Incorporating a Century of Oil and Gas Jurisprudence Into the "Modern" Oil and Gas Lease

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I. Introduction

The oil and gas lease is the basic document used to develop oil and gas in the United States. Although the industry has relied on it for almost a century,[1] there remain several fundamental issues that the typical form of lease either fails to address, or addresses inadequately. Persistent litigation over the meaning of the document suggests the need for either a better drafted document or a document that creates a fundamentally different relationship. Since it is unlikely

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1. *See generally* Leslie Moses, *The Evolution and Development of the Oil and Gas Lease*, 2 INST. ON OIL & GAS L. & TAX'N 1 (1951).

the basic relationship will be restructured,[2] attorneys should focus on how the document creating the basic relationship can be improved.[3]

The term "incorporating" in the title of this paper is used in the context of "learning" from the past. Many of the jurisprudential lessons of the past have been harsh ones for certain parties to the lease—particularly the lessee. In this article I identify the lessons of history and demonstrate how they can be incorporated into the traditional lease document. However, along the way I also offer some rather radical departures[4] from the terms of the traditional lease in an attempt to more fully incorporate the underlying teachings of the past. Too often lease drafters respond to the latest manifestation of the document's disease instead of treating the root cause of the disease. The major surgery I suggest is designed to trigger new ways of thinking about the underlying lease relationship and how it might be improved. My goal is to create a "healthier" relationship for all parties involved.[5]

I view the oil and gas lease as addressing three topics: the interests granted to the lessee, the duration of the grant, and the lessor's royalty. Although most lease forms consist of ten to twenty separately numbered paragraphs, each lease provision is essentially an expansion, or limitation, of the granting, habendum, and royalty clauses.

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2. *See generally* David E. Pierce, *Rethinking the Oil and Gas Lease*, 22 TULSA L. J. 445 (1987) (critically evaluating the standard relationship created by the oil and gas lease and suggesting the inherent conflicts created by the oil and gas lease may justify experimenting with alternative relationships—such as a net profits interest) [hereafter Pierce, *Rethinking the Oil and Gas Lease*].

3. Many commentators have addressed how to improve the position of either the lessor or lessee under the oil and gas lease. Owen L. Anderson, *David v. Goliath: Negotiating the "Lessor's 88" and Representing Lessors and Surface Owners in Oil and Gas Lease Plays*, 27B ROCKY MTN. MIN. L. INST. 1029 (1982); Edwin M. Cage, *The Modern Oil and Gas Lease—A Facelift for Old 88*, 31 INST. ON OIL & GAS L. & TAX'N 177 (1980); Quincy Thomas Hinton, Jr., *Negotiating Oil and Gas Leases for the Lessor*, 1 NAT. RESOURCES & ENV'T 7 (1985); John S. Lowe, *Negotiating Oil and Gas Leases for the Lessee*, 1 NAT. RESOURCES & ENV'T 6 (1985); John S. Lowe, *Representing the Landowner in Oil and Gas Leasing Transactions*, 31 OKLA. L. REV. 257 (1978); Maurice H. Merrill, *The Oil and Gas Lease—Major Problems*, 41 NEB. L. REV. 488 (1962); Ronald D. Nickum, *Negotiating and Drafting a Modern Oil and Gas Lease on Behalf of Lessor*, 13 TEX. TECH L. REV. 1401 (1982); Bernard E. Nordling, *Landowner's Viewpoints in Pipeline Right-of-Way and Oil and Gas Lease Negotiations*, 52 J. KAN. B.A. 35 (1983).

A topic that is left for future commentary is whether better dispute-resolution mechanisms can be incorporated into the oil and gas lease. The focus of this article is on ways to improve the statement of the lease transaction so disputes are avoided. However, the nature of the relationship, and the large amounts of money often at stake, guarantee that disputes will arise even under the most artfully crafted documents. Under the current form of oil and gas lease either party can seek their pound of flesh in court. It would appear that oil and gas lease disputes would be amenable to a number of alternative dispute resolution techniques. The basic issues, however, are whether a technique or menu of techniques, should be mandated in the lease. If so, what technique or menu of techniques? I will save these issues for future scholarly endeavors. *See generally* Joseph W. Morris, *The Viability of Alternative Dispute Resolution in the Oil and Gas Industry*, 39 ROCKY MTN. MIN. L. INST. 14-1 (1993).

4. For example, eliminate the delay rental clause, substitute a minimum royalty and covenant approach for the secondary term of the habendum clause, and eliminate the royalty obligation—at least as we know it.

5. However, some may think I have killed the patient while on the operating table. If so, my suggestions will at least offer a starting point for future discourse on the subject.

From the lessee's perspective, the major problems with the oil and gas lease are the "guillotine provisions." The provisions that terminate the lease in the event a delay rental payment is not made, drilling operations are not commenced or pursued, production is not obtained, production ceases, or production is not profitable. Therefore, the lessee's primary focus will be on issues surrounding the duration of the grant.

The lessor's primary focus will be on maximizing royalty income. This can be done through the royalty clause and by creating incentives in the habendum clause for the lessee to promptly develop the leased land. A lessor who owns the surface of the leased land will also be concerned with the scope of the granting clause. Attorneys representing lessors will want to define clearly not only what the lessee can, cannot, and must do on the leased land, but also what their lessor client can and cannot do on the land once the lease is created.

Often the goals of each party conflict and the party with the superior negotiating prowess and position will prevail—or the leasing transaction will not occur. However, the "must have" provisions for each party are relatively few. The lessee needs the exclusive right to produce oil and gas from the lessor's land for as long as necessary to profitably extract the oil and gas it discovers. The lessee will typically need to use the surface of the leased land to conduct operations. The lessee would also like to obtain the right to develop without having any obligation to explore or develop the leased land; the lessee wants an "option" to develop the leased land.

The lessor's "must have" provisions have traditionally focused on the royalty clause and, to a lesser extent, on surface use issues. Because potentially devastating environmental liabilities are associated with property "ownership" or "operation," the lessor's "must have" provisions will tend to focus on what the lessee can, cannot, and must do while on the leased land. The lessee should also be concerned with what the lessor and others have done on the leased land—and what they might do while the lease is in effect.[6]

II. The Granting Clause: The Most Under-Drafted Clause

A strange attribute of the commonly encountered oil and gas lease granting clause is the couched manner in which the interest being granted is described. The common forms of oil and gas leases list activities that the lessee can pursue on the leased premises without

6. *See generally* David E. Pierce, *Structuring Routine Oil and Gas Transactions to Minimize Environmental Liability*, 33 Washburn L. J. 76, 88-95, 165-77 (1993) [hereafter Pierce, *Structuring Routine Oil and Gas Transactions*].

expressly granting rights in the underlying substances. For example, a representative lease granting clause provides:

> 1. Lessor . . . grants, leases and lets exclusively unto lessee for the purpose of investigating, exploring, prospecting, drilling, mining and operating for and producing oil, liquid hydrocarbons, all gases, and their respective constituent products, injecting gas, water, other fluids, and air into subsurface strata, laying pipe lines, storing oil, building tanks, power stations, telephone lines, and other structures and things thereon to produce, save, take care of, treat, manufacture, process, store and transport said oil, liquid hydrocarbons, gases and their respective constituent products and other products manufactured therefrom, and housing and otherwise caring for its employees, the following described land . . . .[7]

This granting clause fails to state with precision the nature of the interest being granted. The objects of the grant, oil and gas, are preceded and followed by a listing of associated rights to use the surface and subsurface estate to operate for oil and gas.

A. *Jurisprudential Traps*

Traditionally, granting clause disputes have focused on two issues: (1) the *substances* being leased; and (2) the *surface use* rights associated with the leased substances. With regard to the substances being leased, many lease forms have evolved through the years to address whether, for example, constituent substances produced with natural gas will be included in the grant of oil and gas. However, nagging interpretive problems remain such as whether "gas" includes carbon dioxide when it is not produced as a constituent of natural gas.[8] Most recently, the interpretive issue has been whether methane gas found in coal seams is included in a grant of oil and gas.[9] The jurisprudence that has evolved to deal with these problems has proven to be time-consuming, expensive, and unpredictable. You know the "answer" to the substance issue only after the opportunity to appeal the most recent judgment has expired.

The jurisprudential concept that causes problems with the substance issue is what I have called the "equity model."[10] The equity model attempts to ascertain the actual intent of the parties to a conveyance regarding the substances and associated rights being con-

7. Oil and Gas Lease, Form 88—(Producers), Kan., Okla. & Colo. 1962 Rev. Bw, Kansas Blue Print Co. Inc., ¶ #1 [hereinafter called "62 Blue Print Form"].

