56 and accompanying text. When the supreme court affirmed, but reversed the punitive damages part of the judgment, it tossed in a short sentence stating that a later opinion, Amoco v. Alexander, 622 S.W.2d 563 (Tex. 1981), was "dispositive" of the good-faith issue. Hagen, 1987 WL 47847 at *3 n.2. This language has been cited as meaning that the supreme court "disapproved" of First Baptist. See Hurd Enters. v. Bruni, 828 S.W.2d 101, 109 (Tex. App. 1992) (citing a footnote in the withdrawn Hagen, 1987 WL 47847 at *3 n.2.); see also Mark Cotham, Royalty and Related Pricing Mechanism Disputes: Learning the Three "E's," J-2 to J-3 (Aug. 6-7, 1998) (unpublished paper, on file with author) (asking if Hagen had any effect on First Baptist). But First Baptist only came up in Hagen in a discussion of whether the lessee owed a fiduciary or "highest good faith" duty, as opposed to a reasonable prudent operator duty. When the Hagen supreme court added its footnote that Amoco Production Co. v. Alexander was "dispositive" as the "latest pronouncement by this court on the question of the duty of lessees to their lessors," 1987 WL 47847 at *3 n.2, the court seems to have disapproved the suggestion that First Baptist might have raised the lessee's general duty to one of good faith and accordingly avoided the confusion over whether that duty was a "tort" good-faith duty. See id. The supreme court was not rejecting First Baptist's no-separate-benefits principle. Indeed, in the recent decision of Yzaguirre v. KCS Resources, Inc., 53 S.W.3d 368 (Tex. 2001), the Texas Supreme Court discussed with approval First Baptist as a rule that a lessee should not pay royalty based on a below-market rate under a proceeds royalty in bad faith. See id. at 373-74. It held that the duty to market would not apply to a market-value lease on the theory that the market imposed an objective measure of value, but cited First Baptist as holding that the duty to market should prevent self-dealing and negligence, id. at 373; and went to pains to point out that the royalty owners had not argued that the lessee chooses its off-premises sales in order to reduce the royalty payments, see id. at 373 n.3.

Though the traditional rule is that the lease relationship is not a fiduciary one, it may be if there is a basis for finding trust and confidence. For a recent case affirming a jury's finding of a "confidential" relationship but also seemingly putting the producer in a fiduciary relationship to the royalty owner, see Seeco v. Hales, 22 S.W.3d 157, 172-73 (Ark. 2000). Even the traditional rule may not be a foregone conclusion everywhere. See e.g. Roberts Ranch Co. v. Exxon, 43 F. Supp.2d 1252, 1263-66 (W.D. Okla. 1997) (surveying Oklahoma law and concluding that "the prevailing...view in Oklahoma is that an operator occupies a fiduciary relationship or position of trust with respect to the lesors to whom royalties are paid," though agreeing that this duty should be measured by the prudent operator standard and carries less than the "highest level of trust"); Goodall v. Trigg Drilling Co., 944 F.2d 292, 295-96 (Okla. 1997) (Summers, Vice Chief Justice, concurring) (concluding that Oklahoma "oil and gas cases spanning decades" had used fiduciary language for royalty owners, and urging the court to define the precise duty; urging a standard of quasi-fiduciary).
inconspicuous flow of legal disputes like an unwashed gem and extract a sparkling new principle, so the separate-benefit portion of First Baptist has become its enduring legacy.

II. MUTUAL SHARING OF LEASE BENEFITS IS KEY TO A VARIETY OF ROYALTY CASES

First Baptist does not stand alone for the principle that the lessee cannot manage the lease at the expense of the lessors. A line of Texas division order cases used such a rule to find that division orders cannot amend the lease if the change increases the lessee's share of the revenue stream. A series of affiliate cases stand for the same principle: lessees cannot erect affiliates to collect benefits not shared with the lessors. Other prominent cases like Amoco v. Alexander and Phillips v. Shutts represent the same principle that lessees must share all benefits they derive from the lease. And Louisiana, the one state to codify its royalty law, has put the mutual benefit principle at the heart of its Code.

A. The Division Order Cases Enforce an Unjust Enrichment Rule Against Profiting off Lessors

Although courts thus far have not acknowledged that there is another implied covenant, they routinely enforce the First Baptist principle. The division order cases are a prime example. Parties sign a division order to provide a clear record of the legal rights to a well’s proceeds. The division order confirms title, but it is not a contract in the ordinary sense; it is not represented, negotiated, or understood as a new, bargained-for deal.

Nonetheless, division orders often describe the price upon which payment will be made. Not infrequently, their pricing description differs from the lease. Lessees have not been shy about claiming that the division

17. 622 S.W.2d 563 (Tex. 1981).
19. The division order is to protect the purchaser from competing claims to the stream of oil or gas revenues. See First Baptist, 579 S.W.2d at 288 (citing EARL BROWN, THE LAW OF OIL & GAS LEASES §§16.02, at 16-86 (2d ed. 1973)); see generally Ernest Smith, Royalty Issues: Take-or-Pay Claims and Division Orders, 24 TULSA L.J. 509, 535 (1989). The buyer knows who to pay and is assured that it is not stepping into the middle of an ownership dispute.
20. As Louisiana defines a division order in its Mineral Code, for instance, a division order “is an instrument setting forth the proportional ownership in oil or gas, or the value thereof, which division order is prepared after examination of title and by the owners of the production...” LA. REV. STAT. ANN. § 31:138.1.A (West 2000).
order amends the lease and imposes more favorable pricing terms...for them.

From the beginning, even courts that let division orders modify leases acknowledged the transient and slightly disreputable nature of this power. They agreed that royalty owners could unilaterally revoke the change at any time by any objection. But courts ultimately have drawn the line on division orders' supplanting the lease when the change benefits the lessee at the lessor's expense. A division order cannot override the lease, or seemingly "amend" it, if doing so increases the lessee's share relative to the royalty share. In other words, the division order cases apply the principle this Article urges courts to recognize formally. A lease is for the parties' mutual benefit; the lessee cannot take a separate benefit at the lessors' expense.

Texas courts have most fully addressed the effect of division orders. First Baptist itself harbored a division order issue. The leases had provided royalty payments based on the "amount realized" by Amoco, while the division orders said that payment should be based on the "net proceeds at the wells." Assuming that this small verbal difference was legally significant, the court of appeals found that the order did not change Amoco's duties. The division order "was never intended to afford a lessee the opportunity to amend the lease, relieve himself of lease obligations, and secure advantages over the lessor which he could not have asserted under the provisions of the lease." The division order could not relieve Amoco of its duty to market, a duty it had breached.

In subsequent cases, the Texas Supreme Court slowly fleshed out the rule that division orders can amend the lease, but not if the lessee thereby extracts an added benefit or value from the lessor. Progress

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21. One sign of the slightly illegitimate status of the division order as a lease amendment is that the lessor can unilaterally revoke the amendment at any time by suing or otherwise giving notice that it does not accept changes in the division order. See infra note 31 and accompanying text. In contrast, merely filing suit would not revoke the lease itself or an ordinary contract.

22. First Baptist, 579 S.W.2d at 288.

23. In most pricing contexts, "amount realized" and "proceeds" leases dictate the same price, so it is not clear that the verbal difference really should matter in the First Baptist context.

24. First Baptist, 579 S.W.2d at 288 (citing BROWN, supra note 19) (emphasis in original).

25. Id. ("division order does not purport to relieve the lessee from its duty to exercise good faith in obtaining market value....").

26. The First Baptist court cited a much earlier court of appeals opinion, Le Cuno Oil Co. v. T.P. Smith, 306 S.W.2d 190 (Tex. App. 1957). Le Cuno does stand for the proposition that division orders using a price-received basis require good faith marketing, see id. at 192, but the parties apparently agreed that the division orders set the controlling price, id. at 194, so the question whether division orders could amend the lease terms was not presented.
through these cases, however, was slow and sporadic in the absence of a mutual benefit covenant. For example, the court carelessly stepped astray right after First Baptist. In Exxon v. Middleton, the court had to apply the Texas “Vela” rule that under a market value lease a lessee may have to pay its royalty owners more than it receives under its gas sales contract. The

27. 613 S.W.2d 240 (Tex. 1981). It is telling, given the general imbalance of wealth, experience, and power between royalty owners and the operating oil and gas companies that tend to acquire leases, that the Middleton plaintiffs had very large royalty interests. Their combined claims, just for the difference between what they had been paid and a truer market value, amounted to millions of dollars. In the irritatingly fact-averse manner of many appellate opinions and of judicial pretensions to focus on pure issues of law, the supreme court did not hint at how much was at stake, but the court of appeals listed the trial awards; for the plaintiffs as a whole, actual damages amounted to over two million dollars. See Exxon v. Middleton, 571 S.W.2d 349, 355 (Tex. App. 1978), rev’d in part, 613 S.W.2d 240 (Tex. 1981). This explains why they had the wealth to tee up one of the State’s major oil and gas lawfirms, Bracewell and Patterson, to fight Exxon’s Baker & Botts. This imbalance of power operates differently in the formal development of the law than in its day-to-day enforcement. For formal development, one hopes that the differences in wealth may be largely neutralized as long as some representative royalty owners have enough money to wage an aggressive legal battle over the proper standards for royalty law. Of course, if only a minority of royalty owners have these resources, industry companies have an incentive to settle with them and let only weak, underfunded royalty cases come to trial. By contrast, in the day-to-day enforcement of contracts, including the dissemination of misleading information that may prevent royalty owners from understanding differences between their legal entitlement and what they are paid, wealth may be more important because it may be possible to prevent most royalty owners from even seeing that they are being cheated. In this instance, only the class action device may be effective at balancing the two sides’ powers.

A third field of battle is the legislature. Here royalty owners in theory might prevail by their greater numbers and the fact that their battles often will be with out-of-state companies. But royalty owners traditionally have not been well organized, while large companies are and can hire the most expensive legal and lobbying expertise to represent them in Austin, Oklahoma City, Baton Rouge, Santa Fe, and the other energy state capitals. One economic theory about legislation is that smaller but more concentrated interests have the incentive to organize and dominate diffuse stakeholders, even if the latter have more at risk in aggregate. For lead articles, see George Stigler, The Theory of Economic Regulation, 2 BELL J. ECON. & MANAGEMENT SCI. 3 (1971); Gary Becker, A Theory of Competition Among Pressure Groups for Political Influence, 98 Q. J. ECON. 371 (1983); Sam Peltzman, Toward a More General Theory of Regulation, 19 J.L. & ECON. 211 (1976). There is an older tradition in political science that tends to the same conclusion, namely, that concentrated interests subject to regulation are likely to dominate their regulatory agencies. Cf. e.g., MURRAY EDELMAN, THE SYMBOLIC USES OF POLITICS 24 nn.1-5, 56 (Univ. of Illinois Press 1985) (1964) (citing five major post-War studies of administrative behavior that support an “instrumental” theory of agencies “as economic and political instruments of the parties they regulate and benefit....”).

28. For the underlying opinion, see Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968); for discussion, see infra notes 242-48.
lease seemed to require market pricing. Some lessors, however, had division orders with Exxon and Sun Oil Company that provided for payment on a proceeds basis and Exxon and Sun had paid the "proceeds" they actually received, though this was less than market value. The supreme court agreed with the trial court that while these division orders "did not amend the leases to provide for royalties payable on proceeds," Sun and Exxon nonetheless had a defense under the division orders, which the court treated as effective until the respective royalty owners revoked them by suing.

The Exxon v. Middleton opinion, coming just three months after the Texas Supreme Court affirmed First Baptist, might seem to contradict the mutual benefit rule. Even worse, the poor craftsmanship that left this appearance of conflict came in a unanimous opinion. But the cases can be reconciled because Exxon v. Middleton's facts were so different than First Baptist's. Neither Exxon nor Sun received any separate benefit from the royalty owners; all along they only received the same price on which they had paid royalties. It was only the odd Vela rule that might entitle the royalty owners to even more than the production earned for the lessee. Read in this light, Exxon v. Middleton did not pose a threat of separate benefits. Unfortunately, the Texas Supreme Court did not explain this difference.

Five years later, in Gavenda v. Strata Energy, Inc., the court made very clear that Exxon v. Middleton did not change First Baptist's mutual benefit rule. The Gavenda lessee, Strata Energy, erroneously paid its lessors a one-sixteenth royalty, when they were entitled to a full one-half, and kept at least part of the underpayment. The trial court and court of appeals had

29. The parties had a two-prong lease: if sales occurred at the well, Exxon could pay on a proceeds basis (a share of what it received), but if sales occurred "off the premises," the basis was market value (some measure of what willing buyers and sellers would accept as the going price). Middleton, 613 S.W.2d at 241-42. The royalty owners persuaded the court that the sales were off the premises and thus they should be paid market value. See id. at 241-43.

30. See id. at 249-51.

31. Id. at 250-52.

32. The interrelationship between Middleton and First Baptist is even more complex than these dates make it appear. The supreme court issued its first opinion in Middleton on October 1, 1980, before its First Baptist opinion. It issued its First Baptist affirmance on November 5, 1980. The final, binding Middleton opinion that made it into the books came out on February 4, 1981. The connection is even closer yet because the Court denied rehearing in First Baptist after its final Middleton opinion, on March 4, 1981, and then denied final rehearing in Middleton just one week later, on March 11th. The Court had to have these two cases in mind at the same time. Its failure to devote any intellectual rigor to the differences between First Baptist and Middleton, or even to acknowledge the simmering conflict between two opinions issued so close in time, is a sign of poor or hurried craftsmanship.

33. 705 S.W.2d 690 (Tex. 1986).

34. See id. at 691.
found that this was proper, applying Exxon v. Middleton as if all “division orders were binding until revoked.” They felt free to do so because the supreme court had not explained the significance of the fact that Exxon and Sun had not themselves received any special benefit. This time the supreme court distinguished Exxon v. Middleton and said what it should have said in that opinion: the overall purpose of the division order rule was protecting the lessee’s reliance on the division order when the lessees “have not personally benefited from the errors.” Exxon v. Middleton was different because “Exxon and Sun did not benefit from the discrepancy between the leases and the division orders. They paid out [one-eighth] of what they received from the purchaser—[one-eighth] of the contract proceeds.”

In Gavenda, in contrast, Strata Energy’s royalty error transferred a seven-sixteenths royalty from the lessors to the company. As a result, “it

35. Id. This misreading perhaps was not too surprising. Middleton seemed to stand for the principle that a division order could “amend” the lease until revoked. The trial court had denied that the division orders could “amend” the lease, see Middleton, 613 S.W.2d at 250, and it was affirmed in its treatment of the division orders, see id., but as a practical matter the effect of letting division orders set prices until revoked was the same as an amendment as long as the division order continued unchallenged.

For misleading language, see the supreme court’s statement that the Middleton division orders “were binding for the time the parties acted under them,” and its casual citation to another case which held that the orders are binding “whether called a contract or not.” Id. at 250 (citing Pan American Petroleum Corp. v. Long, 340 F.2d 211 (5th Cir. 1964)). This approach gives division orders contract status, even if only a temporary status that could be revoked unilaterally by the royalty owner. The Court inexplicably (and conspicuously) failed to cite its recent First Baptist opinion on division orders in Exxon v. Middleton.

36. Gavenda v. Strata Energy, Inc., 705 S.W.2d 690, 692 (Tex. 1986) (emphasis added). When the lessee did not personally benefit, it could be unfair to allow suit because if an error gave some other party too high a royalty, the lessee might have double liability—one in its initial payment to the overpaid royalty owner under the division order, once to the underpaid royalty owner who sued. See id. This supposedly would not be fair when purchasers and operators relied on the division order and “have not personally benefited”—again the mutual benefit principle. Id. Presumably the underpaid royalty owner would sue the overpaid royalty owner directly. See id.

The Court’s division of responsibility is a bit too glib. After all, in the Court’s hypothetical, it still would most likely be the operator who provided the information to determine the payouts and intentionally or negligently gave the wrong information. The operator certainly was more likely to have the resources to sue and correct any errors than any other party. The operator has a common-law duty to manage and administer the lease. If the operator relied on the incorrect division order, it almost certainly relied on its own mistake, either in preparing the order or in furnishing the information to do so. It is in the best position to correct this problem economically because the ordinary lessee is in the oil and gas business and well equipped with a professional staff.

37. 705 S.W.2d at 692.

38. Id.
profited...at the royalty owners expense." Strata was able to "[retain] for itself...part of the proceeds owed to the royalty owners."  

Gavenda highlighted the substantive principle upon which the division order cases turn: whether or not the operator appropriates a separate benefit for itself from its royalty owners. The rule that division orders "are binding until revoked does not apply when there is unjust enrichment...." A number of states have held more simply that a division

39. Id.
40. Id. at 693.
41. Id. at 691. The clarity of Gavenda dimmed temporarily with the following year's decision in Cabot Corp. v. Brown, 754 S.W.2d 104 (Tex. 1987). Cabot was a factually involved case in which the lease had market value pricing, but the division order described royalties as based on federally regulated prices "if such sale be subject to the jurisdiction of the Federal Power Commission...." Id. at 105, 107. Cabot began paying federal prices at a time when they were higher than the alternative, intrastate prices, so its pricing was "beneficial and profitable to [royalty owner] Brown." Id. at 107. By the time of the suit, however, Cabot had received an exemption allowing it to sell the majority of the gas at higher intrastate prices. See id. at 105-06. The federally regulated price the royalty owner received had grown from 38 cents per mcf in March 1977 to 80 cents in October 1980, but Cabot was receiving a $1.35 intrastate price for the gas. Id. at 106.

The result in Cabot seems to have depended upon the way the court characterized the conduct. The trial court and court of appeals understandably held Cabot to the lease's market value price. The lessor, Brown, argued that the division orders were unenforceable under First Baptist and Le Cuno, with their duty to market in good faith. See id. at 107. To pay the royalty owners 80 cents when Cabot could get $1.35 seemed an easy example of Gavenda's unjust enrichment. When the supreme court reversed, it ignored Gavenda, which the majority did not even cite. This studied avoidance of precedential conflict is reminiscent of the Court's failure to discuss First Baptist in Middleton.

The supreme court, though noting that the division orders did not relieve the lessee of its duty to market, held that the First Baptist opinion "did not preclude the modification of express or implied lease terms by subsequent division orders executed and binding upon the parties." Id. at 107. Because Cabot's initial royalty price under the long-term Transwestern contract was above intrastate prices when entered, the court found no question of bad faith. See id. ("there is no dispute with Cabot's conduct in entering the 1967 contract").

On the surface, the Supreme Court left First Baptist intact but simply did not apply it to Cabot. It was able to reach this result, however, only by shutting its eyes to what was really going on in Cabot. It is telling that the majority never cited Gavenda, which the Court had decided just a year before. The opinion seems designed to disguise the separate benefit that Cabot collected and did not share with its royalty owners. Rather than just sell the gas, Cabot had entered an exchange agreement with an interstate pipeline, Transwestern Pipeline Company. Thus Cabot felt that the highest market value could be achieved through an exchange and putting the exchange gas to its optimal use. This did not produce a seeming difference between its benefit and the royalty owners' in the early years of the contract because Cabot used its exchange gas in a plant at Skelly Town, Texas. See id. at 105. When the plant closed, however, Cabot re-routed the gas into a gas stream it sold at the higher intrastate price. Id. at 105-06. Cabot applied for and received an exemption from federal jurisdiction that let it get this higher price. Id. at 106. Thus it was trading gas exchanged for gas from the royalty owners' well at the much higher price than it paid them. Cabot collected that higher
order cannot amend a lease (even before being revoked)).

In 1996, the Texas Supreme Court again confirmed the division order rule against unjust enrichment in *Heritage Resources, Inc. v. Nations Bank*. This time the dispute was over the deductibility of post-production costs. The supreme court had reversed the courts below and held that the deductions were proper. But the court repeated the underlying *Gavenda* rule that an operator cannot use division orders to improperly allocate royalty payments and keep the benefits. The operator is liable for any

price on all gas, including volumes that should have been allocated to the royalty owners' share.

In dissent, Justice Kilgarlin, who cited *Gavenda* right away, argued that he "can envision no case that would depict as well the inequity of the result reached by the court today." *Id.* at 108, 111 (Kilgarlin, J., dissenting). "Cabot reaped the benefit of FPC jurisdiction over the exchange with Transwestern, paying out royalties based on the lower interstate market rate. Yet Cabot sold the gas on the higher intrastate market." *Id.* at 111. Justice Kilgarlin surely was right that under *Gavenda*, when Cabot was able to "market" gas via the exchange at a higher intrastate price, it had a duty to market its royalty owners' gas in the same way. When it did not, it did not get the best price possible for the royalty owners.

42. Kansas courts rejected lessee efforts to hide behind their division orders, to in essence slip a mickey to the royalty owners via this pro forma title confirmation, in the interest-suspense royalty cases. The lead suspense-royalty case on division orders was *Maddox v. Gulf Oil Corp.*, 567 P.2d 1326 (Kan. 1977), in which the Kansas Supreme Court turned down Gulf's "unilateral" effort to deprive the royalty owners of interest on suspended funds. The division orders were "procured primarily to protect the purchaser in the matter of payment for the oil or gas" and were without consideration as far as amendments to the lease. *See id.* at 1327; *accord* Phillips Petroleum Co. *v. Shutts*, 567 P.2d 1292, 1303 (Kan. 1977) (reciting the trial court's refusal to let division order, which it called an instrument to reflect interests in proceeds from production, modify the lease) (subsequent history omitted); Holmes *v. Kewanee Oil Co.*, 664 P.2d 1335, 1341 (Kan. 1983) (following *Maddox*).

The Oklahoma Supreme Court cited *Gavenda* with approval, as well as *Maddox* and other cases, holding that the division order cannot "alter lease provisions," in *Hull v. Sun Refining and Marketing Co.*, 789 P.2d 1272, 1279 & nn.18-20 (Okla. 1990) (following *Maddox*).

Louisiana has reached the same outcome by statute. See *La. Rev. Stat. Ann.* § 31:138.1.B (West 2000) ("A division order may not alter or amend the terms of the oil and gas lease. A division order that varies the terms of the oil and gas lease is invalid to the extent of the variance...."). Texas now treats the issue statutorily, too. *Tex. Nat. Res. Code. Ann.* §§ 91.402(c)(2)-91.402(d) (1991 statute providing that "division order does not amend any lease or operating agreement" and including form division order with capitalized warning "THIS AGREEMENT DOES NOT AMEND ANY LEASE OR OPERATING AGREEMENT....") (Vernon 1993 & Supp. 2000). This language should be clear enough to surmount any misreadings, be they innocent or mischievous, that might arise from the statute's provision that the division order is binding "for the time and to the extent that they have been acted on and made the basis of settlements" until revoked, *see id.* § 91.402(g), and can "clarify royalty settlement terms...." *id.* § 91.402(i).

43. 939 S.W.2d 118 (Tex. 1996).

44. *See id.* at 123 (division order binding until revoked, but not if it "allocates payments among the interest owners in a manner that differs from the lease provisions and the operator retains the benefits").
improper withholding that it retains. Following this principle, operator Heritage was responsible only for the unpaid royalties (royalties underpaid because of excessive deductions) that it actually retained. If the lessee takes a separate benefit at the expense of its lessor, it is prohibited from doing so and no language in the division order will protect it. This is the law of unjust enrichment, translated into implied oil and gas protection, even if the Texas Supreme Court did not formally describe it as a distinct implied covenant. The supreme court reiterated in Heritage Resources that "the basis of this rule is unjust enrichment.”

B. The Affiliate Cases Embody the Same Rule that Lessees Cannot Treat Royalty Interests as Profit Centers

The affiliate cases are another set of cases holding that the lessee is not to appropriate any part of the lease value from the royalty share. It must distribute all benefits it pulls from the lease proportionately. Because of the overlap between express lease terms and the duty to market, as well as the implied covenant's strong dictate that the lessee must get the best price possible for its royalty owners, affiliate disputes often come up as duty-to-market cases. But the marketing covenant frequently is not necessary to their disposition. The lessors generally are not arguing that the operator failed to get the "best" price in an absolute sense. Nor should the cases usually need evidence of prices in unrelated, third-party sales, the kind of evidence common in a market value case. Instead, the governing problem in most affiliate cases is that a lessee has a separate profit-making arrangement that it is not sharing. Courts will not let lessees use company-

45. See id.
46. See id. at 123-24.
47. Id. at 123 (citing Gavenda, 705 S.W.2d at 692). There can be haggling over when there is a separate benefit, and even mischaracterization (or plain error) on that issue, as Cabot shows, but the core principle should not be diminished.
48. For market value tests, see Exxon v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981) (market value is "the price property would bring when it is offered for sale by one who desires, but is not obligated to sell, and is bought by one who is under no necessity of buying it....Market value may be calculated by using comparable sales. Comparable sales of gas are those comparable in time, quality, quantity, and availability of marketing outlets." (citing Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968)); see generally Heritage Res., Inc. v. Nationsbank, 939 S.W.2d 118, 122 (1996); Middleton, 613 S.W.2d at 245-49. Not that long ago, the Texas Supreme Court called nearby comparable sales—those comparable in "availability of marketing outlets" as well as "time, quality, quantity"—the "most desirable method," Heritage Resources, 939 S.W.2d at 122, but the market-value test is not really this mechanical. It is a factual test that should be reasonably applied and, as gas marketing shifts beyond the wellhead, the test should shift with it, too. In Middleton, for instance, the plaintiff's expert considered gas prices in over 30,000 reports covering three railroad districts, "in effect...the entire Texas Gulf Coast." 613 S.W.2d at 245 & n.3.
provided services to shrink the royalty share of production or to exclude lessors from values they realized from the lease.

Perhaps the single most influential affiliate price case is, ironically, one in which the highest court ultimately withdrew its opinion (because the parties settled). Texas Oil & Gas Corp. v. Hagen\(^49\) was a Texas royalty class action involving three units operated by Texas Oil and Gas Corporation (TXO). TXO sold its production to a wholly owned subsidiary, Delhi Pipeline Company. TXO delivered the gas to Delhi on the lease; Delhi dehydrated it and sent it seven and a half miles to remove hydrogen sulfide and carbon dioxide, another 50 miles where Delhi sold half the gas to an electric company, and a final 50 miles before selling the remainder to International Paper Company at one of its plants. Delhi earned an extra fifteen cents per mcf when it sold the gas. In addition, TXO did not pay royalties on the sulfur.\(^50\) The leases were “two-prong” leases with amount-realized pricing for gas sold at the well, a market price for off-premises sales.\(^51\)

In a non-jury trial, the judge found that TXO’s sales to Delhi were a “sham” and “that TXO used that arrangement and its relationship with its wholly owned subsidiary to create an unfair device to deprive plaintiffs of their rightful royalties.”\(^52\) The evidence persuaded the judge that TXO and Delhi were alter egos, making it appropriate to treat the two companies as one and define the true sale as the later, higher-priced sales off the premises.\(^53\) The court of appeals did not use duty-to-market language, so


\(^50\) See id. at 27.

\(^51\) See id. at 27 n.1.

\(^52\) Id. at 28.

\(^53\) Hagen technically leaves open the possibility that an independently run affiliate might be entitled to collect reasonable fees, including market-level profits for those services. Under the separate benefit principal, however, extra profits would violate the joint nature of the lease. The royalty owners were entitled to the market value that TXO, acting through Delhi, received, minus the reasonable cost of the transportation and processing, as well as their share of the sulfur. See id. at 28-29. For a holding under Louisiana law that a lessee can only deduct actual, reasonable processing costs, not the market value of those costs or costs plus profit, see Babin v. First Energy Corp., 693 So. 2d 813, 815-16 (La. Ct. App. 1997); see also Harding v. Cameron, 220 F. Supp. 466, 468-71 (W.D. Okla. 1963) (ordering lessee that paid royalty on gas at substantially less than price it received in nonaffiliate case to account on basis of higher price, minus actual compression cost; when “defendant acted in a dual capacity, as both buyer and seller [the problem in affiliate cases]...[it] should not be permitted to so deal and thus make a profit...”).

For a discussion of the Hagen standard and some of the questions about the affiliate issue, see John Lowe, Developments in Nonregulatory Oil and Gas Law, 27 INST. ON OIL & GAS L
it did not rely expressly on the "best price" and diligence standards of that implied covenant. Presumably because the mutual benefit principle has not been fully articulated as a separate principle, however, the court did consider other sales in the vicinity—typical market value evidence—even though this would not be necessary to a mutual benefit holding, nor relevant to TXO's failure to pay at all for the sulfur it removed from the gas.\(^5^5\) The Supreme Court had published an opinion affirming this part of the court of appeal's decision when the case settled.\(^5^6\)

The mutual benefit principle has been strongly acknowledged in other affiliate cases.\(^5^7\) The Oklahoma Supreme Court endorsed the principle

\(^{54}\) See Hagen, 683 S.W.2d at 29.

