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Current Lease and Royalty Problems in the Gas Industry

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CURRENT LEASE AND ROYALTY PROBLEMS IN THE GAS INDUSTRY*

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I. INTRODUCTION

The past two years have been a time of restructuring for the natural gas industry, particularly for producers and pipeline companies. The problems of the industry have affected the relationships of producers and the mineral owners who granted them oil and gas leases. Although lease and royalty problems are given little attention on a national basis, they involve hundreds of millions of dollars potentially at issue between producers and royalty owners.

II. LEASE MAINTENANCE PROBLEMS CAUSED BY LOWER PRICES

Recently, a frequent topic of conversation among oil and gas attorneys has been whether their clients' leases are still in effect and, if so, for how much longer. The problem is that falling oil and gas prices generally mean falling profits, and most oil and gas leases are drafted so that they terminate when it is no longer profitable to continue to operate them. The typical lease habendum clause provides for extension of the

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* © John S. Lowe, 1988. This article surveys problems relating to lease maintenance, royalty payments, and implied covenants under current economic conditions. Of necessity, treatment of specific issues is brief.

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lease beyond the initial primary term as long as there is production. Most courts interpret this reference to require *profitable* production.[1] The rationale is that the oil and gas lease is a business transaction, so that the parties intend that the reference to "production" should mean "production in paying quantities."[2] Most states define "production in paying quantities" as production sufficient that operating revenues exceed operating costs over a reasonable period of time,[3] usually at least one year. When, as over the last two years, there is a sharp and sustained drop in price and wide-spread curtailment of production, lease termination claims are likely to confront producers, particularly on leases with high operating costs. Thus, producers have become very concerned with lease savings clauses, particularly the shut-in royalty clause.

A. *Savings Actions and Clauses*

Many in the industry have chosen to ignore the legal problems caused by falling gas revenues and to cross their fingers, hoping that their lessors will not challenge the validity of their leases. That hope is contrary both to human nature and to the common law. Though mineral owners may not move quickly to break leases when the market is depressed, when prices of oil and gas eventually rise again, they will move to challenge leases that have been unprofitable during the downturn. Once a lease has terminated by failing to produce in paying quantities, it generally cannot be revived by resumption of profitability, and a lessor is ordinarily not barred by laches, waiver, or estoppel from asserting that the lease has terminated.[4] Furthermore, a lessor's acceptance of royalties is not a basis for equity to bar lease termination, because royalties represent only a fraction of the production to which the lessor is entitled if the lease has terminated.[5]

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1. Clifton v. Koontz, 160 Tex. 82, 89, 325 S.W.2d 684, 691 (1959) (citations omitted); *see also* J. LOWE, OIL AND GAS LAW IN A NUTSHELL 173-77 (1983). For further treatment of the evaluation production status of oil and gas leases. See Comment at 667 (current issue).
2. 3 H. WILLIAMS & C. MEYERS, OIL AND GAS LAW § 604.5 (1987).
3. *Id. See, e.g.*, Kerr v. Hillenberg, 373 P.2d 66 (Okla. 1962); *Clifton*, 160 Tex. at 89, 325 S.W.2d at 691.
4. *See, e.g.*, Metz v. Doss, 114 Ill. App. 2d 195, 252 N.E.2d 410, 412 (1969); Greer v. Salmon, 82 N.M. 245, 479 P.2d 294, 300 (1970). There are numerous cases, however, in which equitable factors have been cited by the courts as a basis for refusing to find leases terminated. *See* 2 E. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 26.14 (1964).
5. Earp v. Mid-Continent Petroleum Corp., 167 Okla. 86, 27 P.2d 855 (1933).

1. Governmental Action

Producers holding federal and state leases have persuaded the governmental agencies in charge of leasing to amend their rules so that production may be halted without loss of their leases. Thus, for example, shortly after oil prices plunged in the spring of 1986, the federal government set forth a procedure for granting lessees of marginally-producing "stripper wells"[6] a suspension of the production requirement.[7] Some state agencies have extended the time period under rules requiring that nonproducing wells be plugged and abandoned after a certain period of time, thus effectively extending nonproducing state leases.[8] Such actions have substantially lessened the risk of loss of the lease for federal and state lease holders, at least for those who have kept up with the deluge of regulations and memoranda.

Solving the problem of failure to produce in paying quantities for leases on private lands is not as easy. Governmental action will not prevent termination of a private lease by the terms of the habendum clause upon which the lessor and the lessee have agreed. At best, action by government deprives lessors of the argument that state or federal law requires lease termination. In addition, it may not be practical for lessees to negotiate relief with their mineral owners becasue there are literally millions of mineral owners and leases.

2. Lease Terms

Some producers may find the solution to their problem in the terms of their leases. Most oil and gas leases contain a series of savings clauses: the operations clause; the cessation of production clause; the force majeure clause; the pooling and unitization clauses; and the shut-in royalty clause. These clauses are intended to give producers flexibility to deal with interferences with production by providing for specifically defined substitutes for production.[9] However, these savings clauses generally deal with complete failure of production as a result of physical problems with the well or governmental intervention, rather than with

6. A stripper well is generally defined as a well capable of producing less than ten barrels of oil per day or less than 60 MCF of natural gas per day.

7. Bureau of Land Management Instruction Memorandum No. 86-409 (Apr. 22, 1986).

8. *See, e.g.*, Texas Statewide Rule 14 Emergency Amendment, TEX. ADMIN. CODE tit. 16, § 3.14 (1985) (allowing operators of wells that became inactive after January 1, 1986, a full year, instead of ninety days, to plug them or to put them into production again).

9. See J. LOWE, OIL AND GAS LAW IN A NUTSHELL 210-248 (1983) for a concise review of lease savings clauses.

unprofitability as a result of production curtailments. If closely examined, they may not maintain leases in the face of falling prices.

a. *Operations Clause*

The operations clause in an oil and gas lease makes operations for drilling or reworking a well the equivalent of production in paying quantities.[10] However, operations are not likely to be a viable alternative at a time of low prices and high curtailments. While the courts are very liberal in defining what constitutes "operations,"[11] producers are not likely to drill additional wells or to rework existing wells when they cannot profitably sell their production. Moreover, the operations clause merely delays the inevitable: once operations are completed, the profitability standard applies anew.

b. *Cessation of Production Clause*

While a cessation of production clause will usually extend a lease after production ceases "from any cause,"[12] the cessation of production clause is invariably drafted to require additional drilling or reworking operations to begin within sixty or ninety days.[13] A producer who is already losing money from operations will not want to spend more money drilling additional wells or reworking existing wells. Furthermore, some courts have held that the grace period of the cessation of production clause begins to run at the end of any month in which lease operations are unprofitable.[14] Under such an interpretation, the grace period may have run before the producer realizes that its lease is unprofitable.[15]

c. *Force Majeure Clause*

Some producers assume that the fall of gas prices is an event beyond their control that will trigger the savings provisions of the force majeure clause. The force majeure clause is included in an oil and gas lease to

10. *Id.* at 216.

11. *See, e.g.*, A & M Oil, Inc. v. Miller, 11 Kan. App. 2d 152, 715 P.2d 1295, 1297 (1986) (preparatory operations for drilling a slant well constituted "operations," though the drill bit did not actually begin to turn and no activity took place on the leased property).