8. *See generally* Aulston v. United States, 915 F.2d 584 (10th Cir. 1990); Hudgeons v. Tenneco Oil Co., 796 P.2d 21 (Colo. Ct. App. 1990); Libby v. De Baca, 179 P.2d 263 (N.M. 1947).

9. David E. Pierce, *Defining Mineral Ownership in the United States: Methane Gas from Coal Seams*, 11 OIL & GAS L. & TAX'N REV. 373 (1993) [hereinafter Pierce, *Methane Gas*].

10. David E. Pierce, *Toward a Functional Mineral Jurisprudence for Kansas*, 27 WASHBURN L.J. 223, 244-47 (1988) [hereafter Pierce, *Toward a Functional Mineral Jurisprudence for Kansas*].

veyed.[11] In many instances the parties had no "intent" concerning the matter until the issue became focused through subsequent development and value being attributed to the disputed substance.[12] Traditional jurisprudence on the substance issue often considers information and impacts extrinsic to the terms of the document being interpreted to try and achieve what the court perceives to be an equitable result.[13] The product of such an approach has been the creation of considerable uncertainty regarding the basic ownership of mineral substances. Since matters extrinsic to the document are typically considered, the role of the recorded document is supplanted by the quiet title or declaratory judgment action.

In reality, the burden of imperfect drafting is shifted to the public when courts look beyond the document to define the scope of terms like "gas" and "other minerals." Courts that try to ascertain the actual intent of the parties, or to "protect" the interests of a party through "interpretation," are more likely to sacrifice the certainty of title and the integrity and usefulness of the recording system. Courts that limit their interpretation to the literal terms of the document are more likely to sacrifice the actual intent of the parties and may leave one party surprised to learn that the grant of a mineral includes the right to use the surface to extract the mineral—often without any compensation for disruption of the surface. However, as a matter of public policy, if someone must suffer as a result of imperfect drafting, it should be the parties to the conveyance and not the public. The "equity model" places the burden of imperfect drafting on the public at large by limiting the usefulness of the recording system which in turn will impair the marketability of mineral properties.[14]

In previous writings I have proposed a "functional model" as a jurisprudential alternative for interpreting the scope of the granting clause in leases and deeds.[15] The functional model gives literal effect

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11. *Id.* at 246.

12. *See generally* Eugene O. Kuntz, *The Law Relating to Oil and Gas in Wyoming*, 3 WYO. L. J. 107, 112-13 (1949) (addressing the intent issue).

13. For example, courts have been willing to manipulate title to the mineral estate in an attempt to narrow the scope of the implied surface easement associated with the granted minerals. *See, e.g.*, Wulf v. Shultz, 508 P.2d 896, 900 (Kan. 1973) (grant of "other mineral substances" in oil and gas lease did not include minerals that require destruction of the surface for their removal).

14. David E. Pierce, *Defining Mineral Ownership in the United States: Methane Gas from Coal Seams*, 11 OIL & GAS L. AND TAX'N REV. 373, 375-377 (1993).

15. In the "all mineral" and "other mineral" contexts, I have proposed the following:

> Perhaps the best way to define a mineral for title purposes is to employ the animal, vegetable, mineral analysis which has been uniformly rejected off-hand by courts addressing the issue. Under such a rule, a sale or lease of the "oil, gas, and other minerals" in land would authorize the grantee or lessee to remove and sell even the topsoil of the land. The rights of the surface estate owner would be determined under implied surface easement jurisprudence. The grantor always has the ability to restrict the scope of the grant by limiting it to "oil and gas" or otherwise specifying the minerals that are, or are not, granted.

to the express terms of the lease or deed without regard for extraneous matters such as the mining techniques that can be used to extract the mineral[16] or whether the mineral was generally known to exist at the time of the conveyance.[17] Therefore, if A owns the fee simple absolute in Section 30 and leases the "oil and gas" to B, B should be entitled to extract methane "gas" from coal seams located within Section 30. Similarly, if prior to A's lease to B, A leased all the "coal" in Section 30 to C, C should have the right to all substances, including methane gas, found within the coal to the exclusion of a subsequent "gas" lessee. The coal seam not only describes the substance, but also the areal extent of the coal owner's exclusive right of control.[18]

Jurisprudential traps also await the lessor when defining the scope of the lessee's right to use the surface to support extraction of the granted minerals. Although courts have been willing to limit the range of minerals the lessee will obtain under the lease, the lessee has been rewarded with broad easement rights to extract minerals that survive the interpretive process. In many jurisdictions, the lessee's implied easement authorizes use of the surface without compensation to

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> Although this may seem terribly antilandowner, it gives effect to the specific terms of the grant "all minerals" or "other minerals." To balance the interests, the courts could enforce the obligation to provide subjacent support to the surface of the land. The implied surface easement would only permit reasonable use of the surface to mine the minerals. If the subjacent support is disturbed, or destroyed, damages should be paid to the injured surface estate owner without regard for concepts of "reasonable use." As defined by Kansas courts, subjacent support appears to refer to any disturbance of the surface.
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> To protect the marketability of the surface estate, the surface damage rule could require a current market value approach for valuing surface use. If the landowner has improved the surface, either before or after the mineral severance occurs, courts could calculate damages based upon the value of all improvements. This would require the mineral owners to weigh the decision to develop the minerals against the value of the competing property interest such development would impair. If the landowner wants to free their property from the broad mineral grant, or the accompanying implied easement, they could attempt to purchase the right from the mineral interest owner. If the mineral interest owners want to limit the possibility of increased surface damages due to subsequent improvements erected by the surface owner, they could attempt to purchase broader, and more express, rights in the surface estate.

Pierce, *Toward a Functional Mineral Jurisprudence for Kansas*, *supra* note 10, at 249-50 (citations omitted).

16. The "surface destruction test." *See, e.g.*, Wulf v. Shultz, 508 P.2d 896, 899-900 (Kan. 1973) (lease to "dig, drill, operate for and procure natural gas, petroleum and *other mineral substances*" limited to minerals that would not require significant destruction of the surface for their extraction).

17. The "community knowledge test." *See, e.g.*, Roth v. Huser, 76 P.2d 871, 873 (Kan. 1938) (positive presumption from community knowledge of the mineral); Keller v. Ely, 391 P.2d 132, 136 (Kan. 1964) (negative presumption from community knowledge of the mineral).

18. I have articulated the rationale for such an approach as follows:

> When the public interest in certainty of title serves as the guiding principle in resolving coalbed methane issues, the outcome should depend on which mineral interest was clearly severed first. For example, if A owns all the rights to Section 30 and subsequently conveys the "oil and gas" to B in 1950 and the coal to C in 1960, B should own the "gas" found anywhere in Section 30; even gas found in coal seams.

Pierce, *Methane Gas*, *supra* note 9, at 376.

the lessor for disruption, or destruction, of the surface.[19] The jurisprudence to date offers the lessor little in the way of defining the *lessor's* surface use rights once a lease is granted. Leases seldom, if ever, clarify the lessor's rights. Instead, the focus is on the scope of the lessee's rights. Although a few courts have recognized that lessees should try to "accommodate" the lessor's competing surface uses,[20] the concept remains substantially undefined. If the parties, particularly the lessor, want something better than uncertainty, they need to carefully define the nature and extent of the lessee's extraction easement.

B. *Addressing the Jurisprudential Traps*

The parties can create a more precise lease to address the foregoing jurisprudential traps by first granting, or leasing,[21] to the lessee the oil and gas substances followed by a grant of the associated rights to develop the oil and gas. This would seem particularly appropriate in states like Texas where the oil and gas lease is conceptually treated as a defeasible term mineral interest.[22] The granting clause should grant or lease the appropriate minerals to the lessee, subject to the terms specified in the lease. The right to explore for, develop, and produce the granted minerals would be stated as part of an express easement. This approach would permit the parties to effectively deal with the two primary issues under the granting clause: (1) the substances sub-

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19. JOHN S. LOWE, OIL AND GAS LAW IN A NUTSHELL 189-90 (2d ed. 1988) [hereafter LOWE, NUTSHELL]. As Professor Lowe notes in his book, many states have changed, modified, or defined the common law rule by requiring the lessee to pay the lessor for disruption to the surface pursuant to state "surface damage acts."