\(^{55}\) Hagen quickly became notorious because of the trial judge and court of appeals' other holding that TXO had violated a duty of "highest good faith" and that breach of this confidential relationship entitled the class to punitive damages, which the judge set at $300,000, a little less than a third of the actual damages. See id. at 27, 29-30. The Supreme Court was ready to overrule this part of the opinion when the case settled. See Hagen, 1987 W.L. 47847, at 6.

The court of appeals also overruled TXO's claims that the division orders somehow prevented the plaintiffs from recovering added royalties; the division orders merely provided that the price would be set by the leases. See Hagen, 683 S.W.2d at 30.

\(^{56}\) See Hagen, 1987 W.L. 47847, at 3. Instead of discussing why TXO could not lift extra profit from the royalty, the Court simply held that the evidence supported a finding that a reasonably prudent operator would have paid more than TXO paid its royalty owner. See id.

\(^{57}\) In addition to Hagen and Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981), discussed next in the text, see Wegman v. Central Transmission, Inc., 499 So. 2d 436, 439, 441, 443, 448 (La. Ct. App. 1987) (affirming jury verdict awarding higher contract price where defendant assigned leases to limited partnerships that bought royalty gas at a low price, then resold for a profit, rejecting effort to limit lessee's duty to "first sale" where that sale occurred in bad faith, and rejecting claim that defendant's price on resale was "merely a transportation charge" where its rate for a $30,000 pipeline was more than the charge for a major, million-dollar pipeline in same area.).

In Craig v. Champlin Petroleum Co., the trial court found that the lessee, Champlin Petroleum Company, breached its duty to find a market for the royalty owners' gas (the court not indicating what the lease terms were or whether this duty arose from the express price terms or from an implied covenant) when it sold the gas to a plant in which it held a 51 percent interest instead of selling to a nearby plant that offered a higher price. 435 F.2d 933, 935-36 (10th Cir. 1971). Though the Tenth Circuit agreed that the fact that the lessee "was to a large extent dealing with itself requires us to examine carefully the fairness of the contract," there was no evidence that the nearby plant ever could have taken the gas and other nearby plants were paying the same price the royalty owners received, so the court of appeals reversed. See id. at 936-39. In essence, it did not believe that the evidence showed any other available market. See id. at 936 ("Before a market can be said to exist, there must be a available buyer for the product.").

There is an interesting possibility that even the market-value long-term contract cases that fall under the heading of the Vela cases may have begun their long journey because of the separate benefit problem. In the court of appeal's decision in Exxon v. Middleton, Chief Justice Curtiss Brown claimed that "it appears" that in Vela, TXO sold gas to a wholly owned
in *Tara Petroleum Corp. v. Hughey.* The *Tara* royalty owners complained that after their lessee signed its gas sales contract, a related company resold the gas to El Paso Natural Gas for a much higher price. *Tara* is an affiliate case because the royalty owners claimed that the lessee and the first buyer were controlled by the same men and argued that the royalty interest should benefit from the higher price received by this "middleman" first purchaser. The court rejected this claim because the allegations of subsidiary, which of course would have been free to resell at a higher price. See 571 S.W.2d 349, 358 (Tex. App. 1978), aff'd, rev'd in part on other grounds, 613 S.W.2d 240 (Tex. 1981). Apparently TXO's subsidiary would not even reveal the "ultimate proceeds" it got for Vela's gas. See id. Justice Brown found this fact "significant...in light of the obvious injustice of allowing payment of royalties based upon a low price and the subsequent receipt by the affiliate of a higher price upon the resale of the gas." See id.

*Exxon v. Middleton* itself had the same potential for self-dealing. Exxon processed the lease gas at its own plant and then sold some of it to "the Exxon Gas System," Exxon's intrastate marketing system. See id. at 355-56. The court of appeals approved an expert's exclusion of those affiliate sales from his market value calculations. There was no sign these were arms-length sales and "[i]t would be manifestly unjust for a lessee to sell gas to a subsidiary or to an affiliated firm, person or corporation for a low price and allow that company to extract a larger price in the resale of such product." Id. at 358. The Supreme Court did not discuss the affiliate issue; it approved the expert's exclusion of Exxon's field price on the different ground that interstate sales under then-existing price regulations were "not comparable in quality," but instead were "conceptually and legally different" from the market for this intrastate gas. See *Middleton,* 613 S.W.2d at 248.

58. 630 P.2d 1269 (Okla. 1981). The *Tara Petroleum* opinion is better known for Oklahoma's rejecting the Texas *Vela* rule and deciding instead that a long-term contract price can satisfy "market value" leases if the lessee entered the contract in good faith and secured the "best price and term available to the producer at the time." Id. at 1273. All this occurred without a suggestion that the lessee had not acted in good faith. Had the lessee been required to pay royalties using market prices, its royalty burden would have quadrupled in a year and amounted to half of its revenues. See id. *Tara* is a poster child for the unfairness of the contrary *Vela* rule. It shows how the rule can let royalty owners get a separate benefit not earned by their production and can put them in proportionately a much better position than the lessee.

59. See id. at 1271, 1275. For the years in dispute, the contract had the low price of 32 cents per mcf the first year and 33 cents the second. See id. at 1271. Apparently there was no evidence to suggest that the lessee could have received a better price when it entered the contract. It may be hard to believe the lessee could not have secured a better price, given how rapidly the El Paso contract price surged beyond Tara's contract price. El Paso's price was roughly four times the middleman contract within two years. See id. at 1271. This difference apparently occurred, however, only because the FPC substantially raised the regulated, interstate price that applied to the El Paso contract. See id. Thus the lawsuit in essence faulted Tara for not foreseeing that a federal agency would sharply increase interstate gas prices. This issue is not well developed in the opinion, but presumably there was no evidence that a reasonable lessee acting in good faith would or should have foreseen this regulatory development.

60. See id. at 1275.
common control were not supported. But its dictum perfectly captures the no-separate-benefit ban that applies to lessee affiliates:

Courts should take care not to allow lessors to be deprived or defrauded of their royalties by their lessees entering into delusory or collusive assignments or gas purchase contracts. Whenever a lessee or assignee is paying royalty on one price, but on resale a related entity is obtaining a higher price, the lessors are entitled to their royalty share of the higher price.

61. See id.
62. Id. at 1275. Another way to describe the duty is that the responsibility to negotiate the sales contract at arm's length "becomes an explicit duty" when affiliate contracts are at stake. See Roger Williams, Lessee Duties and Lessor Rights in Gas Contracting Under the Implied Marketing Covenant of Oil, Gas, and Mineral Leases, 26 TULSA L.J. 547, 556 (1991). Lessee dealings with related companies "[warrant] stricter scrutiny of marketing activities." Id. at 569.

Another very influential Oklahoma case that supports a strong stand against operator profiteering, albeit under somewhat different reasoning, is Young v. West Edmond Hunton Lime Unit, 275 P.2d 304 (Okla. 1954). The Young lawsuit was brought by unit royalty owners against an operator who was paying $2.65 per barrel of oil in an area where the posted price was $3.00. See id. at 307. Presumably the operator resold at the higher price. The court held that the operator had to pay royalty owners the higher price. Its basis for the decision, however, was that the unit operator is a trustee to those with either working or royalty interests in the unit and cannot profit on this trust. See id. at 309-10.

Because part of the decision was based on the lessors' losing their right to sell their production because of the unitization, see id. at 308, Young can be read as standing for a separate involuntary unitization principle. This is a somewhat careless reading, however, because Young's unit agreement seems to have left the lessors with the right to keep taking their production in kind, and so to sell it, exactly contrary to the court's suggestion. See id. at 309 (the unit "plan," the contractual agreement implementing the unit statute's dictates, letting at least some interest owners take their production in kind; part of it began, "[t]o the extent that any person entitled to take and receive in kind any portion of the Unit Production..." (emphasis added)). Given the court's announcement that Young should apply to working interest and royalty owners alike, a unit-based loss of control cannot have been a sufficient basis for its decision, even if royalty owners did not have a right to take-in-kind.

For the general proposition, the Oklahoma Supreme Court was very clear in its endorsement of the principle that an operator cannot profit if it chooses to be both buyer and seller, the classic affiliate situation. The court cited Magruder v. Drury, 235 U.S. 106, 120 (1914), for the proposition that a trustee "is not allowed to unite the two opposite characters of buyer and seller...because his interests, when he is the seller or buyer on his own account, are directly conflicting with those of the person on whose account he buys or sells." Young, 275 P.2d at 309; accord Beadle v. Daniels, 362 P.2d 128, 130 (Wyo. 1961) (citing Young for principle that fiduciary cannot unite opposite characters of buyer and seller). In the oilfield, the lessee is allowed to be buyer and seller if this is the best way to market its and its royalty owners production; but, as Young dictates, it cannot use that controlling position to profit from their share of the revenue stream.

In Hillard v. Stephens, 637 S.W.2d 581, 585 (Ark. 1982), the Arkansas Supreme Court adopted Tara's reasoning and held that a good-faith long-term contract that lessee Stephens Production Company had entered with Arkla set the market value, when there was no sign that the contract was not "fair and representative of other contracts negotiated at the time in
A class action affiliate case, *Altheide v. Meridian*, involved a national class action suing Meridian Oil Company on pricing and cost issues. A Texas state court certified a class of all royalty owners whose properties were "dependent upon sales of gas by the producing affiliates" of Meridian at any time from January 1985 forward. The class alleged that Meridian resold gas from its wells to a trading affiliate, Meridian Oil Trading, Inc. (MOTI), at a price based on regional price indices, but that MOTI routinely re-sold the same gas at a profit. The core dispute focused on this problem.

*Meridian* is another example of what really is at stake in many affiliate cases. The class did not need to canvas the surrounding area to see if Meridian could have found even higher prices than the ones MOTI received. It was content to say that the class deserved the price Meridian got using its best efforts in truly independent sales—via the sales Meridian made through MOTI. The class was not second-guessing the reasoned business judgment of the Meridian family of companies on gas marketing.

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63. *Id.* at ¶ 39.

64. *Id.* at ¶ 18, 28-29. The class argued that Meridian used "broad geographic 'pricing pools,' and sets the same price for each lease and each well within each pool." *See Plaintiffs' Reply to Defendant's Opposition to Class Certification at 19, Altheide v. Meridian Oil, Inc., (No. 92-026182) (113rd Dist. Ct. Harris County, Texas, filed Nov. 22, 1994).*

65. *In their effort to certify a class, plaintiffs stressed the fact that regardless of the lease terms, Meridian had promised to pay royalties "on the same terms and conditions under which its gas is sold or disposed of" and under the "same terms and conditions it is currently marketing its own gas." Plaintiffs' Motion for Class Certification at 17-21, Altheide v. Meridian Oil, Inc., (No. 92-026182) (113rd Dist. Ct. Harris County, Texas, filed Sept. 23, 1994).*

Thus, the case also had an underlying current of fraud. In addition, the class alleged that Meridian was deducting transportation costs greater than its actual costs and paying less for liquids than it received. *See Plaintiffs' Second Amended Petition, supra note 63, at §§ 29, 31.*
What it was saying, instead, was that Meridian had to share the value its work generated. After all, that was why landowners leased property to Meridian.

Large interstate pipelines have been shifting gas marketing to subsidiaries because the Federal Energy Regulatory Commission (FERC) "unbundled" their "merchant function" from their traditional role as gas transporters. Deregulation led interstate pipelines, traditionally the major natural gas buyers in the United States, to create separate corporate entities for each distinct service (gathering, processing, etc.). As pipelines did so, many tried to move their profit-taking "downstream" from the well and then claim that any profit made after an affiliate resold the gas was just a return to the independent risk and activity of the trading affiliate. They used this corporate reconstitution to segregate profits they did not want to

67. The author has discussed some ramifications of these changes in John Burritt McArthur, Antitrust in the [De]Regulated Natural Gas Industry, 18 ENERGY L.J. 1 (1997).
68. A Texas state court not long ago certified a Texas-wide class against the largest gas producer in Texas, UPRC, where this issue appeared. The class said that UPRC breached its duty to market by paying royalty owners on index prices that systematically understated market value pursuant to a policy to move its "value chain" downstream and reap profits on affiliate sales. See generally Plaintiffs' Third Amended Petition, Neinast v. Union Pacific Resources, Inc., (No. 32,040) (31st Judicial District, Washington County, Texas, filed Sept. 20, 1999). The gas market has become much more complex because gas is often sold at a price set at its final destination, minus intervening transportation charges, so that the price "at the well" has to be "netbacked" by subtracting those charges. If the royalty owner is entitled only to the price at the well, lessees will try to claim that all of the difference between the final price and a wellhead price is a return to downstream services. Interstate pipelines that restructure their gas trading through an affiliate will claim that most of their profit is earned between the well and the final market. Yet the profit is profit on the gas and the gas in a netback contract may be delivered to the buyer at or near the wellhead.

Pipelines will say that value-adding aggregation occurs between the wellhead sale and the delivery to the LDC customer. They may claim that their new trading affiliates are providing a service formerly submerged in their old role as transporters, not as producers. In their eyes, their trading profits may appear unrelated to their job as lessees, but integral to their former role as pipelines, an unbundled and supposedly competitive activity to which, they will say, the returns should be entirely theirs. For a thoughtful observer with no pipeline affiliation who seems to suggest that there should be compensation for the actual cost of services like marketing, see COTHAM, supra note 16, at J-8; see also Owen L. Andersen, Calculating Royalty: "Costs" Subsequent to Production—"Figures Don't Lie, But...," 33 WASHBURN L.J. 591 (1994) (reviewing cases and proposing that lessee should be allowed to deduct actual, reasonable post-production costs, but not profit). For an article questioning how far lessors should share benefits downstream from the wellhead and deciding not much after analyzing such factors as returns to lessees' "entrepreneurial" effort (including in marketing and processing), see David Pierce, Incorporating a Century of Oil and Gas Jurisprudence into the "Modern" Oil and Gas Lease, 33 WASHBURN L.J. 786, 795-99 (1994); for another argument that lessors should not share the benefits of such activity, see John S. Lowe, Defining the Royalty Obligation, 49 SMU L. REV. 223, 259-64 (1996) (arguing that post-production profits should be treated as returns to lessees' downstream entrepreneurial activity).
share with royalty owners.

Yet part of the lessee's promise is that it will make its expertise available to the royalty owners. The obligation to share fully should not be lessened if the lessee's efforts can produce a better than average return. If the lessee is a large, experienced marketer, its expertise will be precisely why landowners want to sign up with it. It cannot avoid this obligation just by donning a new set of corporate colors.

Another set of cases that often raised affiliate claims are the oil posted price cases. There again, a class of royalty owners (as well as working interest owners) sued because many of the largest integrated oil companies paid royalties using a price that understated market prices. When these companies finally sold their oil in arm's-length, third-party sales, they received a higher price. They routed many of these sales through affiliates. The trades could be more complex and difficult to unravel because the companies traded oil to each other at posted prices, thus fabricating the appearance of objective, market-based prices. But the companies had comprehensive balancing agreements so that ultimately these trades had no economic effect. They were wash transactions.

The lessee does have to get a separate benefit to violate this duty. In a case involving TXO and Delhi decided just two years after TXO v. Hagen, the court of appeals found no breach of the duty to market. TXO sold gas to its affiliate Delhi and paid royalties at a price below that paid by other companies in the area because TXO deducted five percent for compression. The plaintiffs apparently could not rebut TXO's claim that it did not consider Delhi's profit or loss in entering the gas sale contract, but just whether compression would let the gas flow quickly to market. Unlike TXO v. Hagen, here the facts did not suggest that TXO and its affiliate were pocketing the difference between the royalty price and a higher resale price. There was no suggestion, for instance, that the deduction was more than actual compression costs or that TXO did not bear the same charges on its gas.

69. For an earlier, contrary posted price decision, see Garfield v. True Oil Co., 667 F.2d 942, 945-46 (10th Cir. 1982), discussed in infra note 204; see also generally infra part III.B.

70. See Parker v. TXO Prod. Corp., 716 S.W.2d 644, 645-46, 648 (Tex. App. 1986). The court noted that other pipelines were paying the maximum lawful rate, without deductions, so others were paying 100 percent of that price, while TXO's royalty owners only got 95 percent. See id. at 646.

71. The court believed evidence showing that TXO had installed compression to get the gas connected quickly and to avoid drainage, that it sold its gas to subsidiary Delhi because of Delhi's ability to move large volumes, that other sellers had been accepting terms like these at the same time, and that the compression might increase production. See id. at 647.

72. Although it is not developed in Hagen, presumably TXO could have argued that it was entitled to deduct the cost of transportation under the market value lease. This contention would have been resolved under the separate body of Texas law addressing the costs
Confirmation for the rule against affiliate-profiteering comes by analogy from working interest cases. Working interest owners often are more sophisticated than royalty owners and may have a larger share of production, but they too depend on the operator's management, including its care in marketing.

Working interest owners generally have a more detailed contract than royalty owners, but no implied covenants. The standard for marketing production traditionally was about the same, however, because the Joint Operating Agreement (JOA) applying to most joint oilfield investments had a "best price" term that was tantamount to the duty-to-market's "best price possible." A few courts even have found that the operator's gas sales under the JOA create a fiduciary "special agency" to the working interest owners.

In theory, it should not change the principle of recovery whether the lessee receives a separate benefit by not paying royalties at all, or not paying in a timely manner. But not all courts have seen it that way. In Coosewoon v. Meridian Oil Co., royalty owners on Indian land sued to cancel their lease because the Mineral Management Services failed to secure timely royalty payments. Their claims were rejected because, among other things, they failed to exhaust administrative remedies and there was a comprehensive federal scheme to protect Indian interests. See 25 F.3d 920, 924-29 (10th Cir. 1994). Although the opinion flowed from the court's sense that the plaintiffs already had adequate means of redress, the court did reject a breach of fiduciary duty claim against Meridian brought on the Young unit-trust theory because, it opined, a failure to pay in a timely manner was not "evidence of a failure to market." Id. at 931. Given the economic reality that the lost time value of money can be as true an economic loss as an unpaid royalty, this conclusion makes very little sense. It honors form with no regard to substance.

A majority of joint oilfield investments are covered by the American Association of Petroleum Landmen's Joint Operating Agreement (JOA). The pre-1989 JOA provided that if a non-operator did not take its production in kind, the operator could sell the oil or gas but had to do so at the "best price obtainable in the area of such production." 1977 JOA, Article VI, § C. (The nonoperator is the owner of the working interest "without operating rights by reason of an operating agreement." WILLIAMS & MEYERS, supra note 1, at 787). It should not matter whether the operator used an affiliate to get this price. A 1989 amendment somewhat moderated this language to require sales "in the manner commercially reasonable under the circumstances." 1989 JOA, art. VI, § G.

Courts have been eroding traditional JOA marketing duties by stepped-up enforcement of the JOA's disclaimer and exculpatory clauses. See generally infra note 270. In jurisdictions where these clauses are turning into near immunity for operators, working interest owners' protection has severely diminished.

Atlantic Richfield Co. v. Long Trusts, 860 S.W.2d 439, 444-45 (Tex. App. 1993). The Long Trusts court relied on another working interest case, Johnston v. American Cometra, Inc., 837 S.W.2d 711 (Tex. App. 1992), and an article by Ernest E. Smith, Gas Marketing by Co-Owners: Disproportionate Sales, Gas Imbalances and Lessor's Claims to Royalty, 39 BAYLOR L. REV. 365 (1987), both of which support a special agency in the operator's marketing. In Johnston v. American Cometra, the court of appeals reversed summary judgment dismissing interest owners' claims that the operator had failed to enforce a take-or-pay contract under which
Though most royalty affiliate cases have been about prices, the mutual benefit rule applies to costs, too. The paucity of royalty cost litigation presumably reflects the fact that the royalty interest does not bear the costs of production. When royalty owners do raise a cost issue, it has been more often about that magic point where "production" ends and whether the lessee can deduct certain allegedly post-production costs,\textsuperscript{75} not about the measure of those costs or whether the operating company is padding them.

Nonetheless, the principle that bars a lessee from making extra profits by shaving the royalty owner's price should just as surely prevent their gas had been dedicated; the operator had a fiduciary duty "if [it] acted as agent of the non-operators in entering into the gas purchase contract," an issue on which fact issues existed. 837 S.W.2d at 716.

Under the special agency, an operator could not sell gas to its wholly-owned pipeline that resold the same gas for as much as double that price, but not cut the interest owners in on the deal.\textit{See Long Trusts,} 860 S.W.2d at 444-45. The operator had to account for the gas, avoid conflicts of interest, and not act "as an adverse party."\textit{See id.} at 445. It failed this test when it made as much as a million dollars by reselling the gas through its pipeline.\textit{See id.}

Somewhat peculiarly, the \textit{Long Trusts} headnote described the case as one between the operator and royalty owners.\textit{ See id.} at 439. But \textit{Long Trusts} is a working interest case. The court relied on the specific language in the JOA governing interest owners, and it even expressly stated that "the present case does not concern royalty owners...."\textit{ Id.} at 445. Moreover, the court noted that it would not extend the marketing agency to royalty owners because they have no gas to sell; a lease transfers title for all gas to the lessee.\textit{ See id.} at 444-45. In fact, the royalty still flows out of a measurable share of the total gas produced, and the duty to market itself indicates that the lessee operator has a similar, if not always technically fiduciary, responsibility via the duty to market to the royalty owners.

The affiliate issue was not the "primary" issue in \textit{Long Trusts}. This case was more focused on whether an operator and its affiliate can amend their contract to insert a lower price in settlement of take-or-pay claims. The court held for Arco because, in large part, the interest owners' gas was not committed to those contracts. They could have resold their gas under higher, long-term contracts had one become available—unlike royalty owners, whose gas is committed and disposed of by the lessee.\textit{ See id.} at 443-44.

One later court tried to limit \textit{Long Trusts} by holding that the agency does not arise if the nonoperators do not dedicate their reserves to the operator's contract. See Holloway v. Arco, 970 S.W.2d 641, 643 (Tex. App. 1998). Because the gas was not dedicated, Arco only had a duty to "account for the monies received for selling his gas, to avoid conflicts of interest, and not to act as an adverse party in its capacity as the seller of this gas."\textit{ See id.} (citation omitted). This emphasis on formal dedication is unrealistic when operators so routinely sell royalty and working interest production without asking the owners whether it should be dedicated to the purchaser.

There is a catch on the agency duty to market for working interest owners that has yet to be fleshed out in the caselaw; the duty would have to elude the disclaimers that courts increasingly apply to the overall operator's duty,\textit{ see infra} note 270 and accompanying text.

\textsuperscript{75} For two recent summaries of cost deduction issues and the caselaw on post-production costs, see \textit{COTHAM, supra} note 16, at J-18 to J-24; Mark Christiansen, Recent Royalty Litigation and Industry Response 430-37 (Oct. 6-9, 1999) (unpublished paper, on file with author);\textit{ see also supra} note 68.
it from cutting the royalty by using an affiliate (or acting directly) to inflate the costs it is entitled to charge against the royalty. With deregulation, cost issues may become more common. The Altheide v. Meridian class, for instance, alleged that Meridian had cut their royalty by deducting a greater transportation cost than it paid. And pricing disputes can turn into cost disputes when a lessee’s defense to not sharing the price its affiliate receives is that a higher affiliate resale price reflects the costs of aggregating, storing, “trading,” or otherwise handling production.

Both leases and JOAs presume that the operator’s dependence upon the production stream will give it the right incentive to act in its partners’ best interests. When the lessee agrees to develop a lease, it is promising that its share of the proceeds is motivation enough for its undertaking. It cannot defeat that obligation by tinkering with its corporate structure.

76. See e.g., Le Cuno Oil Co. v. Smith, 306 S.W.2d 190 (Tex. App. 1957). Le Cuno as operator contracted with its own gathering system to bring gas to a pipeline buyer and deducted almost twice what the jury found to be its actual gathering cost. Id. at 192. Le Cuno had to account for the difference between this deduction and its actual cost. See id. at 193. Le Cuno was decidedly not a pricing case; the court even noted that under the division order (which provided for royalties at the price Le Cuno received at the well), Le Cuno was free to buy the gas itself at the well, but “no sale of that nature is under examination here,” see id. at 192. The court did not address how the affiliate link would constrain the price in that circumstance.

77. See supra note 66.

78. In the posted price cases, for instance, the defendants argued that using a price off the lease (and subtracting transportation costs) overstated the amount due to the royalty owners because it “fail[ed] to recognize the role of downstream value-adding functions.” See In re Lease Oil Antitrust Litig.,186 F.R.D. 403, 410 (S.D. Tex. 1999); see generally infra part III.B.

Cost issues have been more litigated in working interest cases because nonoperators pay the lion’s share of well costs. The industry has a complex set of working interest accounting standards, so that most major groups of costs (charges for overhead, equipment, and material, for instance) have their own formulas and standards. These accounting provisions are documented in the Copas accounting form, which ordinarily is appendix C to the JOA. But underlying these terms is the basic principle that the operator can only bill its actual cost and “shall neither gain nor lose” from handling the joint account. See JOHN JOLLY & JIM BUCK, JOINT INTEREST ACCOUNTING 203 (1988). For details on the way this general standard has and has not been translated successfully into particular areas, see John Burritt McArthur, A Twelve-Step Program for Copas to Strengthen Oil and Gas Accounting Protections, 49 SMU L. REV. 1447 (1996). For a sample of cases holding that the operator is not to make an extra profit on the various things it buys for the joint account, see John Burritt McArthur, The Class Action Tool in Oilfield Litigation, 45 KANSAS L. REV. 113, 220-23 & nn.589-95 (1996).

First Baptist and its unusual facts, division order cases, and affiliate cases are not the only examples of the mutual benefit rule. Three other oilfield cases additionally illustrate the principle. A familiar example is Amoco v. Alexander, a Texas Supreme Court drainage case. The Alexanders were "downdip" royalty owners in a water-drive oil reservoir. They alleged that Amoco, which operated both parts of the reservoir, was producing the updip wells more quickly and, as a result, watering out their reserves. Amoco was not hurt because it would recover through the updip property, but the downdip owners would get less than if Amoco drilled their properties aggressively.

The jury found that Amoco breached its duty as a reasonably prudent operator by slighting the Alexanders. Amoco tried to "maximiz[e] its profits" by diverting production from the Alexanders. After the court of appeals affirmed, Amoco complained to the Texas Supreme Court that it was between a rock and a hard place; if it pushed downdip production, updip royalty owners would sue. What Amoco wanted, of course, was a free hand to favor whichever lease made it the most money. Indeed, a logical extension of Amoco's position would have been that it could

79. 622 S.W.2d 563 (Tex. 1981). Amoco v. Alexander is not the only drainage case that imposes a higher duty on the lessee who drains onto its own adjoining property. Although not all courts agree, a number of courts have held that drainage by the lessee, or what they sometimes call "fraudulent drainage," will lighten the plaintiff's burden of proof. See generally 5 WILLIAMS & MEYERS, supra note 11, § 824. Because of the obvious conflict of interest when the lessee owns the draining property as well as its next-door victim, Williams and Meyers recommend that courts shift the burden of proof to the lessee to show that a protective well would not have been profitable. See id. § 824.3. For an early influential argument that there really are two drainage covenants, one when a third party is draining the acreage (in which event the lessor and lessee's interests are aligned); another higher duty when the lessee drains the acreage, see Verle R. Seed, The Implied Covenant in Oil and Gas Leases to Refrain from Depletory Acts, 3 U.C.L.A. L. REV. 508 (1956).

80. See Amoco, 622 S.W.2d 565-66.

81. Id. at 566. Amoco had three incentives for favoring updip property. First, while the Alexanders had a one-sixth royalty, the updip owners had a smaller one-eighth royalty. Amoco thus kept more of the revenue stream if it shifted production to less-burdened updip properties. Id. at 569. Second, Amoco's "chief competitor in the field," Exxon, owned interests between the Alexanders and the updip properties, so rapid updip drilling would cause Exxon's and the Alexanders' interests to water out quickly. Id. at 566, 569. Third, wells drilled updip would have a longer life (if Amoco could divert reserves into them), so presumably Amoco's costs would be reduced. See id. at 569.

82. Id. at 566.

83. Id. at 569. Amoco argued that it was being subjected to "contrary obligations from which there is no escape" and that the "fulfilling of one obligation necessarily causes the breach of the other."
produce everything updip if this maximized its profits. As in First Baptist, Amoco wanted to raise its return at certain lessors' expense.