12. *See, e.g.*, Texas AAPL Form 675 Oil & Gas Lease, ¶ 6 (Kraftbilt, Tulsa), *reprinted in* E. KUNTZ, J. LOWE, E. SMITH & O. ANDERSON, OIL AND GAS FORMS MANUAL 20, 21 (1987).

13. *Id.*

14. *See, e.g.*, French v. Tenneco Oil Co., 725 P.2d 275 (Okla. 1986).

15. Lowe, *Developments in Nonregulatory Oil & Gas Law*, 32 INST. ON OIL & GAS L. & TAX'N, 117, 177 (1981).

excuse performance and maintain the lease when a force beyond the control of the lessee and lessor interferes with performance.[16] Courts generally interpret force majeure clauses in oil and gas leases strictly.[17] Moreover, most force majeure clauses define only physical or regulatory phenomena such as fires, floods, strikes, or governmental orders as force majeure events, and excuse only the lessee's failure to perform lease covenants.[18] Few leases specifically cover the possibility that a substantial drop in demand will result in production surpluses and lower prices so that the lessee will lose money if it opts to produce.[19]

d. Pooling and Unitization Clauses

Pooling and unitization clauses may permit producers to maintain unprofitable leases by combining them with profitable leases. Pooling and unitization clauses permit a lessee to hold a lease even without production from the premises, so long as the lease is combined with a lease that is producing profitably.[20] In theory, a lease that the producer does not wish to drill may be pooled or unitized with producing leases and maintained as long as there is profitable production from any well on the unit. The pooling power must be exercised in good faith, however, and the business judgment of combining profitable leases with unprofitable leases is certainly subject to question.[21] Historically, the purpose of pooling and unitization clauses was to give producers the flexibility to conform operations to geologic realities or to the requirements of administrative agencies, and not to maintain leases in a time of declining prices and profitability.

e. Shut-In Royalty Clause

The shut-in royalty clause is the lease savings clause offering the best chance for producers confronted with drastically lower gas revenues to

16. J. LOWE, *supra* note 9, at 236.

17. E. KUNTZ, J. LOWE, O. ANDERSON & E. SMITH, CASES AND MATERIALS ON OIL AND GAS LAW 186 (1986). *See, e.g.*, Champlin Petroleum Co. v. Mingo Oil Producers, 628 F. Supp. 557, 561 (D. Wyo. 1986) (bankruptcy was not within the force majeure clause).

18. *See, e.g.*, Texas AAPL Form 675 Oil & Gas Lease, ¶ 11, *reprinted in* E. KUNTZ, J. LOWE, E. SMITH & O. ANDERSON, *supra* note 12, at 22.

19. The force majeure clause should preserve an oil and gas lease only if (a) the event complained of is defined as a force majeure event, (b) the failure of performance is excused by the clause, and (c) the event caused the failure of performance. 4 E. KUNTZ, *supra* note 4, § 53.5. The garden variety force majeure clause neither defines market failure as a force majeure event nor defines a failure to produce as an excused failure of performance.

20. E. KUNTZ, J. LOWE, O. ANDERSON & E. SMITH, *supra* note 17, at 198.

21. *See, e.g.*, Southwest Gas Producing Co. v. Seale, 191 So. 2d 115 (Miss. 1966); 4 H. WILLIAMS, OIL AND GAS LAW § 670.2 (1985).

maintain their leases.[22] The shut-in royalty clause gives lessees the right to shut in actual production and substitute shut-in royalty payments to lessors.[23] Again, however, the effect of the clause is likely to be limited. Shut-in royalty payments must generally be made in strict compliance with lease terms, and an inadvertent mistake will result in automatic termination.[24] In addition, several courts have held that the clause can be used only where a lease is capable of producing in paying quantities.[25]

3. Lease Amendment

Thus, for all its practical disadvantages, lease renegotiation and amendment seems a far better option than reliance upon lessor goodwill, governmental intervention, or boilerplate lease language. Despite the administrative burden involved, many producers have successfully approached their mineral owners seeking lease amendments providing specific periods of lease extension or liberalizing the restrictive language of the habendum[26] or lease savings clauses.[27] Even if prices for oil and gas improve, producers with leases that have been only marginally profitable over the last few years would be well advised to consider amending their lease terms as a safety measure against price downturns in the future.

B. *Shut-In Royalty Problems*

For more than five years, the American gas industry has been confronted by what was supposed to be an eighteen month gas "bubble." At the height of the gas surplus, as much as fifteen percent of United States gas delivery capacity may have been shut-in on any given day.[28] Widespread shut-ins have attracted attention to the limitations of typical shut-in royalty clauses in oil and gas leases.

The lease shut-in royalty clause provides for "constructive production" in lieu of actual production in paying quantities by permitting the

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22. *See infra* notes 28-30 and accompanying text.
23. J. LOWE, *supra* note 9, at 239.
24. *See infra* notes 31-40 and accompanying text.
25. *See infra* notes 41-44 and accompanying text.
26. For example, the habendum clause might be modified to define "in paying quantities" in terms of (a) the capability of a specific volume of production or (b) the actual production of a stated dollar value of oil and gas. *See* 2 E. KUNTZ, *supra* note 4, § 26.7(b).
27. For example, the lack of a market price for natural gas that would permit the lessee to produce profitably might be defined as a force majeure event, or the shut-in royalty clause might specifically permit shut in when the market price will not permit the lessee to produce profitably.
28. True, *Annual Gas Processing Report*, OIL & GAS J., July 13, 1987 at 36.

lessee to make shut-in royalty payments.[29] Shut-in royalty clauses have been included in oil and gas leases since early in this century because drafters have recognized that natural gas cannot be economically stored, and that there inevitably will be substantial swings in demand as a result of weather changes and economic cycles.[30] Unfortunately, however, the adage that "for every draftsman there awaits an advocate" has proved true, and shut-in royalty clauses have frequently ended up before the courts.

1. Risk of Termination if Payment is Not Made Properly

One of the most frequent problems with shut-in clauses, and one that has arisen frequently over the last few years, is what happens if a shut-in payment is improperly made. Does the lease automatically expire, or does the lessee merely owe the lessor the shut-in payment? The answer appears to depend upon the location of the property and upon the precise terms of the clause.

In states like Oklahoma that follow the minority rule that "production" means merely a capability of gas production (because the business purpose of the lease is substantially performed when gas has been discovered and a well prepared to produce), failure to pay a shut-in royalty properly will not cause the lease to terminate.[31] Since the lease is already "producing," even though it is shut-in, the shut-in royalty provision is regarded as a compensation provision, rather than as a substitute for production. Breach of its terms subjects the lessee to liability, but not to loss of the lease, unless it is clear from the lease terms that the parties intended otherwise. This is also probably the law in Kentucky, Montana, West Virginia, and Wyoming as well as Oklahoma.[32] It apparently is also the position in Louisiana because of the terms of the Louisiana Mineral Code, although the reasoning there is different.[33]

In most states, however, a failure to make a shut-in royalty payment properly may cause the lease to terminate.[34] The determining factor is

29. Lowe, *Shut-In Royalty Payments*, 5 E. MIN. L. INST. § 18.02(1) (1984).

30. *Id.* § 18.02.

31. Gard v. Kaiser, 582 P.2d 1311, 1313 (Okla. 1978).

32. Lowe, *supra* note 29, § 18.03(2).

33. Acquisitions, Inc. v. Frontier Exploration, Inc., 432 So. 2d 1095 (La. Ct. App. 1983). The court reasoned that the shut-in royalty was a royalty within the meaning of § 137 of the Louisiana Mineral Code, so that written notice of breach from the lessor to the lessee was required to support a demand for dissolution. *Id.* at 1100-01.