My analysis of the issue under Kansas law has led to the conclusion that although Kansas recognizes an implied right to make reasonable use of the surface, the permissible damage done to the surface within the scope of the easement may nevertheless be compensable. Pierce, *Toward a Functional Mineral Jurisprudence for Kansas*, *supra* note 10, at 240-44. Kansas does not have any sort of surface damage act, but a limited surface reclamation obligation is imposed by KAN. STAT. ANN. § 55-177 which requires that lessees, as operating sites are abandoned, remove equipment and:

> [G]rade the surface of the soil in such manner as to leave the land, as nearly as practicable, in the same condition after the removal of such structures . . . as it was before such structures . . . were placed thereon, unless the owner of the land and the abandoning party have entered into a contract providing otherwise.

KAN. STAT. ANN. § 55-177(a) (Supp. 1993).

20. Hunt Oil Co. v. Kerbaugh, 283 N.W.2d 131 (N.D. 1979); Diamond Shamrock Corp. v. Phillips, 511 S.W.2d 160 (Ark. 1974); Sun Oil Co. v. Whitaker, 483 S.W.2d 808 (Tex. 1972); Getty Oil Co. v. Jones, 470 S.W.2d 618 (Tex. 1971).

21. The precise terminology—"grant" or "lease"—will depend upon how the courts in a particular state classify the interest created by the oil and gas "lease." For example, in Kansas the oil and gas lease is viewed as granting the lessee a license to enter the land to explore and extract oil and gas; a profit a prendre. *E.g.*, Burden v. Gypsy Oil Co., 40 P.2d 463, 466 (Kan. 1935). The lessee does not receive a present right to the leased minerals in place. The lessee's interest is a non-possessory interest, an incorporeal hereditament, which Kansas courts classify as creating an interest in personal property. *E.g.*, Connell v. Kanwa Oil, Inc., 170 P.2d 631, 634 (Kan. 1946). In contrast, Texas classifies the oil and gas lease as a conveyance of the oil and gas in the leased land to the lessee. In Texas the lessee has a possessory interest, a corporeal interest in real property. Stephens County v. Mid-Kansas Oil & Gas Co., 254 S.W. 290 (Tex. 1923).

22. *E.g.*, Stephens County v. Mid-Kansas Oil & Gas Co., 254 S.W. 290 (Tex. 1923).

ject to the grant and (2) the easement rights granted to develop the leased substances.

1. *The Leased Substances*

The granting clause should carefully define the substances that are being leased. Many lease forms cover "oil, gas, and *other minerals*." Through the years, cases interpreting the "other minerals" conveyance have demonstrated the inadequacy of such language.[23] Among the lessons taught by the conveyancing cases is the importance of expressly listing in the lease the minerals being granted. If the parties know of a mineral of particular interest in the region where the property is located—such as helium, hydrogen, coalbed methane, carbon dioxide, sulfur, or other substances—it should be specifically addressed in the granting clause. The lessee wants to ensure that it has control of all the minerals necessary to remove and market the oil and gas from the leased land.[24] For example, one oil company uses the following language in its leases:

> [O]il and gas, along with all hydrocarbon and nonhydrocarbon substances produced in association therewith. The term 'gas' as used herein includes helium, carbon dioxide, gaseous sulfur compounds, coalbed methane and other commercial gases, as well as normal hydrocarbon gases.[25]

A more lessor-oriented form might deal with the "hydrocarbon and nonhydrocarbon substances produced in association" with the oil and gas by giving the lessor the option to separate the component substances if it can be done without interfering with the lessee's production activities.[26] The approach followed in a particular case will

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23. *See, e.g.,* Moser v. United States Steel Corp., 676 S.W.2d 99 (Tex. 1984). Courts continue to grapple with defining the scope of the "minerals" and "other minerals" language used in conveyances. The root of the interpretive problem is courts have taken it upon themselves to interpret conveyances to protect the surface owner from unwittingly granting minerals that may require destruction of the surface for their mining. Wulf v. Shultz, 508 P.2d 896 (Kan. 1973). In pursuit of this goal, courts have considered facts outside the conveyance to define its scope. For example, courts have gone outside the document to ascertain what was known in the general community about the mineral in issue at the time the conveyance was made. Roth v. Huser, 76 P.2d 871 (Kan. 1938). They have also considered extrinsic information concerning available mining techniques and the impact they may have on the surface. Reed v. Wylie, 597 S.W.2d 743 (Tex. 1980). However, this interpretive exercise to narrow the scope of the term "minerals" or "other minerals" is usually undertaken to limit the scope of the grantee's implied easement to make reasonable use of the surface to mine granted minerals *without any obligation to pay for disruption of the surface associated with legitimate mining operations*. Pierce, *Toward a Functional Mineral Jurisprudence for Kansas*, *supra* note 10, at 244-47; Pierce, *Methane Gas*, *supra* note 9, at 374.

24. *See generally* 1 DAVID E. PIERCE, KANSAS OIL AND GAS HANDBOOK § 11.03, at 11-3 to 11-4 (1986) [hereafter PIERCE, KANSAS HANDBOOK].

25. Oil and Gas Lease, Prod 88 Unitization/Pref. Right (1994) (Oryx) ¶ #1.

26. PIERCE, KANSAS HANDBOOK § 12.04, at 12-7. A lessor-oriented constituent substance clause might include the following:

Substances in the Leased Land.

1. Granted Substances. Substances in the Leased Land which are subject to the terms of this Lease include: Oil, gas, and similar hydrocarbon substances. For pur-

depend upon how much involvement the lessor wants to have in the development process. For example, does the lessor really want to concern itself with the negotiation of gas processing agreements with plant operators?

From the lessor's perspective, the oil and gas lease should grant the lessee the rights necessary to allow it to efficiently extract the oil and gas. However, the lessor need not convey substances that are not produced as constituents of oil and gas. For example, the lessor may want to exclude substantially pure streams of hydrogen or carbon dioxide. The lessor may opt for language similar to the following: "Oil, gas, and similar hydrocarbon substances, but excluding carbon dioxide, helium, hydrogen, and other substances that are not produced as mere constituents of the gas stream." Gas produced from coal seams should also receive special attention.[27] The lessor's goal is to retain any rights that are not economically necessary for the lessee's targeted activity: the exploration, development, and production of oil, gas, and similar hydrocarbon substances.

2. *Associated Easement Rights*

The lessee's use of the surface often ignites disputes between the lessor and lessee that may prompt the lessor's attorney to carefully audit all provisions of the lease in search of ammunition for the ensuing lawsuit. When it comes to surface use, the lessor invariably gives up too much while the lessee invariably gets too little. Since the parties rights to use the surface are rather nebulously stated, the granting clause often becomes the initial source of ill will and dispute between the lessor and lessee. For example, the day after the lease is signed, what can the lessor legally do on the surface of the leased land? Can the lessor build a new house on the leased land? A pole barn? Under a strict interpretation of the lessee's easement to use the surface to support development of the leased minerals, it would appear the lessee could object to any use of the surface that would interfere with

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poses of this Lease, the listed substances will be referred to as the "Leased Substances." The term "Leased Substance" is used to identify any one of the listed substances.

2. *Component Substances.* Substances, other than Leased Substances, produced in the same production stream as Leased Substances, will be referred to as "Component Substances." LESSEE is given title to produced Component Substances.

However, if LESSOR provides for the separation of Component Substances, without unreasonably interfering with LESSEE's rights under this Lease, title to Component Substances, to the extent they are actually separated from the production stream, will be in LESSOR. LESSOR may arrange for separation of Component Substances either before or after the Component Substances leave the Leased Land. To the extent LESSOR fails to provide for separation of a Component Substance, and LESSEE separates and sells or uses the Component Substance, LESSOR will be entitled to a royalty on the Component Substance as specified in SECTION 8 of this Lease.