The supreme court affirmed Amoco v. Alexander using traditional language of reasonable prudence in the drainage context, but what really troubled the court was Amoco's taking benefits separately from the downdip royalty owners. The "conflicts of interest of Amoco, as a common lessee" were what "cause us concern." If Amoco had no updip acreage, it would have tried to "capture the most oil possible from the Alexander leases before they watered out." Given the various separate benefits to Amoco from updip production, however, Amoco had "no economic incentive" to increase production on the Alexanders' property. Amoco could not reduce the Alexanders' recovery just because it was better off. It could not manipulate its leases to increase its recovery versus its royalty owners' recovery.

Another prominent example of the mutual benefit rule in action is Phillips v. Shutts. This case is better known for its class action aspects. But
its underlying holding was based on an unwillingness to let an operator make extra money off its royalty owners.

Phillips Petroleum had been the catalyst for the Supreme Court's 1954 decision extending federal jurisdiction and rate regulation to the wellhead price of interstate gas. \textsuperscript{90} Phillips v. Shutts was one offshoot of that historic decision. Ill prepared to set gas prices, the Federal Power Commission (FPC) quickly developed an extraordinary backlog of rate cases. \textsuperscript{91} Producers like Phillips raised their prices each time they applied for a rate increase, but they had to refund their interim collections if the FPC denied their requests years, or even decades, later. \textsuperscript{92} From 1954 until 1961, Phillips raised its royalties whenever it increased interim rates, but in 1961 it changed its policy. It decided to withhold, or, euphemistically, to "suspense" the increase until the FPC approved the rates. \textsuperscript{93} If the FPC did so, Phillips would pay royalties on the increased rate but not back interest. \textsuperscript{94} Instead, Phillips mixed the suspended funds with its other funds and used the money in its ordinary business. \textsuperscript{95} The Phillips v. Shutts class sought to recover the time value of suspended royalty funds. It was one of

\textsuperscript{90} See Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954). The Court's statutory interpretation that Congress intended to regulate wellhead prices, as well as interstate gas transmission, seemed implausible, to say the least, because Congress had expressly excluded "production and gathering" from the Natural Gas Act, 15 U.S.C. § 717(b) (1994), the statute that provided the basis for federal rate regulation. However, this was one of those occasions (in contrast to the over-devotion to words in the take-or-pay royalty cases discussed in part III.A.2) when the courts decided to ignore the statutory plain language, no matter how obvious.

\textsuperscript{91} As one sign of the Commission's incapacity to handle rate issues, it was not until 1970 that it issued Order 586, which addressed rate increases \textit{going all the way back to 1956!} See Shutts I, 567 P.2d at 1300. This was hardly the kind of flexible pricing one hopes for in a free market, even a regulated free market. In Order 586, the Commission allowed roughly $153,000,000 in rate requests, and denied over $29,000,000. See id.

\textsuperscript{92} Lest rate increases sound like a rare occurrence, at various times between 1961 and 1970, Phillips had nineteen rate applications pending before the FPC in the geographic area involved in Shutts. See id. at 1300.

\textsuperscript{93} After changing its policy, Phillips would not pass on the increase unless royalty owners indemnified it for the possible refund. The Kansas Supreme Court understood that the indemnity was more than a minor formality. It was a "burdensome condition." \textit{Id.} at 1320. The fact that only 17 royalty owners complied (it is a good bet that these 17 were large, corporate royalty owners or wealthy individuals), while roughly 6400 did not, shows that the indemnity was not just a little bump in the road for royalty owners. See \textit{id.} at 1300.

\textsuperscript{94} See \textit{id.} at 1300, 1311.

\textsuperscript{95} See \textit{id.} at 1300, 1311, 1316.
a series of Kansas class actions filed on this issue against major oil companies.96

The Kansas Supreme Court held that Phillips had to pay interest on the royalty share of suspended funds because the money really belonged to the royalty owners.97 Phillips had "no entitlement" to the suspended funds. It could collect all of the increased rate, but "under no condition was the one-eighth (1/8) of the increase attributable to the royalty owners ever to go to Phillips."98

96. The Kansas Supreme Court denied Phillips the right to keep the extra interest under Kansas law and listed Texas authority that required sharing interest on suspended royalties, including a recent case involving the Hugoton-Anadarko area rate. See id. at 1317 (citing Fuller v. Phillips Petroleum Co., 408 F. Supp. 643 (S.D. Tex. 1976)). The court also cited Oklahoma authority that it believed would require the same holding in that state, see id. (citing Smith v. Owens, 397 P.2d 673 (Okla. 1963); First Nat'l Bank & Title Co. v. Exchange Nat'l Bank & Title Co., 517 P.2d 805 (Okla. Ct. App. 1973)). In a later Phillips decision, the court discussed the interest-suspense issue and reached the same result under the laws of Texas, Oklahoma, Louisiana, New Mexico, and Wyoming. See Shutts IV, 732 P.2d 1286, 1293-311 (Kan. 1987). The interest-suspense issue seems to have been mainly addressed by Kansas courts because they certified a series of large class actions against major producers to resolve the issue. In another opinion in the Phillips v. Shutts line, the Kansas Supreme Court rejected Phillips' argument that it did not have to pay interest if it used the gas in its own operations rather than sold it, and so did not actually receive funds that it could deposit to earn interest. See Shutts II, 679 P.2d 1159, 1176-78 (Kan. 1984). The court looked to the economic substance of the benefits Phillips received from the increased rates, not just their form.


98. Id.; see also id. at 1316 (stating that "[w]hat is significant is these gas royalty suspense monies never did or could belong to Phillips."). As Thomas Harrell has pointed out, technically the Kansas Supreme Court got that wrong: title to the gas and therefore the initial right to payments belonged to Phillips, not its royalty owners. See Thomas A. Harrell, Developments in Non-Regulatory Oil & Gas Law, 30 INST. OIL & GAS L. & TAX'N 311, 337 (1979). At a deeper level, the court was merely honoring the true economic workings of the royalty relationship, one shown by the commonplace references to the royalty owner's "share" of production. See id. at 338. Even if "technically the lessors did not own or have any claim to the actual proceeds, the court still viewed it as 'their' money." Id.

It may seem odd that if Phillips had no entitlement to the royalty owners' share, it could suspend their funds at all. But Phillips' interim control over royalties was an artifact of federal law that royalty owners had no "legally enforceable right" to the incremental royalties until the FPC approved the new rates. See Shutts I, 567 P.2d at 1299. The Kansas Supreme Court agreed with Phillips that it could retain the suspense royalties until the FPC acted. See id. at 1315. It found Phillips' use of the suspended funds "clearly a sound and profitable business practice" that the court could not "condemn," given that the FPC scheme did not require it to pay out unapproved rates. Id. at 1316. The court also did not blame Phillips for the FPC's delay. Id. at 1316-17. It would not, however, let Phillips "enrich itself in the absence of any contractual sanction or seize upon the procedural complexities of the FPC to avoid responsibility for an appropriate measure of damages, expressed in terms of interest." Id. at 1317.

This decision to let Phillips keep the suspended funds pending a final FPC rate ruling still seems at odds with the rest of the Kansas Supreme Court decision. The court noted
This rarely discussed substantive holding in *Phillips v. Shutts* is a strong statement of the rule that the lease dictates a balanced and mutual sharing from the same revenue stream. A lessee cannot invade the royalty owner's share for its own gain.99 Even if an artifice of federal pricing temporarily blocks the royalty owner from immediately receiving all royalties, the lessee has to hold the funds in trust and preserve every resulting benefit for the royalty owners.100 In a mature reading, *Phillips v. Shutts* is a key case for the proposition that "there is a mutuality of objectives and sharing of benefits in the ordinary mining lease."101

that the FPC did not have jurisdiction to decide whether Phillips had to pay interest to royalty owners. See id. at 1319. Yet, if this is so, and if Phillips never owned and could not own the suspended funds, exactly what right was it exercising when it held onto the funds and used them in its business, even if it ultimately paid interest on them? Did Phillips pay a higher amount right away to working interest owners? If Phillips made a higher rate of return on these funds than the statutory interest awarded by the courts, could the royalty owners recover that profit on a constructive trust theory? When the court affirmed the trial judge's determination that letting Phillips keep interest on the royalty share of the price increase would constitute unjust enrichment, it reprinted the trial court's findings in its opinion. Id. at 1302-04.

99. *Phillips v. Shutts* received this reading in an article that, though it has received a lot of attention, is too often pigeon-holed as applying to Louisiana law only. See Harrell, supra note 98.

100. In the final opinion in the *Phillips v. Shutts* line, as mentioned in note 96, the Kansas Supreme Court decided that the laws of Texas, Oklahoma, Louisiana, Kansas, New Mexico, and Wyoming all compelled payment to the royalty owners. See Shutts IV, 732 P.2d at 1293-1311.

*Phillips v. Shutts*’ interest suspense rule may have been somewhat buried for another reason besides the prominence of the class-action questions: the way the Court explained the source of the duty. The Kansas Supreme Court suggested that Phillips’ duty to pay interest on suspended funds could be found in the lease language, as if the leases expressly required Phillips to do so. To avoid rules that provided low statutory interest rates when the parties did not agree on interest, the court held that “[h]ere, of course, an agreement for the payment of interest on the part of Phillips is clearly present.” Shutts I, 567 P.2d at 1319. The court never cited any language showing the leases required interest on suspended funds or mentioned suspended royalties at all. The court seems to have meant that Phillips “expressly contracted to pay a percentage of the price received,” and that this “price” had to include the suspended funds. Id. at 1320.

Unfortunately, the pretense that the lease language told the parties what to do detracts attention from the real basis for decision, which is the mutuality inherent in the lease. Thus, in some ways *Phillips v. Shutts* is as oversimplified on this point as the treatment of contract language in the take-or-pay cases discussed in part III.A.2, with the critical distinction that here the ambitious reading bolstered a correct analysis of intent, rather than thwarting it.

101. Harrell, supra note 98, at 338. For other cases that should be listed among important, well-known examples of the rule against separate benefits, see Henry v. Ballard & Cordell Corp., 418 So. 2d 1334, 1339 (La. 1982), discussed as part of the take-or-pay/royalty analysis below. See infra notes 247-48 and accompanying text. *Ballard* is an interesting example of this rule because it protected the lessee rather than the lessor. See also Kansas Baptist Convention
Finally, a recent Arkansas Supreme Court opinion, *Seeco v. Hales*,\(^{102}\) applies the mutual benefit principle to an unfortunate take-or-pay problem that faced a 7000-member class of royalty owners. The facts established a stark abuse of royalty owners. The lessee, Seeco, was the exploration and production affiliate of Arkansas Western Gas (AWG), which owned the intrastate gas distribution system in northwestern Arkansas. Seeco sold

\(v.\) Mesa Operating Co., 864 P.2d 204 (Kan. 1993), in which Mesa drilled an infill well that its own analysis showed would render the church’s interest worthless. See *id.* at 208.

Another well-known case turning on the mutual benefit principle that was set to add to this legal corpus until the Fifth Circuit finally held that all claims were covered by a prior settlement was *Shelton v. Exxon*, 719 F. Supp. 537 (S.D. Tex. 1989), rev’d, 921 F.2d 595 (5th Cir. 1991). Exxon sold gas from the King Ranch to satisfy long-term corporate guarantees to certain gas buyers, even though Exxon could have sold the gas for more by dedicating it to a federal price category. See *id.* at 545-56. Shelton presented a funny separate benefit problem because Exxon did half the right thing. It classified the gas as section 109 gas under the Natural Gas Policy Act (NGPA), 15 U.S.C. §§ 3301-3432 (1994), and based its royalty settlements on that regulated price, even though the price Exxon actually received for the gas was lower. See *id.* Exxon could have sought a higher section 105 price classification but did not because it would have lost more on its guarantees. See *id.* at 546. Exxon did pay royalties above the price it received, but Exxon wasn’t willing to pay too much more than the below-market price its uneconomic corporate guarantees thrust upon it.

Exxon tried to argue that no reasonably prudent operator would have satisfied corporate guarantees like its guarantees with “high-priced” gas bought on the open market just to free the King Ranch gas and sell its gas at better prices. See *id.* at 548. Exxon essentially argued that it should be able to use the Ranch as a patsy for its corporate priorities. The plaintiffs responded that Exxon could not consider “outside costs” to decide what to do with the ranch’s gas. See *id.* The court agreed, holding that the interest owners could not be “penalized” for Exxon’s costly corporate guarantees. See *id.* at 549. Exxon could not defend its failure to get the highest price when it “can only be attributed to its interest in fulfilling its corporate warranties without having to purchase gas on the open market.” *Id.* at 549. Exxon violated the mutuality of the lease: “Exxon’s method of marketing the King Ranch gas completely subordinated the rights of the mineral interest owners to Exxon’s financial gain.” *Id.* The court left no doubt that such violations of the mutual benefit principle cannot stand. All of this became moot when the Fifth Circuit held that the lessor’s “imprudent marketing” claim was covered by a prior settlement. See 921 F.2d at 601-03.

*First Baptist* and *Amoco v. Alexander* were two of the three cases the court cited in rejecting such self-directed operations. See *Shelton*, 719 F. Supp. at 548-49. The third case, *Freeport Sulphur Co. v. American Sulphur Royalty Co.*, 6 S.W.2d 1039 (Tex. 1928), is another case that bars lessees from pursuing their separate interests rather than mutual goals that would benefit royalty owners equally. The defendant leased a large sulphur-producing property, paying $450,000 for the lease and promising a seventy-five cent per ton royalty, plus a dollar per ton for the first 200,000 tons mined. *Id.* at 1040. It later stopped producing from the plant on plaintiff’s property, complaining that it had stockpiled as much sulphur as it could sell, even though it kept another plant 15 miles away running, and even though bigger companies kept their plants in operation. See *id.* at 1044. The supreme court agreed that the case had to be remanded for a jury to decide the diligence of the defendant’s plant shutdown.

virtually all of its gas to AWG under a single gas purchase agreement, known as Contract 59.

Like so many producers who wound up mired in take-or-pay disputes, Seeco entered this long-term take-or-pay contract in the late seventies. Contract 59 contained typical industry terms: a price clause promising to pay Seeco the maximum lawful regulated price and an average of highest prices upon deregulation (with a price floor), and a take-or-pay promise that AWG would pay for much of this gas even if it did not want to take it.103

Almost from the beginning of Contract 59, Seeco allowed AWG to ignore its promises. AWG never took full contract quantities, yet Seeco never asked it to pay the resulting take-or-pay deficiency, and starting just a few months into the twenty-year contract, AWG paid less than the contract price. AWG underpaid the contract price right through the boom years of the late seventies and early eighties, when reserve commitments drew premium prices.104

In a rate proceeding before the Arkansas Public Service Commission (APSC) in the early nineties, Seeco and AWG admitted how badly


Defendants' primary defense rested on another contract clause, the regulatory-out clause. But the supreme court agreed with the plaintiffs that defendants had no viable defense based on actual or prospective acts of the Arkansas Public Service Commission. See Seeco, 22 S.W.3d at 166-67.

Contract 59 did not have a market-out clause that would have let AWG lower the contract price if the market price for gas fell. See WILLIAMS & MEYERS, supra note 1, at 694 (market out clause lets "a pipeline purchaser...lower its price if market conditions dictate").

104. As the Arkansas Supreme Court succinctly summarized the allegations, they were that "SEECO never requested nor required AWG to pay the market price or take the volumes of gas set out under the express terms of the contract." Seeco, 22 S.W.3d at 166-67. When the gas became regulated in 1978, just two and a half months after the parties signed Contract 59, its price was supposed to increase each month according to an inflation-indexed price published by the Federal Energy Regulatory Commission. But Seeco phased in each monthly increase over the next twelve months, rather than adding the full increase in the month it went into effect. So AWG never paid the right price after the first few months of the contract. See id. at 168. When the gas was deregulated, Seeco and AWG should have redetermined the price to the highest of any price in a five-county area in Northwest Arkansas. See Contract 59, supra note 103, §§ 6(D),(F), & May 21, 1979 Amendment §§ 1-2. Instead, AWG unilaterally sent a letter announcing that it would freeze the price at its existing level. See Seeco, 22 S.W.3d at 161-61, 169. Seeco acquiesced; the evidence showed that "Seeco apparently did not play any role in redetermining the price," even though this should have been an adversarial negotiation between Seeco and AWG. See id. at 169. AWG "ignored the redetermination formula and then froze the price." Id. at 171. The evidence supported the jury's finding that AWG did not pay the right contract price during regulation or upon deregulation. See id. at 168. Seeco never complained about these underpayments, in contrast to the way an arms-length producer would have protected its interest and its royalty owners'. See id.
they had hurt Seeco's royalty owners. AWG thought that the Commission would let AWG charge a higher rate for its gas if it could show that it had diligently avoided paying Seeco $295 million of its price and quantity obligations under Contract 59—one-eighth of which should have gone to the royalty owners. The APSC made this testimony confidential after AWG asked the Commission's help in keeping royalty owners from learning of the contract violation. The jury found that this conduct violated the lease and the duty to market, and in addition created several tort violations. The damages, with interest, totaled $93,222,157.

When the Arkansas Supreme Court affirmed, it agreed that Seeco could not hurt its royalty owners just to advance its corporate interests, in this case, AWG's desire for cheaper gas. The court traced Seeco's violation directly to its succumbing to this separate interest: "There was a conflict of interest in this case because of SEECO's affiliation with AWG. Had there been no affiliate, the jury was free to conclude that SEECO would have attempted to get the best price possible, thus benefiting the royalty owners." Seeco had a duty to act for itself and its royalty owners in their shared interest. "We agree with the royalty owners' experts that SEECO's duty was to obtain the best price for itself and the lessors." As in Amoco v. Alexander and Phillips v. Shutts, so the Seeco v. Hales court readily understood that the lessee's core duty is to share the benefits it receives with its royalty owners. It cannot use its position of trust to appropriate or diminish the economic values attributable to their interest.

105. See Seeco, 22 S.W.3d. at 170 (citing testimony of Seeco's own expert to $295 million underpayment by AWG).

106. The jury found for the 7000-person royalty owner class on civil conspiracy, tortious interference by AWG with Seeco's royalty contracts, and on fraud-and-deceit and constructive fraud claims that rested on Seeco and AWG's concealing their favorable, high-priced take-or-pay contract that AWG was not honoring, even while Seeco was trying to buyback some of the royalty interests. See id. at 163, 171-72. The concealment went so far as keeping Contract 59 confidential in APSC proceedings so that royalty owners would not have a "road map" for a future lawsuit—so that they would not know that Seeco had violated their rights. See id. at 173, 181. In addition, the companies destroyed documents after the lawsuit began. See id. at 181. The jury found that the two companies were alter egos, see id. at 163, a finding ensuring that liability would extend to both but that was not a predicate for the violation of the duty to market.

107. Id. at 163.

108. Id. at 171; see also id. at 170 ("And, of course, the affiliated relationship between SEECO and AWG raises additional questions about SEECO's lack of enforcement. Charles Scharlau admitted at trial that the reason SEECO did not demand full performance from AWG under Contract 59 was due to the affiliate relationship between the two corporations.").

109. Id.
D. Louisiana Recognizes the Same Rule Under Its Mutual Benefit Principle

One reason that courts may not have recognized the mutual benefit principle as a separate covenant expressly is the lack of systemization in common law reasoning. The state with the most codified law, our one civil-code state, Louisiana, has written the mutual benefit principle into its Mineral Code.

It might be tempting to dismiss Louisiana because it is a code state, but this would be a mistake. Louisiana draws its royalty law from the common law. A Louisiana lessee's duty to act as a "good administrator" imposes the same obligations as implied covenants in common-law jurisdictions. Louisiana has put the mutual benefit principle, which common-law courts already enforce de facto but should recognize de jure as an independent implied covenant, at the heart of its Code. Article 122 provides that "while a lessee is not a fiduciary, it has to act in good faith, develop the property as a reasonably prudent operator," and, critically, "for the mutual benefit of himself and his lessor."

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110. See LA. REV. STAT. ANN. § 31:122, cmt. at 274 (West 2000). The Comment states, in Louisiana there is available in the Civil Code a general principle which can serve as a basis for achieving the result of the doctrine of implied covenants in other jurisdictions. Article 2710 requires that the lessee enjoy the thing leased as a "good administrator." This objective standard can aptly be translated into the field of mineral law as the "reasonable, prudent operator" standard which has been consistently applied by Louisiana courts to oil, gas, and mineral leases.

Id. The Code describes in detail Louisiana's adoption of the common-law covenants of reasonable development, of further exploration, of protection against drainage, and of diligent marketing. Id. at 275-79.

111. Id. § 31:122 (emphasis added). The Mineral Code comments explain that the "principal expectation of the parties to a mineral lease is that the property will be developed for the mutual advantage and profit of both parties." Id., cmt. at 274. The comment confirms that "this general principle is specified in the form of individual covenants" in other jurisdictions, but cites HOWARD WILLIAMS & CHARLES MEYERS, OIL AND GAS LAW (1969), for the proposition that the basis for all of these covenants is the "general principle of required cooperation among parties to all contracts." Id. The source commonly cited in Louisiana cases for this cooperative venture principle is Harrell, supra note 98.

For an article elaborating on Louisiana's mutual benefit principle, see generally Larry C. Hebert, Louisiana Mineral Code Article 122: The Concept of Mutuality (Nov. 19, 1998) (unpublished paper, on file with author). Hebert discusses that the lessee must handle "all of its operations...for the mutual benefit of both himself and his lessee." Id. at 13.
The Failure to Recognize a Mutual Benefit Covenant in Its Own Right Has Hurt Royalty Owners

Far from being a victimless error, the failure to formalize this substantive mutual benefit covenant that would prohibit lessees from taking separate benefits out of the lease has inflicted real damage on royalty owners. The incompleteness of oil and gas law without such a covenant is perhaps the only way to explain why so many courts erroneously let lessees strip royalty owners of take-or-pay proceeds. Another sign that current law remains too loose, and lessees too unconstrained, is the widespread fraud by major industry companies unearthed in posted price cases. Similar problems just now are emerging in the natural gas industry.

A. Many Courts Have Cavalierly Let Lessees Appropriate Take-or-Pay Payments Belonging to Royalty Owners

The cases that may best show the cost of not formally elevating the mutual benefit duty to implied covenant status are the take-or-pay royalty cases. In the boom years of the late seventies and early eighties, many lessees entered very high-priced gas sale contracts like the one in Seeco v. Hales. As mentioned in part II.C, these contracts usually made the buyers, often interstate pipelines, pay the “maximum lawful price” while gas was regulated under the Natural Gas Policy Act of 1978 and a redetermined price based on an average of highest nearby prices upon deregulation. The “take-or-pay” promise meant that, even if the buyer’s market deteriorated and it no longer needed reserves, it had to pay for the gas. These very favorable terms for sellers reflected the high demand for natural gas.

As long as the buyers kept taking gas under these lucrative contracts, royalty owners enjoyed the same good price as other interest owners. When natural gas prices fell sharply in the mid-80s, however, most interstate pipelines stopped honoring their take-or-pay contracts. A surprising number of producers were forced to accept less-than-contract prices. Even though courts had held that the market downturn generally was not a defense to take-or-pay contracts (because those contracts put the

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112. For a good basic picture of take-or-pay disputes, see generally J. Michael Medina et al., Take or Litigate: Enforcing the Plain Meaning of the Take-or-Pay Clause in Natural Gas Contracts, 40 ARK. L. REV. 185 (1987). The Seeco v. Hales dispute was another fruit sown in this same season.
risk of market decline on the buyer), disputes settled for as little as 20 cents on the dollar.\textsuperscript{113}

It would seem an obvious application of the joint nature of the lease, of this common undertaking to divide the proceeds of whatever production the lessee finds on the lessor's property, that royalty owners were entitled to share all take-or-pay payments and settlements. After all, buyers entered take-or-pay contracts to buy gas from the royalty owners' leases. Yet only the few courts applying a mutual benefit rationale have taken this view. The contrary majority rule shows why this protection is so badly needed.

1. A Few Courts Have Prevented Lessees from Purloining Royalty Owners' Take-or-Pay Benefits

Courts that approached take-or-pay cases through the mutual benefit prism did make lessees share the payments with their royalty owners. The lead case is a Louisiana Supreme Court case, Frey v. Amoco Production Company.\textsuperscript{114} As the Frey lessee, Amoco had settled a take-or-pay contract dispute with Columbia Gas Transmission Company for $66.5 million.\textsuperscript{115} The royalty owners had a one-fifth royalty, so they should have received a little more than $13 million, but Amoco would not pay them.

Frey took a tortured route to the Louisiana Supreme Court. A federal district judge relied on Judge Brown's recent opinion in Diamond Shamrock Exploration Corp. v. Hodel\textsuperscript{116} to dismiss the royalty claim on partial summary judgment. The Diamond Shamrock court had held that royalties are not due on take-or-pay prepayments unless and until gas actually is produced.\textsuperscript{117} When the Fifth Circuit reversed Frey in an opinion by Judge Reavley, the case began its transformation into the principle it represents today.


\textsuperscript{114} 603 So. 2d 166 (La. 1992). The full history of Frey is Frey v. Amoco Prod. Co., 708 F. Supp. 783 (E.D. La. 1989) [hereinafter Frey I], rev'd, 943 F.2d 578 (5th Cir. 1991) [hereinafter Frey II], opinion withdrawn in part on reh'g by 951 F.2d 67 (5th Cir. 1992) [hereinafter Frey III], certified question answered by 603 So. 2d 166 (La. 1992) [hereinafter Frey IV], opinion reinstated in part on reh'g by 976 F.2d 242 (5th Cir. 1992) [hereinafter Frey V].

\textsuperscript{115} See Frey IV, 603 So. 2d at 170. There were two payments, a $45.6 million "recoupable" payment for gas that Columbia could make up and a $20.9 million nonrecoupable payment that Columbia had to write off. These payments were just for volume disputes. In a good sign of the vast amounts often at stake in take-or-pay litigation, Columbia already had paid Amoco $280.2 million for "price deficiencies," that is, for having paid less than the contract price. Id. at 170. Amoco did pay royalties on the price damages.

\textsuperscript{116} 853 F.2d 1159 (5th Cir. 1988).

\textsuperscript{117} Id. at 1161. See generally infra notes 147-55 and accompanying text.
Judge Reavley methodically distinguished *Diamond Shamrock.* Though he was careful never to come out and simply say that Judge Brown had made a (bad) mistake, Judge Reavley cut away the foundations of the earlier Fifth Circuit decision. Most fundamentally, Judge Reavley understood that language alone does not answer the take-or-pay royalty question—the parties "did not specifically address" the disputed

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118. Judge Reavley mentioned three differences: (1) the *Diamond Shamrock* leases were keyed to "production," while Frey focused on the "amount realized" from the "sale"; (2) *Diamond Shamrock* interpreted federal leases and regulations, while Frey invoked Louisiana law; and (3) the government wrote the *Diamond Shamrock* leases, while here the operator Amoco did (i.e., so Amoco would come under the rule of construction that contracts are construed against the drafter). See *Frey II*, 943 F.2d at 581.

Differences in deference cannot explain the irreconcilable results in these two cases. The Fifth Circuit in *Diamond Shamrock* should have deferred to the Minerals Management Service (MMS), unless its interpretation was "irrational, arbitrary, an abuse of discretion, or otherwise not in accordance with law." See *Diamond Shamrock*, 853 F.2d at 1165. Thus, the courts should have given the government at least as much deference in *Diamond Shamrock* as they gave Amoco in *Frey.*

Turning to the lease itself, the court pointed out that royalties were due "on the amount realized... from such sales," not on "production" as in *Diamond Shamrock,* and held that (it believed) Louisiana would find a sale even without production. *Frey II*, 943 F.2d at 581, n.1. The court saw support for its reading in the clause that oil royalties were predicated on "production," but the royalty on gas was to be on the "amount realized at the well from such sales." See id. at 581 n.2.

119. Some of the points of disagreement were minor. For instance, *Diamond Shamrock* worried that lessees might have to make a second royalty payment if the buyer later bought the gas. With a little common sense, Judge Reavley dismissed this fantastically exaggerated concern over a minor bookkeeping detail. Courts cannot diminish lease requirements "simply because Amoco could have to send two checks to Frey instead of one if the market value of gas rises when Columbia takes it." See *Frey II*, 943 F.2d at 582.

Amoco had grown enthusiastic about the two-check argument in the wake of *Diamond Shamrock,* and argued that it would be an "absurd result[ ]" for it to have to make "two royalty payments on one purchase of gas." Id. at 582. Of course, Amoco never tried to quantify the cost of cutting these two checks, which it might well have to do for working interest owners in any event. Say it took a clerk half an hour, or even an hour, to prepare the paperwork. Maybe, giving Amoco every benefit of the doubt and assuming that it was woefully inefficient and not computerized, it might cost a few hundred dollars per double payment. Even assume a few thousand dollars in total. Why should that cost, which presumably is part of post-production overhead for which Amoco will be billing the Freys, derail payment of millions of dollars in royalties? Were Amoco even a little bit worried about this cost, why didn't it build the charge into its overhead, and let the interest owners decide whether to complain? We know the answer: Amoco did not want to lose the million-dollar windfall it made by cutting the Freys out of their royalties.