34. Lowe, *supra* note 29, § 18.03. Texas, Kansas, and New Mexico are among the states that apparently follow this view. *Id.*

the precise language of the shut-in royalty clause which provides for constructive production when there is no actual production. Thus, the key question in analyzing a shut-in royalty clause is what is the constructive production? If the shut-in clause is drafted so that the mere existence of a well capable of producing is the constructive production under the lease, then an improper payment or failure to pay should not result in loss of the lease. Even though the shut-in payment is not made properly, the term "production" as used in the habendum clause will be equated by the lease to the existence of a shut-in well on the premises. On the other hand, if the lease is drafted so that the substitute for actual production is a payment of shut-in royalty, as is the case with most shut-in clauses, then a failure to make the payment properly will cause the lease to terminate. If there is no actual production, and no substitute for production is provided, there is nothing to maintain the lease.

The classic case illustrating the importance of the way the shut-in clause defines constructive production is *Gulf Oil Corp. v. Reid*.[35] Gulf's oil and gas lease contained a shut-in royalty clause which provided: "[W]here gas from a well producing gas only is not sold or used, Lessee may pay as royalty Fifty Dollars ($50.00) per well per year, and upon such payment it will be considered that gas is being produced within the meaning of Paragraph 2 [the habendum clause] hereof. . . ."[36] Gulf began drilling a well on its lease a few days before expiration of the primary term, and completed and shut-in the well shortly after the end of the primary term. A month later, Gulf tendered the shut-in royalty payment to the lessor, who rejected it. The Texas Supreme Court held that the lease had terminated.[37] The court reasoned that "[t]he lease lapsed as a matter of law, there being no gas produced from the premises on the last day of the primary term, and the royalty not having been paid on or before that date."[38] If there is no actual production and no substitute for production, there is nothing to maintain the lease.

What can be done about this problem? Nothing short of amending the shut-in clause or other lease savings provisions will maintain a lease in the event of a failure to pay or an error in payment where the lease makes proper payment the only constructive production. Payment of shut-in royalty under such a lease is like sudden death overtime—one mistake and it is all over. Many producers have their lawyers prepare

35. Gulf Oil Corp. v. Reid, 161 Tex. 51, 337 S.W.2d 267 (1960).
36. *Id.* at 53, 337 S.W.2d at 269 n.1.
37. *Id.* at 55, 337 S.W.2d at 271.
38. *Id.*

"shut-in royalty opinions" for each of their leases to give administrative employees directions about how to make shut-in payments. Others have added staff to their lease administration departments, despite company-wide cuts in employment. These steps will help, but it is inevitable that many producers will lose their leases.

In Oklahoma, one frequently sees a bumper sticker that implores God to "give me one more oil boom." Motivated by faith that the boom will come, and be followed inevitably by a bust that will once again make shut-in payments important, the drafters of most lease forms prepared in the 1980's have formulated shut-in royalty clauses that clearly provide that failure to make shut-in payments will not terminate the lease. The following is typical: "If . . . at any time . . . there is any well on said land . . . capable of producing oil or gas, and all such wells are shut-in, this lease shall nevertheless, continue in force as though operations were being conducted on said land for so long as said wells are shut-in. . . ."[39] Such clauses almost uniformly make the presence of a well *capable* of production the equivalent of *actual* production from the lease.[40] Payment of shut-in royalty or rental is a compensation promise rather than the factor that extends the lease. Many also contain specific savings language excusing inadvertent failure to make payment. Due to better drafting, improper payments under the shut-in royalty clause should not cause nearly as many problems during the next economic cycle.

2. When the Shut-In Royalty Clause Can Be Used

There are two problems with shut-in royalty clauses that are not likely to be solved by current drafting techniques: (a) the requirement of a capability of production "in paying quantities;" and (b) the application of the reasonable prudent operator standard to the shut-in clause. These problems may open to question the validity of many leases that producers have shut-in during recent years.

39. Producers Form 88 (7-69) - Paid-Up, ¶ 3 (available from Pound Printing & Stationary Co., Houston). In fact, there is no case law directly upholding the proposition that a shut-in clause drafted to make the existance of a shut-in well constructive production will preserve a lease against a failure to make payments properly. However, that conclusion is suggested by the reasoning of *Gulf*, *supra* note 35.

40. The author drafted an extensive shut-in royalty clause at Lowe, *supra* note 29, § 18.05(2), which is offered as a basis for further discussion and drafting.

a. *The "In Paying Quantities" Requirement*

Though many producers are unaware of it, there is substantial precedent holding that the shut-in royalty clause in an oil and gas lease cannot be invoked to maintain the lease unless the well is capable of production "in paying quantities."[41] This requirement substantially limits the flexibility of lessees who would rely upon the shut-in clause to maintain leases. It means, for example, that it will not be enough merely to drill to a depth where a substantial show of gas is encountered and then to cap the well until there is a market available or until the price rises so that it is once again profitable to sell.[42] In order to hold a lease under the shut-in royalty clause, there must be a well on the lease that has been drilled, completed, and equipped for production.[43]

Perhaps the most difficult problem presented by the "in paying quantities" requirement is one of timing where the clause is utilized in a lease which is producing. When a producer chooses to shut-in a lease that is producing, the "in paying quantities" requirement arguably must be met at the time that the shut-in occurs. If the producer has ridden the spot market down, hoping that there will be a price turnaround, a court may find that the producer's lease has not been maintained by the shut-in clause if the decision to shut in is made at a time when revenues are so low that lease operating costs exceed operating revenues.

Of course, the "in paying quantities" concept overlaps with the reasonable prudent operator standard. The premise should be that because

41. *See, e.g.*, Pray v. Premier Petroleum, Inc., 233 Kan. 351, 662 P.2d 255, 258 (1983); Taylor v. Kimbell, 219 La. 731, 54 So. 2d 1 (1951); Bixler v. Lamar Exploration Co., 733 P.2d 410, 412 (Okla. 1987); Hoyt v. Continental Oil Co., 606 P.2d 560, 564 (Okla. 1980). In Oklahoma, payment of shut-in royalty is not *necessary* to maintain a lease. McVicker v. Horn, Robinson & Nathan, 322 P.2d 410 (Okla. 1958) (a well capable of production in paying quantities is "producing" within the meaning of the habendum clause). However, the issue often arises as to whether the lessee has the *right* to pay shut-in royalty.

42. The rationale for such a limitation was stated recently by the Kansas Supreme Court in Pray v. Premier Petroleum, Inc., 233 Kan. 351, 662 P.2d 255 (1983):

> [A]lthough the shut-in royalty clause does not normally specify the shut-in gas well must be capable of producing in paying quantities, such a requirement is implied. As noted, the shut-in royalty clause is a savings clause allowing for constructive production. Such clauses provide that upon payment of the shut-in royalty it will be considered gas is being produced within the meaning of the habendum clause. In order to achieve the desired result, namely a profit, production, whether actual or constructive, must be in paying quantities.

Id. at __, 662 P.2d at 258.