27. *See generally* Vines v. McKenzie Methane Corp., 619 So. 2d 1305 (Ala. 1993) (owner of coal owns coalbed methane gas).

the lessee's previously granted development rights. The express terms of most oil and gas leases provide broad easement rights. Lessors who own the surface rights in the property will want to clearly define what they, as the surface owner, can and cannot do on the property while the lease remains in effect.[28]

The lessor should also consider whether to impose specific restrictions on what the lessee can do when it actually exercises its easement rights. Restrictions might include the location of wells and equipment, whether pits can be used, storage and removal of supplies and equipment, restoration of disturbed land, use of water, and advance notice to the lessor of proposed activities.[29] The owner of a

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28. For example, consider the following provision:
1. SCOPE OF GRANT; SURFACE USE RESTRICTIONS.
a. LESSOR's Surface and Subsurface Rights. LESSOR excepts from this Lease the following:
(1) The right to construct any structure or other improvement, at any location selected by LESSOR, anywhere on the Leased Land. The rights granted LESSEE under the terms of this Lease will not restrict in any manner the LESSOR's ability to use the surface of the Leased Land. Any activities by the LESSEE must accommodate fully the current land uses of the LESSOR, even though such uses are not commenced until some future date after the Effective Date of this Lease. If, prior to LESSEE commencing Operations at a location, the LESSOR commences construction of a structure or other improvement on the Leased Land, the LESSEE will not locate any equipment, nor conduct operations, within 300 feet of the proposed structure or improvement.
(2) The right to raise livestock on the Leased Land. If LESSOR is currently using, or elects in the future to use, all or any part of the Leased Land to raise livestock, LESSEE will construct the necessary fence gates and cattle guards, and fence all drill sites, pits, tanks, and other drilling or production facilities on the Leased Land, and otherwise adjust its operations to accommodate LESSOR's use of the Leased Land for raising livestock.
(3) The right to initiate or continue irrigation and agricultural activities on the Leased Land. If LESSOR decides to conduct agricultural activities on the Leased Land, to include irrigation and recognized soil conservation practices, LESSEE will adjust its operations to accommodate LESSOR's agricultural use of the Leased Land.
(4) The right to connect with any gas well completed on the Leased Land, at LESSOR's sole cost and risk, and take gas, free of charge, for domestic and agricultural activities conducted on the Leased Land.
(5) The right to use the surface and subsurface of the Leased Land as may be reasonably necessary to explore for, extract, and market minerals from the Leased Land, to the extent such minerals are not covered by this Lease, or to the extent such minerals, including oil and gas, revert to LESSOR pursuant to the terms of this Lease.

29. For example, consider the following surface use limitations:
b. LESSEE's Surface Use Obligations. LESSEE's rights under this Lease are subject to the following:
(1) LESSEE will not locate any equipment, nor conduct operations, within 300 feet of any house, garage, barn, stream, creek, pond, lake, water well, or other structure, improvement, or water source located on the Leased Land.
(2) LESSEE will locate and maintain Lease access roads so as to minimize disruption to the Leased Land.
(3) LESSEE will pay to LESSOR, as compensation for using the surface of the Leased Land to conduct operations under this Lease, an amount equal to the actual damages caused by LESSEE's surface use, or an amount equal to $5,000.00 per drill site located on the Leased Land, whichever is greater. Prior to commencing drilling operations for any well on the Leased Land, LESSEE will pay to LESSOR $5,000.00. If the actual damages caused by LESSEE's drilling or operations on the Leased Land ultimately exceed $5,000.00 per drill site, LESSEE will pay to LESSOR the amount by which actual damages exceed $5,000.00 per drill site. Within 5 days following issuance of a drilling permit, LESSEE will provide LESSOR with a copy of the permit and LESSEE's permit application.

severed mineral interest will also need to ensure that any surface use rights they grant in the oil and gas lease are consistent with the terms of the mineral deed that created their interest. A well-informed owner of the fee simple estate should define, in any mineral conveyance, the precise surface use rights being granted so as to avoid the uncertainty of the "reasonable use" doctrine to define the mineral interest owner's rights.[30]

The lessor may also want to include additional restrictions to address the lessor's exposure to environmental liability associated with the lessee's mineral development activities. Although the risk of surface owner and lessor environmental liability has been around for sev-

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(4) LESSEE, with regard to activities associated with its operations, will be strictly liable for any damage to or interference with: cultivated land, growing crops, pasture land, unimproved land, livestock, fences, roads, ditches, culverts, trees, turf, terraces, springs, streams, ponds, lakes, water wells, groundwater, personal property, fixtures, or improvements on the Leased Land. LESSEE will minimize its disruption of the Leased Land and whenever excavation is necessary, LESSEE will remove and store the topsoil and when the excavation is to be closed, LESSEE will remove all foreign substances from the excavation, fill it with soil, and then replace the topsoil. The affected area will then be graded to its original contour, seeded, fertilized, and maintained until the original cover in the affected area is reestablished.

(5) LESSEE will provide LESSOR with written notice at least 15 days before conducting any surface operations on the Leased Land, to include geophysical operations and activities preparatory to drilling operations. The notice will include a plat showing the portion of the Leased Land to be affected by such operations and the LESSEE's proposed route across the Leased Land. However, notice to LESSOR, and LESSOR's failure to object to the planned surface use and operations, will not affect LESSOR's rights, or the limitations and obligations imposed on LESSEE by this Lease.

c. USE OF WATER AND LEASED SUBSTANCES. LESSEE will not use any water from the Leased Land except for Produced Water. "Produced Water" means any water that is necessarily produced in conjunction with the production of Leased Substances. When removed from the oil or gas producing strata, title to Produced Water will be in LESSEE. LESSEE is given the right to use any Leased Substance to support Lease operations. If a Leased Substance is consumed, or removed from the Leased Land for use, LESSEE will pay a Royalty on such Leased Substance pursuant to the terms of this Lease.

d. REMOVAL OF EQUIPMENT AND FIXTURES. For a period of 60 days following Termination of this Lease, and upon giving LESSOR prior written notice, LESSEE is given the right to enter the Leased Land to remove any Material on the Leased Land owned by LESSEE. "Termination" means the Lease, or a relevant portion of the Lease, is no longer in effect. The cause of termination does not matter. "Material" means anything placed on the Leased Land by LESSEE, or LESSEE's contractors, to include such things as equipment, supplies, fixtures, and tubing, casing, and other equipment in the well. Upon Termination, LESSOR may elect to keep certain Material on the Leased Land and may do so by tendering to LESSEE the reasonable salvage value for the Material LESSOR desires to acquire. LESSEE's failure to act within the 60-day period will not in any way limit its liability associated with the presence of the Material on the Leased Land; nor will it cause title to any Material to vest in LESSOR unless LESSOR affirmatively elects to accept title to the Material. In any event, LESSEE will remain liable for the removal of equipment and fixtures, the plugging of wells, and remediation of the impacted area. The LESSEE will also remain liable for having the area graded to its original contour, seeded, fertilized, and maintained until the original cover in the affected area is reestablished.

30. In such situations the fee owner conveying a severed mineral interest is in much the same position as a lessor entering into an oil and gas lease. The same sort of surface use reservations, limitations, and requirements should be imposed on the mineral interest grantee that are imposed on the oil and gas lessee. *See* Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 151-62.

eral years,[31] the significance of the risk, and the need to address the risk in oil and gas leases and mineral deeds, has only recently been acknowledged by commentators.[32] New jurisprudential challenges, and drafting challenges, are presented by a new breed of environmental laws that seek to achieve their goals by imposing liability on persons that have a certain relationship with property where an environmentally unacceptable substance is found. Typically this relationship is either "ownership" or "operation" of *the property* or a relationship with *the substance* that is found on the property. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA")[33] is the primary law that gives rise to this sort of "status" liability. However, the Resource Conservation and Recovery Act ("RCRA"),[34] the Clean Water Act (CWA),[35] and the Oil Pollution Act (OPA)[36] each impose their own brand of status liability that may pick up situations that are not otherwise covered by CERCLA liability. Each of these laws can apply to the ownership, development, and operation of oil and gas interests.

The concept of "owner" under CERCLA can include persons who merely own an interest in contaminated property. To date, courts have generally looked to a person's ownership interest to evaluate the degree of control the interest permits the person to exercise over the property. For example, even though the owner of a severed surface interest may have no ownership interest in the mineral estate, activities on the surface to develop the mineral estate can impose CERCLA liability on the surface owner—as well as the mineral interest owner. If there is an abandoned pit on the property, or other contamination associated with oilfield development, the surface owner will have a substantial amount of control over the site and, for CERCLA purposes, will be an "owner" of the facility.[37]

If the lessor permits a lessee to come onto the property, the lessor is exposed to environmental liability for what the lessee, and indeed anybody else, does on the lessor's property.[38] Therefore, the lessor will want to address the environmental issue by limiting, to the extent feasible, lessee activities that could increase the lessor's environmental

31. *E.g.*, Quaker State Corp. v. United States Coast Guard, 681 F. Supp. 280 (W.D. Pa. 1988) (surface owner liable for cleanup of oil containment pit associated with prior oil and gas operations).

32. *See generally* Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6.

33. 42 U.S.C. §§ 9601 to 9675 (1988).

34. RCRA comprises Subchapter III—Hazardous Waste Management (42 U.S.C. §§ 6921 to 6939b (1988)) of the Solid Waste Disposal Act, 42 U.S.C. §§ 6901 to 6992k (1988).

35. 33 U.S.C. §§ 1251 to 1387 (1988).