The court gave short shrift to a different *Diamond Shamrock* refund problem. This panel understood that the federal limitations statute, which Judge Brown suggested might bar seeking a refund from the government, almost certainly would not have that effect. See id. at 583 n.4.
issue—and that contract purpose required sharing. Applying Louisiana law, he noted that the Louisiana Supreme Court had defined a lease as a "cooperative venture: the lessor contributes the land and the lessee the capital and expertise necessary to develop the minerals for the mutual benefit of both parties." The lease was set up to share the "economic benefits" from developing the minerals:

The payments, like the market price paid for gas taken, constitute economic benefits that Amoco received for granting Columbia the right to take gas from the leased premises, a right that Amoco got through the Lease. It would be contrary to the nature of the lease as a cooperative venture to allow a benefit by any name that is attributable to the gas under the leased premises to inure exclusively to the lessee. Judge Reavley squarely rejected Diamond Shamrock's argument that the sole purpose of take-or-pay contracts is to repay producers for the risk of production. Diamond Shamrock is bad law and Judge Reavley knew it.

120. The language is more difficult than Judge Reavley suggested. The royalty clause made payment "of the amount realized" depend on the "sale" "at the well." Id. at 583. "At-the-well" could suggest that the parties meant gas had to be produced at the well-site. Or it could just mean that prices had to be netbacked to the well. Amoco's counsel had no position on this language when asked about it at oral argument. See id. Judge Reavley pointed out that the language serves to separate the net wellhead price from the price after transportation and processing have occurred. Id. He correctly let the larger purpose of the joint endeavor overcome the linguistically possible reading that "at the well" required "production." Id. at 583-86.

121. Id. at 584 (citing Henry v. Ballard & Cordell Corp., 418 So.2d 1334, 1338 (La. 1982)).

122. Id.

123. Id. (citations omitted). It did help that Louisiana by statute required a lessee to operate the property in good faith "for the mutual benefit of himself and his lessor"; this duty would be defeated if the operator could essentially deal the royalty owner out of the contract. See id. at 585.

In a much earlier Louisiana case dealing with casinghead gas, a byproduct not foreseen at the time of leasing, the Fifth Circuit required the lessee to share the revenue from this new, unanticipated benefit because the lessor and lessee were to share the property's benefits. See id. at 585 (citing Wemple v. Producers' Oil Co., 83 So. 232 (La. 1919)).

Amoco owed royalties on Columbia's settlement both as part of the "amount realized...from sale" and because the settlement was a joint benefit that Amoco could not appropriate for itself. See id. at 584.

124. For Judge Brown's argument on this point, see infra notes 152-53 and accompanying text. Judge Reavley understood that the royalty embodies a sharing of benefits from the mineral acreage. The risk-of-production doctrine is inconsistent with the rationale the Frey court adopted. If a take-or-pay payment is compensation for the risk of production, then it is a return to a unilateral risk (in this case, Amoco's), rather than a mutual risk. But if the lease is a venture for mutual benefit, a conclusion both Judge Reavley and the Louisiana Supreme Court reached from their reading of the structure and economics of the relationship, it makes no sense to divert the royalty share to increase the operator's risk reimbursement.
Only highly socialized comity among brother judges could have stopped him from more directly criticizing this still fresh precedent.\textsuperscript{125}

Perhaps feeling pressured because of the obvious if unspoken conflict with \textit{Diamond Shamrock}, the Fifth Circuit then stepped back and certified Frey's take-or-pay question to the Louisiana Supreme Court.\textsuperscript{126} That court agreed with Judge Reavley's basic purpose analysis.\textsuperscript{127} Holding that neither Amoco nor the Freys would have contemplated the poor gas market when entering their lease in 1975 (in a booming market), the court

\textsuperscript{125} Although Judge Reavely strained not to state flat out that \textit{Diamond Shamrock} is wrongly decided, he did not mince words when discussing issues on which \textit{Diamond Shamrock} erred. He understood that it is "wholly unrealistic to think that one would pay to not take gas outside the context of a gas sales contract securing the right to certain reserves." \textit{Frey II}, 943 F.3d at 584 n.5.

\textsuperscript{126} This shift from the Fifth Circuit to the Louisiana Supreme Court has been unfortunate. It de-emphasizes the conflict between \textit{Frey} and \textit{Diamond Shamrock}, because certification encourages the false perception that \textit{Frey} can be distinguished as a uniquely-Louisiana opinion. In fact, as the text argues, it is the rejection of Judge Brown's \textit{Diamond Shamrock} purpose analysis that explains both \textit{Frey} opinions, and this rejection of the judicial error symbolized by \textit{Diamond Shamrock} could just as well be applied to any of the other cases that unfortunately have swept along in \textit{Diamond Shamrock}'s wake.

\textsuperscript{127} The Court did begin by citing the Louisiana Mineral Code's definition of "royalty," which includes "any interest in production, \textit{or its value, from or attributable to land subject to the mineral lease,}" including payments classified as "constructive production." \textit{Frey IV}, 603 So.2d 166, 171-72, 171 n.8 (La. 1992) (citing LA. REV. STAT. ANN. § 31:213(5) (West 2000) (emphasis added)). This statutory discussion, however, was merely preface to the court's purpose analysis. As the Oklahoma Supreme Court has noted, its Louisiana counterpart found the Louisiana Code "not dispositive" and moved on to the purpose of the lease. See \textit{Roye Realty & Developing, Inc. v. Watson}, 2 P.3d 320 (Okla. 1996); see also \textit{Randy King, Note, Royalty Owner Claims to Take-or-Pay Payments under the Implied Covenant to Market and the Duty of Good Faith and Fair Dealing}, 33 So. TEX. L. REV. 801, 814 (1992) (arguing that although Fifth Circuit opinion on merits issued before certifying royalty issue to Louisiana Supreme Court was "[o]stensibly...based on...factual distinctions" with \textit{Diamond Shamrock}, a "close reading" of the opinion shows it was tied to the court's analysis of lease purpose and implied covenants); see \textit{generally Lowe, supra} note 68, at 240-43, 254-55 (discussing both \textit{Frey} and \textit{Klein} as "cooperative venture" cases). Others have tried to limit \textit{Frey} to a Louisiana-only decision, as if its challenge to \textit{Diamond Shamrock} could be contained by state lines. See, e.g., \textit{Harvey E. Yates Co. v. Powell}, 98 F.3d 1222, 1233 (10th Cir. 1996) (arguing that \textit{Frey} and \textit{Klein} were based on "unique state statutes"); \textit{Alameda v. TransAmerican Natural Gas Co.}, 950 S.W.2d 93, 99 (Tex. App. 1997) ("cooperative venture" theory adopted in \textit{Frey} based on "unique state statutes," following \textit{Yates}' distinction of \textit{Frey}); \textit{Beverly Barrett, Note, Oil and Gas: Roye Realty v. Watson: Are Royalties Owed on All Take-or-Pay Settlements in Oklahoma?}, 46 OKLA. L. REV. 745, 752 (1993). The problem is accentuated by the care with which the \textit{Frey} court studiously kept its distance from \textit{Diamond Shamrock} in an effort to downplay the conflict. See infra note 180; see also \textit{Indep. Petroleum Ass'n of Am. v. Babbitt}, 92 F.3d 1248, 1259 (D.C. Cir. 1996) (discussing \textit{Frey}'s insistence upon its separate Louisiana law issue in an opinion that unimaginatively followed \textit{Diamond Shamrock} and rejected the government's effort to at least shield take-or-pay settlements from the reach of Judge Brown's opinion).
looked to their "general intent." The lessee supplies the land and the lessee the capital and expertise necessary to develop the land for the *mutual benefit* of both parties. The royalty owner enters the lease motivated by expected royalty payments and "would not relinquish a valuable right arising from the lease premises without receiving something in return." Moreover, all benefits accruing to Amoco were "derivative of the rights transferred to Amoco by Frey." The mutual benefit would be "rendered meaningless" if the lessee could increase its percentage of revenues by refusing to pass on take-or-pay settlements. The court cited with

128. See Frey IV, 603 So. 2d 166, 172 (La. 1992). It almost certainly is not true that Amoco did not contemplate that the gas market *might* not decline. The fact that a producer wanted take-or-pay protection shows that Amoco and Columbia provided for the risk of a falling market, even if they did not "expect" it to occur. It is less likely that the royalty owners, with their inexperience and their structured reliance on the lessee, gave much thought to the gas market. One reason for entering a lease is to rely on the marketing expertise of the lessee, which as in this case often is a very large operating company with decades of industry experience.

When parties do not provide for a particular situation, courts have to imply terms "necessary for the contract to achieve its purpose." Id. at 172 (citing LA. CIV. CODE ANN. art. 2054 (West 1987); LA. REV. STAT. ANN. § 31:122 (West 2000)).

129. Frey IV, 603 So.2d at 173. The lease is a cooperative venture "in which the lessor contributes the land and the lessee the capital and expertise necessary to develop." Id.

130. Id.

131. Id. at 180. Amoco's right to develop the property was itself "conferred by and dependent upon the Lease." See id. at 178.

132. Id. at 174. The take-or-pay proceeds were part of the "amount realized" by Amoco. They were "economic benefits which are derivative of Amoco's right to develop and explore the lease property," the right Amoco got from the Freys in the first place. Id. at 178. The amount realized included any "economic benefits" Amoco got from the lease. Id. Requiring pass-through of these payments was an easy decision. "[F]ailure to characterize these payments as part of the total price paid for gas sold under the contract is to disregard the obvious economic considerations underlying the take-or-pay clause." Id. at 180. This interpretation became obvious given any "appreciation of the cooperative nature of the lease arrangement as well as an understanding of the economic and practical considerations underlying the royalty clause." Id. at 181.

The supreme court dismissed some other objections to this holding. It would not accept the "cramped characterization" that the take-or-pay payment is a payment for gas *not* produced; the buyer never would have bargained for a right "*not to take gas*" if it did not have the right to take gas. Id. at 178 (emphasis added). The vision that the payment was purely a return to the risks of exploration had to emanate from [Judge Brown's] "myopic eye." Id. The contract required royalty payments on the "sale" of gas, not just "production," so the court was able to skirt cases that had based their opinions on "production" alone. Id. at 179.

The opinion contains a section on implied covenants and Louisiana's adoption of the duty to market, but a close reading of the case does not indicate that this added anything to the outcome. See id. at 174-76.
approval the "cooperative venture" theory, known as the "Harrell Rule," after Professor Thomas Harrell.\(^{133}\)

The Frey opinion ended by casually dismissing competing common law cases. Louisiana's law evolved "not from the common law, but from the Civil Code, richly steeped in our civilian heritage."\(^{134}\) In reality, though, Louisiana interprets its Mineral Code, certainly its royalty provisions, in parallel with the common law.\(^{135}\) Thus, Frey's reasoning from Louisiana's mutual benefit principle should be just as applicable in every other state as it is in Louisiana. It is not only in Louisiana that all rights of the lessee derive from the royalty owners' property. It is not only in Louisiana that royalty owners depend entirely upon the lessee to develop, or secure development of, their land. Nor is it only in Louisiana that a lease issues only on the assumption that every act the lessee undertakes will accrue to the benefit of its royalty owners, who provided the property in the first place.

Frey was followed and its reasoning adopted under Arkansas law just a few months later by the Eighth Circuit in Klein v. Jones.\(^{136}\) Klein graphically illustrates the unfairness of not requiring royalty pass-through. The defendants were lease developers who had settled a variety of take-or-pay disputes with a major pipeline company, Arkla. Among the payments they pocketed were $24 million for committing gas and $100 million for "revaluation of gas reserves."\(^{137}\) Not only did defendants keep for themselves these payoffs derived from the lease, but they also concealed the settlement at the Arkansas Public Service Commission, thus increasing the odds that the royalty owners never would learn of their loss.\(^{138}\)

It no doubt helped the Eighth Circuit follow Frey that Arkansas, like Louisiana, had a broad royalty statute.\(^{139}\) But as in Frey, the fulcrum of

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133. See id. at 173 (citing Harrell, supra note 98, at 334). The court additionally cited a prior supreme court opinion following Harrell, Henry v. Ballard & Cordell Corp., 418 So.2d 1334, 1338 (La. 1982), the opinion using cooperative venture analysis to reject the Texas Vela rule. See infra notes 247-48 and accompanying text.
134. Frey IV, 603 So.2d at 182.
135. See supra note 110 and accompanying text.
137. Klein II, 73 F.3d at 783 n.4; see also Klein I, 980 F.2d at 524-25. Klein had its affiliate aspects. For instance, one of the defendants, Jerry Jones (better known as the owner of the Dallas Cowboys), had been on the board of Arkoma when the take-or-pay contract was entered. See Klein I, 980 F.2d at 524. But the affiliate issue and any concerns about joint control were not developed in the case.
138. Klein I, 980 F.2d at 525.
139. Under Arkansas law, the lessee and any company buying oil or gas from it have a duty to protect the royalty owner "by paying to the lessor or his assignees the same price including premiums, steaming charges, and bonuses of whatever name for royalty, oil, or gas
Klein was not statutory language. Instead, the Eighth Circuit relied on Frey in claiming a "strong, developing recognition that a restrictive interpretation of the royalty clause in a conventional lease can be inconsistent with its basic purpose...." Letting the lessee appropriate take-or-pay settlements would give it an artificial incentive to cut a deal that excludes royalty owners.

If courts squarely recognized the mutual benefit covenant, the Frey and Klein courts would not have needed to spend this much time juggling statutory terms, implied covenants, and express lease terms. Because these two cases reached the right result anyway—they did force lessees to treat their royalty owners equally with other interest owners—the cost of not articulating a mutual benefit covenant may seem slight. In contrast, the majority take-or-pay royalty rule shows why courts must be clearer about this implied protection. Most courts have stripped royalty owners of take-or-pay payments. This state of affairs almost certainly could not have occurred under the mutual benefit principle.

that is paid the operator." Id. at 529 (citing Ark. Code. Ann. § 15-74-705 (Michie 1987)).

140. Id. at 531; see generally id. at 529-31. The court cited with equal approval the Harrell cooperative venture rule. See id. at 531-32.

141. See id. at 531. The Eighth Circuit additionally cited Amoco Production Co. v. First Baptist Church, 579 S.W.2d 280 (Tex. Civ. App. 1979) and the Louisiana Supreme Court opinion in Henry v. Ballard & Cordell Corp., 418 So.2d 1334 (La. 1982) for the proposition that "all benefits grounded on the existence of a lease must be shared in accordance with the lease." Klein I, 980 F.2d at 532. The Court did not believe that a lessor would "relinquish a valuable right without receiving something in return." Id. at 531. In this context, it would not give up its right to its gas if it understood that the lessee could keep the benefit of high gas prices all to itself. Id.

On the legal claims, the Eighth Circuit agreed that allowing Amoco to keep the royalty owners' money would be unjust enrichment. See id. at 527. Among the reasons that unjust enrichment should apply were that the lessors were not represented when Congress deregulated the gas market, and they did not have anyone representing their interests after an Arkoma affiliate bought the lessee's operating company. "Thus the lessors no longer had a representative dealing at arm's-length with the pipeline." Id. The court held that the claim based on the duty to market was not time-barred. Id. at 532-33. The Eighth Circuit rejected claims that the lessee was a fiduciary, that the lessors were third-party beneficiaries of the gas purchase agreement, or that they could sue for tortious interference with that contract. See id. at 526-27.

The Eighth Circuit reiterated its position when the district court on remand still would not follow the command to share these lease benefits with the royalty owners. See Klein II, 73 F.3d at 786. When the court affirmed again, it discussed two legal theories, unjust enrichment and the duty to market. The unjust enrichment claim was not precluded by express contract terms, which the court held did not fully address the subject in dispute. See id. at 786. The duty to share take-or-pay proceeds arose by virtue of the leases and the court seems to have envisioned them as part of the implied covenant to market. See id. at 787.
2. Most Courts Have Rejected Take-or-Pay Sharing

The majority rule that lets lessees and their investors pocket the royalty share of take-or-pay payments, both prepayments and settlement payments, began in 1988 with opinions by the Wyoming Supreme Court and the Fifth Circuit. In the first, State v. Pennzoil, Pennzoil and Marathon did not want to pay the State of Wyoming royalties on take-or-pay prepayments under a state lease providing for a one-eighth royalty on the "amount realized" on gas "produced from said land, saved and sold...." Ignoring the purpose and the context of the amount-realized clause, the Wyoming Supreme Court held that the word "produced" required actual severance of the gas. It held that no production had occurred, so the companies did not owe any royalty. The court would not look at other contract clauses or consider whether "common sense and good faith" required the companies to share prepayments with the State.

State v. Pennzoil was a short, abrupt opinion. It gained substantive support a few months later, however, when the Fifth Circuit decided Diamond Shamrock Exploration Co. v. Hodel. The appeal stemmed from two federal district court decisions interpreting federal leases. One required a producer to share take-or-pay payments with the Minerals Management Service (MMS), the Interior Department agency that administers federal

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142. A prepayment is a payment for gas before it is produced. See Williams & Meyers, supra note 1, at 939 (defining prepayment as "interest-free loan or advance payment for gas to be delivered at some future time"). This description of a prepayment as a loan is somewhat misleading; it was this kind of thinking that encouraged pipelines to argue that at most they should be liable for interest instead of the base prepayment in take-or-pay disputes. Under many take-or-pay contracts, the pipeline was not entitled to a refund if it did not take the gas, so the contract transferred much more than loaned funds. Even in contracts with a recoupment provision, the bargained-for benefit was a cash flow equal to the full take-quantity-times-contract-price, with the seller having the risk of some later refund if the contract so provided.

143. 752 P.2d 975 (Wyo. 1988).

144. Id. at 976.

145. Id. at 979. Bruce Kramer has reminded us that the court ignored a most favored nations clause entitling Wyoming to at least the royalties received by the United States on its leases in the field; the United States was demanding royalties but "apparently the state could not show that the United States was actually receiving take-or-pay payments...." Bruce M. 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, 5-9 n.20 (1988).

146. See State v. Pennzoil, 752 P.2d at 981. The court’s odd reference to “common sense and good faith” can be taken as a Freudian slip suggesting that it knew its holding could not really withstand substantive analysis.

147. 853 F.2d 1159 (5th Cir. 1988).
leases; the other court held that the government was not due any royalty on the payments. \(^{148}\)

The federal royalty was sixteen and two-thirds percent of the “amount or value of production saved, removed, or sold from the leased area.” \(^{149}\) MMS had interpreted this language to include take-or-pay prepayments. Though the Fifth Circuit only had authority to reverse this interpretation if it was arbitrary or capricious, it purported to find that the plain meaning of the royalty clause compelled reversal. The lease required producers to share their gross proceeds; however, the gross proceeds were on “the value of production saved, removed, or sold...,” of funds from the sale or disposition of “produced substances.” \(^{150}\) In addition, the court claimed to be troubled by what might occur if the producer had to pay royalties before it produced any gas. In that case, it would have to make a second payment if the buyer later bought the gas at a higher price. \(^{151}\)

The fundamental reason for the Diamond Shamrock decision, however, was the court’s *deus ex machina* pronouncement that the purpose of the take-or-pay clause is not to pay for gas. Instead, in an unfortunate diversion into the realm of factfinder, the court treated take-or-pay clauses as if their only goal is to pay producers for drilling risk. Even though all of the disputed payments originated from government leases, the court pulled out of its hat the conclusion that the take-or-pay payments were not benefits “attributable, at least in part, to the government’s interest.” Instead, it called them “intended to compensate primarily the producer, not the owner of the minerals, for the risks associated with development production.” \(^{153}\)

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148. The two cases are described in *Diamond Shamrock*, 853 F.2d at 1162-63. Though *Diamond Shamrock* reviewed two conflicting trial-level opinions, the case won by the royalty owners appeared the more significant going into the appeal because it was a test case brought by five major producers: Diamond Shamrock, Cities Service, Mobil, Exxon, and Texaco.

149. *Id.* at 1163.

150. *Id.* at 1163, 1165 (emphasis added).

151. *See id.* at 1166. The worried court said it had yet another fear. If the pipeline buyer did not take the gas, and if it had a right to a refund, the seller’s limitations period against the government might have run and the producer might not be able to recover the government’s share of the overpaid royalties to give back to the buyer. *See id.* This reading is a cramped one that assumes the cause of action against the government would arise before the refund was due. For a dismissive view of this fear, see Judge Reavley’s reaction to the idea, *supra* note 119.

152. Even Judge Brown’s hedging with “primarily” begs for a different outcome. If Judge Brown believed that the payments were intended “primarily” to repay the producer, why wasn’t the government’s perhaps lesser, perhaps “secondary” interest enough to entitle it to one-sixth of the payments?

153. *Diamond Shamrock*, 853 F.2d at 1167. The court also cited a FERC regulation treating prepayments as payments for gas not taken and not allowing pipelines to recover their gas costs until they actually took the gas. *Id.* at 1167 n.36. In doing so, Judge Brown ignored the very different context of this issue, in which pipelines had argued unsuccessfully that
With this unique purpose analysis in place, the court held that production could only mean "the actual physical severance of minerals from the formation." On this assumption that royalties were not payable without "production," it then held that the federal lessees could pocket all of the take-or-pay prepayments attributable to the government's one-sixth interest. In the next few years, over a dozen more cases adopted similar simplistic reasoning and let producers and their investors appropriate the royalty owners' share of take-or-pay prepayments and settlements.

Prepayments should be added to the price of gas actually taken, in an effort to claim that the resulting sum would violate the Natural Gas Policy Act's maximum lawful price ceiling—all in pipeline efforts to void their take-or-pay obligations.

The court's only authority on its risk-of-production argument was a recent Fifth Circuit decision that addressed the very different question of whether a producer could enforce its take-or-pay contract against the gas buyer. The case was Universal Resources Corp. v. Panhandle Eastern Pipeline Co., 813 F.2d 77, 80 (5th Cir. 1987), cited in Diamond Shamrock, 853 F.2d at 1167 n.33. Universal Resources was one of the first major published decisions in a take-or-pay case and it rejected a representative smorgasbord of standard pipeline defenses. It addressed solely whether the gas buyer had a legal defense against its take-or-pay obligations. The case did not discuss the impact of a producer's high-priced gas contract on its royalty obligations.

154. Diamond Shamrock, 853 F.2d at 1168.
155. Because so many of these cases seized upon the first few precedents and followed them without serious analysis, the sequence of decisions is necessary to understanding the take-or-pay royalty cases. This Article lists the cases in their order of appearance. See Killam Oil Co. v. Bruni, 806 S.W.2d 264, 266-68 (Tex. App. 1991) (reversing and rendering summary judgment for royalty trust seeking to share settlement proceeds where lease provided royalties on gas "produced from said land and sold or used off the premises"; reasoning that "production" required physical extraction; arguing that royalty trust could have included a provision requiring sharing of take-or-pay provisions, but did not and so "unambiguously limited its right to royalty payments only from gas actually extracted from the land"; and that gas stayed in the ground anyway); Mandell v. Hamman Oil & Refining Co., 822 S.W.2d 153, 159-64 (Tex. App. 1991) (rejecting direct claims against gas purchaser to share settlement because, inter alia, royalty owners were neither parties to the gas purchase contract nor third party beneficiaries, and upholding jury findings supporting purchaser's affirmative defenses; then affirming trial court's summary judgment for lessee rejecting duty to market claim because lease only required royalty on "production"; following Killam's interpretation that take-or-pay payment is for non-production, in a case where a lessee sold its interest and settled take-or-pay claims but did not share funds with royalty owners); Hurd Enters. v. Bruni, 828 S.W.2d 101, 103-09 (Tex. App. 1992) (rejecting claim to non-recoupable take-or-pay settlement because royalties on gas "produced from said land and sold or used off the premises" required actual production under Killam and rejecting application of duty to market because producer did get the highest price it could in the contract; rejecting good faith duty in lease relationship; and rejecting agency argument because "the lessor has no gas to sell"; leaving open possibility that royalty owners might have right to share non-recoupable payments, but not addressing issue because it was "not submitted in the case before us," id. at 106 n.8; also relying on Diamond Shamrock's view that take-or-pay provisions merely allocate risks of production, see id. at 110 n.12.); TransAmerican Natural Gas Co. v. Finkelstein, 933 S.W.2d 591, 596-600 (Tex. App. 1996) (reversing judgment in jury trial for royalty owner,
based on unjust enrichment and breach of duty to market, by following Bruni in holding that language applying to gas “produced and sold” did not apply to take-or-pay payments; rejecting Bruni’s suggestion that royalty owners might have claim to non-recoupable payments, and citing Texas Supreme Court’s ultimate decision in Lenape Res. Corp. v. Tenn. Gas Pipeline, 925 S.W.2d 565, 572 (Tex. 1996) (holding that a take-or-pay contract is not a requirements contract that can be limited by the UCC’s requirements provisions, as that would “fundamentally alter the risk allocation” in the contract), as confirming that take-or-pay payments were payments for an exclusive dedication of reserves, but not for “the sale of gas”; worrying that Finkelstein would receive two royalties on the same gas if he did share take-or-pay settlement; finding unjust enrichment claim barred because express contract governed terms; and rejecting argument that damages should be passed through because they were repudiation damages); Indep. Petroleum Ass’n of Am. v. Babbitt, 92 F.3d 1248, 1258-60 (D.C. Cir. 1996) (rejecting MMS effort to limit Diamond Shamrock rule to take-or-pay payments, while having government share in take-or-pay settlements; reiterating Diamond Shamrock’s emphasis on requirement of “production saved, removed or sold” and finding take-or-pay prepayments and settlements “functionally indistinguishable with respect to the calculation of royalties”; all this in the face of long-standing MMS rules that “under no circumstances” should royalty value be less than gross proceeds “accruing to the lessee from the sale [thereof]”; Roye Realty & Developing, Inc. v. Watson, 2 P.3d 320, 328-29 (Okla. 1996) (rejecting royalty owners’ claim to take-or-pay settlement on gas “produced and sold” in case where defendants had even refused to show royalty owners the take-or-pay settlement agreement; treating requirement that royalty be on substances “produced, saved and sold” as conclusive and rejecting third-party beneficiary claims; leaving open possibility that “amount realized” rather than “gross proceeds” leases might lead to different outcome); Harvey E. Yates Co. v. Powell, 98 F.3d 1222, 1229-37 (10th Cir. 1996) (citing state lease language requiring one-eighth royalty on gas “produced and sold,” as well as extensive precedent including Diamond Shamrock and State v. Pennzoil Company, for three “guiding principles”: (1) royalty not due under “production” lease unless gas is produced; (2) non-recoupable proceeds in settled contract do not bear royalties while settlement for reduced price does bear royalty; and (3) rejecting Frey and Klein rules as based on “unique” state statutes, as well as different lease language in Frey, and questioning viability of Harrell “cooperative venture” rule; remanding for determination of which portions of settlement were due to price deficiency claims and thus would be royalty bearing when production later occurred); Alameda v. TransAmerican Natural Gas Co., 950 S.W.2d 93, 96-100 (Tex. App. 1997) (following Bruni and TransAmerican v. Finkelstein and holding royalty not due even on nonrecoupable settlement buyout, nor on repudiation damages; finding duty to market issues not triggered without actual gas production); Watts v. Arco, 115 F.3d 785, 791-95 (10th Cir. 1997) (following Yates in holding that royalty was due at time gas was produced on any portion of settlement due to pricing issues, in case where Arco had paid royalties when it produced gas on $300 million settlement but not on other portions; remanding because of fact dispute over whether additional settlement funds were payments for price dispute and holding that they might be so even if pre-settlement price was not reduced; also reversing because of fact issue on whether Arco’s settlement satisfied its duty to get the best price in marketing gas); Condra v. Quinoco Petroleum, Inc., 954 S.W.2d 68, 70-73 (Tex. App. 1997) (following Bruni rule that royalty owners do not share in take-or-pay settlements, even where division orders required sharing of proceeds “from the sale of products produced” or “attributable to said property,” and straining to avoid obvious broad implication of “attributable”; following TransAmerican v. Finkelstein in holding that repudiation damages are not royalty bearing; finding no breach of duty to market in absence of production); Williamson v. Elf Aquitaine, Inc., 138 F.3d 546, 549-52 (5th Cir. 1998) (rejecting implied
covenant claim under Mississippi law because contract terms controlled; interpreting royalty on gas "produced from said land when sold by lessee" under amount realized lease to require production; following TransAmerican v. Finkelstein and rejecting distinction between recoupable and non-recoupable settlements); Westerman v. Rogers, 1 P.3d 228, 233-34 (Colo. App. 1999) (adopting Yates and Watts, but reversing summary judgment for lessees for determination of whether proceeds were due "solely to non-production," or instead due at least in part to a price adjustment); EEX Corp. v. U.S. Dept. of Interior, 111 F. Supp.2d 24, 31-33 (D.D.C. 2000) (holding payments not due on nonrecoupable payments, even if settlor was ultimate later purchaser, and thus rejecting Century Offshore limitation on Diamond Shamrock discussed below).