43. *Hoyt*, 606 P.2d at 564. The logic of this rule is subject to question, at least where the geologic characteristics of the potentially producing formations are such that the reasonable prudent operator would not fracture the well until actually ready to produce (as some have asserted to the author is true of the Mississippian Formation in Oklahoma). The lease should not be interpreted to require the lessee to act imprudently to maintain it.

an oil and gas lease is a business transaction, the lessee must act as would a reasonable prudent operator under the circumstances. Thus, the meaning of "in paying quantities" should be determined not by whether revenues exceed costs when the shut-in occurs, but by reference to what the future is likely to bring, and to whether the amount of production the well is likely to produce would justify a reasonable prudent business person in continuing to operate the property.[44] There is no "bright line" distinction, however, so conservative lawyers are advising producer-clients who expect to have to shut in wells to do so at a time while they are still capable of producing "in paying quantities."

b. *The Reasonable Prudent Operator Limitation*

A second issue is whether the lessee must act as a reasonable prudent operator in invoking the shut-in royalty clause. The answer may substantially limit the availability of the shut-in clause to maintain oil and gas leases.

A hypothetical case may clarify the problem. Suppose that the Board of Directors of Independent Oil Company decides that the value of gas in the ground is inherently greater than the current spot market price and adopts a resolution ordering management to shut in any well from which gas cannot be sold for at least $2.50 per MMBTU. May leases that are shut-in be held by the tender of shut-in payments? At issue is the breadth of the lessee's discretion in deciding when to shut in. Is Independent Oil Company entitled to invoke the shut-in royalty clauses of its leases whenever management decides it is advisable to do so, or is it permitted to hold its leases by shut-in payments only when a reasonable prudent operator would decide to do so?

There is little doubt that the lessee has a theoretical duty to utilize the shut-in royalty clause in accord with the reasonable prudent operator standard. That obligation permeates the lessee's rights.[45] However, most commentators have urged that the interests of the lessee and the lessor in making the shut-in decision are virtually identical, so that the courts should defer to the lessee's decision.[46] Furthermore, most case

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44. Clifton v. Koontz, 160 Tex. 82, 86-87, 89-90, 325 S.W.2d 684, 689-91 (1959); *see also* J. LOWE, *supra* note 9, at 173-77.

45. The oil and gas lease is a business transaction in which the lessor gives to the lessee the right to make operational decisions. Since the lessee acts for the lessor, a duty to act in good faith, competently, and with due regard for the lessor's interest is implicit. J. LOWE, *supra* note 9, at 279-81.

46. *See* Lowe, *supra* note 29, § 18.04(1)(ii); Martin, *A Modern Look at Implied Covenants to Explore, Develop, and Market Under Mineral Leases*, 27 INST. ON OIL & GAS L. & TAX'N 177, 190-

law has recognized broad discretion in the lessee to determine when shut-in is justified, at least where the lessee's judgment that production should be shut in now (because prices will increase) turns out to be correct. There are, however, cases that suggest that shut-in may be a prohibited "speculation" where the lessee's judgment as to what the future will bring proves to be wrong.[47] Thus, those producers who have taken or expect to take unilateral action to shut in gas production would be well advised to build a record based upon more than the gut reactions of their directors, however distinguished they may be, that natural gas is inherently worth more than the price it will bring on the market.

III. Royalty Problems

A. *Market Value Royalty*

For nearly twenty years, natural gas producers have been confronted with the market value royalty problem. It takes on a new twist in the current market.

Many royalty clauses in oil and gas leases drafted before the mid-1960's provide for a royalty based upon the "market value at the well of gas sold or used." Beginning in the 1960's, there have been hundreds of cases in which royalty owners have argued that the reference to "market value" obligates their producers to pay a royalty calculated on the basis of the market value of the gas when produced, which is what a willing buyer and a willing seller would agree upon, even where that price is greater than the price for which the lessee had agreed to sell the gas produced under a long-term contract negotiated at arm's length. Of course, lessees have argued that they should not be held liable to pay royalty on a value greater than the price for which the gas is actually sold. Their theory is that the interpretation of "market value" most consistent with the implied covenant to market is that the contract price entered into at an arm's length basis *is* the market value.[48] In a majority

93, 200-01 (1976); Pierce, *Lessee/Lessor Relations in a Turbulent Gas Market*, 38 INST. ON OIL & GAS L. & TAX'N 8-1, 8-9 (1987).

47. *See, e.g.*, Hutchinson v. McCue, 101 F.2d 111 (4th Cir.), *cert. denied*, 308 U.S. 564 (1939).

48. The clearest statement of this position is in Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981), where the Oklahoma Supreme Court concluded that "market value" was ordinarily the "proceeds" actually received. The lessee is required by the implied covenant to market to sell gas, and since gas has customarily been sold under long-term contracts, the lessee is forced to accept such contracts. It would be unfair to the lessee to permit his profit to be whittled away, as would occur if the lessee had to pay royalties on market value when prices were rising. *Id.* at 1273. On the other hand, requiring a lessor to accept a share of whatever the lessee receives is not unfair to the lessor, because the lessor is protected by the lessee's duty to make a reasonable sales contract. *Id.* at

of the states in which the issue has been considered, lessors have prevailed.[49] Generally, the courts have reasoned that oil producers are experienced in the industry, and accordingly their leases should be interpreted to mean exactly what they say: "market value" is what a willing buyer and a willing seller would agree upon at the time of the production and sale.[50]

In the past, market value royalty litigation has always arisen in a situation in which the alleged market value was greater than the contract price for the gas produced. In the current gas surplus, the contract price received by a producer for gas now frequently is greater than the market value of that gas in the open market. For example, there are many contracts executed in the early 1980's covering NGPA Section 102 or 103 gas under which gas is currently being sold at prices substantially above current spot market prices. If gas is being sold at $3.50 per MMBTU, but the spot market price is only $1.50 per MMBTU, can the lessee require that the lessor accept "market value," $1.50 per MMBTU or some other price less than $3.50, as the basis for royalty calculation?

There is as yet no case law which deals directly with the issue. However, the logic of the market value royalty cases suggests that in those states which have concluded that "market value" may be greater than the contract price, the lessor should be due only a royalty calculated on the basis of "market value," even if that is lower than the contract price. If "market value" means a price that a willing buyer and seller would agree upon, then that standard should apply regardless of whether it is advantageous to the lessor in a given fact situation.[51] The parties

1274. This reasoning has been suggested by others. *See* Morris, *The Gas Royalty Clause - What is Market Value?*, 25 INST. ON OIL & GAS L. & TAX'N 63, 79-83 (1974).

49. For a further discussion, see J. LOWE, *supra* note 9, at 263-67. The states that have adopted the market value royalty rule (that a market value royalty may be based on a price greater than the contract price) are Kansas, Texas, Mississippi, and (perhaps) Montana and North Dakota. It has been rejected in Oklahoma, Arkansas, and Louisiana. *Id.* at 266-67.

50. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985), is the classic case on point. In rejecting the lessees' argument, the court said that "[i]t is not the function of the courts, construing and enforcing contracts under [Mississippi] state law, to intervene on behalf of producers experienced in the petroleum industry, and thereby deprive lessors of their legitimate contractual expectations." *Id.* at 237. The court described the market value royalty provision as a "business risk." *Id.*

51. This reasoning is implicit in the opinion of the Fifth Circuit in *Piney Woods*, 726 F.2d 225, 237. It is also implicit in the leading Texas case of Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981), where the Texas Supreme Court noted that "[w]hen Exxon negotiated the [fixed price] gas contracts, it took the risk that the revenue therefrom would be sufficient to satisfy its royalty obligations." *Id.* at 245. The reasoning of the Kansas Supreme Court in Lightcap v. Mobil Oil Corp., 221 Kan. 448, 562 P.2d 1, *cert. denied*, 434 U.S. 876 (1977), is not so clear. To this reader, *Lightcap* seems to turn on the maxim that "ambiguities are to be interpreted against the drafter" rather than a business risk analysis.

have clearly expressed their agreement, and the agreement should be given effect.