36. 33 U.S.C.A. §§ 2701 to 2761 (West 1992).

37. *See generally* Quaker State Corp. v. United States Coast Guard, 681 F. Supp. 280 (W.D. Pa. 1988) (surface owner held to be "owner" under Clean Water Act and therefore responsible for cleanup of oil containment pit).

38. *See* Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 151-55.

liability. At the same time, the lessor will want to leverage its remaining environmental risk through indemnity agreements.[39] The lessor

39. Likewise, the lessee should be concerned with limiting what the lessor does on the leased land in which the lessee has an express or implied easement. Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 168-70. One drafting approach to these issues could employ a clause similar to the following:

6. ENVIRONMENTAL ISSUES; INDEMNITY.

a. Land Use Restrictions. To the maximum extent feasible, LESSEE will minimize the use of surface pits and hazardous materials in drilling operations on the Leased Land. Any pits, ponds, or other surface impoundments used in connection with the development or operation of the Leased Land shall comply with all applicable local, state, and federal standards and in any case shall meet or exceed the standards for such structures located within a wellhead protection or critical aquifer protection area as defined by the federal Safe Drinking Water Act or any state law counterpart. Any pit or other surface disruption associated with drilling operations on the Leased Land will be fully reclaimed and restored to its natural condition immediately following the completion of drilling operations. All substances brought onto the Leased Land, and wastes generated as part of the exploration, development, or production process, will be removed from the Leased Land immediately following the completion of drilling operations. All equipment designed to separate, dehydrate, treat, compress, process, or otherwise condition Leased Substances will be located off of the Leased Land. Any tanks used to collect and store a Leased Substance prior to marketing will be located off of the Leased Land. No injection or disposal well will be placed on the area encompassed by the Leased Land. No pipe, chemicals, or other material or equipment will be placed on the Leased Land except items that are on-site for immediate use in operations. Equipment or material placed on site and not actively used for ten consecutive days will be deemed not to be for immediate use in operations. Within five days after a development or production operation is completed, all the associated development structures, equipment, and any other material brought to or generated at the site will be removed from the site. If any topsoil has been disturbed by the operation, the area will be graded to its original contour, and the topsoil replaced, properly seeded, fertilized, and maintained until the original cover in the affected area is reestablished.

b. Assumption of Liability. LESSEE assumes the following liabilities associated with the Leased Land: LESSEE acknowledges that it is entering into this Lease without relying on any representations by LESSOR concerning the condition, environmental or otherwise, of the Leased Land. Instead, LESSEE is relying solely upon its independent investigation to determine the status of the Leased Land. As partial consideration for this Lease, LESSEE agrees to assume all liabilities it may incur as an owner or operator of the Leased Land, including any environmental cleanup obligations that may be imposed under any local, state, or federal law, including the common law. LESSEE further agrees to hold LESSOR harmless from any claim LESSEE may have or acquire, in contribution or otherwise, associated with the condition of the property or LESSEE's liability as an owner or operator. This includes, without limitation, any claim or cause of action LESSEE may have at common law or under any local, state, or federal statute such as the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or a state or local counterpart. LESSEE agrees to assume all liabilities associated with any activity conducted on the Leased Land, by LESSEE, its contractors, and any other person or entity exercising or purporting to exercise rights through LESSEE or on LESSEE's behalf.

c. Agreement to Remedy Environmental Problems. LESSEE agrees to remedy any Environmental Problem resulting from, arising out of, or in any manner associated with any activity by LESSEE, its contractors, and any other person or entity exercising or purporting to exercise rights through LESSEE or on LESSEE's behalf, that presently impacts, or is likely to impact, the Leased Land. In the event an Environmental Problem is identified, LESSOR will give LESSEE notice of the Environmental Problem and LESSEE will, at its sole risk and expense, take the necessary action to define and remedy the Environmental Problem. For purposes of this section, "Environmental Problem" means any situation which: violates any local, state, or federal requirement, is reportable under any environmental law, gives rise to a cleanup, sampling, testing, monitoring, assessment, or similar obligation under any common law, statutory, or regulatory theory, concerns conditions, structures, or substances that require special environmental handling for their proper renovation, demolition, or disposal, or exposes LESSOR to a substantial threat of liability associated with the health, safety, and welfare of the public, workers, or the environment.

should also revise the typical form of assignment clause to ensure the lessee, and any intervening assignees, remain bound to the terms of the lease. Under the typical form of assignment clause the lessee's liability to lessor is limited to activities taking place prior to the date of assignment.[40] The lessor's goal should be to ensure the lessee remains liable for performance of the lease terms once it is assigned to the lessee's chosen successor. Presumably, this will encourage the lessee to select responsible assignees.[41]

The lessee must also consider its potential environmental liability when it acquires an express or implied right to use the surface of the

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d. Agreement to Indemnify. LESSEE will protect, indemnify, hold harmless, and defend LESSOR against any claim, demand, cost, liability, loss, or damage suffered by LESSOR (including LESSOR's reasonable attorney fees and litigation costs) resulting from, arising out of, or associated with one or more of the following events: LESSEE's breach of any covenant, obligation, or duty created by the terms of this Lease. LESSEE's failure to comply with the LESSOR's retained rights under this Lease. Any matter encompassed by LESSEE's assumption of liabilities, including environmental liabilities, under the terms of this Lease. Any activity expressly or impliedly authorized or required by this Lease. Any matter associated with producing wells, nonproducing wells, existing wellbores, unplugged wells, or previously plugged wellbores. Any matter associated with the management, use, and disposal of produced water and wastes or substances associated with the development or operation of the Leased Land. Any matter associated with the generation, processing, handling, transportation, storage, treatment, recycling, marketing, use, disposal, release or discharge, or threatened release or discharge, of oil, natural gas, natural gas liquids, all other petroleum substances, any waste material, or any "hazardous substance" or "pollutant or contaminant" as those terms are defined (now or in the future) under CERCLA and its state counterpart. Any matter relating to LESSEE's ownership, use, or occupancy of the Leased Land or any area impacting the Leased Land. LESSEE's obligations created by this Section are continuing obligations which will remain in effect, and be enforceable by LESSOR, even after the Lease terminates or otherwise ceases to burden the Leased Land. In the event LESSOR conveys or assigns all or any part of its interest in the Leased Land, LESSOR will nevertheless continue to be covered by LESSEE's indemnity. However, LESSOR's grantees or assignees will also be covered by LESSEE's indemnity to the extent of the interest they receive in the Leased Land. *LESSEE's indemnity obligation will apply even though the basis for LESSOR's liability arises out of LESSOR's statutory or common law strict liability, sole or concurrent negligence, or any other statutory, tort, or contract theory.*

40. One common form of lease provides: "An assignment of this lease, in whole or in part, shall, to the extent of such assignment, relieve and discharge lessee of any obligations hereunder . . . ." 62 Blue Print Form, *supra* note 7, ¶ #8. *See* David E. Pierce, *An Analytical Approach to Drafting Assignments*, 44 Sw. L.J. 943, 949-54 (1990).

41. For example, the assignment clause of the lease could provide:

5. CHANGE IN OWNERSHIP; EFFECT OF ASSIGNMENT. LESSEE will provide LESSOR with a copy of any assignment within 5 days after the assignment is made. However, as to any assigned interest, LESSEE will remain obligated for the proper performance of all express and implied Lease obligations. LESSEE's liability for the non-performance of Lease obligations (including the obligation to indemnify LESSOR pursuant to the terms of this Lease) will be in addition to the liability of any assignee obtaining an interest through the LESSEE or any assignee obtaining an interest through LESSEE's assignee. Any person or entity obtaining an assignment of rights in this Lease: (1) Is deemed to have accepted liability for the non-performance of any express or implied Lease obligations (including the obligation to indemnify LESSOR pursuant to the terms of this Lease) accruing prior to the date of assignment; and (2) Is liable for the proper performance of express and implied lease obligations (including the obligation to indemnify LESSOR pursuant to the terms of this Lease) from and after the date of assignment. The liability of LESSEE and all assignees transferred an interest in the Lease is joint and several.

leased land.[42] In previous writings I have noted the value of the "tactical acquisition" in which the lessee acquires only the "authority to control" areas it needs to control in order to conduct its operations.[43] Since the oil and gas lessee's surface easement rights are the main source of lessee CERCLA problems, they should be carefully crafted to give the lessee only the surface rights necessary for effective development and operation of the leased land.[44] Surface use rights covering questionable portions of the leased land should be restricted. For example, if the lessee knows there is an abandoned pit associated with a third party's prior operations on the leased land, the lessee may want to expressly provide that it has no right to enter or use the area where the pit is located. If the lessee has no right to enter or use the pit, it will be difficult for a court to find the lessee was an "owner" or "operator" of the pit for cleanup purposes.[45] For uncontaminated areas, the lease could grant the lessee an option to declare the surface areas it can use as they are needed for development; if the lessee never conducts operations on the leased land it could argue it never had an ownership or operational right in the surface because it never exercised its option. If the lessee actually conducts operations on the leased land, it would argue it only triggered an ownership interest in the area actually impacted by its operations.[46]

C. *Structural Improvements*

The drafter can significantly improve the lease document merely by grouping the separate paragraphs that concern each of the three major topics. The first portions of the lease should address granting clause issues. In addition to identifying the granted substances and easement rights, the initial paragraphs of the lease should also address the title issues such as warranty, after-acquired title, proportionate reduction,[47] subrogation, and related matters.[48] The next section should contain the habendum and related clauses defining the duration of the

42. Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 168-73.