In Diamond Shamrock, the Fifth Circuit held that royalty payments would only be due when the gas was "produced and taken." Diamond Shamrock, 853 F.2d at 1161. In In re Century Offshore Management Corp., 111 F.3d 443, 449-50 (6th Cir. 1997), the Sixth Circuit held that when the lessee accepted a $12.25 million payment to replace its fixed-price contract with a floating-price contract, and the same buyer (Enron) actually took the gas, the "nexus" with production missing in Diamond Shamrock was present and the lessee had to add one-eighth of the $12.25 million to the royalty payments. The Sixth Circuit made a feeble effort at distinguishing IPAA v. Babbitt, 92 F.3d 1248 (D.C. Cir. 1996), which held that take-or-pay settlements should get the same treatment as Diamond Shamrock's prepayments (i.e., not be shared), because Babbitt involved a buyout settlement and the old contract was replaced by a new contract with an unrelated third party, while in Century Offshore the original buyer, Enron, kept buying the gas under a new replacement contract. See Century Offshore, 111 F.3d at 451-52. The Sixth Circuit said that the Babbitt sales therefore lacked a "nexus" with production, while the later Century Offshore Enron sales did have such a nexus. Id. This seems a valiant effort to breathe life into a lifeless principle. Can the Sixth Circuit really have thought it fair that producers could pocket all of take-or-pay buyouts if they shift to a new gas buyer but have to share if they are dumb enough to negotiate a replacement contract with the same buyer? This is a weaker approach than the flawed, but at least comprehensible, idea that if a producer enters a "buydown," the royalty owner should have to wait for the buyer to make-up the production before getting royalties on the bounty, but that if the producer agrees to a "buyout," so that the valuable take-or-pay contract disappears, royalty owners should share immediately because the lessee has contracted away the rights that the royalty owners otherwise could realize in the future. See infra notes 196-97 and accompanying text (discussing the early assumption that nonrecoupable payments would have to be passed through).

Perhaps the most surprising of the royalty-rejection cases was Roye Realty because the Oklahoma Supreme Court earlier had adopted such a broad purpose analysis when it rejected the Texas Supreme Court's Vela rule in Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981). In general, courts sticking to literalist opinions were more likely to agree with Diamond Shamrock; those taking a serious look at purpose tend to side with royalty owners. See infra notes 166, 175 and accompanying text. Thus it seemed likely that Oklahoma would join Frey and Klein. For a well-developed analysis of this likelihood, including what surely was an unlikely but sophisticated and ultimately correct prediction that Oklahoma would not have to join the Frey line, see Lowe, supra note 68, at 240-43, 254-64. Yet while the Oklahoma Supreme Court got it right in Tara, its analysis deteriorated by Roye, where it opted for an inappropriately simple literal interpretation.

John Lowe's correct prediction that Oklahoma's position in Tara would not necessarily determine its take-or-pay rule is even more interesting because he provided a thoughtful and seemingly supportive analysis of the cooperative venture theory. Lowe pointed out that the uncertainty of any given oil and gas project made it hard to set a fixed price for the lease and simpler to enter what really is an "economic partnership" to locate
mineral wealth. See Lowe, supra note 68, at 252. Second, because parties generally do not make fine distinctions between the major lease pricing terms and certainly did not expect before the mid-eighties the fallen gas market into which the industry stumbled, it makes less sense to pretend that leases expressly deal with the take-or-pay situation (predicated as it is on the failure of demand for gas). See id. Finally, Lowe argued that royalties payable in cash (as opposed to production) can sustain a "broader concept of royalty." id. at 253. Lowe then backtracked, however, and argued that cooperative venture theory need not require sharing take-or-pay payments because Klein and Frey may be read as unjust enrichment cases, upon statutory language that may sustain such a theory, and other states may not follow this path, id. at 255-57; and such an extension might extend the royalty obligation into entrepreneurial areas that best be left to the lessee. id. at 257-64. This ultimately narrow reading of Klein and Frey underemphasizes how essential the logic of the cooperative venture theory is to their result and is unfaithful to the nature of the take-or-pay exchange by pretending that take-or-pay payments are returns to some specialized entrepreneurial skill when they are fundamentally payments for the gas earned under the lease. Lowe deserves great credit, though, for foreseeing the unlikely result that Oklahoma would not step straight from Tara to Roye Realty and join Louisiana and Arkansas as a third state requiring royalty passthrough of take-or-pay payments and settlements.

John Lowe has noted another irony in the Vela to take-or-pay transition. In the Vela situation, lessees strained to argue that they "sold" their gas when they entered a gas purchase agreement so the market value was fixed at that time (and if market prices later rose, the "market value" or "market price" for a given well's production nonetheless had been set when the contract was entered). See id. at 243. In the take-or-pay context, of course, lessees argue that the "sale" or "production" occurs not when they enter a gas purchase agreement but should wait until the day when a particular molecule emerges from the wellhead. Royalty owners, in contrast, argued in the Vela context that market value had to be measured as the gas flowed, but in take-or-pay disputes sought to fix production at the moment of contracting. See id. The true guide in both instances should have been whether the parties envisioned a separation in their share of production. Vela is wrong because it drives a wedge between lessee and lessor. The take-or-pay majority is just as wrong because they also separate lessor and lessee in ways neither had any reason to expect when the lease began.

It is interesting to contrast the judicial stampede to adopt Diamond Shamrock's simplistic view with trends in academic commentary. In general, authors most seduced by the plain meaning interpretation have tended to have less experience. See Angela Jeanne Crowder, Note, Take-or-Pay Payments and Settlements—Does the Landowner Share?, 49 LA. L. REV. 921 (1989); Barrett, supra note 127, at 755-56.

Those who paid their industry dues offered more temperate and reserved judgments or at least were more skeptical of depriving lessees of all benefits shared by the other interest owners. See generally Frank Douglass, Tort Liability Between Lessors and Lessees—The Duty of Good Faith and Fair Dealing (If Any), Punitive Damages, Royalty Owner Exposure, in STATE BAR OF TEXAS, ADVANCED OIL, GAS AND MINERAL LAW COURSE I-1, I-9 to -11 (1991) (surveying status of law and arguments available to both sides and predicting that fight "is not quite over"); Kramer, supra note 145 (suggesting broad interpretation of "production" and "sale" and that settlements should not deprive royalty owners of nonrecoupable payments); John S. Lowe, Current Lease and Royalty Problems in the Gas Industry, 23 TULSA L.J. 548, 560-64 (1988) (reviewing arguments but not taking final position); Lowe, supra note 68, at 266-67 (breaking cases into plain meaning and cooperative venture camps, though arguing with what turned out to be uncanny prescience that even cooperative-venture jurisdictions should not necessarily require sharing with royalty owners); William White, The Right to Recover Royalties on Natural Gas Take-or-Pay Settlements, 41 OKLA. L. REV. 663 (1988)
A Fifth Circuit opinion that followed within barely a year offers a glaring example of the unfairness of Diamond Shamrock and its no-production, no-royalty rule. Gerard J.W. Bos & Co., Inc. v. Harkins & Co. was a forced integration case. The gas from Bos's property was committed to a long-term take-or-pay contract. Bos received royalty payments like clockwork for eight years. As long as the buyer took the gas, Bos bathed fully in the gas revenue stream, as did the operator and working interest owners.

After eight years of production and royalty payments—eight years of equal treatment among operator, working interest, and royalty owners—the operator accepted the buyer's offer to cancel the contract. It collected a $7.3 million buyout. With the contract termination went the high gas price, so the operator shut the well down.

Neither the Fifth Circuit nor the trial court seems to have perceived any unfairness in letting the operator redo its contract to extinguish the royalty stream, as if having no duty to Bos. In spite of Diamond Shamrock, Bos may have felt particularly confident going into the case because of precedent that operators in unitized properties have a fiduciary duty to

(reviewing arguments on both sides, though seemingly finding some support for lessee's position in federal energy policy); cf. Smith, supra note 19, at 511-19 (in article that surveyed both sides, finding immediate sharing of prepayments unlikely under standard lease terms, but claims on settlements more viable).

One telling tea-leaf reading is the 1987 article by Richard Pierce, Lessor/Lessee Relations in a Turbulent Gas Market, 38 OIL & GAS L. & TAX’N 8-1 (1987). The article is interesting because the royalty-exclusion trend in the cases was not yet apparent. Pierce argued for broad deference to producers who agreed to lower prices in settling disputes, see id. at 8-17 to 8-19, but that courts should treat lump sum payments as "proceeds of production" and make producers pay royalties on them, thus avoiding the "potential injustice and distortive effect of allowing producers to retain 100 percent of the lump sum payment," see id. at 8-19 to 8-20; that producers should have to share any benefit received on another contract in return for a lower price, a la First Baptist, see id. at 8-19 to 8-20; and that damage awards for failure to take gas would have to be shared while on those for failure to pay, "probably the right answer" would be payment when production occurs (or immediately if gas was not made up), see id. at 8-21 to 8-22. As with other mature observers' proposals, so Pierce's ideas were his best effort to find a set of rules that would have royalty owners share all true economic benefits earned by the lessee, while observing the traditional rule that royalty only is paid when gas comes from the ground. He saw the unfairness of a rule under which royalty owners never would get to share certain take-or-pay revenues. Unfortunately, few courts have seen as clearly.

156. Gerard J.W. Bos & Co. v. Harkins & Co., 883 F.2d 379 (5th Cir. 1989). Bos's property was "force-integrated" under Mississippi's conservation statutes, which provided that if the owners did not voluntarily combine their acreage, "the [Oil and Gas Board] may, for the prevention of waste or to avoid the drilling of unnecessary wells, require such persons to integrate their interests and to develop their lands as a drilling unit." Id. at 381 (citing MISS. CODE ANN. § 53-3-7 (1999)).
working interest and even royalty owners.\textsuperscript{157} But the Fifth Circuit rejected the unit-operator argument\textsuperscript{158} as well as those from trust and agency law.\textsuperscript{159} Even if Bos had a directly enforceable claim against operator Harkins as long as the contract was in place, at least if any production occurred, the court nonchalantly said that Bos lost standing to complain when Harkins cashed out the contract’s net present value. Bos was a “mere incidental beneficiary” of the take-or-pay contract.\textsuperscript{160} By the economically simple act of capitalizing the contract’s value into a single payment, Harkins unilaterally ended Bos’s royalty benefit. The court gave Harkins an incentive to split the savings from not paying any royalty with the gas purchaser or to try to keep it all. Just as surely, it removed the incentive for Harkins to protect Bos.\textsuperscript{161}

*Gerard Bos* illustrates *Diamond Shamrock’s* extremism because the contract termination seems to have ended the royalty stream. “Bos alleges that as a result of this action the well on the unit was shut down, causing Bos’s royalty income to be permanently lost.”\textsuperscript{162} Ruling on appeal from

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\textsuperscript{158} The Fifth Circuit distinguished the argument that operators in forcibly pooled units are fiduciaries to royalty owners by noting that Bos had not cited any authority under Mississippi law and, in any event, Bos’s duty to market had not been among the operator’s statutorily mandated duties. See *Gerard Bos*, 883 F.2d at 381. The problem with this dismissive statutory reading is that the court made no effort to show that other royalty owners, say those unitized in *Young v. West Edmond Hunton Lime Unit*, had a more effective power than royalty owners integrated under the Mississippi statute. Even royalty owners with rights set just under their original royalty agreement do not have meaningfully greater powers than under a unitization statute.\textsuperscript{159}

\textsuperscript{159} *Gerard Bos* is an unusual take-or-pay royalty case for its time because the plaintiff did not raise or preserve on appeal arguments drawn from the lease language or the duty to market. The reason might be that the Fifth Circuit had decided *Diamond Shamrock* little more than a year before and the lawyers saw the writing on the wall.\textsuperscript{160}

\textsuperscript{160} *Gerard Bos*, 883 F.2d at 382.

\textsuperscript{161} The punitive unreality of *Gerard Bos*, and the head-in-the-sand quality of so many similar take-or-pay royalty cases, is underlined by the Fifth Circuit’s gratuitous dictum that Bos having leased its acreage to another operator, “it is to that operator Bos should look in such circumstances as these.” *Id.* “That” operator, Bos’s initial lessee, had lost its job when the unit was formed. Forcible integration deprived “that” operator of any authority over the acreage. It retained no control over the production and received no payment to act as operator. Indeed, if “that” operator tried to sell Bos’s gas, the Fifth Circuit should have held that it had usurped the unit operator’s powers under Mississippi’s conservation statutes. Bos’s excluded lessee had no legal basis to determine in any way what the unit operator did with the production, not in the contract the unit operator entered in 1978, nor in the settlement to which it succumbed in 1986. Bos’s lessee had every right to have forgotten all about the property.\textsuperscript{161}

\textsuperscript{162} *Id.* at 381.
summary judgment, the Fifth Circuit had to treat this allegation as true. Rather than merely postponing the royalty owner revenues, the settlement may have extinguished them. The royalty owners might get their now-uneconomic lease back under lease forfeiture provisions, but the operator would not feel any pinch with the $7.3 million still warm in its pocket.

Gerard Bos provides yet another example of the unfairness of the royalty-exclusion rule. At first, operator Harkins kept the full $7.3 million and did not even share the money with its investing partners. But no one had trouble spotting the indefensibility of that unjust enrichment. When the working interest owners sued, Harkins cut them in on the deal. Bos, whose property after all was the original source of all this bounty, naturally demanded a share. But the court denied Bos the right to intervene in the working interest owners' lawsuit, and when Bos sued separately in federal court, it lost there, too. Bos had lost, entirely at its operator's whim, a payment stream that had years more to run, without getting a penny for this judicially-sanctioned sacrifice.

3. The Errors of Diamond Shamrock's Royalty-Exclusion Rule

The fact that there now is a widespread majority rule in the take-or-pay royalty-exclusion cases should not obscure how badly these cases misinterpret the royalty relationship. Their plain meaning arguments gloss over the difficulties of trying to fit language that assumes production onto a payment that is made to delay or never produce. Their purpose analysis ignores the primary purpose of the take-or-pay contract, which is to sell gas, and of the lease, which is to share all basic lease benefits. Other technical arguments present specious objections that could be raised against working interest owners as well, but are not.

a. The Plain Meaning of Words Like "Produced" and "Sold" Cannot Resolve the Take-or-Pay Royalty Cases

The first of the two foundation stones for courts that will not let royalty owners share take-or-pay benefits is contract language keyed to

163. See id.
164. See id. at 380-81.
165. With the abstraction that can dog court opinions (as in Diamond Shamrock's giving no hint of the amounts at stake), the Fifth Circuit did not tell its readers the duration of the terminated contract or total projected contract revenues, so they cannot determine the full scope of the sacrifice the court imposed on the royalty owners. The court did state, however, that the contract was a "long-term" contract that had run only eight years. Id. at 380. Long-term take-or-pay contracts in the late seventies and early eighties tended to last fifteen or twenty years, so it is most likely that Bos lost as much as seven to twelve years of high-priced royalty payments. When courts fail to list the amounts in dispute, a lawsuit might just as well be over peanuts as real money; but the buyout price was $7.3 million and presumably the total foregone income was significantly more than this.
"production."\textsuperscript{166} For instance, the Wyoming leases in \textit{State v. Pennzoil} turned on gas "produced from said land, saved and sold or used off the premises," with payment to follow in the month "succeeding the month of production and removal and sale...."\textsuperscript{167} In \textit{Diamond Shamrock}, royalties were due on the "value of 'production saved, removed, or sold from the leased area.'"\textsuperscript{168} These leases, too, timed payment to the last day after the month when "production is obtained."\textsuperscript{169}

The question in the take-or-pay royalty cases is whether this language covers the situation when a buyer pays for gas but it is not yet produced, or pays the producer \textit{not} to produce. When a buyer makes a prepayment, gas is not actually "produced," but the payment still is "for" gas intended to be produced and sold. All that has happened is that the production has been delayed, while payment stayed on schedule.\textsuperscript{170} None

\textsuperscript{166} See generally Smith, \textit{supra} note 19, at 513 (issue "turns in large part upon a construction of the royalty and related clauses in the oil and gas lease"). The "best argument" for \textit{not} sharing take-or-pay payments comes from contract language. See Lowe, \textit{supra} note 155, at 562; Lowe, \textit{supra} note 68, at 236-40 (discussing the "plain-meaning" roots of the cases denying royalty sharing); Roye Realty, Inc. v. Watson, 2 P.3d 320, 324 (Okla. 1996) ("jurisdictions favoring the producer rely primarily on a strict interpretation of the language in the leases concerning what constitutes a 'sale' and 'production'...."). At least, it comes from readings that oversimplify that language. See \textit{generally Crowder}, \textit{supra} note 155, at 935 (using plain-meaning reading to argue that royalties are not due on prepayments or settlements); cf. King, \textit{supra} note 127, at 807 (labeling the "production" argument based on lease language a "losing argument" for royalty owners). It is true that the market value/ market price term and the proceeds/amount realized term both key payment to what sounds like physical "production," to gas "produced and saved, sold, or used," or to the proceeds from the "disposition of produced gas." See Kirk Bily, Comment, \textit{Royalty on Take-or-Pay Payments and Related Consideration Accruing to Producers}, 27 \textit{Houston L. Rev.} 105, 129-30 (1990). Moreover, leases for the federal government and some of the major producing states used production in their definitional language, too. See \textit{id.} at 122-29 (analyzing state leases in Wyoming, Texas, and Louisiana); see also \textit{id.} at 113-22 (discussing standard U.S. lease language and its interpretation). That should be the beginning, not the end, of the discussion.

\textsuperscript{167} \textit{State v. Pennzoil}, 752 P.2d at 976 (emphasis added).

\textsuperscript{168} \textit{Diamond Shamrock}, 853 F.2d at 1161 (emphasis added). Underlying regulations did require lessees to pay no less than the "gross proceeds accruing to the lease from the disposition of the produced substances." \textit{Id.} at 1163-65. The Fifth Circuit seems to have ignored the broad definition of production in the Outer Continental Shelf Lands Act in addition to the MMS regulations. For criticism of the trial-level slightning of these regulatory provisions, an analysis which the Fifth Circuit's \textit{Diamond Shamrock} opinion would perpetuate, see Kramer, \textit{supra} note 145, at 5-16 to 5-18.

\textsuperscript{169} \textit{See Diamond Shamrock}, 853 F.2d at 1163-64 (emphasis added).

\textsuperscript{170} Ernest Smith is right that the logic of the lessees' position should have been merely that paying royalty was deferred until production. See Smith, \textit{supra} note 19, at 511, 517. This position, however, overlooks the often heavy loss in the time value of money. Moreover, the damage to royalty owners would be limited to the time value of money only if courts ordered royalties paid on prepayments as soon as it became clear that the buyer would not take the gas, and on nonrecoupable settlements when they were made. Yet the law has not required
of the leases in published take-or-pay cases dealt specifically with this situation. None said that "lessee and its partners can keep every penny of all prepayments, buyouts, and buydowns and need not share them with royalty owners if the lessee takes money without producing the gas." None said that the royalty owner (but no one else) can be forced to ignore the moment of payment and wait to see if production occurs before getting paid.

*Diamond Shamrock* strained to achieve such a result-driven verbal analysis. The Fifth Circuit ignored governing federal regulations that the "value of production" shall "under no circumstances...be less than the gross proceeds accruing to the lessee from the disposition of the produced substances...." It is hard to think of clearer words to indicate that taxpayers are to share in all benefits derived from federal leases. Something is wrong when a court cannot see that this blunt and broad language entitled the federal government to share the lessee's proceeds on the accrued disposition of production (even if for gas not yet produced). That is particularly so when "production" in oil and gas law does not invariably require physical severance from the ground.

sharing in these circumstances, either. So, as Gerard Bos shows, royalty owners can lose their entire right to any part of the take-or-pay revenue stream.

171. *See Diamond Shamrock*, 853 F.2d at 1164-65 (emphasis added).

172. Judge Brown hardly could have been confused about the true meaning of the deferential standard of review. *See id.* at 1164-65. Just three years later he wielded exactly this deference as the proper justification for endorsing that agency's decision to include reimbursed post-production costs as part of the royalty "amount" or "value" and affirm summary judgment for MMS. *See generally* Mesa Operating Ltd. v. U.S. Dept. of Interior, 931 F.2d 318 (5th Cir. 1991). Although Judge Brown indicated in *Mesa Operating* that he might find the producer's position plausible, he correctly held that "we may reject [the government position] only if the agency's interpretation is impermissible or unreasonable." *Id.* at 322-23 & nn.27-28. *Mesa* had tried to bootstrap *Diamond Shamrock* by arguing that it must apply to post as well as pre-production events, and that because the post-production costs occurred after production, they were no more a payment "for production" than take-or-pay prepayments. *See id.* at 322. Judge Brown turned *Mesa* down with a broad reading of the "gross proceeds" on which the government could claim a share and did so without any visible sign of shame or even recognition that he had violated that principle in *Diamond Shamrock*.

173. *See Smith*, *supra* note 19, at 514-16 (discussing states that separate "production" from severance of gas in determining how much production is needed to hold a lease, or that require payments on gas "sold" or "marketed" without requiring production); *Kramer*, *supra* note 145, § 5.04[2]-[3], at 5-15 to 5-30, 5-35 to 5-36 (arguing that neither "production" nor "sale" is as clear as might seem, and that "production" could include all benefits from lease and that "sale" could occur before production); *Lowe*, *supra* note 155, at 553-55 (discussing Oklahoma minority rule that "production" only "means merely a capability of gas production (because the purpose of the lease is substantially performed when gas has been discovered and the well prepared to produce)," as well as contrary majority rule).

What one sees is not necessarily what one gets with "production." Even Judge Brown seems to have known that language was not a sufficient justification for *Diamond Shamrock*. 
Lease terms that require payment 30 days after production do tie some payments to actual production, but they do not address the unusual situation when the buyer defers taking gas. This is another way of asking whether, if the parties separate production from payment, "produced and sold" royalty language addresses the situation. None of the many take-or-pay opinions has found a persuasive reason why this language differentiates royalty owners from other interest owners who do benefit when the buyer pays months before gas is produced (or if the gas never is produced).

b. Diamond Shamrock Misconstrued the Purpose of the Take-or-Pay Contract and of the Lease

The other bulwark of the royalty-exclusion courts is Diamond Shamrock's quirky purpose analysis. One would have predicted that if courts found purpose relevant, they would require shared benefits under the mutual benefit principle. For example, the Frey and Klein courts' purpose analysis led them to require sharing. How could it not be true that "the lessor contributes the land and the lessee the capital and expertise necessary to develop the minerals for the mutual benefit of both parties?" That should have been particularly obvious in Diamond Shamrock, where the court was to defer to MMS's mutual benefit interpretation. Yet Judge Brown held that prepayments are payments for non-production, intended only to repay "the risks associated with development production." He thought of royalty owners as undeserving free riders who should not "reap the benefits, through royalty payments, without..."

He called "production" a "horse of many colors" that is used in the industry "in several different but related senses." Diamond Shamrock, 853 F.2d at 1165-66. Judge Brown admitted the term can be used to refer to the products from a well or to the well. See id. at 1166. Presumably a sense that language could not really resolve the dispute is why he leaned so heavily on his purpose analysis.

174. For the same reason, in the event of a prepayment or settlement, the shut-in payment that the lessee might otherwise owe to the royalty owners under the literal terms of the lease—the payment to hold the lease when actual production gets curtailed, including for market conditions, see Williams & Meyers, supra note 1, at 1149, should not be due.

175. See supra notes 117-21, 124-30, 137-38 and accompanying text; see generally Lowe, supra note 155, at 563 (courts looking beyond literal terms have tended to recognize implied covenant to market); Lowe, supra note 68, at 240-43 (discussing Frey and Klein as cooperative venture opinions, though later arguing that that theory need not lead to sharing of take-or-pay royalties); Roye Realty & Developing, Inc. v. Watson, 2 P.3d 320, 324 (Okla. 1996) (jurisdictions "finding for the royalty owners have [gone beyond contract language and] adopted a broader 'economic benefit' test....").

176. See Frey IV, 603 So. 2d at 173.

177. See, e.g., Roye Realty, 2 P.3d at 329.

178. Diamond Shamrock, 853 F.2d at 1167.
having to shoulder the associated risks of exploration, production and development."

This off-the-cuff idea that take-or-pay payments are not payments for gas is a prime example of why judges should not usurp fact determinations. But for the deference we accord judges, this analysis would be treated as a gaffe, a howler, a mistake bizarrely at odds with industry practices. It is one of the problems of a precedent-based system of law that once a decision this unfounded becomes identified with a case name, its solidification into "precedent" gives it a respectability that is entirely undeserved. Experienced oil and gas lawyers (those representing producers, of course) could start pontificating about "the Diamond Shamrock case" and its royalty/exclusion principle as if it made some sense, all the while knowing that the holding is preposterous. Producers are happy to treat the opinion as one of great sagacity because it gives them a windfall: suddenly here is judicial sanction for pocketing their royalty owners' proceeds.

179. See id. at 1167. As note 155 documents, Diamond Shamrock's purpose analysis then was adopted by court after court. One commentator has argued that the "inherent cooperativeness and mutuality" of the lease cannot decide the cases because the lease is not a fiduciary relationship, see Crowder, supra note 155, at 934, an irrelevant argument when the implied covenant is a contract, not tort, duty.

180. The same excess deference is apparent in the way that the few courts that clearly held that Diamond Shamrock was just wrong, on the most fundamental basis, struggled to avoid saying so directly. When a judicial king wears no clothes, it can be as rare for peer judges as for judicial subjects to point out the obvious as it is in the fable.

This lack-of-candor problem, not surprisingly, was acute when the opinions were in the same jurisdiction. Thus Judge Reavley, who rejected the core underpinnings of Judge Brown's opinion, see supra notes 118-25 and accompanying text, nonetheless went out of his way to avoid saying directly that Judge Brown got it wrong, see supra note 118 (laboriously trotting out three differences to spare Diamond Shamrock this embarrassment). But one can trace the funny little judicial dance of politeness even in jurisdictions that had no legal need for deference. The Louisiana Supreme Court, for instance, had no need to be polite to the Fifth Circuit (after all, that court had asked it to interpret its own law!), yet it treated Diamond Shamrock with kid gloves. Its reasoning was entirely at odds with Diamond Shamrock, but the Court stated that "we do not deem prudent an excursion far beyond the bounds of the precise question certified." Frey IV, 603 So. 2d at 171. It nominally based its opinion on Louisiana law. See supra note 124 and accompanying text. In other words, it was not going to say just what it thought of any other Fifth Circuit decision...like Diamond Shamrock. In Klein, the Eighth Circuit was just as delicate in putting the differences between Diamond Shamrock and Frey in the record, see Klein I, 980 F.2d at 529-30, rather than simply saying that Frey was wrongly decided. And see the exquisite, but implausible, "nexus" analysis that the Sixth Circuit in In re Century Offshore Management claimed did not conflict with Babbitt, which after all is rotten fruit off the Diamond Shamrock tree. See In re Century Offshore Mgmt. Corp., 111 F.3d 443, 449-52 (6th Cir. 1997).

In Frey, concurring Judge Jones wanted to remind everyone that "we are not attempting to overrule the Diamond Shamrock case," and that "[w]e could not do so" under rules about one panel not overturning another. See Frey II, 943 F.2d at 588 (Jones, J.,
Judge Brown made two basic mistakes in his purpose analysis. He improperly narrowed the functions of take-or-pay contracts and he ignored the lease. On the first point, the most that can be said for his risk-of-production theory is that repaying the production risk is among the gas seller's hopes. The lessee obviously wants to repay its costs. But when it enters a gas purchase agreement, its primary goal is to get as much as it can for its gas. The buyer's purpose is centered entirely on reserves. The buyer could care less about the seller's risk; it is trying to secure as much gas as it can.