In fact, few producers with market value royalty clauses in leases and gas contracts with prices above the market have taken advantage of the turbulence in the market to lower royalty payments. This hesitancy probably results from a concern that it may not be wise to goad royalty owners into suits that may raise other issues upon which lessees may be more vulnerable. Those who have lowered royalty payments are keeping quiet about it, hoping that their royalty owners will not realize that they are being paid on a basis other than the price for which gas produced is being sold.

B. *Royalty Owners' Right to Share in Take-or-Pay Payments*

Take-or-pay clauses in gas contracts, which require purchasers to pay for gas even if they do not take it,[52] lie close to the heart of the problems of the natural gas industry. One of the reasons that natural gas prices to residential consumers shot up in the early 1980's was that pipelines took gas from high-priced sources rather than make take-or-pay payments for it. Thus, consumers who could have been supplied with cheap gas received expensive gas instead. Despite devices to avoid making take-or-pay payments, pipelines now are confronted by what some have estimated to be as much as fifteen billion dollars in take-or-pay liabilities. Pipeline companies have not willingly paid most of those payments, so the courts in the major gas producing states are clogged with litigation over the clauses. Billions of dollars have been paid in take-or-pay settlements and damage awards. Billions more remain in dispute.

Take-or-pay liabilities are likely to be put to rest within the next few years. Time is running out in the litigation process, and pipeline companies are losing most of the cases.[53] Furthermore, the Federal Energy

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52. A typical take-or-pay clause, taken from a mid-continent area contract, reads as follows:

> Subject to the other provisions of this Contract, Seller agrees to sell and deliver and Pipeline agrees to purchase and receive, or pay for if made available hereunder but not taken, a daily quantity of gas, average over each accounting period (contract quantity) during the term hereof, equal to seventy-five percent (75%) of the maximum quantity of gas that Seller's wells can deliver to Pipeline . . . .

53. For a summary of take-or-pay issues, see Medina, McKenzie & Daniel, *Take or Litigate: Enforcing the Plain Meaning of the Take-or-Pay Clause in Natural Gas Contracts*, 40 ARK. L. REV. 185 (1987) *reprinted in* 24 PUB. LAND & RESOURCES DIGEST 192 (1987). *See also* Legg, *Natural Gas Contract Litigation in Oklahoma*, 11 OKLA. CITY U.L. REV. 63 (1986); Medina, *A Report from the Battle Zone: The Take-or-Pay Wars*, 58 OKLA. B.J. 2554 (1987), *reprinted in* 24 PUB. LAND & RESOURCES DIGEST 268 (1987).

Regulatory Commission has devised a regulatory scheme that will encourage settlement of claims.[54] With prodding from the courts, FERC has required producers who wish pipelines to transport their gas to end user or local distribution company purchasers to offer credits against take-or-pay claims.

However take-or-pay liabilities are settled, substantial amounts of money have changed hands, and much greater amounts will probably pass in the next few years. The take-or-pay problem has been only of academic interest for all but the small group of attorneys involved in complex take-or-pay litigation or in related FERC proceedings. As take-or-pay payments are made or take-or-pay claims are settled, however, the issue of whether royalty owners are entitled to share in take-or-pay payments becomes increasingly more important.

The issue was raised in the context of a state lease in *Pennzoil Co. v. State*.[55] The lease royalty clause in *Pennzoil* provided that royalty was due "on gas . . . produced from said land saved and sold or used off the premises. . . ."[56] Further, the royalty payment clause provided that payment was due "on or before the twentieth (20th) day of the calendar month succeeding the month of production and removal and sale of oil and gas from said land. . . ."[57] On the basis of the language of the lease, the state district court held that no royalty was due to Wyoming on take-or-pay payments. Gas was not "produced" or "removed," so royalty was not due, concluded the court.[58]

More recently, two cases from Louisiana involving federal leases addressed the same issue with radically different results. In *Mesa Petroleum Co. v. United States Department of the Interior*,[59] a federal district court followed much the same reasoning as the Wyoming court in *Pennzoil*. The court held that royalties to the United States were not due on take-or-pay payments received by Mesa from Tennessee Gas Pipeline Company under the terms of an offshore lease from the United States.[60]

54. *See* Associated Gas Distrib. v. F.E.R.C., 824 F.2d 981 (D.C. Cir. 1987), *petition for cert. filed*, (Dec. 11, 1987); F.E.R.C. Order 500, 52 Fed. Reg. 30,334 (1987) (to be codified at 18 C.F.R. §§ 2,284); F.E.R.C. Order 500-B, 52 Fed. Reg. 39,630 (1987); F.E.R.C. Order 500-C, 52 Fed. Reg. 48,986 (1987); F.E.R.C. Order 500-D, Doc. Nos. RM 87-34-000 - RM 87-34-053 (Mar. 8, 1988).

55. Pennzoil Co. v. State, No. 104-39, slip op. (Dist. Ct. Wyo. Mar. 27, 1986) (LEXIS, States library, Wyo. file).

56. *Id.*

57. *Id.*

58. *Id.*

59. Mesa Petroleum Co. v. United States Dept. of Interior, 647 F. Supp. 1350 (W.D. La. 1986).

60. *Id.* at 1355.

Under the lease, Mesa agreed to pay the United States a royalty of sixteen and two-thirds percent "in amount or value" of production saved, removed or sold from the leased area.[61] Subsequently, Mesa and Tennessee entered into a gas contract that provided for take-or-pay payments and Mesa made the take-or-pay payments. The United States claimed royalties. The district court granted Mesa's motion for summary judgment, holding that the United States was not entitled to share and that the lease and the appropriate statutes and regulations require royalties only on "production," which occurs only when natural gas is severed from the ground and sold.[62]

In contrast, in *Diamond Shamrock Exploration Co. v. Hodel*,[63] a federal district court concluded that the United States was due royalties on take-or-pay payments. The court in *Diamond Shamrock* reasoned that federal leases granted to the lessees the right to drill for, mine, extract, remove, and dispose of oil and gas deposits.[64] It concluded that "take-or-pay payments are part of the revenue gained from the exercise of this right or privilege" and should be subject to royalty.[65] Furthermore, the court concluded that the word "production" as used in the Outer Continental Shelf Leasing Act and the Mineral Leasing Act means not only the severance of oil and gas, but also the activities associated with maintaining a working gas well where production is not taken.[66] Because take-or-pay payments are made in part to pay for the ongoing costs of gas wells, the court reasoned, such payments are "production."[67] Thus, the federal district court upheld the order of the Department of Interior requiring royalty on take-or-pay payments.

The conflict in these two decisions will ultimately be decided by the Fifth Circuit Court of Appeals. Whatever is the decision as to federal leases, the issue will not necessarily be settled for royalty owners under oil and gas leases on private lands. However, the two most likely lines of reasoning are those taken by the district courts in Louisiana.