43. *Id.* at 168, 170.

44. I have offered suggested language for such a clause in my previous writings. *See* Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 170-71.

45. *See* Nurad, Inc. v. William E. Hooper & Sons Co., 966 F.2d 837, 843 (4th Cir. 1992) (tenants were not liable for contamination associated with underground storage tanks because their leases did not confer any right to possess or use the tanks).

46. Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 168-71.

47. Since the proportionate reduction clause will primarily impact the calculation of royalty, some drafters may prefer to place it in proximity to the royalty clause.

48. For example, one representative lease form addresses granting clause issues in paragraphs numbered 1, 7, 10, and 11. Habendum clause issues are addressed in paragraphs numbered 2, 4, 6, and 9. 62 Blue Print Form, *supra* note 7. Although the placement of the clause probably has little substantive impact, a logical grouping of the clauses tends to better inform the parties as to the basic terms of the bargain. If the parties understand the terms going into the transaction, they are probably more inclined to accept the terms, without challenge, when they become burdensome.

grant, such as the production requirement, delay rental clause, operations, dry hole, cessation, force majeure, and shut-in royalty clauses, and any clause providing for the termination of undeveloped portions of the lease. The third grouping should include the royalty provisions. Since the pooling clause generally modifies to varying extents the granting, habendum, and royalty clauses, it should follow the royalty clause. The "miscellaneous" clauses should follow the pooling clause and would typically address assignment and change in ownership issues, environmental issues,[49] notice and access to information, and the binding effect of the lease.

III. The Habendum Clause: Guillotines and Time Bombs

The "habendum clause", used broadly, includes any provision which defines, limits, or expands the duration of the lessee's granted interest. The drilling/delay rental clause, for example, can be viewed as a limitation on the duration of the grant while the shut-in royalty clause can be viewed as an expansion of the grant's duration under certain conditions. Therefore, the duration of the grant is defined by the operation and interaction of what has traditionally been called the habendum clause,[50] the drilling/delay rental clause,[51] commencement/

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49. Since the environmental provisions will necessarily impact the scope of the grant, some drafters may prefer to address environmental issues in conjunction with the granting clause.

50. 62 Blue Print Form, *supra* note 7, ¶ #2.

> [T]his lease shall remain in force for a term of ten (10) years . . . and so long thereafter as oil, liquid hydrocarbons, gas or other respective constituent products, or any of them, is produced from said land . . . .

Id.

51. 62 Blue Print Form, *supra* note 7, ¶ #4:

> If operations for drilling are not commenced on said land . . . on or before one (1) year from this date, this lease shall terminate as to both parties, unless on or before one (1) year from this date lessee shall pay or tender to the lessor a rental of ——— Dollars ($——) which shall cover the privilege of deferring commencement of such operations for a period of twelve (12) months.

Id.

operations/completion clause,[52] dry hole clause,[53] cessation clause,[54] shut-in royalty clause,[55] and force majeure clause.[56] The pooling

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52. 62 Blue Print Form, *supra* note 7, ¶ #6:

If, at the expiration of the primary term, oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, is not being produced on said land . . . but lessee is then engaged in operations for drilling or reworking any well thereon, this lease shall remain in force so long as drilling or reworking operations are prosecuted (whether on the same or different wells) with no cessation of more than sixty (60) consecutive days, and if they result in production, so long thereafter as oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, is produced from said land or land pooled therewith.

Id.

53. 62 Blue Print Form, *supra* note 7, ¶ #6:

If, prior to discovery of oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, on said land . . . lessee should drill and abandon a dry hole or holes thereon, . . . this lease shall not terminate if lessee commences reworking or additional drilling operations within sixty (60) days thereafter or, if it be within the primary term, . . . commences or resumes the payment or tender of rentals or commences operation for drilling or reworking on or before the rental paying date occurring twelve (12) months after expiration of the rental period during which such dry hole was drilled . . . .

Id.

54. 62 Blue Print Form, *supra* note 7, ¶ #6:

[I]f, after discovery of oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, the production thereof should cease from any cause, this lease shall not terminate if lessee commences reworking or additional drilling operations within sixty (60) days thereafter or, if it be within the primary term, . . . commences or resumes the payment or tender of rentals or commences operation for drilling or reworking on or before the rental paying date next ensuing after the expiration of three (3) months from the cessation of production.

Id.

55. 62 Blue Print Form, *supra* note 7, ¶ #3.(c):

[A]t any time, either before or after the expiration of the primary term of this lease, if there is a gas well or wells on the above land . . . and such well or wells are shut in before or after production therefrom, lessee or any assignee hereunder may pay or tender annually at the end of each yearly period during which such gas well or wells are shut in, as substitute gas royalty, a sum equal to the amount of delay rentals provided for in this lease for the acreage then held under this lease by the party making such payments or tenders, and if such payments or tenders are made it shall be considered under all provisions of this lease that gas is being produced from the leased premises in paying quantities.

Id.

56. 62 Blue Print Form, *supra* note 7, ¶ #9:

Lessee shall not be liable for delays or defaults in its performance of any agreement or covenant hereunder due to force majeure. The term 'force majeure' as employed herein shall mean: any act of God including but not limited to storms, floods, washouts, landslides, and lightning; acts of the public enemy; wars, blockades, insurrections, or riots; strikes or lockouts; epidemics or quarantine regulations; laws, acts, order or requests of federal, state, municipal or other governments or governmental officers or agents under color of authority; freight embargoes or failures; exhaustion or unavailability or delays in delivery of any product, labor, service, or material, if lessee is required, or ordered or directed by any federal, state or municipal law, executive order, rule, regulation or request enacted or promulgated under color of authority to cease drilling operations, reworking operations or producing operations on the land covered by this lease or if lessee by force majeure is prevented from conducting drilling operations, reworking operations or producing operations, then until such time as law, order, rule, regulation, request or force majeure is terminated and for a period of ninety (90) days after such termination each and every provision of this lease that might operate to terminate it or the estate conveyed by it shall be suspended and inoperative and this lease shall continue in full force. If any period of suspension occurs during the primary term, the time thereof shall be added to such term.

Id.

clause[57] also expands the scope and effect of the habendum clause by expanding the area from which the required production, or activity in lieu of production, can take place.

A. *Terminating the Terminator: What's So Special About a "Special Limitation"?*

One of the most notable acts of commercial suicide occurred when lessees embraced a fee simple determinable model for defining the duration of their lease rights.[58] This single fateful act of commercial drafting has probably contributed to more litigation under the oil and gas lease, and financial loss to the lessee, than all other issues combined. Under the fee simple determinable model lessees must be ever vigilant to ensure there is the required production, or some contractual substitute for production, or their interest will be gone. The equities of the situation simply don't matter, and shouldn't matter, under the fee simple determinable model.[59] The lessee has created a commercial time bomb that will terminate the lease relationship for such minor things as being 13 days late in commencing reworking operations[60] or misconstruing the payment date for a $50 shut-in royalty payment.[61] The bomb can go off even when the events are totally out of the lessee's control; such as when the price of oil drops from $18.50/barrel to $12.00/barrel and lease revenues no longer exceed operating costs.[62]

Courts have had difficulty, in some contexts, with treating the habendum clause as a special limitation on the lessee's interest. If the court views the habendum clause as creating essentially a fee simple determinable, any jurisprudential basis for avoiding automatic termination becomes problematic. For example, under the "unless" form[63]

57. Pooling clauses typically provide: "The entire acreage pooled into a gas unit shall be treated for all purposes, except the payment of royalties on production from the pooled unit, as if it were included in this lease." 62 Blue Print Form, *supra* note 7, ¶ #5.