The central transaction in a take-or-pay contract is not a payment for the risk of drilling wells. It is cash for gas. This purpose infuses every part of the transaction: the title, the commitment of reserves and their description, the measure of the obligation, the technical attachments about gas quality and manner of production, many of the force majeure terms, and the basis for paying royalty including the lengthy pricing terms that dominate the contract.\textsuperscript{181}

\textsuperscript{181} Take-or-pay contracts are invariably titled "gas purchase agreement" or "gas sales agreement." They are never called "production-expense reimbursement agreement," "drilling cost repayment contract," or "risk defraying agreement." The standard buyer's obligation is not tied to the cost of drilling. The contract price does not rise or fall with production costs, nor do payments vary with the producer's success as it drills more wells. Lessees who drill dry holes receive nothing for that risk under a take-or-pay contract. Those who drill expensive wells that cost more than the total revenues are not protected. Conversely, lessees who have great success, so that their drilling cost is only a fraction of the take-or-pay payments, do not find that their costs serve as a ceiling capping the payments due from the buyer. A take-or-pay contract makes no adjustment for whether its revenues cover the seller's cost and risks.
Even Judge Brown's take-or-pay purpose analysis, though, is not the worst mistake in *Diamond Shamrock* and its progeny. That honor is reserved for its conclusion that take-or-pay contracts should set the lease obligation.  

Even if take-or-pay payments purely compensate the risk of production, royalty owners still have a right to production "free of costs."

Another fact that shows that a take-or-pay contract is centrally about gas reserves is that the contracts ordinarily were not entered until at least one well had been drilled. The seller would then dedicate the reserves it had found to the buyer. The exchange is a payment for gas. Moreover, the formula for calculating the take-or-pay prepayment typically was a measure of reserves—usually set by a gas deliverability test—multiplied by the contract price. The starting point for buyout and buy-down settlements invariably was a reservoir engineer's report of the likely reserves, times the price; settlement talks would focus on how heavily these figures should be discounted. 

The effort to pretend that take-or-pay contracts are not basically about gas should be no more successful than failed pipeline efforts to contend that their take-or-pay promises did not encompass the falling market of the eighties. As the Oklahoma Supreme Court would note in that context, "take-or-pay provisions permeate[] the entire contract," with their varied price provisions to fix and limit the protection pipelines could hope to get against a drop in the market. *See* Golsen v. ONG Western, Inc. 756 P.2d 1209, 1213-14 (Okla. 1988). There is no reason to believe the parties thought they were tying gas payments to cost or risk reimbursement rather than reserves, but somehow forgot to say so, when references to the gas reserves so permeate the contract.

The timing of prepayments helps disprove the risk-reward theory. Pipelines stopped taking gas under contracts that had been in effect for some years. In many instances, most or all of the wells had been drilled and the lessees and their partners had recouped their well costs. The disputed prepayments came at the middle or end of the contract life, not in the beginning when drilling costs still needed to be compensated. Payments often came when the operator and interest owners were collecting nearly pure profit. The production risk at this stage was minimal. *Diamond Shamrock* has deprived many royalty owners of prepayments and settlements in order to reward operators for risks that often did not need to be repaid. 

As more proof that this risk-protection cannot be the purpose of the take-or-pay contract, the industry does have contracts that tie payments for gas to drilling costs. As an example, producers sometimes enter contracts with drilling companies in which costs are paid only from a share of production. *See* Jane Romanov et al., An Overview of Sources of Capital and Structure in Investments in Oil and Gas, 34 R. MTN. MIN. L. INST. 13-1, 13-26 (1988). The operator sometimes will guarantee payment, but at other times the driller may look solely to production. There would not have been anything difficult in tying a gas purchase agreement to the producer's costs—but take-or-pay contracts did not do so. 

182. As one author has put it, "why should the purpose for which the lessee and the pipeline enter into a gas contract dictate the terms of the relationship between the lessor and the lessee?" King, supra note 127, at 821; see also Weaver, supra note 3, at 538-39 (criticizing courts that ignore the way that gas contracts affect lease). That Texas state courts and other jurisdictions applying the Texas Vela rule would make the mistake of letting a reading of the take-or-pay contract trump the lease is particularly odd (putting aside for the moment the fact that the take-or-pay reading is a misreading, too) because, as a later opinion rejecting Vela pointed out, that rule is based on the independence of the lease obligation from the gas purchase agreement. *See* Henry v. Ballard & Cordell Corp., 418 So. 2d 1334, 1337-38 (La. 1982) (quoting *Vela* as principle that lease royalty entitlement must be determined under lease, independently from gas sales contract (citation omitted)).
They are supposed to share in the revenue stream from the first dollar—even when the lessee and its partners are just beginning to recoup costs.\textsuperscript{183} In contrast, were royalties conditioned on drilling risk, the lease would postpone royalties until "payout" when costs had been reimbursed.\textsuperscript{184} Yet no standard lease and no lease in the published cases ties royalties to producer cost recoupment. The idea of limiting royalties to drilling costs cannot be squared with the goal of establishing the royalty as an interest free of costs.

c. Lessors Did Not Intend to Disclaim Take-or-Pay Prepayments and Settlements

A frequently advanced reason for denying royalty owners their share of take-or-pay payments is an inferential argument about specific intent. This punitive argument runs that lessors must not have intended to share prepayments and settlements, or else they would have inserted that right in the lease.\textsuperscript{185}

Unfortunately for this argument, none of the cases denying sharing has turned up even one occasion when lessors specifically discussed the treatment of take-or-pay royalties, much less agreed that lessees could keep the money. Judicial reasoning that lessors intended this result surely is incorrect. Most lessors are inexperienced and have relatively small financial stakes.\textsuperscript{186} When lessors sign a lease, they may not even know if their lessee

\textsuperscript{183}. If the fact that producers bore some risks not shared with royalty owners could defeat the duty to share lease benefits with lessors, it "would also logically follow that 'all royalties are unfair.'" White, \textit{supra} note 155, at 669.

For a proper distinction between the allocation of risks in the take-or-pay contract and lease obligations, see \textit{In re Century Offshore Mgmt. Corp.}, 111 F.3d 443, 451 (6th Cir. 1997).

\textsuperscript{184}. This suggestion is not fanciful. Farm-out agreements often postpone payments, or vary revenue percentages, until payout, the "period required for a well to produce sufficient oil or gas to reimburse the investment in the well." \textit{Williams & Meyers, supra} note 1, at 885. Operating agreements have another sophisticated provision to tie payments to cost, the "nonconsent" penalty. If some partners go nonconsent, giving notice that they will not pay for a well, the "participating" parties get to recoup a multiple (often 300 percent or so) of the costs before the others resume their revenue interests. See \textit{Andrew Derman, The New and Improved 1989 Joint Operating Agreement: A Working Manual} 51-55 (1991) (discussing customary non-consent penalties). Had lessors and lessees intended to make royalty payments contingent upon well risks and costs, they could have done so using language already common and familiar in the industry.


will drill a well, and they quite often won't know the gas purchaser or terms of purchase. It would have taken extraordinary clairvoyance for royalty owners, who assumed they would share proportionately in whatever value the lessee could extract from the mineral interest, to divine that they needed an express requirement to share payments for gas not taken.

The timing of take-or-pay disputes makes the idea that royalty owners intended to disclaim take-or-pay payments far-fetched. When producers and pipelines entered these contracts in the seventies and early eighties, it was a time of high prices and expectations.187 Virtually every published take-or-pay opinion turns on a lease entered in this period of gas shortage.188 It is hard to imagine why a royalty owner who assumed it

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187. See Medina et al, supra note 112, and accompanying text.
188. Looking at the contracts in the major published decisions, from the earliest decided case first: There is no indication of when Pennzoil leased the state property in State v. Pennzoil Co. The government issued the Mesa lease at issue in Diamond Shamrock in 1973. See Diamond Shamrock, 853 F.2d at 1161. The opinion does not indicate when the government granted the leases in the other Diamond Shamrock case. Mr. Frey gave Amoco its lease in 1975. See Frey I, 708 F. Supp. at 784. The initial lease entered before the forced integration in Gerard Bos was made in 1976. See Gerard J.W. Bos & Co. v. Harkins & Co., 883 F.2d 379, 380 (5th Cir. 1989). The Bruni Mineral Trust executed its lease to Killam Oil Company, the one at stake in both Killam Oil Co. v. Bruni and Hurd Enterprises v. Bruni, in 1974. See Killam Oil Co. v. Bruni, 806 S.W.2d at 265. The Mandell v. Hamman Oil lease was a 1978 lease. See Mandell v. Hamman Oil & Refining Co., 822 S.W.2d at 156. Klein was a class action with about 3000 members, but development of the field began in the 1950s, see Klein I, 980 F.2d at 523, so the great majority of leases should have been in existence before the late seventies. TransAmerican Natural Gas v. Finkelstein stemmed from a 1974 overriding royalty agreement. See TransAmerican Natural Gas v. Finkelstein, 933 S.W.2d at 593-94. Samedan became lessee under the Indian lease in 1979 in Independent Petroleum Association of America v. Babbitt, 92 F.3d 1248, 1254 (D.C. Cir. 1996). The Oklahoma Supreme Court did not give the date of the lease it emasculated in this key
would share whatever the lessee found, and who issued its lease when pipelines were buying all the gas they could lay their hands on, "intended" to give up the right to take-or-pay payments.

d. Double Payments, Gas in the Ground: Two Trivial Arguments

Courts have used several other throw-away arguments to deprive royalty owners of take-or-pay royalties. For instance, Judge Brown purported to worry about "two royalty payments" on "one purchase of gas."189 Yet the double payment problem would affect working interest area of performance in Roye Realty v. Watson. Yates v. Powell was a declaratory judgment action brought by one large producer and a trade association of oil and gas companies to invalidate a New Mexico Commissioner of Public Lands' regulation that applied to over thirteen million acres of state land held in trust for such beneficiaries as schools, see Harvey E. Yates Co. v. Powell, 98 F.3d 1222, 1226 (10th Cir. 1996), so there is no single date for the leases but most surely would pre-date the last boom. In Alameda v. TransAmerican Natural Gas, the lease was last assigned in 1982. See Alameda v. TransAmerican Natural Gas Co., 950 S.W.2d 93, 95 n.3 (Tex. App. 1997). The Condra v. Quinoco lease came about in 1979. See Condra v. Quinoco Petroleum, Inc., 954 S.W.2d 68, 69 (Tex. App. 1997). The Fifth Circuit did not give the date of the leases in Williamson v. Elf Aquitaine, but the trial court indicated that the leases in dispute predated the early eighties downturn. See Williamson v. Elf Aquitaine, 25 F. Supp.2d 1163, 1166 (N.D. Miss. 1996). The leaseholds in Westerman v. Rogers apparently predated the 1977 gas purchase agreements. See Westerman v. Rogers, 1 P.3d 228, 229 (Colo. App. 1999). In EEX Corp. v. U.S. Dept. of Interior, the leases predated the 1969 gas contracts. See EEX Corp. v. U.S. Dept. of Interior, 111 F. Supp.2d 24, 25 (D.D.C. 2000).

Each of the identifiable leases was entered before or during the last boom, with its common predictions of $10 per mcf of gas and $90 per barrel of oil. Sophisticated producers may have understood the need to get protection against market decline (even if they did not "expect" the market to fall). Only with gross unrealism, however, can judges suggest that the average royalty owner in the boom years should have understood or seen any need to protect itself from the risk that its lessee would, in spite of their shared interest, cut it out if the gas buyer decided to make a prepayment but not take gas at the same time. Royalty owners had no reason to expect their lessees to break the royalty bond. They surely had no reason to expect courts to allow that to occur, nor would they expect to have to think about the minutia of gas purchase agreements. Leases do not mention the terms of the gas purchase agreement, much less technical payment concepts like "prepayments," "contract quantities," measures of "deliverability," or "makeup." The great majority of royalty owners could not have told a judge what those terms meant, either when they signed the lease or when they sued.

189. See Diamond Shamrock, 853 F.2d at 1166; see also White, supra note 155, at 669-70 ("Some of the most persuasive arguments against a royalty obligation are practical ones," discussing two-payment issue and claiming that "accounting will be even more complicated" if refunds are needed after prices fall); Crowder, supra note 155, at 934.

Diamond Shamrock is an unsatisfying opinion on so many grounds that the double-payment argument cannot head the list, but it deserves a firm footing on it. In his Olympian detachment, Judge Brown did not mention how much money his ruling was taking from the federal government and taxpayers. By not listing the very large amounts at stake, the court deflected attention from the absurdity of letting this minor bookkeeping arrangement block royalty payments. If it would cost the producers millions to figure out how to transfer a second payment and if royalties were in the thousands, perhaps these parties would not have
partners, too. If a buyer later takes prepaid gas at a higher price, the lessee will have to cut a second check to those interest owners as well. The lessee and its partners are thus saying that they cannot offer their royalty owners a payment mechanism they would use for themselves. The lease does not justify a double standard so customized to punish royalty owners.  

Another weak argument is that the royalty owner is not losing anything because its gas remains in the ground and can be sold later. To take-or-pay lawyers, this argument resurrects with a vengeance an already rejected pipeline position that producers suffered no injury when pipelines refused to make gas prepayments because the gas stayed in the ground. In fact, whether the gas ultimately is taken pursuant to a prepayment or later sold to some other buyer, the delay costs royalty owners the time value of the prepayment. They suffer a real economic loss. They have to wait for a hypothetical resumption of purchases while the present value of their interest keeps falling. If the well is shut-in irretrievably, as in Gerard Bos, the value may drop to nothing. Courts that had no trouble getting intended to pass on a second payment. Yet common sense indicates that the opposite will be true. The court has just blessed the redistribution of what are certain to be millions of dollars from the government to oil and gas operators. Even if the sum were far less, it would be hard to take seriously an objection that the possibility of one more bookkeeping measure per month, which might cost the operator a few dollars monthly, could derail its obligation to pass on royalty payments. If the objection were stated in its proper legal form — "Judge, we can’t afford to comply with our duties to give the royalty owners the same benefits from the lease that we get," or, "But your honor, we can’t afford to find these royalty owners the best price possible" — summary judgment for the royalty owners would be likely.

Moreover, if buyers ultimately bought gas under a settled and renegotiated contract, the royalty then due would in effect consist of two payments anyway: the lower current price and the part of the earlier payment due on that gas. So there still would be two payments (albeit at the same time), and this would not "present[] a problem." See In re Century Offshore Mgmt. Corp., 111 F.3d 443, 451 (6th Cir. 1997); for Judge Reavley’s rejection of the two-check argument in Frey, see supra note 119. As for the risk of nonrecoupable refunds, the lessee is exposed to the same risk with working interest owners, for they too (or it too) might go into bankruptcy.

Not only would producers lose the time value of money, but they could suffer other injuries as well. In many fields, other producers will be draining the reservoir and the unlucky seller whose gas is shut-in may never realize its loss. The issue is even more complicated when some owners are shut-in and others are not or where a shut-in may damage the reservoir and make resumption impossible. See, e.g., Valero Transmission v. Mitchell Energy, 743 S.W.2d 658, 665 (Tex. App. 1987) (affirming temporary injunction upon evidence that reservoir would be drained or "would probably suffer a permanent loss of gas from beneath its leased tracts" if operator had to stop production, and operator might even lose eleven leases).

See, e.g., Gerard J.W. Bos & Co. v. Harkins & Co., 883 F.2d 379, 380-81 (5th Cir. 1989) (royalty owner complaining after well in unit was shut down upon settlement of take-or-pay dispute). Even if the gas was dedicated under a long-term contract and ultimately taken, the royalty owners’ true economic return might be cut by half, two-thirds, or more, all depending on the discount rate and when the payment occurred. Where the gas ultimately is produced
underlying economic values right for the lost time value of money in producer/pipeline take-or-pay disputes and when dealing with suspended royalties in *Phillips v. Shutts*\(^{193}\) inexplicably carved out a special rule for these royalty cases.

4. A Clear Mutual Benefit Rule Should Have Prevented This Take-or-Pay Aberration

A clear enunciation of the mutual benefit covenant would have made this diminution of the lease obligation much less likely. As part III.A.1 showed, the two courts that respected the cooperative nature of the lease understood that lessees must treat prepayments and settlements like

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under a later contract, be it a renegotiated contract or released gas sold to a new buyer, the price invariably is much lower. In that case, the royalty owner loses entirely the benefit of the favorable take-or-pay contract, with its share of that benefit up for grabs between the operator and its investing partners.

An odd public policy argument contends that paying royalties would lower the value of gas payments to producers and so reduce the number of settlements, thus conflicting with a federal goal of fostering settlement of pipeline/producer disputes. See White, *supra* note 155, at 680-84. The author likened royalty payments to a tax on producers. See id. at 683. Yet if federal policymakers could regulate leases, FERC could arbitrarily lower the royalty payment to any level. Moreover, were there a federal policy to abrogate royalty agreements to further a competitive gas market, surely FERC would have announced the policy in its numerous, intricate deregulation orders and awaited the inevitable legal challenges.

It is hard to see how the Commission could reach behind take-or-pay contracts and void the royalty agreements on which the take-or-pay contracts subsisted when FERC repeatedly washed its hands of doing anything to take-or-pay contracts themselves. See, e.g., Order 436, Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, 50 Fed. Reg. 42,408, 42,423-24 (Oct. 18, 1985) (codified in scattered sections of 18 C.F.R.) (refusing to void take-or-pay contracts; holding that “[n]either the legal nor the factual basis for potentially voiding billions of dollars in freely negotiated contracts was made clear in the filings made with the Commission,” and that “[m]oreover, the Commission has sought to make it crystal clear that nowhere in the final rules...has the Commission abrogated any contracts nor created a regulatory framework predicated on any unilateral contract abrogation.”); see also Order 500-H, 54 Fed. Reg. 52,344, 52,365-70 (Dec. 21, 1989) (discussing reasons for leaving renegotiation to private marketplace).

Moreover, we know that by the mid-nineties pipelines had been settling these contracts for very low percentages. (White cited statistics of 10 cents on the dollar, see White, *supra* note 155, at 665; FERC’s own calculations were less than 20 cents on the dollar, see *supra* note 113 and accompanying text.) So if anyone needed help, it was not the pipeline buyers. On the other hand, if federal policy is to push for settlement at any cost, why not strike down royalty agreements altogether and impose a free servitude on land owners, all in the name of a federal policy favoring cheap gas? Such a rule would make no sense when the premise of the lease is that the lessee’s share of production is incentive enough for it to toil diligently for the mutual benefit of all involved. For rejection of the argument that making lessees share settlements with royalty owners will deter settlements, see *In re Century Offshore Mgmt. Corp.*, 111 F.3d at 452.

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193. *See supra* notes 88-101 and accompanying text.
other lease benefits. The Frey and Klein courts understood that cutting out royalty owners is fundamentally contrary to the mutuality of a lease.

The damage caused by the take-or-pay majority may extend even beyond take-or-pay disputes because the majority seems to reject the Harrell "cooperative venture" theory. What message does this send on other issues? Do royalty-exclusion courts really mean that the typical lease is not fundamentally an exchange of money from inexperienced parties who give up their mineral interests to induce an experienced oil and gas company to drill and share the fruits of the lease in return? How could the idea that leases are not cooperative ventures ever square with cases like First Baptist, with its strong statement of the lessee's duty not to structure the lease for its benefit at lessors' expense, the division order cases that turn on the rule against unjust enrichment, or the other cases analyzed in part II?

One interesting sign of the illegitimacy of the take-or-pay majority came in the limitations and caveats with which the first royalty-exclusion

194. If courts truly believed that plain language compelled them to deny royalty owners any take-or-pay sharing, they could say that they simply did not reach the nature of the lease. Yet as Frey and Klein demonstrate, denying royalties is so contrary to the purpose of this relationship that purpose arguments should be addressed. So an honest, complete decision should require even courts that ultimately deny sharing in simple words to discuss the nature of the lease. For instance, the Tenth Circuit considered and decided that New Mexico would not adopt the "cooperative venture" approach in Harvey E. Yates Co. v. Powell, 98 F.3d 1222, 1234-35 (10th Cir. 1996), though it also argued that Louisiana and Arkansas had different statutes that might explain their positions on take-or-pay royalties, see id. at 1231-33. (The Tenth Circuit was forced to analyze the Harrell position because the New Mexico Commissioner of Public Lands, whose regulation it voided, had adopted the theory, see id. at 1231.) The Oklahoma Supreme Court in Roye Realty discussed both Frey and Klein and their adoption of the Harrell rule at length, see Roye Realty & Developing, Inc. v. Watson, 2 P.3d 320, 324-27 (Okla. 1996), before siding with the no-royalty rule, and so rejected one of the most obvious applications of the cooperative venture rule. A Texas intermediate court also expressly rejected the Harrell rule. See Alameda v. TransAmerican Natural Gas Co., 950 S.W.2d 93, 99 (Tex. App. 1997).

Part of the problem is that the Louisiana Supreme Court in Frey, the final Fifth Circuit opinion, and the Eighth Circuit in Klein all gave some weight to state royalty statutes, no doubt in part to minimize the appearance of conflict with Diamond Shamrock. Yet if the lease truly is a cooperative venture, Diamond Shamrock becomes impossible to justify.

195. In an odd contrast with take-or-pay cases, Oklahoma, the other leading jurisdiction to reject take-or-pay sharing, rejected the Texas market value rule precisely because of its perception of the one-sidedness of Vela. The court noted that limiting royalties to a good-faith long-term contract price is "the only interpretation that would operate fairly for producers," and that any other rule [i.e., Vela] would "penalize the producer who was forced into the contract in large measure by his duty to the lessor." Tara Petroleum Corp. v. Hughey, 630 P.2d 1269, 1274 (Okla. 1981) (in other words, because of the mutual purpose of the lease). So Oklahoma has rejected the extreme linguistic analysis of Vela, but embraced ultra-literalism in Roye and its take-or-pay rule. For a discussion of the relationship between these doctrines, see John Lowe's analysis, discussed supra, note 155.
courts surrounded their holdings. Initially, they did not support the broad principle that has developed. This hedging fell away as the precedent took on a life of its own.

At first, it seemed that while courts might not require lessees to share recoupable payments—because the royalty owner ultimately would get something when the buyer made up the gas—lessees would have to pay royalties on nonrecoupable payments. Many early commentators assumed that this was a fair place to draw the line, too. But when the exclusionary doctrine reached full throttle, courts casually rejected passthrough even of nonrecoupable settlements, which therefore were lost to royalty owners forever. In a similar transition, it initially seemed that courts would make lessees pay royalties at least on “amount realized” leases, given the obvious fact that the lessee actually “realized” the take-or-pay payment. This distinction was also tossed aside as courts indiscriminately turned down royalty owners in such leases.

As soon as the lease is viewed as a mutual endeavor, it becomes striking how many benefits are not shared under the Diamond Shamrock rule. The lessee and its partners enjoy the benefit of a payment “for” production before production actually occurs, but royalty owners do not. The lessee and its partners enjoy full protection against the risk of market decline, but royalty owners suffer its full brunt. Working interest owners who have no duty-to-market protection enjoy the operator’s best efforts to sell their gas anyway, but royalty owners who supposedly are protected by that duty do not get even the price the operator secures. Working interest

197. See generally predictions by experienced industry authors at the end of note 155 supra.
198. See Williamson, 138 F.3d at 551; Yates, 98 F.3d at 1234; TransAmerican Natural Gas Corp., 933 S.W.2d at 599.
199. The reading that amount-realized leases might better support royalty recovery was encouraged by the Louisiana Supreme Court in Frey, where that court several times stated its holding in terms of the “amount realized” lease. See Frey IV, 603 So. 2d at 178-80. The Oklahoma Supreme Court breathed life into the difference by suggesting it as one distinction with Frey in Roye Realty, 2 P.3d at 326, 328 n.8.
200. For instance, the Fifth Circuit in Williamson v. Elf Aquitaine, Inc. kept royalty owners from sharing settlement on a nonrecoupable take-or-pay obligation in spite of their amount-realized argument, see 138 F.3d at 550. Moreover, when royalty owners do not share even under the accrual language in Diamond Shamrock or the proceeds “attributable to said property” in Condra v. Quinoco Petroleum, Inc., 954 S.W.2d 68, 71 (Tex. App. 1997), most courts have stripped hapless royalty owners of every take-or-pay payment except for price-based settlements.
201. To compound the fiction, when prepayment gas later is made up, even under a proceeds lease, the court has to pretend that the “proceeds” have just been paid (when in fact they may have been paid years before), while all other interest owners long ago received their “proceeds.”
owners get a free loan, at the least, of the royalty proceeds, but royalty owners have to sit helplessly and hope the buyer ultimately takes the gas. Finally, the lessee and its partners may enter a buyout or buydown that lets them divide the royalty share among themselves; however, the royalty owner may not even have the right to see a record of this diverted payment. The rule gives interest owners every reason to collude with the

202. The new division of spoils creates an interesting problem for the operator under the Diamond Shamrock rule. If it does not share a prepayment with the royalty owners, does it spend the money itself, put it in escrow, or share it with its working interest owners? If the gas later is taken, where will it come up with the funds to pay the royalty owners if it has already shared those proceeds with other interest owners? This rule imposes a risk of interest owner bankruptcy on the royalty owner, the reverse of the insolvency problem Judge Brown said he feared operators risked if they had to recoup payments from royalty owners and repay the buyer that did not make-up the gas.

203. Given that courts routinely enter confidentiality agreements to protect legitimate business secrets, and that lessors generally do not compete with lessees, it is hard to understand lessees' refusal to even share their settlement documents and some courts' approval for this stance. In Klein, for instance, the defendants hid their settlement from the Arkansas Public Service Commission and so kept the news from royalty owners. See Klein I, 980 F.2d at 525. In Williamson v. Elf Aquitaine, the lessee and buyer made their settlement "confidential" and kept it from the lessors. See 138 F.3d at 548. In Roye Realty, the lessee and buyer filed a motion to keep their "confidential" settlement from the royalty owners, though the motion apparently was not "resolved." See 2 P.3d at 323. The defendants in Seeco v. Hales kept their contract secret from Seeco's royalty owners. See supra note 106. Even in states where the royalty owner only is entitled to share the price portion of a prepayment or settlement (unless gas is taken), surely the royalty owner has a right to see all settlement documents to make sure the lessee did not spurn a form of payment that it would have to share, in order to bargain for a kind of payment that it no longer has to split with royalty interests.

How far an agent can structure its compensation to avoid forms that would have to be shared is an issue that comes up in executive rights cases when a lessor sells the full right to control lease decisions but keeps an interest in the proceeds. Ordinarily, it will share in the royalty, but not in other payments like a bonus. Courts have had to devise a duty of good faith, which some call fiduciary and some do not, to make sure that the executive uses its exclusive control in the joint interest. For a sample of the executive fiduciary cases, see Manges v. Guerra, 673 S.W.2d 180, 183 (Tex. 1984); Dearing, Inc. v. Spiller, 824 S.W.2d 728, 732, 734 (Tex. App. 1992); Donahue v. Bills, 305 S.E.2d 311, 312-13 (W. Va. 1983); Teas v. Twentieth Century Fox Film Corp., 178 F. Supp. 742, 745, 748-49 (N.D. Tex. 1959), rev'd in part on contract grounds, 286 F.2d 373 (5th Cir. 1961). For the competitive executive good faith (i.e., nonfiduciary) cases, see Pickens v. Hope, 764 S.W.2d 256, 264 (Tex. App. 1988) (post-Manges Texas lower court opinion refusing to follow Manges); see also Pilcher v. Turner, 550 So. 2d 198, 200-02 (Ala. 1988); Schroeder v. Schroeder, 479 N.E.2d 391, 397-99 (Ill. App. Ct. 1985). Louisiana imposed a good-faith duty by statute in 1975. LA. REV. STAT. ANN. § 31:109 (West. 2000). The lower good-faith duty has such staying power in part because of its endorsement in the leading early article, Lee Jones, Non-Participating Royalty, 26 TEX. L. REV. 569 (1948); in the most influential later article, Ernest E. Smith, Implications of a Fiduciary Standard of Conduct for the Holder of the Executive Right, 64 TEX. L. REV. 371 (1985); and in Howard Williams' seeming endorsement of this standard in his well-known article on the larger fiduciary issue, Howard Williams, The Fiduciary Principle in the Law of Oil and Gas, 13 INST. ON OIL & GAS L. & TAX'N 201, 239-52, 242-43 (1962).
buyer to accept prepayments or settlements that are lower than the full contract amount, all at the royalty owners' expense. Such results cannot be squared with a transaction designed to trade a mineral interest for a proportionate share of whatever wealth the lessee can extract from the earth.

B. The Absence of Tighter Controls May Have Facilitated the Posted Price Problem

The posted price cases introduced in part II.B offer another example of the damage done by the judicial failure to recognize the mutual benefit covenant formally. The traditional, superficial view of posted prices had been that they were a proxy for market value.\footnote{See, e.g., Garfield v. True Oil Co., 667 F.2d 942, 945-46 (10th Cir. 1982), a net profits case. The Tenth Circuit held that the operator had no trust duty and that a sale of oil at the posted price that was the “going price in the field” was appropriate, even if gatherers or first purchasers resold the production at a higher price. See id. at 945-46. Even if such later resales occurred, that the operator, True Oil, used the posted field price meant that it “thereby met the good faith requirements.” Id. at 946. This Tenth Circuit opinion rests on what we now know was a pollyannaish view of posted prices. One hopes and expects that the court would decide Garfield differently now that the way posted prices really work has become public. The posted price litigation has exposed a network of sham sales designed to give posted prices the appearance of being an independent market value. Yet major oil companies using this price recorded millions of dollars of excess profits on their books because they consistently resold oil for more.