The best argument that lessors should not share in take-or-pay payments is the language of the royalty clause. Most oil and gas leases on privately owned lands specifically provide that royalty is due on gas

61. *Id.* at 1354.
62. *Id.* at 1355.
63. Diamond Shamrock Exploration Co. v. Hodel, No. 86-537, slip op. (E.D. La. Jan. 23, 1987) (WESTLAW, Federal library, Dist. file).
64. *Id.* at 4.
65. *Id.*
66. *Id.* at 6.
67. *Id.*

"produced . . . and sold."[68] Take-or-pay payments are not made for gas produced; by definition, they are made in lieu of production. Therefore, if the issue is decided by reference to literal lease terms, royalty owners probably should not share in take-or-pay payments.

On the other hand, there are many cases in which courts, in interpreting oil and gas leases, have looked beyond the literal terms of the lease to focus upon the broader general intent of the parties.[69] The basic agreement of the oil and gas lease is that the owner of mineral rights, who does not generally have the equipment, the capital, or the expertise to develop them, transfers the right to drill and produce to an oil company that supposedly does have the equipment, capital, and expertise to develop. From that tacit understanding of the parties a variety of implied covenants arise, including an implied promise of the lessee to market within a reasonable period of time and for the best price available.[70] From recognition of an implied promise to market on the best available terms to recognition of a right of a royalty owner to share in whatever benefits are provided by the lessee's marketing efforts is but a step.[71]

The likelihood that royalty owners will be held entitled to share in take-or-pay payments will increase if the fact situation presented to the court is one in which the lessee has received a settlement for take-or-pay claims rather than take-or-pay payments themselves. Almost invariably, where take-or-pay claims are settled, there are amendments to other provisions of the agreement, particularly pricing and quantity provisions. Where a payment is received in part for the lessee's tradeoff of favorable pricing provisions or for lowering of the take obligations, even though the settlement agreement clearly allocates settlement payments between take-or-pay payments and modification of pricing provisions, the implied covenant to market is likely to be triggered.[72]

If royalty owners are permitted to share in take-or-pay payments, the courts will almost certainly have to confront other unresolved issues.

68. *See, e.g.*, Texas AAPL Form 675, ¶ 6, *reprinted in* E. KUNTZ, J. LOWE, E. SMITH & O. ANDERSON, *supra* note 12, at 20.

69. The cases in which courts, like the Oklahoma Supreme Court, have rejected the market value royalty rule are good examples. *See supra* notes 48-51 and accompanying text.

70. For discussion of the implied covenant to market, see J. LOWE, *supra* note 9, at 307-13.

71. One court has permitted royalty owners to intervene in a take-or-pay suit between a producer and a pipeline. Amoco Prod. Co. v. Columbia Gas Transmission Co., 455 So. 2d 1260 (La. Ct. App. 1984). There has been no appellate ruling on whether the royalty owners were entitled to share in any recovery, however. *See* Amoco Prod. Co. v. Columbia Gas Transmission Co., 490 So. 2d 1138 (La. Ct. App. 1986).

72. *See infra* notes 81-87 and accompanying text (discussing Amoco Prod. Co. v. First Baptist Church, 579 S.W.2d 280 (Tex. Civ. App. 1979), *writ ref. n.r.e.*, 611 S.W.2d 610 (Tex. 1980)).

For example, most gas contracts with take-or-pay provisions provide for adjustment of the price when production which has been paid for but not taken is ultimately delivered to the purchaser. Thus, if the price at the time the take-or-pay payment accrued was $2.50 per MMBTU, but the price has firmed to $3.00 per MMBTU when the production is actually taken by the purchaser, the producer receives a compensating payment from the purchaser. If the price has fallen further, the producer may be required to make a compensating payment. How should the royalty owner, who is not ordinarily a party to the gas contract, be included in this scheme? The same logic that might require the producer to pay royalty or take-or-pay payments should require the royalty owner to share in adjustments, but what if the royalty owner has sold his interest, died, or gone bankrupt? Because of the millions of royalty owners, such problems would be difficult for the courts.

Industry practice is split regarding how to handle take-or-pay payments. Most attorneys have advised their clients to adhere to the literal terms of their leases. On that basis, most oil companies do not share take-or-pay payments or settlements with their royalty owners. On the other hand, there is a significant minority that shares such payments, either because counsel has advised them that they must, or because someone in management considers it fair.

Of course, the issue is not what is "fair," but what the parties intended or would have intended had they considered the issue. Intention is a close call that will be litigated in the coming years, greatly expanding the numbers of natural resources attorneys interested in take-or-pay payments.

IV. Implied Covenants

In addition to the specific terms of oil and gas leases, the courts have imposed upon lessees the obligation of complying with implied covenants, which are unwritten promises that arise from the relationship of the parties and the lack of detail in the typical oil and gas lease.[73] Generally, producers are held to be obliged to protect a lease against drainage and to operate diligently and prudently. If production is obtained on a lease, the lessee is required to reasonably develop, to explore further, and to market within a reasonable period of time at the best available price. Failure to do what the reasonable prudent operator would do under the

73. For a general discussion of implied covenants, see J. Lowe, *supra* note 9, at 276-316.

circumstances may subject the producer to lease cancellation or money damages.

The current hard times in the gas industry have spawned increased litigation over implied covenants. Mineral owners are as financially pressed as producers and pipelines, and they have sought to pass the burdens and relieve their frustrations through the courts. Suits claiming a breach of the implied covenants to develop or to explore further present little threat to the industry as a whole. The lessee's obligation is not to drill when and where his lessors demand, but to act as a reasonable prudent operator, which is essentially to do what a reasonable and prudent businessperson would do under similar circumstances. With oil and gas prices depressed, it is unlikely that the facts will frequently warrant a finding that the standard has been breached in development and exploration. Only the best prospects will be drilled in times like these. However, the diligent operation and the marketing and drainage covenants are other stories. Producers face large potential liabilities in these areas.

A. *FERC Rules May Trigger Covenant to Market Liabilities*

When Ronald Reagan ran for President in 1980, one of his favorite themes was that government regulations often cause as many problems as they cure. Ironically, that may be demonstrated by FERC Order No. 451,[74] which was adopted by the Reagan FERC in an attempt to move further toward deregulation of the gas industry, and Order No. 500,[75] which attempts to mitigate the huge take-or-pay liabilities confronted by some pipeline companies. Order 451 was intended to substantially increase American natural gas reserves and to offer natural gas pipelines a first step out of the heavy take-or-pay liabilities they faced. At the same time, the order represented an effort to push the gas industry an additional step toward complete deregulation.[76] What Order No. 451 does is to provide producers of natural gas, still regulated at low prices under Sections 104 and 106 of the Natural Gas Policy Act of 1978, the right to negotiate with their purchasers for higher prices.[77] Of course, leases will remain profitable longer if producers receive higher prices, resulting in increased gas reserves.

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74. F.E.R.C. Order No. 451, 51 Fed. Reg. 22,168 (1986).

75. F.E.R.C. Order Nos. 500, 500-B, 500-C, 500-D, *supra* note 54.

76. For a comprehensive discussion of Order 451, see Shoneman & McConnell, *FERC Order No. 451: Freedom (Almost) for Old Gas,* 7 ENERGY L. J. 299 (1986).