58. By employing a fee simple determinable model failure to comply fully with the stated condition in the grant will cause it to terminate automatically. Courts will generally not intervene to mitigate an accidental or unintentional triggering of the event that terminates the lease. *See infra* text accompanying notes 59-69.

59. "Termination of a grant, because of a special limitation, is not a forfeiture. Equity cannot mitigate the effect of the special limitation. Acts of God and the lessee's good faith effort will not mitigate the termination." 1 PIERCE, KANSAS HANDBOOK, *supra* note 24, § 9.22, at 9-22 (citing Kahm v. Arkansas River Gas Co., 253 P. 563, 566 (Kan. 1927)).

60. Samano v. Sun Oil Co., 621 S.W.2d 580 (Tex. 1981).

61. Freeman v. Magnolia Petroleum Co., 171 S.W.2d 339 (Tex. 1943).

62. *See, e.g.*, Reese Enterprises, Inc. v. Lawson, 553 P.2d 885, 897 (Kan. 1976) (employing a mathematical analysis to determine whether production income exceeded production expenses during a relevant time frame).

63. There are two types of drilling/delay rental clauses: the "or" form and the "unless" form. The "or" form requires the lessee to either commence drilling operations *or* pay the stated delay rental. It creates a covenant which obligates the lessee to pay the delay rental in the event it fails to commence drilling operations. The "unless" form gives the lessee a three-way option. The lessee can either commence drilling operations, pay delay rental, or do nothing, in which case the lease terminates. The lease will terminate "unless" the lessee elects to commence drill-

of drilling/delay rental clause, if the lessee is a "day late[64] or a dollar short"[65] with the delay rental payment, the lease automatically terminates—most of the time. If the lessee sent the payment by registered mail in time to arrive in due course, but it didn't, many courts have granted the lessee relief.[66] Oddly enough, once the court decides to grant relief, they speak of avoiding a "forfeiture;" if they decide to deny relief, they speak of a "special limitation" on the grant.[67]

The fee simple determinable model is perhaps the best gift the lessee gives to the lessor even before the negotiations take place.[68] Once the "gift" is given, courts are reluctant to let the lessee take it back with other language in the lease.[69] Also, the lessor has become painfully aware of the importance of a fee simple determinable as opposed to mere lessee promises. Any lessor or top lessee that has financed implied covenant litigation knows the tremendous value of guillotines and time bombs. Mere covenants rarely get them what they want and need—separation from the existing lessee. A judgment awarding damages or conditional cancellation will often be a hollow victory for the lessor and the top lessee. Under a fee simple determinable model, if you win, you win it all. A statute may even let you recover your attorney fees and litigation costs.[70] For the lessee, any "modern" oil and gas lease should attempt to deal with the special limitation trap.

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ing operations or pay the delay rental; but the lessee is not required to anything. *See* LOWE, NUTSHELL, *supra* note 19, at 202-06.

64. *E.g.*, Gasaway v. Teichgraeber, 191 P. 282 (Kan. 1920) (delay rental due 17 April, mailed 17 April, arrived 18 April, credited to account 19 April, lease terminated).

65. Young v. Jones, 222 S.W. 691 (Tex. Civ. App. 1920) (amount sent was $2.96 less than the required payment so the lease terminated).

66. *E.g.*, Kays v. Little, 175 P. 149 (Kan. 1918) (delay rental due 2 December, lessee sent payment by registered mail on 27 November, lost in mail and arrived on 5 December, lease did not terminate).

67. *See* 1 PIERCE, KANSAS HANDBOOK, *supra* note 24, § 9.30, at 9-38 to 9-41 and § 9.39, at 9-52 to 9-56 (discussing the special limitation/forfeiture analysis and excuses for improper payment).

68. It is doubtful lessees ever raise the issue in their lease negotiations. In effect, it has been conceded to the lessor by years of custom and practice.

69. For example, in Freeman v. Magnolia Petroleum Co. the lease had a sort of savings clause that provided:

> The covenants of lessee mentioned in this lease, as well as all implied covenants, are not to be understood as conditions, and the breach of one or all of same will not work a forfeiture, abandonment or termination of this lease . . . .

Freeman v. Magnolia Petroleum Co., 171 S.W.2d 339 (Tex. 1943). However, the court refused to apply the savings clause to the shut-in royalty clause which stated the lease would be maintained "while said royalty is so paid." The court observed that the shut-in royalty clause did not create a "covenant" to pay but rather was a "condition" and the savings clause only applied to "covenants."

70. *E.g.*, KAN. STAT. ANN. §§ 55-201, -202, -206 (1983). *See* 1 PIERCE, KANSAS HANDBOOK, § 8.08, at 8-11 to 8-17.

1. *What's So Special About Delay Rental?*

Originally delay rental clauses were added to the oil and gas lease to negate an implied obligation to drill a test well on the leased land.[71] Unfortunately for lessees, delay rental clauses are frequently written as special limitations on the grant.[72] Lessees can bumble delay rental payments. When they do, the courts are very unforgiving. One approach to the problem would be to eliminate the guillotine and time bomb effect of the bumble; make the payment an obligation instead of an option—a covenant instead of a condition—an "or" instead of an "unless."[73] Another approach would be to use an "unless" form of lease but include a "bumble clause" which would allow the lessee to correct any error in payment without suffering death on the guillotine.[74] However, lessees sometimes bumble the bumble clause.[75]

Instead of chasing delay rental obligations, why not eliminate the clause? Since the primary term of the oil and gas lease is generally shorter than in the past, the economic significance of delay rental becomes less important to the lessor. If the lessor is hesitant to break with tradition, this can usually be dealt with in the bonus payment. Instead of using paid-up leases, the parties could eliminate the drilling/delay rental clause and simply provide in the habendum clause:

> 3. DURATION OF GRANT. Unless otherwise extended by the terms of this Lease, this Lease terminates at 5:00 p.m. local time on 1 November 1995 (the 'Termination Date'). *Unless necessary to protect the Leased Land from drainage, LESSEE, prior to the specified Termination Date, is under no obligation to drill a test well on the Leased Land.*

Such an express clause negating a development obligation during the primary term of the lease should adequately deal with the implied

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71. EUGENE O. KUNTZ, ET AL., OIL AND GAS LAW 160 (2d ed. 1993) [hereafter KUNTZ, ET AL.].

72. *See supra* text accompanying notes 63-67.

73. *See supra* text accompanying note 63.

74. A workable bumble clause could provide:

> If on or before any rental due date Lessee in good faith makes an erroneous rental payment by paying the wrong person or the wrong depository or the wrong amount, Lessee shall be unconditionally obligated to pay or tender the proper rental for the period involved and this lease shall continue in effect as though such rental payment has been properly made, provided that proper rental shall be paid or tendered within 30 days after receipt by Lessee of written notice of the error from Lessor, accompanied by any documents and other evidence necessary to enable Lessee to make proper payment.

Note that this clause does not address the "I forgot to pay" bumble. For example, if your client just purchased the leases and missed several delay rental payments while they were getting their records and payment systems set up, this bumble clause would not save the lease since no payment, erroneous or otherwise, was made "on or before any rental due date."

75. *See, e.g.*, Barbee v. Buckner, 265 S.W.2d 869 (Tex. Civ. App. 1954) (clause excused lessee's failure to comply with "obligations" and required lessor to provide advance notice that lessee "breached" the lease contract).

covenant to drill an initial well that prompted creation of the drilling/delay rental clause.[76]

2. *Lessee Responses to Special Limitations: An Improved, Traditional Approach*

The goal of the lessee under the habendum clause is to ensure that the lease addresses each contingency in which the production requirement may not be satisfied. However, the lessor only wants the lease to address those contingencies in which continuation of the lease would not unduly prejudice its interests. The lessor wants, to the maximum extent possible, *objective and automatic* remedies to keep transaction costs to a minimum while providing the lessee with built-in incentives to comply fully with lease terms with little or no lessor intervention. For example, if the operations clause requires actual drilling with a rig capable of penetrating the formation identified in the lessee's drilling permit, the lessor can police compliance by observing the leased land on the critical date. If there isn't a rig there, the lease has terminated.[77] Although lessees probably share the desire to have *objective* standards to define their required performance, an *automatic* policing mechanism that employs termination of the lease should be unacceptable in many situations—such as the failure to properly tender a shut-in royalty payment.

a. *"Paying Quantities": Chasing the Price of Oil & Gas*

A fundamental problem with the lease habendum clause is the market-sensitive nature of its guillotine peg. Most leases provide for termination unless there is production "in paying quantities."[78] However, one of the most important factors in the paying quantities equation is the price received for the production. Oil prices are particularly volatile and swings of 100% or more up or down are not uncommon. The price of oil that caused the lessee to initially develop the well may not hold throughout the life of the lease. As the price of oil declines, so does the life of the lease; its contractual economic limit creeps closer as prices fall. Although some states, like Texas,[79] provide the lessee with some leeway for its future price optimism, other

76. *See generally* KUNTZ, ET AL., *supra* note 71, at 328.