See Laura Johannes, Suit May Mean Wide Increases in Oil Fees, WALL STREET J., July 19, 1995, at T3.} For a long time, public information seemed to confirm this view; however, in litigation that lasted through much of the nineties, it turned out that oil companies artificially maintained low posted prices. They used those prices to compute royalties and severance taxes, but routinely and systematically resold their oil for more.

The truth began to get out after a three-state audit commissioned by the states of Texas, Colorado, and New Mexico found that posted prices were three percent to six percent below market prices.\footnote{See Laura Johannes, Suit May Mean Wide Increases in Oil Fees, WALL STREET J., July 19, 1995, at T3.} Texas sued the state's eight largest oil producers (Amoco, Chevron, Exxon, Marathon, Mobil, Phillips, Shell, and Texaco) in 1994 in a case filed on behalf of the
Texas General Land Office and a class of Texas royalty owners. 206 A wide variety of copycat suits followed for royalty owners against other oil companies and for working interest owners. 207

The legal principles surrounding these cases were not fully fleshed out because the cases settled in May 1999 after being consolidated in federal court. 208 Yet the evidence developed before settlement showed how oil companies used posted prices to skim extra profits from the royalty interest. The victims were not just private royalty owners, but also state and federal lessors. 209

Sometimes the oil companies expropriated royalty values simply by buying at the posted price and quickly reselling, often at the wellhead. The transactions were more complex when the companies sold to an affiliate or ran posted price purchases through a third party to give them a veneer of legitimacy. 210 Many of the sales disappeared into a complex web of intercompany exchanges. The participants used “balancing” agreements to match the trades and end up with the same number of barrels after the dust settled. 211 These exchanges made it much harder to track the value the companies realized on their sales.

The initial Texas royalty claim, which after consolidation became the template for all royalty claims, focused on claims for breach of express

206. See Original Petition, Texas General Land Office on Behalf of the Permanent School Fund of the State of Texas, Cause No. 95-08680, in the 345th District Court of Travis County, Texas (July 14, 1995) [hereinafter Posted Price Petition]. This Texas posted price case is one of many consolidated in the MDL 1206 proceeding settled in federal court in Corpus Christi. See infra note 208.

207. For a list of the fifteen federal cases consolidated in the MDL proceeding, see In re Lease Oil Antitrust Litig., 186 F.R.D. 403, 408 n.3 (S.D. Tex. 1999). The working interest cases raised antitrust as well as common-law claims.

208. The last major hearing for approval of the settlement of private claims came in April 1999; the court’s order approving the settlement is dated May 10, 1999. In re Lease Oil, 186 F.R.D. at 403. The settlement was appealed by a handful of objectors, but those objections were settled on appeal just before oral arguments.

209. There is an ongoing posted price qui tam lawsuit over federal leases. See generally United States ex. rel. Johnson v. Shell, 33 F. Supp.2d 528 (E.D. Tex. 1999). The MDL class-action settlement excluded state government entities, In re Lease Oil, 186 F.R.D. at 414, though the Texas General Land Office was an original plaintiff in the Texas lawsuit and has settled. Some states, like Louisiana, now are pursuing posted price claims for state lands and severance taxes on their own.

210. For instance, Judge Jack’s settlement order in the MDL litigation described a convoluted transaction in which an operator sells to an independent “transporter,” who moves the oil to a “Trading Center” but then resells the oil to the operator, who finally gets to resell the oil in an “arm’s length” sale at a true market price. See In re Lease Oil, 186 F.R.D. at 413 n.15.

211. See id. (describing allegations of “overall balance” agreements).
lease terms and of the duty to market. But the essence of the claims had little to do with lease terms and whether they dictated market value or proceeds royalties. Nor did the claims really match the test of the duty to market—that the royalty owners prove that the oil company did not get the best price available in some absolute sense. Surveying market prices could be one way to prove posted price damage, but the gravamen of the complaint was that the companies were not sharing the price they actually were receiving. It was only because of the complexity of inter-company balancing (which disguised the values actually received) that this loss might need to be estimated by overall market value.

Had the courts already fleshed out the mutual benefit principle, the legal issues could have been simplified. The basic allegation was that the defendants arranged an accounting and trading system to receive higher prices than those on which they paid royalties. The legal argument was that this self-aggrandizement is inconsistent with a relationship designed to share all benefits from the property. The lessee is not to take a separate benefit, an extra cut of the revenues, from the volume of oil attributable to the royalty interest. Nor is it to earn some other benefit from the lease and not share part with its lessors.

Oil companies can argue, of course, that because the posted price cases settled, they are not an admission that anything was wrong with posted prices, but the royalty claims settled for an average of 53 cents per dollar of overcharge, not the kind of money paid out on frivolous or dubious claims. The overall sums were large—roughly $190 million, 70 percent of which went to the royalty plaintiffs.

212. The first two counts were for breach of express contract and breach of implied covenants. See Posted Price Petition, supra note 206, §§ 28-33.

213. The defendants argued that the initial price paid on the lease, the one they most often used to compute royalties, was in fact the market value, and that the higher price paid for transactions further away were for "value-adding functions." See In re Lease Oil, 186 F.R.D. at 410. In fairness, when the court described the plaintiffs' allegations in more detail, she was careful to describe them as still allegations, not "a finding of fact for any purpose." Id. at 413 & n.15.

214. See id. at 423. The recovery for working interest owners, who had sued primarily on antitrust claims, was much less, 3 to 13 cents on the dollar. See id. Working interest owners recovered less due to a number of factors. Perhaps the biggest problem was that they had relied primarily on difficult-to-prove antitrust claims, instead of alleging that the operator marketing production under the JOA is a fiduciary, see supra note 74 and accompanying text. The court was skeptical about JOA claims because working interest plaintiffs only raised them at the final fairness hearing, see In re Lease Oil, 186 F.R.D. at 416 n.21, and working interest claimants had not demonstrated that these arguments had merit, see id. at 426-27 & n.36.

215. The Global Settlement that covered most parties came to $164.2 million; another seven settlements totaled roughly $25 million. See id. at 414-15. The 30 percent not paid to royalty owners went to the working interest plaintiffs.
No implied covenant can prevent problems like these posted price shenanigans, but it can increase the risk by imposing a clearer penalty for cheating. The fact that so many of the largest oil companies in the United States participated in this wide-ranging scheme to underpay royalties is powerful evidence that existing implied covenants do not sufficiently establish the lessee's obligations.

C. Similar Problems May Exist in the Deregulated Gas Market

A new wave of royalty litigation in the deregulated natural gas industry bids to unearth problems similar to the posted price disputes. Many of the problems stem from the deregulation of the gas market described in part II.B. Government mandated "unbundling" has encouraged large interstate pipelines to try to push profits downstream and away from the well. The companies then argue that they do not have to share any profits they make by trading and marketing with royalty owners because the profits are a return for their downstream risk, and not payments for "production."

The royalty owner, of course, only leases to an oil company because it believes that the lessee has special expertise in locating production and arranging its sale. Very few royalty owners take their production in kind, even when they have the right to do so. If the lessee believes that marketing production downstream (instead of at the well) will produce the best price, the royalty owners expect it to share the fruits of that professional judgment and the resulting marketing effort with them. The issue that results can look exactly like the oil posted price cases. For instance, in the Meridian v. Altheide national class action discussed in part II.B, one of the claims was that Meridian settled its royalties using indices of average prices for large pools of gas, but that its trading company routinely and consistently sold the gas for more, often right at the wellhead, keeping millions of dollars for itself. Its gas indices were no better than oil's posted prices. In a statewide Texas class, royalty owners for the largest gas producer in Texas, Union Pacific Resources Company (UPRC), have made similar claims. Allegedly, UPRC pays royalty owners based on indices that understate the price it ordinarily receives for the

216. See supra notes 67-68 and accompanying text.
217. Taking in kind is even less likely with natural gas than with oil. Gas is sold through pipelines and small quantities can be harder to sell than with oil, where small quantities can be stored in tanks and from time to time trucked to buyers. Even with oil, where the standard lease includes a right to take in kind, see 3 EUGENE KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 39.1(a), at 263-64 (1989), royalty owners generally do not exercise the right and the operator ordinarily assumes that it also will sell the royalty owner's production.
218. No. 92-026182 (113d Dist. Ct. Harris County, Texas).
gas. Another class has sued Exxon in an effort to certify a national class over Exxon's allegedly underpaying dry gas and liquids royalties, and the same issues now are appearing in federal qui tam litigation. Some of these cases also challenge cost deductions on natural gas liquids.

Although couched under the duty to market or something based on lease terms, the true issue is again the narrower mutual benefit issue. These cases rarely claim that a higher price was available than the price the lessee actually received when it or its affiliate resold the gas. Nor do they seek a full review of market values. The royalty owners are not contesting the operator's marketing diligence. They just want equal treatment by sharing the price received, directly or indirectly.

Nor should these royalty owners need to prove that the price the lessee ultimately did receive in third-party sales was the comparable market value in the field. What they are saying is that diligence in getting the best price requires at least the efforts that their own lessee thought best for its own production; presumably it did act prudently in getting the price it did; but it has to share that price. The lessee got a separate benefit and should have to disgorge the portion attributable to its royalty owners' share. The royalty bargain that trades mineral interests for capital and experience is supposed to include the lessee's marketing expertise, too.

Companies can incur separate expenses marketing oil or gas downstream. One area that will be heavily litigated is whether lessees are entitled to the reasonable, actual cost of downstream marketing, at least in states where they can deduct the actual cost of certain post-production expenses. But the lessee should not be able to deprive the royalty owners of the same price that it receives in its own marketing. If it realizes a better price by shifting the marketing focus from the wellhead to a distant, net-backed sale, so should its royalty owners. Clear enunciation of the mutual benefit covenant would point much more clearly to the fair, efficient

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Another large group of qui tam cases claiming that major oil companies producing natural gas have systematically undermeasured the volume of natural gas received, and so underpaid royalties, originally were filed in a consolidated complaint in Washington, D.C., see United States ex rel. Jack Gryenberg v. Alaska Pipeline Co., (D. D.C. Apr. 17, 1995). That court dismissed this mismeasurement complaint for improper joinder in February 1997, and the relator then sued the dozens of companies individually. See, e.g., United States ex rel. Mobil, No. 97-D-1543 (D. Colo. Feb. 12, 1998).

221. See generally supra note 68.
resolution of these gas price cases and would suggest that, at most, these companies could deduct their actual, reasonable cost of certain post-production services.

IV. THE MUTUAL BENEFIT COVENANT MEETS THE STANDARDS FOR RECOGNIZING A NEW IMPLIED COVENANT

The mutual benefit implied covenant satisfies the requirements for a new implied covenant. Courts impose implied covenants to fill out the parties' intent or when "necessary" to make the lease effective.222 The mutual benefit covenant satisfies either standard. It is what the parties would have intended had they addressed the issue, and it is necessary to effectuate the lease. Adopting this rule will clarify a number of areas of law and enhance efficiency by making leases more transparent carriers of the mutual goal of maximizing shared production.

This covenant can be labeled positively as a mutual benefit covenant, or negatively as a covenant against appropriating separate benefits from the lease. If taken broadly, these labels are mirror images: if lease benefits are to be mutual, a lessee has no business taking them separately. Moreover, deciding which benefits are mutual will decide, in the same breath, which benefits the lessee cannot take separately. "Mutual"

222. The question of whether implied covenants are factual duties or imposed as a matter of law has a long pedigree in royalty law. The authority most associated with the view that implied covenants are duties imposed by law is Professor Merrill; the dean of the Question-of-Fact School is A.A. Walker, see A.A. Walker, The Nature of the Property Interests Created by an Oil and Gas Lease in Texas, 11 Tex. L. Rev. 399 (1933). For some background, see Eugene Kuntz, Professor Merrill's Contribution to Oil and Gas Law, 25 Okla. L. Rev. 484, 487 (1972) (siding with Professor Merrill's view; implied covenant doctrine "has at its base something more fundamental than the intention of the particular parties...The doctrine is one of general application that is designed to determine what constitutes fair and reasonable dealing between any lessor and his lessee...."); Patrick Martin, A Modern Look at Implied Covenants to Explore, Develop, and Market under Mineral Leases, 27 Inst. on Oil & Gas L. & Tax'n 177, 193-98 (siding with Merrill as having the "most tenable position"); Patrick Martin, Implied Covenants in Oil and Gas Leases—Past, Present & Future, 33 Washburn L.J. 639, 640 (1994) ("candor requires us to acknowledge that implied covenants are judicial creations, just as we are all now legal realists who will admit that courts often make law rather than merely find it" and covenants actually are just courts making lessees "conform to some standard of fair dealing"). Martin's position might sound like one that would sustain strong implied covenants, but what he gives with one hand he takes away with the other by urging courts to apply a test of subjective good faith, see Martin, A Modern Look, supra, at 198-205, a test that allegedly would leave room for courts to accommodate public interest concerns. Yet such a standard would give great deference to lessees and let them defend even gross errors of judgment on the ground that they erred in good faith. See Bruce Kramer & Chris Pearson, The Implied Marketing Covenant in Oil and Gas Leases: Some Needed Changes for the 80s, 46 La. L. Rev. 787, 820 (1986). The test would become whether the jury liked and trusted the lessee, rather than whether it made much effort to act in the lessors' interests as well as its own.
benefit is a better label, however, because it has stronger connotations of the cooperative nature of the lease.

A. A Rule Against Profiteering on the Royalty Interest Is Necessary to Effectuate the Purpose of the Lease

The current list of implied covenants, with its general "reasonably prudent operator" standard and roughly five specific covenants, is by no means exhaustive. The Texas Supreme Court gave consideration to a new covenant just two years ago in *HECI Exploration Co. v. NEEL*. Though the court rejected that effort to create a duty to notify royalty owners of plans to sue a neighbor for drainage, it considered the proposed covenant without any hint that the law is stuck at today's covenants.

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223. The "great majority" of jurisdictions use the prudent-operator test. See 5 WILLIAMS & MEYERS, supra note 11, § 806.3, at 36; JOHN LOWE, OIL AND GAS LAW 306-09 (1988) (prudent operator standard underlies all implied covenants, and generally requires good faith, competence, and due regard to lessors' interests). A minority once applied a test of subjective good faith, see 5 WILLIAMS & MEYERS, supra note 11, § 806.2, at 33, but it is "doubtful that these states would follow the good faith standard today." Id. at 34.

224. The five covenants are the covenants to explore undeveloped property, to develop whatever reserves are located, to protect against drainage, to "manage and administer," and to market. Williams and Meyers list six covenants, five specific ones and one catchall obligation. The specific duties are to drill an exploratory well, protect against drainage, reasonably develop, explore further, and market; the general duty is to use reasonable care and due diligence in all operations including drilling, producing, and marketing. See 5 WILLIAMS & MEYERS, supra note 11, § 804, at 28.1 to 28.2. The duty to manage and administer has tended to be a catch-all provision to cover "acts or omissions not comprehended by the more specific implied covenants," id. § 861, at 424.1, but this duty sounds very much like the general reasonable prudence standard for all implied covenants. Williams and Meyers cite quite similar categorizations by Professors Merrill, Walker, and Summers. See id. § 804, at 26-27.

For John Lowe's list, see LOWE, supra note 223, at 309-10. Lowe agrees that the covenant of diligent and prudent operation (which sounds like the general standard of reasonable prudence) "overlaps several of the other implied covenants," all of which "may be seen as applications of the reasonable prudent operator standard." See id. at 343-44. This Article discusses the mutual benefit covenant as a sixth implied covenant because it is the sixth specific covenant, as distinguished from this one general duty.

The covenant to explore has become less important because modern leases allow the lessee to pay "delay payments" as a substitute for production if it does not drill an initial well. See WILLIAMS & MEYERS, supra note 1, at 28.1 (covenant to drill exploratory well "no longer has importance" because of modern lease terms); accord, LOWE, supra note 223, at 310.

225. 982 S.W.2d 881 (Tex. 1998).

226. See id. at 889-91.

227. Cf. Hebert, supra note 111, at 12 (claiming that many lessees "look at this 'list' [implied covenants applicable under Louisiana's Mineral Code] as an exclusive one and as defining what a reasonable and prudent operator is. Instead, however, a lessee should look..."
The **HECI** court articulated the standard reasons courts use to imply covenants. One reason is that a term was "so clearly within the contemplation of the parties that they deemed it unnecessary to express it." The other is that an added term is necessary "to effectuate the full
to the general rule or obligation and view these specific enumerated ones as merely illustrative examples thereof.").

This Article does not address another possibility, namely, that the industry should restructure the royalty relationship from scratch. David Pierce has argued that the dominance of form contracts and the rule of precedent has given standard leases a life they may not deserve; and that private interests might be better protected if both sides shared some risks of drilling, while the public interest might fare better with less development-oriented standards than today's implied covenants. See generally David Pierce, *Rethinking the Oil and Gas Lease*, 22 *Tulsa L.J.* 445 (1987). Pierce has campaigned for amendments to standard leases; he elsewhere has proposed to solve pricing disputes by shifting royalties to index-based clauses, see Pierce, *supra* note 68, at 806-09. For concurrence that implied covenants may accentuate lessor rights and development at the expense of public interests, including environmental ones, see Martin, *A Modern Look*, *supra* note 222, at 202-13.

It is unlikely that the industry will discard a contract that has allowed such widespread development, or landowners one that is so generally familiar. It certainly is hard to picture the average royalty owner's committing to pay a share of drilling costs even if the result is a dry hole. Not only would they need significantly more compensation to justify this new risk, but it would change the cost-free rationale of the royalty with which all sides of the industry seem comfortable. One can imply from Pierce's writing that he might agree that royalty owners need more protection, as argued here, from his argument that leases are "industry-generated" forms that have endured—that both sides have been willing to keep using—because of "the willingness of courts to take what they perceive to be an unfair contract and make it fair through creative interpretation." Pierce, *supra*, at 453. "The interest which courts identify for protection is the lessor's expectation of royalty." Id. at 469 (citation omitted). A mutual benefit implied covenant would clarify and strengthen the major underground principle to which courts return again and again to give lessors necessary protection.

228. **HECI**, 982 S.W.2d at 883, 889. Dual phrasings of the source for these duties go back to the earliest roots of implied covenants. The foundational *Brewster v. Lanyon Zinc Co.*, 140 F. 801, 811 (8th Cir. 1905), one of the first articulations of the implied covenant of development by then-Judge Van Devanter, described (1) covenants that were "reasonably calculated to effectuate the controlling intention of the parties as manifested in the lease," and (2) the more objective "[w]hatever is necessary to the accomplishment of that which is expressly contracted...." See also *Danciger Oil & Refining Co. v. Powell*, 154 S.W.2d 632, 635 (Tex. 1941) (covenant "must rest entirely on the presumed intention of the parties as gathered from the terms as actually expressed in the written instrument itself" or "it must appear that it is necessary to infer such a covenant in order to effectuate the full purpose of the contract as a whole as gathered from the written instrument").

*Brewster* has been read as an intent case, see, e.g., Kramer & Pearson, *supra* note 222, at 790, but this reading ignores the fact that both factual language of intent and the "necessity" language of judicial implication coexist in the opinion. One of *Brewster*'s notable features is that the intent analysis hewed much closer to the parties' actual intent than the average implied covenant case (see for instance the detailed discussion of lease terms and of the history of the lease, 140 F. at 806-08). Once an implied covenant makes its way into law, courts will impose it without looking this hard at the particular intent of the individual contract, unless, that is, there are conflicting lease provisions.
purpose of the lease." 229

Both standards partake of the amorphous, uncertain language often seen in discretionary standards. It certainly cannot be true that covenants are only efforts to reach a party's actual, subjective, but unexpressed intent. Most royalty owners are inexperienced. They rarely think about how many wells the lessee ultimately will drill, if the lessee will avoid drainage, how the lessee will administer accounts, or of the many possible ways the lessee might cheat them. When disputes do arise, lessors often had not considered the specific issue. So it can be a fiction that the terms were so obvious that "the parties deemed it unnecessary to express it." 230

Another factual explanation for implied covenants is that the future of an oil and gas operation is so uncertain that the parties cannot predict every eventuality. 231 This cannot explain the lack of a given implied covenant, though, because they are also general rules of law. Anyone with grounding in the industry can foresee that it will be helpful to have a general provision about drainage, exploration and development, administration, marketing, and mutual benefits.

The fact that the implied covenants have become well-established makes it even harder to rely on actual intent deduced from contract language. The covenants change the parties' reasonable expectations. They make it at least marginally more likely that some royalty owners will have thought about some of their rights. At the same time, the existence of

The two phrasings of the factual and legal justification for implied covenants overlap. The more a protection seems "necessary" for the lease, the more likely that parties assumed they had this protection even without expressing it. The more willing a court to find the parties must have intended a term, the more likely it is to think the term is "necessary" for protecting some lease purpose. For one example of how these distinctions can break down, see Weaver, supra note 3, at 497-502 (analyzing what she calls the Texas implied-in-fact standard but admitting that "leading cases still often discuss fair dealing and good faith in language reminiscent of the equity model").

229.  HECI, 982 S.W.2d at 883.
230.  See id. at 888.
231.  Cf. Brewster v. Lanyon Zinc Co., 140 F. 801, 801 (8th Cir. 1905) (parties could not specify drilling program ("the number of wells to be drilled, as to when the wells, other than the first, should be drilled, or as to the rate at which the production therefrom should proceed, because these matters would depend in large measure upon future conditions, which could not be anticipated with certainty, such as the extent to which oil and gas, one or both, could be produced from the premises") because of uncertainty prior to drilling, which is why they needed some covenant of reasonable development); Conine, supra note 186, at 675 (arguing that the lease is silent on many "operational" issues because it is executed before "reliable" reserve information is available, "making it impossible for the parties to anticipate the nature, potential or timing of operations"); id. at 711 (parties lack information to negotiate "sales price for an outright transfer"); Hebert, supra note 111, at 5 (lessee and lessor cannot determine in advance how lease should be operated in future); Weaver, supra note 186, at 1485.
implied protection increases the odds that royalty owners will not see the need to document their rights (because they expect courts to protect them anyway). 232

The other reason for implying covenants is to “effectuate the purpose” of the lease. 233 Though this rationale comes with a standard disclaimer that courts should not use implied covenants “just to make the contract fair,” 234 the covenants are inseparable from a judicial sense that some pure-contract results would be unfair. So these cautions have to be taken with a grain of salt. Courts indeed should not use implied covenants to change contract terms, for instance to cushion a low price in a rising market or cap an agreement to pay maximum lawful prices in a depressed market, but the idea that the parties would have stated an unspoken term if they thought it ”necessary,” or that a term is “necessary” to a contract’s purpose, is indistinguishable from a judgment that it would be unfair to enforce a contract without the added term. Perhaps a better description of this rationale is that courts will elaborate contract rights when necessary to implement general contract purposes. They should not imply covenants just to make an individual contract fair, but they can and will intervene to make a class of contracts fair.

The mutual benefit covenant should satisfy either the intent or necessity test. It is hard to imagine a lease in which the lessor agreed that the lessee can take a separate benefit and did not have to share all lease values. 235 That is one of the facts of life for lessees. Expressed or not, the mutual benefit duty is almost certain to match the actual intent and understanding of the lessor and to be a precondition for its willingness to lease. As the examples in the text show, the covenant is necessary to effectuate the lease. This shared interest is the royalty owners’ protection and guarantee that the lessee will act in the mutual interest, rather than detour for private gain.

A mutual benefit covenant fits squarely into existing royalty law. The rule can be characterized as this industry’s version of unjust enrichment. Underlying it is the understanding that the lease embodies a

232. In Indep. Petroleum Ass'n. of Am. v. Armstrong, 91 F. Supp. 2d 117, 127-28 (D.D.C. 2000), one district court discounted duty-to-market arguments under federal leases because it could not find language describing the duty in the lease. Yet implied covenants add protection that is not written into the lease but are to be given equal weight with the written terms; requiring unwritten rights to be written ignores the theory behind providing implied protection in the first place.

233. See HECI, 982 S.W.2d at 883, 888.

234. See id. at 889.

235. The implausible alternative would be lessors who say, “Sure, we agreed that the lessee could make money off our interest, even in ways not disclosed to us.” Before holding a lessor to such an abnormal understanding, courts should demand it be in writing.
mutual, shared venture to develop the property that the royalty owners turned over to the lessee (regardless of whether courts have formally adopted the "cooperative venture" theory). The rule is based on the economic reality that when the lessor contributes the lease in exchange for the lessee's capital, know-how, and efforts, both contributions are essential ingredients in an oilfield project. A covenant against profiting off the royalty owners' share is "necessary" to effectuate the joint project.

B. A Rule Against Separate Benefits Will Clarify Several Areas of Oil and Gas Law

Recognizing an implied covenant barring lessees from taking separate or added benefits from the revenue stream will clarify a number of areas in oil and gas law that today betray confusion or worse. The take-or-pay/royalty cases present one such area. Those cases foundered on simple questions of "plain meaning." The pretense that leases really dealt with the situation was a convenient excuse for not deciding the real issue. Courts generally do put plain meaning analysis at the top of their interpretative hierarchy. If the words of a contract or statute are "clear," courts generally will not look to purpose, legislative history, the parties' interactions, or other factors. But whether particular words are clear is a question that only can be posed in the context of the question asked. Here that question necessarily looks to the parties' relationship. Do terms like "production" control the outcome in the very unusual circumstance when payment occurs before production and the buyer may not even take the gas? To argue that words alone resolve this issue is to trivialize the problem in advance.

This exaltation of plain meaning should not have survived a clear mutual benefit rule. It is impossible to square the fundamental exchange of property for exploration and development with a judicial diminution under which an unexpected delay, postponement, or even extinction of production can deprive the royalty owner of proceeds that in fact are paid and that every other interest owner receives. At a minimum, courts imbued with a mutual benefit approach, and wary of lessee aggrandizement,

236. The written words of a contract cast a long shadow on subsequent disputes. When interpreting a contract term, the "express terms" take precedence over extrinsic evidence of things like course of performance or course of dealing. See RESTATEMENT (SECOND) OF CONTRACTS § 203(b) (1981). Evidence of prior or contemporaneous agreements and talks are not admissible if they contradict express terms in an integrated agreement. See id. § 215. Moreover, every word is to be given effect. See id. § 203(a). It is an old rule of oil and gas law that if a lease deals expressly with an area, courts will not enforce an implied covenant set up in opposition to the contract language. See supra note 3.
would begin their analysis closer to Frey and Klein than to Diamond Shamrock and State v. Pennzoil.

Every legal generation has its bad mistakes, decisions inexplicable to later generations. So it is that a society reared on Brown v. Board of Education looks back with wonder at Plessy v. Ferguson and the separate-but-equal doctrine, and the post-New Deal world looks back smugly at Lochner's cramped, myopic contract clause analysis. An industry and generation of lawyers raised on a mutual benefit covenant, one with roots embedded in mainstream oil and gas doctrines, will look back at the take-or-pay cases and shake their heads. They will wonder how courts could have gone so far wrong.

Straightforward acknowledgement of a mutual benefit covenant, one inchoate today and not yet fully surfaced in judicial consciousness, would have spared much of the muddle in the division order cases. The covenant should have blocked the tortuous zigzag from First Baptist to Exxon v. Middleton with its confident assertion that division orders can amend leases, through the brief moment of clarity represented by Gavenda v. Strata Energy, Inc. and its prohibition on amendments that only benefited the lessee,237 the descent again into the bog of Cabot Corporation v. Brown, that later broad amendment case,238 and the final resurrection on solid ground almost a decade later in Heritage Resources, Inc. v. Nations Bank.239 The governing principle of these cases is fairly straightforward: the lessee cannot use a document that confirms title to siphon off a share of the royalty owner's income stream. That rule would not have been open to doubt under a clear covenant against separate benefits.