77. Order 451, *supra* note 74, at 22,219.

The catch from the producers' viewpoint is that if a producer requests renegotiation of prices for low-priced gas under Order No. 451, it must also lay on the table for renegotiation its higher-priced contracts covering similar gas.[78] The theory is that the market will give pipeline companies and producers incentives to trade off their current rights: producers will trade high-priced contracts with hefty take-or-pay obligations (that few pipelines are honoring anyway) for substantial increases in the price of old regulated gas. Low-priced contracts will be negotiated to a higher price more clearly reflecting the value of the gas in the market, while high-priced contracts with heavy take-or-pay obligations will be negotiated to a lower price.

However, FERC's drafters have placed producers in a difficult situation: Order No. 451 places gas producers in a position in which they may be sued regardless of whether they take advantage of its provisions. The problem is the implied covenant to market. For many years, the courts in major oil producing states have recognized that the lessee under an oil and gas lease owes a duty to its lessor to market lease production in a reasonable time and at a reasonable price, which is the best available price in the absence of compelling reasons to accept a lower one.[79] In applying implied covenants, the lessee's duty is to be determined on a lease by lease basis.[80] Thus, the lessee must obtain the best available price for production from each of its leases.

The classic case requiring the lessee to obtain the best available price is *Amoco Production Co. v. First Baptist Church*.[81] Amoco had entered into a long term gas sales contract in 1969 covering several small leases included in a gas unit.[82] Because market conditions in 1969 were poor, Amoco had to commit to the contract future production from undeveloped leases outside the unit, as well as the production from the leases in the unit.[83] In 1973, a well was drilled on another unit that included several of the previously undeveloped leases dedicated to the 1969 contract.[84] By that time gas prices had climbed substantially, so Amoco

78. *Id.*

79. J. LOWE, *supra* note 9, at 309.

80. Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 569 (Tex. 1981). The Texas Supreme Court rejected Amoco's contention that its duty to protect the Alexanders against drainage should be reduced because Amoco owed conflicting duties to other lessors. *Id.*

81. 579 S.W.2d 280 (Tex. Ct. App. 1979), *writ ref. n.r.e.*, 611 S.W.2d 610 (Tex. 1980).

82. *Id.* at 282.

83. *Id.*

84. *Id.*

negotiated an amendment to its 1969 contract which committed additional leases in the 1973 unit to the contract in return for an increase in the contract price.[85]

Though the renegotiated contract was obviously good business for Amoco, it was not appreciated by lessors whose leases had been committed to the 1969 contract by the 1973 amendment. They sued for breach of the implied covenant to market because the selling price of their gas under the 1973 amendment was less than the selling price which could have been obtained in the open market.[86] The Texas courts held that the implied covenant had been breached, because Amoco had gained a substantial improvement in the price that it received under the 1969 contract by trading off the interests of its lessors.[87]

The application of the reasoning of *First Baptist Church* to the situation covered by Order No. 451 is obvious. A producer who chooses to renegotiate low-priced gas contracts under Order No. 451 may be liable to continue royalty payments to the lessors of leases subject to the higher contractual provisions if it trades off the higher-priced contracts for improvements in low-priced contracts. Even the producer who decides not to renegotiate under Order No. 451 may face liability. The producer may be sued by the lessors subject to low-priced contracts for failing to take advantage of Order No. 451 to market at the best available price.

Order No. 500[88] exposes producers to the same liabilities. The Order was adopted in response to the requirement of the District of Columbia Circuit in *Associated Gas Distributors v. FERC*,[89] that FERC address the plight of pipelines confronted with take-or-pay liabilities.[90] Order No. 500 establishes an interim rule that a producer wishing to avail itself of open-access transportation by a pipeline must offer to credit gas transported against the pipeline's take-or-pay obligations on a volumetric basis.[91] In other words, a producer must be willing to trade take-or-pay claims for transportation. Furthermore, if a pipeline has more than one contract with a producer, it may select the contract to be credited.[92]

A producer that agrees to transport gas under Order No. 500 may well face suits by royalty owners whose interests have been damaged by

85. *Id.* at 282-83.
86. *Id.* at 282.
87. *Id.* at 287.
88. *See supra* note 54.
89. 824 F.2d 981 (D.C. Cir. 1987).
90. *Id.* at 1044.
91. 52 Fed. Reg. at 30,352-53 (1987).
92. 52 Fed. Reg. at 30,353 (1987).

the trade-off. The royalty owners will have strong cases; there may be no benefit at all to the royalty owners since pipeline companies can select the contracts to be credited. One contract may have take-or-pay liabilities extinguished so that gas subject to another contract can be transported. Even if the gas transported and sold is gas for which a given royalty owner will be paid, there is a good argument that the implied covenant to market is breached if the producer accepts a price less than the price provided for by an existing contract.[93]

A producer that elects not to transport under Order No. 500 is not shielded from liability either. It faces suit by royalty owners of leases subject to contracts that would have been benefited had the producer been willing to transport. The argument that transportation would have exposed the producer to liability to royalty owners damaged by the take-or-pay trade-off is no defense to a suit by those who would have been benefited by transportation. The duty of the lessee to a particular lessor is determined by the four corners of the lease, without reference to duties that the lessee may owe to other lessors under other leases.[94]

Of course a producer can raise defenses such as force majeure and preemption, and it can protect itself, at least partially, by inserting excess royalty clauses in renegotiated contracts to obligate the pipeline to pay any additional royalties for which the producer becomes liable.[95] Whether or not such devices will work remains to be seen, however, and that will be established only after years of litigation. Order No. 451 and Order No. 500 may be good ideas from an economist's viewpoint, but they create unforeseen problems for producers. Many producers will say that an imperfect regulatory system should have been left to run its course.

B. *The Implied Covenant to Protect Against Drainage*

Nothing upsets an oil and gas lessor more than the thought that his lessee is permitting his oil and gas to be drained away from under his

93. As has been noted, ordinarily the implied covenant to market requires that the lessee obtain the best available price for the lessor. The best available price for high priced gas may well be the price required to be paid under the existing gas contract.

94. Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 569 (Tex. 1981).

95. Whether Order 451 or Order 500 constitutes force majeure is uncertain, but it is unlikely given the commonly encountered terms of oil and gas lease force majeure clauses. Whether the federal rules preempt state enforcement of implied covenants is also uncertain, but is even less likely in this writer's opinion; enforcement of the implied covenant will not interfere with the operation of the rules, it will merely work a hardship on producers. An excess royalty clause may be difficult to negotiate, but it should be effective.

property. The complaining lessor has legal protection from the implied covenant to protect against drainage. The courts have reasoned that though the lease gives the lessee an option to search for, develop, and produce oil and gas from the land during the primary term, the lessee cannot stand by and watch the leased property be depleted by drainage. If a reasonable prudent operator would drill an offset well to protect against drainage, and it would be profitable to do so, the lessee must either drill or pay compensatory damages to the lessor.[96]

As has been discussed, many leases with gas wells are currently shut-in or producing at a reduced rate. Still other leases with gas potential have never been drilled because of the unattractive economic climate. In this situation, the potential for drainage by a nearby producer who has a market is great. Gas will tend to migrate from a lease that is not producing or is producing at a low rate to nearby leases that are producing at full capacity.

1. The Effect of *Transcontinental Gas Pipeline Corp. v. State Oil & Gas Board*

The drainage problem is exacerbated by the United States Supreme Court's decision in *Transcontinental Gas Pipeline Corp. v. State Oil & Gas Board*.[97] The Court held that the Natural Gas Act and the Natural Gas Policy Act preempted the use of ratable taking orders by state conservation agencies against interstate pipelines.[98] Preventing drainage by ordering pipelines to take ratably from all who wished to sell would subject interstate pipelines to a variety of regulation that would thwart Congress' purposes in the NGA and the NGPA and would ultimately result in higher gas prices to the consumer.[99] The Supreme Court left open the possibility that conservation agencies could act to prevent drainage by regulating producers through prorationing orders.[100] However, ordering some producers to restrict production or shut-in to protect others against

96. For a discussion of the implied covenant to protect against drainage, see J. LOWE, *supra* note 9, at 298-307.

97. 474 U.S. 409 (1986).

98. *Id.* at 424-25.

99. *Id.* at 422-24.

100. *Id.* at 419 n.4. The Kansas Supreme Court has moved purposely into the opening left by the Supreme Court, holding in Northwest Central Pipeline Corp. v. State Corp. Comm'n, 732 P.2d 775, 780 (1987), that the Kansas Corporation Commission could permanently cancel unproduced gas allowables even though cancellation might indirectly affect the purchasing practice of interstate pipeline companies.

drainage will cost the state severance tax revenues and subject the conservation commissioners, who generally are elected, to great political pressure from those adversely affected.[101] Whether state conservation agencies will have the political will to exercise the power left to them remains to be seen.

Of course, the obligation of a gas producer is merely to act prudently, not to insure its lessors against all losses. If the state cannot or will not act to prevent drainage, it is hard to perceive a basis for concluding that the producer has breached its duty, at least if the producer has tried diligently to alleviate the problem. Whether the producer has done enough to meet the reasonable prudent operator standard, however, is probably a question of fact. It is likely a fact issue that will usually be resolved by juries against producers. At best, the industry will be embroiled in expensive and lengthy litigation.

2. Acceptance of Delay Rentals

Also relevant to the drainage problem are fundamental issues of when the implied covenant applies and what must be proved. The Oklahoma Supreme Court addressed these problems in *Rogers v. Heston Oil Co.*,[102] which dealt with the problem of what happens if a lessor accepts payment of delay rentals under the terms of the lease knowing that his property is being drained. Is the protection of the covenant waived? Law professors have almost always argued that it should not be, claiming that the purpose of the delay rental clause in the oil and gas lease is to waive the implied covenant to test, not to give the lessee a license to permit drainage.[103] However, there is precedent to the contrary,[104] and the issue has frequently forced premature settlement of suits.

In *Rogers*, the Oklahoma Supreme Court came down on the side of the angels (and the law professors) on the issue.[105] The court held that acceptance by a lessor of delay rentals while his property is being drained does not in and of itself waive his right to complain of drainage.[106] To

101. *See* Note, *Mississippi's Ratable-Take Rule Preempted:* Transcontinental Gas Pipeline Corp. v. State Oil & Gas Board, 7 ENERGY L.J. 361, 369 (1986).

102. 735 P.2d 542 (Okla. 1984).

103. *See, e.g.*, J. LOWE, *supra* note 9, at 306.

104. *See, e.g.*, Clear Creek Oil & Gas Co. v. Bushmaier, 161 Ark. 26, 255 S.W. 37 (1923).

105. *Rogers*, 735 P.2d at 545. Texas also follows this rule. Texas Co. v. Ramsower, 7 S.W.2d 872 (Tex. Comm'n App. 1928), *reh'g denied*, 10 S.W.2d 537 (Tex. Comm'n App. 1928).

106. *Rogers*, 735 P.2d at 545.

reach its result, the court had to overrule fifty-year old precedent.[107] The decision removes an illogical barrier to enforcement of the covenant to protect against drainage. However, it increases the exposure to suit of producers confronted by the current surplus of gas.

3. Burden of Proof

Rogers v. Heston Oil could have been worse for the industry, however, because in the same case, the Oklahoma Supreme Court considered whether the lessor who is being drained by his own lessee should have a lighter burden of proof in order to enforce the covenant to protect against drainage.[108] Some commentators and a few courts have concluded that a lessor who is being drained by operations conducted by his own lessee ought not have to prove the probability that an offset well would be profitable, either because the drainage is "fraudulent" or because it violates an implied promise by the lessee to do nothing to harm the lessor.[109] However, most cases have concluded that absent bad faith the lessee's only obligation to its lessor should be to act as a reasonable prudent operator under the circumstances.[110]

In *Rogers*, the Oklahoma Supreme Court adopted the latter view.[111] The court said that the test of breach of the covenant is whether the lessee, as a prudent operator, would drill a protection well on the lessor's tract if the draining lease were owned by a third party.[112] In other words, the elements of proof of breach of the implied covenant to protect against drainage do not change just because the alleged drainage is caused by the royalty owner's own lessee. While this may be disappointing to many lessor's attorneys, it is undoubtedly the more logical rule. There is no special relationship of trust or confidence between the lessor and the lessee under an oil and gas lease.[113] The lease is a business transaction, and the lessee should not be required to protect it against

107. *Id.* at 544-45. The *Rogers* court expressly overruled Carter Oil Co. v. Samuels, 181 Okla. 218, 73 P.2d 453 (1937), and Eastern Oil Co. v. Beatty, 71 Okla. 275, 177 P. 104 (1918).

108. *Rogers*, 735 P.2d at 547-48.

109. *See, e.g.*, Cook v. El Paso Natural Gas Co., 560 F.2d 978, 983-84 (10th Cir. 1977); H. WILLIAMS & C. MEYERS, OIL AND GAS LAW § 824.2 (abr. ed. 1986). The *Cook* case relieved the lessor of the burden of proving the probable profitability of the offset well. Professors Williams and Meyers urge that the lack of a probability of profitability should be an affirmative defense for the lessee. *Id.*

110. The major cases are summarized in R. HEMINGWAY, LAW OF OIL AND GAS § 8.3 (2d Ed. 1983).

111. *Rogers*, 735 P.2d at 544-45.

112. *Id.* at 547.

113. For a very recent affirmation of this principle, see Texas Oil & Gas Corp. v. Hagen, No. C-3768, slip. op. (Tex. Dec. 15, 1987), overruling a court of appeals decision that a lessee owed its

drainage unless a reasonable prudent operator would do so in the same circumstances. There is law to the contrary of *Rogers* on both of the issues it addresses. However, it brings Oklahoma and Texas into accord on these important issues,[114] and their lead is likely to be followed by other courts.

V. CONCLUSION

Lease and royalty problems in the gas industry tend to trail economic and regulatory developments by several years. Notably, the most important lease and royalty problems discussed above are only beginning to wend their way through the courts. The current gas surplus, the market chaos it has caused, and the regulatory responses to it are likely to be ancient history by the time these lease and royalty problems are resolved.

Lease and royalty cases also tend to involve smaller amounts than regulatory issues or producer/pipeline disputes. Litigation over the validity of a FERC order is potentially worth billions of dollars. Take-or-pay suits often claim tens or even hundreds of millions of dollars. Producer/royalty owner litigation seldom involves more than a few million dollars in any single case.

Because of the huge number of persons and transactions involved in these lease and royalty problems, however, they loom large for the gas industry. There are millions of royalty owners, and tens of thousands of producers and lawyers who may have to deal with them in the years to come.

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lessor a duty of highest good faith. The Texas Supreme Court found liability based on the reasonable prudent operator standard.

114. *Rogers*, 735 P.2d at 544-45.