A mutual benefit covenant will crystallize the guiding principle of the affiliate cases. The principle is not that a lessee can gouge its royalty owners through a separate affiliate as long as it observes corporate formalities, but not if the affiliate is an alter ego. The affiliate cases run the risk of getting off track every time they put much weight on alter ego technicalities.240 The rule against separate benefits largely dispenses with the details of corporate structure. It offers a much simpler principle: a lessee cannot extract an extra profit just by shifting certain services into

237. The division order progression from First Baptist to Gavenda is discussed at supra notes 19-47 and accompanying text.
238. See supra note 41.
239. See supra notes 43-47 and accompanying text.
240. For instance, even though the lower court got it right in Texas Oil & Gas Corp. v. Hagen, 683 S.W.2d 24 (Tex. App. 1984), aff'd in part, rev'd in part, No. C-3768, 1987 WL 47847 (Tex. Dec. 15, 1987), opinion withdrawn by 760 S.W.2d 960 (Tex. 1988), its consideration of alter ego issues, see supra notes 52-53 and accompanying text, increased the risk of error. Had it found TXO and its affiliated Delhi pipeline truly separate, its concern with corporate relationships could have betrayed it into a different result.
separate legal entities. It does not matter whether it does this to keep too much of the revenue or to charge excessive costs. This bar does not turn upon whether the affiliate is housed in a separate building, has its own employees, holds directors’ meetings, has a separate letterhead, or any number of other corporate formalities.241

Lessees will argue that making them share their gain on services robs them of the incentive to perform those services themselves. That argument could apply to every service, even every ordinary production service. The argument slights the point of the lease. A lessee puts its skill at the royalty owner’s service in return for a mineral interest. As far as the leased property, a lessee has a much closer relationship with the lessor than any vendor. The lease represents the lessee’s commitment that the incentive embedded in its mineral interest is reward enough for it to develop the lease aggressively and in good faith. A lessee might say it would cut off its nose to spite its face and never enter the marketing business unless allowed to profit off the royalty owners, but its duty to market is an integral part of its overall promise to find and produce mineral assets for the lessor without such extra cash compensation.

A covenant against separate benefits would cast in a clearer, though harsher, light another area of the law that, along with the take-or-pay cases, should come to be viewed as one of this generation’s oil and gas mistakes. This is the Vela principle that lessees under market value leases must pay royalties at higher prices than they receive if they commit the gas to long-term contracts, but market prices rise above the contract level.242 The Oklahoma Supreme Court illustrated how this rule can lead to ridiculous results in Tara Petroleum, where the lessor would have received

241. Control issues still may be relevant where the controlled company is not owned by the lessee, directly or indirectly, but the royalty owners argue that the lessee nonetheless exercises actual control. Here there must be some attention to corporate formalities, or royalty owners could claim that even third-parties with whom the lessee does business are de facto affiliates. In cases about apparently unrelated companies, the courts will want proof of control. For example, consider the lack of evidence supporting allegations of common control among not-obviously-related parties that led the Oklahoma Supreme Court in Tara Petroleum to dismiss the middle man allegations, 630 P.2d at 1275, or the lack of evidence about the Stevens’ interest in Arkla that brought the same result in Hillard v. Stevens, 637 S.W.2d 581, 584 (Ark. 1982).

almost half the revenue stream, four times its nominal royalty share, if paid by current market value.243

Refusing to let the lessee hide behind a long-term contract can make sense if the contract was with an affiliate, which itself was reselling the gas at a higher price. This may have been the concern, though the Texas Supreme Court did not articulate it as such, in Vela and Exxon v. Middleton.244 In a recent case enforcing the "reverse-Vela" rule, that Court has again confirmed that it will not let Vela shield self-dealing.245 In general, the mutual benefit should be as mutual for the lessee as the lessor. If the lessee enters a gas purchase agreement in good faith and gets the best price it can, it is not fair to transmute the lease into a price guarantee for the lessor while putting all the market risk on the lessee. Under Vela, one side is taking a separate benefit from the other. This time it is the lessor who exploits the relationship.246

243. See supra note 58 and accompanying text.
244. See the discussion by Chief Justice Curtiss Brown in the intermediate opinion in Exxon Corp. v. Middleton, 571 S.W.2d 349 (Tex. App. 1978), aff'd in part, rev'd in part, 613 S.W.2d 240 (Tex. 1981), discussed in supra note 57.

A lessee might respond that it entered a long-term contract with its affiliate to shift certain market risks to an unrelated company, and that its affiliate was doing no more than what any third-party buyer would have done under an independent contract entered at the same time. This begs the question of why the lessee wanted to keep the market risk within its corporate family but shift it to another arm of that body. Sometimes such decisions can be motivated by tax or other "neutral" motivations. In one area of the law, antitrust cases, courts have provided companies some immunity. See Copperweld Corp. v. Interdependence Tube Corp., 467 U.S. 752 (1984) (rejecting intra-corporate conspiracy doctrine for antitrust lawsuits). But the history of fleecing royalty owners through affiliate devices is sufficiently strong that affiliate cases do not merit the Copperweld shield from liability.

246. The underlying argument, which the Texas Supreme Court blessed in Vela, is that accepting a long-term contract price as the "market" price impermissibly removes any difference between "proceeds" and "market value" leases. See Vela, 429 S.W.2d at 871 (parties contracted for market-value price; they "might have agreed that the royalty...would be a fractional part of the amount realized", but they did not). Yet this linguistic dilemma should hardly settle the issue. Those two price terms already are equated in the short run, as a short-term spot price would equalize values under market value and proceeds leases. Giving them the same meaning over the longer term would not truly render the difference in language superfluous. Other differences would persist, for instance, certain different interpretations on post-production costs.

In Vela states where the operator can be liable for more than the contract price if the market rises, it is only logical that it should not have to share the benefit of its contract if the relative market price falls. See Lowe, supra note 68, at 259. This is the "reverse-Vela" problem, the situation where the Texas Supreme Court recently followed Vela in this circumstance in Yzaguirre v. KCS Resources, Inc., 53 S.W.3d 368 (Tex. 2001). Even if courts do have to treat the price effects of market value and proceeds leases as the same in Vela and reverse-Vela situations, frank acknowledgement of the mutuality of the lease shows that among two
It is not only the Oklahoma Supreme Court in *Tara Petroleum* that recognized that the *Vela* rule is incompatible with the mutual nature of the lease. The Louisiana Supreme Court agreed in *Henry v. Ballard & Cordell Corp.* Treating the lease as a cooperative venture, with the lease evils—the often absurd result of the *Vela* rule versus the generally undesirable result of arriving at the same royalty value under two different descriptions of value—the injury caused by *Vela* is the greater evil.

One could argue that *Vela*’s injustice to the lessee in a rising market might be balanced out in a falling market, where the lessee might pay less to royalty owners than it received. Over time, even if the rule distorts the royalty relationship, the distortions might average out, but there are many problems with this position. There is no reason to expect the excesses on the lessee side and those on the lessor side to end up in a self-canceling equilibrium. Why should two wrongs always balance each other? Courts appropriately shy away from the principle that two wrongs make a right. Moreover, a rule under which both lessor and lessee almost always get a different share of the revenue stream than the agreed-upon percentage has to be looked at with great suspicion. Such a result ignores the most fundamental, mutual purpose of the lease.

Thomas Harrell has pointed out that one flaw in *Vela* is that few people thought differences in lease price terms were much more than “particularized expressions by different draftsmen of the basic idea that the gas produced would be sold by the lessee for the best price he could get....” Thomas Harrell, *Recent Developments in Nonregulatory Oil and Gas Law*, 31 INST. ON OIL & GAS L. & TAX’N 327, 341 (1980). In addition, by insisting that gas is “sold” only when delivered, the court removed the volume or quantity of gas committed from the value calculus. See id. at 331-32. *Vela* poses a dilemma for lessor and lessee alike. Say a very high long-term contract price is available, but naturally it requires a gas commitment. Should the lessee commit the gas, or must it sell only at some lower spot market price because the future spot price might rise above this good contract price and it has to keep its production free in case that happens? The good long-term price is only available to sellers who are willing to tie their reserves to the contract’s pricing mechanisms. Surely lessors cannot both insist that they get today’s best long-term contract price (which will force the lessee to commit their reserves) but also any higher spot price that happens to come along (even though the lessee bound to a long-term contract cannot sell in the spot market without breaching its contract.) The smart lessee stuck in *Vela* jurisdictions should make its royalty owners choose which contract they prefer if a good long-term opportunity arises.

For a sample of contemporaneous criticism of the *Vela* rule, see authorities cited in *Henry v. Ballard & Cordell Corp.*, 418 So. 2d 1334, 1338 n.8 (La. 1982).

247. 418 So. 2d 1334 (La. 1982); accord, Hillard v. Stephens, 637 S.W.2d 581, 583 (Ark. 1982). These cases stand on the cooperative venture ground. “The cooperative venture principle stated in *Henry* was an important, if unstated, premise for *Tara v. Hughey* and *Hillard v. Stephens.*” Lowe, *supra* note 68, at 235. *Ballard* is a particularly important cooperative venture opinion because the Louisiana Supreme Court applied the rule to protect the lessee, not the lessor. At issue was whether a lessee who enters a gas purchase contract in good faith and at arm’s length, indeed one that was “quite favorable” when entered, *Ballard*, 418 So. 2d at 1336, would have to pay royalties on more than the prices it received if market prices rose. The court believed that any such rule would ignore the practical realities of the oil and gas industry, particularly given the cooperative nature of a lease, and the lessee’s need to enter a long-term contract. *See id.* at 1337-39.
documenting the proportionate division of benefits, the Court saw no reason to punish the lessee/operator for its good faith gas sales decision.\textsuperscript{248}

This new covenant’s deeper insight could further improve results in less well-known disputes. Consider \textit{Pritchett v. Forest Oil Corp.}, a case blessing an operator’s dissemination of incomplete, misleading information to a royalty owner who was thinking of selling her interest.\textsuperscript{249} The plaintiff owned 200 acres in a voluntarily pooled unit. In the spring of 1971, the plaintiff offered to sell 50 acres to the operator at $1000 an acre. The operator countered at less than a third of her price. The plaintiff’s son, a geophysicist, repeatedly called seeking geologic information on the property.\textsuperscript{250} When her son tried “to determine the facts concerning the porosity of the formation,”\textsuperscript{251} the defendant did not tell him about fluid loss that suggested the well soon would become much more valuable.\textsuperscript{252} After the plaintiff sold her acreage, the well indeed did turn into a better producer.

In most circles, this would be pretty straightforward fraud, but a Texas court of appeals decided that Forest Oil had no duty to the unfortunate Pritchett. The court seemed to believe that royalty owners are not equal partners in the venture. Twice it referred, without explanation of the point’s relevance, to the fact that royalty owners do not pay the cost of production.\textsuperscript{253} “[I]t is an entirely different matter when the lessor or royalty interest owner, who is not charged with the cost of production, attempts to inquire of the producer information entirely foreign to any legitimate

\textsuperscript{248} Citing Thomas Harrell’s article, \textit{see supra} note 98, the court reminded readers that this cooperative venture was the exchange of land for the capital and expertise of the lessee “necessary to develop the minerals for the mutual benefit of both parties.” \textit{See} \textit{Ballard}, 418 So. 2d at 1338. The lease set the “division” of the resulting “economic benefits,” the fractional share the royalty owners were to get. \textit{See id.} When the discovery was made, there only was one “economically feasible market for the gas,” the long-term contract the lessee actually entered. Nothing in this mutual exchange suggested that courts should punish a lessee as long as it acted in good faith. \textit{See id.} at 1340.

\textsuperscript{249} 535 S.W.2d 708 (Tex. App. 1976).

\textsuperscript{250} \textit{See id.} at 709. The son told the operator’s employees that “he never wanted any information that was not being made public, but that he wanted all information that they felt was permissible to give him.” \textit{Id.}

\textsuperscript{251} \textit{Id.}

\textsuperscript{252} The withheld information “would have been valuable...in determining porosities.” \textit{Id.}

\textsuperscript{253} Pritchett had also cited the lead unit-fiduciary case. \textit{See id.} at 710 (\textit{Young v. West Edmond Hunton Lime Unit}, discussed in note 62 \textit{supra}). The court summarily dismissed Pritchett’s authorities because they did not deal with what it saw as the governing issue, which the court narrowed into hairsplitting minutiae: “[n]either do they ever state that a fiduciary duty is owed by a unit operator regarding the giving of drilling information to a royalty owner who has no interest in the cost of production.” \textit{Id.} The court might as well have noted that the plaintiffs did not all have the same name.
interest." So the court let Forest Oil keep the property it repurchased by subterfuge. This reward for concealment permitted an unjustified appropriation of value belonging to the royalty owner.

Making formal and conscious the principle that lessees must develop leases for mutual benefit and not take separate benefits from the lessor's interest would bring greater precision to a number of areas of oil and gas law. This new covenant would give a much more tangible, integrated sense of this economic relationship. Accepting this principle formally will facilitate the development of oil and gas law.

C. The Mutuality of Lease Interests Furthers Efficiency

American courts deciding commercial cases have elevated economic efficiency to the dominant judicial policy concern in recent decades. Private contracts govern the disposition of most assets, including mineral rights, in the United States. A society that allocates its primary assets through market exchange puts a very high value on efficiency.

Markets have several structural advantages in societies sufficiently stable for their citizens to trust that contracts will be enforced and property values protected. Markets promote freedom because each consumer and producer can pursue its self-interest without government interference.

254. Id. (emphasis added).

255. One should not have to think twice to realize the flaw in the court's position. Why is a royalty owner's right to truthful information an "entirely different matter" than other investors' rights? How does a royalty owner's bearing or not bearing the direct costs of production (and by contributing acreage, royalty owners do bear what would be viewed as a direct cost but for the ideology of royalty exclusion) reduce its right to be treated honestly? Why is someone who gives up valuable acreage less protected than someone who donates cash? Why is a royalty owner asking the lessee about its property's reserve value when it is negotiating with that lessee to sell its interest invading an area "entirely foreign to any legitimate interest"? Why didn't Pritchett have a right to the truth? The court provided no reason for denying royalty owners a share of the value in the mutual property.

256. Even in oil and gas law, "economic considerations have been used to identify and correct inefficiencies embedded in early court decisions on oil and gas issues." Conine, supra note 186, at 671. In the cited article, Conine shows how economic concepts are built into standards for handling exploration, development, and drainage, with a few suggestions for change.

257. For the general argument that the legal tools necessary for market trading were significant factors in the development of modern economies, see DOUGLASS C. NORTH, ECONOMIC PERFORMANCE THROUGH TIME 1-23 (1993).

They increase welfare by facilitating mutually beneficial exchanges.259 Leaving the disposition of major resources in private hands, with profits and gains going to owners, is a strong incentive to innovation.260 The social consensus on allocating so many resources by private negotiation rather than government dictate in theory allows quick, flexible allocation without the barriers imposed by command economies or those run by custom, status, or hierarchy.261

Yet neither the promotion of freedom and efficiency nor concerns with flexible resource allocation tells courts where to allocate values between lessees and lessors. Private exchange should let parties determine how they value resources, not abstractly, but in concrete practice. The requisite freedom of economic choice requires that contracts be reliable conveyors of preferences when a bargain is reached; it does not say which party should win or determine the level of prices.262 Returns to innovation, similarly, require that the agreed-upon profits inure to the innovator but

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259. The intuitive explanation for the way exchanges increase at least one side's utility, and in most cases both, can be shown in a two-dimensional space by the Edgeworth box diagram. See BRIAN R. BINGER & ELIZABETH HOFFMAN, MICROECONOMICS WITH CALCULUS 176-79 (1988).

260. For the ceaseless transforming effects of the capitalist endeavor, see JOSEPH A. SCHUMPETER, CAPITALISM, SOCIALISM AND DEMOCRACY 81-86 (1942). Even a small increase in innovation may, over time, produce a very large-scale advantage in levels of output and living standards. See, e.g., Phillip Areeda, Antitrust Law as Industrial Policy: Should Judges and Juries Make It?, in ANTITRUST, INNOVATION, AND COMPETITIVENESS 31 (Thomas M. Jorde & David J. Teece eds., 1992) ( "At least since Schumpeter wrote nearly fifty years ago, innovation has been thought to contribute far more to our well-being than keeping prices closer to costs through competition.").

261. Hayek argued that critical knowledge for a changing economic system is knowledge of “particular circumstances of time and place,” instead of aggregate statistical knowledge that might be easy to gather for central planners. See F.A. Hayek, The Use of Knowledge in Society, 35 AM. ECON. REV. 519, 521 (1945). He believed that the price mechanism could communicate the right signals quickly and efficiently so that people would “move in the right direction” even without a full understanding of what changes were shifting prices or why. See id. at 526-27.

Part of the market’s precision is that the price mechanism sends accurate signals of the true marginal cost of using a resource. For these signals to be appropriate, they must reflect the values that resource owners put on their assets; the marginal “cost” of oil and gas properties is heavily set by the prices landowners charge for their mineral interest.

262. The inability of economics to say how much different factors of production “should” get paid in an absolute sense is both a strength and a weakness. As is perhaps most graphically shown by economists’ refusal to compare utilities, so that they cannot even say that a dollar is more important to a starving man than to a millionaire, this version of neutrality lets economics masquerade as pure science without value judgments even if following these dictates creates the harshest ordering of society.
cannot decide the division of profits between joint investors like lessors and lessees.\

Economics does shed light on the balance of rights in the royalty relationship in one way.\textsuperscript{264} Economic theory points to the importance of maintaining joint dependence upon the flow of production as an agency-enforcing mechanism. Many agents, including lessees, provide services whose measure and results are heavily within their professional control. This presents a challenge for principals, including lessors: how can royalty owners judge their lessees' performance?\textsuperscript{265} If the lessee fails, can lessors distinguish innocent failures from those born of fraud and deception? Vigorous exchanges of value that allow the development of professional expertise will occur in market societies only if principals can trust their agents to serve the principals' interests as well as their own.

One solution to the agency problem is to link both sides' incentives as closely as possible, so that even an agent acting in blind self-interest will serve the principal as well.\textsuperscript{266} The industry has adopted this solution in the lease. Courts assume a commonality of interests and that the joint return from mineral production will ensure fair development of the property.\textsuperscript{267}

\begin{itemize}
  \item \textsuperscript{263} Leaving all returns to the lessee, for instance, would increase its incentive to develop a property but give lessors no reason to ever lease their mineral interests in the first place.
  \item \textsuperscript{264} Another economic concept that lurks behind all implied covenants is market power. Though that issue is beyond the scope of this Article, the consensus that royalty owners are less experienced and have smaller stakes than lessees in general is a coded way of saying that there is a severe imbalance of power between these two oilfield groups.
  \item \textsuperscript{265} The complexity of expert services increases the range of necessary discretion allowed to an agent and can make supervision and control "very costly if not impossible" and, accordingly, the principal more vulnerable to the agent. See generally DIETRICH RUESCHEMeyer, POWER AND THE DIVISION OF LABOUR 108 (1986). The expert can be "dangerous" to its client or principal because of the difficulty in controlling its work. See id. at 109.
  \item \textsuperscript{267} Hence the economic significance of the rule that courts generally defer to the lessee's judgment on the assumption that its interests coincide with the lessor's. See 5 WILLIAMS & MEYERS, supra note 11, § 856.3, at 411-12 (courts give "greatest possible leeway" to lessee because their interests ordinarily coincide with lessors; but if interests "diverge and the lessee lacks incentive to market gas, closer supervision of his business judgment will be necessary"); Lowe, supra note 53, at 1-20 ("Evidence of self-dealing by the lessee, as was involved in Hagen, or other conflict of interest between the lessor and the lessee, is likely to have the practical effect of substantially lightening the lessor's burden."). The presumption of common ground is in all but words an assumption that a structure in which both parties are to derive their return from their share of the same productive stream gives them exactly the same interest in finding and developing oil and gas, rather than giving the operator an incentive to help itself to the lessor's pie. The widely varied disputes discussed in this Article suggest that the
The policing mechanism that protects this mutuality is shared dependence upon production. If the lessee cannot earn any gain that is not shared with the lessors, it should serve their interests as faithfully as its own by trying to maximize its profits. This mutuality is a precondition of the lease exchange. It lets royalty owners who often have little or no experience and lack interests large enough to justify effective monitoring nonetheless count on the lessee to protect them. The rule that courts increase their scrutiny of lessees when their interests diverge from lessors' recognizes the importance of this shared economic incentive.\

D. Royalty Owners Have Relatively Little Contract Protection, Another Reason They Need Implied Protection

Another reason royalty owners need the mutual benefit covenant is that they have so little contract protection. Leases have a relatively simple price term and no detailed provisions on how costs are to be allocated. Whatever its cause, the rudimentary level of detail suggests the need for more extra-contract protection. In contrast, most joint equity

presumed identity of interests is as often myth as reality. Gary Conine has suggested that the reason courts had to develop the reasonably prudent operator test is that the interests of lessor and lessee were "too disparate." See Conine, supra note 186, at 711.

268. For the same reason, this is why the actual-cost basis and shared reliance upon production is so important to working interest owners under JOA investments. Profits are not to come from services provided to the partners, so interests should not be at odds, or so the theory goes. See generally Ernest E. Smith, Duties and Obligations Owed by an Operator to Nonoperators, Investors, and Other Interest Owners, 32 ROCKY MTN. MIN. L. INST. 12-1, 12-20, 12-21 (1986) (in general discussion of operator duties, claiming that "[s]elf interest of the party with the executive or managerial responsibility may be trusted to protect the interests of non-executive and nonmanaging parties").

269. The generality of lease language is striking. See, e.g., A.W. Walker, supra note 222, at 399 ("One of the most distinctive features of oil and gas leases is the almost total absence in the ordinary type of lease of express clauses protecting the royalty interest of the lessor."). cited with approval, Kramer & Pearson, supra note 222, at 788-89 & n.12; cf. Lowe, supra note 68, at 229 ("Typical lease royalty clauses are simply too general to help define the royalty obligations."). If leases are not detailed enough, one can naturally ask why parties do not just write more specific contracts. Cf. Pierce, supra note 68, at 786-833 (suggesting various improvements, from author's perspective). Given the differences in sophistication and resources between lessees and lessors, the result of an industry-rewritten lease is likely to be an unfair contract biased toward lessees. (Consider, for instance, Pierce's suggestion that one change be making clear that the "royalty-triggering event should be gas flowing through the valves at the wellhead." Id. at 817. This would have legitimated lessee profiteering from takeor-pay royalties.) When even the more experienced nonoperators have to suffer the broad disclaimers of responsibility in today's JOA, see infra note 270, there is little reason to think that industry-wide renegotiation of leases would produce fairer outcomes. That will not be likely until royalty owners organize and begin to use the pressure of their numbers to balance the larger economic interests and power that lessees enjoy as a group.
investments proceed under one or another form of the Joint Operating Agreement with its Copas accounting attachment. The Copas form has detailed accounting terms, including extensive audit provisions, that put the project on an actual cost basis.270

Given the inexperience and lack of resources of the average lessor, it would be unrealistic to expect them to employ even the same care as a working interest owner. Even if their experience and sophistication were not an issue, not many royalty owners have the money to commission a revenue or cost audit. Moreover, given the small size of many royalty interests, even wealthy royalty owners can find that the cost of auditing a large operating company (which predictably will resist providing information and make the process unnecessarily expensive) exceeds the likely return.

Royalty owners need more protection. Leases contain a price term —almost always a “market value/market price,” an “amount realized/proceeds” clause, a two-pronged combination of those two standards, or, in some older leases, a fixed price term—but generally no explanation of what these standards mean. Leases almost never say a word about the operator’s use of affiliates. They do not explicitly address the use of indices or resales through trading affiliates and say nothing about costs. Royalty owners have a strong need for the clarification of a mutual benefit covenant.

V. IT IS TIME TO LET THE MUTUAL BENEFIT COVENANT SURFACE

Because the royalty owner does enjoy many rights, express and implied, it is not customary to think about how much it gives up when it

270. “It has always been the intent of the Operating Agreement that the Operator should not make a profit or conversely suffer a loss just by the fact that he is the Operator of the joint operations.” JOLLY & BUCK, supra note 78, at 108; see also id. at 203; accord, C.M. Kennedy, Joint Venture Accounting, A La Copas—1962, 1964 NAT’L INST. PETROLEUM LANDMEN 159 (1991) (“It is a well established principle in our industry that an operator is not supposed to profit from the operation, at the expense of his co-venturers.”). For details of this actual-cost basis, see McArthur, supra note 78, § II.A., at 117-33.

If stronger contract protection brought with it the disclaimers and exculpatory clauses and Copas claims limitation that have marred the operator-friendly JOA in recent years, royalty owners are better off than with a detailed “industry” contract. JOA Article VII says that the parties do not intend to form a partnership or other fiduciary relationship. See 1989 JOA, supra note 73, art. VII. Article V.A. provides that the operator will perform in a “good and workmanlike manner” and that it will not be liable except for “gross negligence or willful misconduct.” See id. at art. V.A. For a case showing how far courts can go with the disclaimers, see Stine v. Marathon Oil Co., 976 F.2d 254, 259-61 (5th Cir. 1992). Copas provides that all joint account bills will be conclusively “presumed to be true and correct” unless challenged within two years of the end of the bill’s calendar year. See 1984 Copas, article I.4; 1995 Copas, article I.4.A.
signs a lease. Yet the royalty owner cedes full control over the mineral development of its property. The standard arrangement puts a landowner’s economic fate in the hands of the lessee. The lessee or its assignee will make all key development decisions, including when to drill, where to drill, and who else will invest in the project. It makes the technical decisions that can so alter the outcome, including decisions with very long-term environmental effects that may only become apparent after operations are long over.\textsuperscript{271} When production does occur, the royalty owner becomes even more dependent. The operator has full control over the contract that fixes the price paid for production. To these structural features must be added the lower sophistication of royalty owners, the relatively small size of their stake in a given well, and the generally smaller scope of their total holdings, so often limited to one or two wells.

With this backdrop, it is little surprise that courts have recognized a mutual dependence in which the lessee is charged to act for the lessors. It is no surprise to see this principle emerging from \textit{First Baptist}; from the elaboration of Texas division order cases; from various affiliate cases; from such lead cases as \textit{Alexander v. Amoco} and \textit{Phillips v. Shutts}; and to find it ensconced in the Louisiana Mineral Code. The idea that the lessee cannot feather its nest by soiling the royalty owner’s is a fundamental principle of oil and gas law and, as such, has been acknowledged by a wide array of existing cases.

Royalty law is in transition because while many cases recognize the lessee’s fundamental duty to treat lessors with equal fairness and not to diminish their interest, the law has yet to elevate that principle to the same level as, say, its protections against drainage and the duty to market. Though courts may often get this principle right, they can cause spectacular damage when they do not. The take-or-pay failures are Exhibit A to the damage caused. The posted price problem is not far behind. The new wave of natural gas liquids and gas price and cost litigation threatens to unearth on the gas side problems much like the posted price disputes.

\textsuperscript{271} “Typically, lessees make decisions which directly impact the lessor’s interests without any input from the lessor.” Pierce, \textit{supra} note 227, at 462; Pierce, \textit{supra} note 68, at 826 (“lessor is, to a large extent, at the mercy of the lessee when it comes to the machinations of the marketplace”). In the standard equity venture, these are all decisions on which all equity investors, operator included, get to vote. In many operations, however, the nonoperators will have little or no technical expertise and will follow the operator’s advice. They will figure that it has no incentive to complete a well or drill a subsequent well unless the well will produce in paying quantities. (For examples of many of the ways that operators may try to improve on these pure incentives, see John Burritt McArthur, \textit{A Twelve-Step Program for Copas to Strengthen Oil and Gas Accounting Protections}, 49 SMU L. REV. 1447 (1996)). Even active nonoperators have to rely heavily on information the operator generates during the drilling in making well decisions.
A clear mutual benefit rule should over time clarify other areas of the law as well. It can remove affiliate cases from the possible confusion of alter ego and corporate-veil principles. The rule should force courts in jurisdictions following *Vela* to think again about the arbitrary division of lessor and lessee interests represented by that rule.

Lessor and lessee share the same hope of making valuable discoveries, but their interests diverge sharply and fundamentally in many routine aspects of an oilfield project. The disputes discussed in this Article all arose because of divergent incentives. Yet oil and gas companies only secure leases in the first place because landowners believe they will be treated fairly and share whatever happens with the lessee. Lessors trade their property for the lessee's experience, skill, and financial investment.

Building a stronger relationship by adding this clear implied covenant protection is not just a benefit for lessors. The lease is designed to let oil and gas companies take the risks of exploration without having to pay much for the land. The standard American lease lets oil companies explore and develop "with a minimal capital outlay because the major compensation to the landowner will be paid out of production from the land, if and when production is obtained."272 The near universal use of leases in the development of American oil and gas fields shows that operators and lessees as well as landowners prefer the mutuality of this allocation of risk. It is time for implied covenant law to install a mutual benefit principle and recognize that both sides of the lease are to share in whatever happens next. Both oil and gas law and the larger body of natural resources law of which it is a part will benefit from finally acknowledging this key covenant that courts routinely enforce. Formal recognition of this legal right should prevent some of the errors that can occur when it remains unacknowledged, a risk demonstrated all too well by the take-or-pay royalty cases.

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