77. Since this issue falls in the "winner-take-all" category, it is frequently the focus of litigation to determine whether the lessee's actions constituted "commencement of operations to drill a well." *See, e.g.*, Wilds v. Universal Resources Corp., 662 P.2d 303 (Okla. 1983) (although lessee took the necessary action to meet the "commencement" requirement, factual issue remained whether such action was pursued with due diligence). *See generally* KUNTZ, ET AL., *supra* note 71, at 193-95.

78. *E.g.*, Stewart v. Amerada Hess Corp., 604 P.2d 854 (Okla. 1979).

79. Clifton v. Koontz, 325 S.W.2d 684 (Tex. 1959); Evans v. Gulf Oil Corp., 840 S.W.2d 500 (Tex. Civ. App. 1992). The Texas two-step approach to the paying quantities issue has been recently articulated in the *Evans* case where the court stated:

states, like Kansas,[80] take a more historical accounting approach to the issue.

The problems with achieving actual production that plagued lessees in earlier years have been mitigated by the addition of commencement/operations/completion, dry hole, cessation, shut-in royalty, and force majeure clauses. However, not much has been done to mitigate the requirement of production in "paying quantities."[81] Lessees have little or no control over the "paying quantities" aspect of the lease and are at the mercy of the price their production can fetch in the marketplace.[82]

One technique for addressing price volatility is to provide that an average value for production over a specified time will be applied to determine paying quantities. For example, if the lessee initially drilled the well because oil was selling for $30/barrel[83] this would be a relevant factor a prudent operator would consider in continuing to operate the lease.[84] Also relevant would be the highest price paid for oil produced from the lease up to the time of the paying quantities litigation. However, depending upon how far removed in time these events are from the paying quantities litigation, a court may, or may not, consider it relevant evidence.[85]

Nothing, however, prevents the lessee from including such variables in the habendum clause. For example, consider the following provision:

> To determine paying quantities, Production sold during the Accounting Period[86] will be deemed to have been sold for an amount calculated by taking the average price paid for extracted Leased

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> The test for determining a well's profitability is 1) whether the production yields a profit after deducting operating and marketing costs, and 2) whether a prudent operator would continue, for profit and not for speculation, to operate the well as it has been operated. . . .
>
> To terminate a lease, the landowner must show both 1) and 2). If a well is profitable under part 1) of the test, part 2) is not applied . . . .

Evans, 840 S.W.2d at 503.

80. Reese Enterprises, Inc. v. Lawson, 553 P.2d 885 (Kan. 1976). Kansas follows more of a "one-step" approach which merely compares production income and expenses.

81. One attempt to deal with the problem has met with judicial hostility. *See* Greer v. Salmon, 479 P.2d 294 (N.M. 1970) (habendum clause extending lease "so long as oil or gas is produced *or producible* from the land" did not prevent lease from terminating when lessee bumbled a shut-in royalty payment).

82. One might ask, does placing the risk of falling prices on the lessee do anything to promote efficiency?

83. The same sort of formula could be applied to gas prices.

84. The lessee could legitimately believe oil might rise to that level again in the future.

85. *See generally* Texaco, Inc. v. Fox, 618 P.2d 844, 847 (Kan. 1980) (defining how the relevant accounting period will be identified to determine the paying quantity issue when the parties have failed to address the issue).

86. The accounting period is the most nebulous part of the equation. The lessee, or lessor, may want to expressly define the accounting period. For example, the lessee might provide:

> If production proceeds attributable to the working interest in the Lease do not exceed operating expenses during any twenty-four consecutive month period, this Lease will be deemed not to be producing in paying quantities.

A lessor might try and negotiate for the following clause:

> Substances during the Accounting Period, adding to such average price the highest price ever paid for extracted Leased Substances during the existence of the lease, and then dividing the total by two.

Therefore, if the average price of oil during the relevant accounting period is $15.00/barrel, and the highest price ever paid for oil during the existence of the lease is $35.00/barrel, oil during the accounting period will be deemed to have been sold for $20.00/barrel—even though current market prices may actually be $9.00/barrel or some other number.

b. *Chasing Other Terminating Events: The Cessation Clause*

A problem closely related to the paying quantities requirement is what happens if there is a cessation of production. If the cessation is permanent, the lease will terminate unless there is a lease provision that addresses the event. If the cessation is temporary, the common law rule gives the lessee a reasonable amount of time to take action to regain production.[87] Lessees, however, wanted to provide for situations where there is a permanent cessation of production which would not be covered by the common law "temporary" cessation doctrine. However, the traditional response by lessees has been to use a "cessation" clause similar to the following:

> [I]f, after discovery of oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, the production thereof should cease for any cause, this lease shall not terminate if lessee commences reworking or additional drilling operations within sixty (60) days thereafter . . . .[88]

Such a clause eliminates the flexibility lessees generally enjoyed under the common law temporary cessation doctrine.[89] It can also prove difficult to administer when cessation is defined to include a lack of production in paying quantities as opposed to a total stoppage of production.[90]

Lessees may want to consider drafting the cessation clause so it only addresses the problem area: permanent cessation.[91] This would

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> If production proceeds credited to Lessee's net revenue interest do not exceed operating expenses during any twelve consecutive month period, this Lease will be deemed not to be producing in paying quantities.

The profitability of production can also be impacted by defining in the lease the expenses that will, or will not, be included in the equation. The volume of production (and the resulting income) to be attributed to the lessee should also be defined. For example, will the lessee's share of production be net of any overriding royalties carved out of the working interest?

87. *See* KUNTZ, ET AL., *supra* note 71, at 215-16.

88. 62 Blue Print Form, *supra* note 7, ¶ #6.

89. *See generally* Samano v. Sun Oil Co., 621 S.W.2d 580 (Tex. 1981) (defining the impact of the cessation clause on the lessee's lease rights).

90. *See* Hoyt v. Continental Oil Co., 606 P.2d 560 (Okla. 1980) (cessation clause required lessee to commence drilling or reworking operations within 60 days from date well ceased to produce in paying quantities).

91. Consider the following approach:

SECTION 5. PRODUCTION CEASES

retain for the lessee the benefit of the typically more forgiving temporary cessation *doctrine*.[92]

c. *Chasing Other Terminating Events: The Commencement/ Operations/Completion Clause*

A common form of commencement/operations/completion clause provides:

> If, at the expiration of the primary term, oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, is not being produced on said land . . . but lessee is then *engaged in operations for drilling or reworking any well thereon*, this lease shall remain in force so long as drilling or reworking operations are prosecuted (whether on the same or different wells) with no cessation of more than sixty (60) consecutive days, and if they result in production, so long thereafter as oil, liquid hydrocarbons, gas or their respective constituent products, or any of them, is produced from said land or land pooled therewith.[93]

Similar language is found in the commencement portion of the drilling/delay rental clause.[94] The time bomb issue is: What must the lessee be doing on the critical date to be "engaged in operations for

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A. Temporary Cessation.

LESSOR and LESSEE recognize that Production will be interrupted periodically due to marketing patterns, operational considerations, well maintenance, regulatory compliance, reworking, and other activities. Such temporary cessation of Production will not terminate this Lease so long as LESSEE, within a reasonable period of time, takes the appropriate action under the circumstances to resume Production.

B. Permanent Cessation.

If Production ceases, due to an exhaustion of recoverable Leased Substances from existing wells, or due to any other cause not covered by Section 5.A., LESSEE has 120 days following the date of such cessation to begin Operations in an effort to regain Production from the Leased Land.

92. A lessor version of the cessation clause could provide:

SECTION 5. PRODUCTION CEASES

A. Cessation of Production.

If Production in Commercial Quantities from the Leased Land ceases, regardless of the cause, LESSEE has 60 days following the date of such cessation to begin Operations or Reworking Activities in an effort to regain Production in Commercial Quantities from the Leased Land.

1. Operations. If LESSEE commences Operations within the stated period of time, LESSEE's rights will be governed by SECTION 4 of this Lease.

2. Reworking Activities. If LESSEE commences Reworking Activities within the stated period of time, this Lease will remain in effect for so long as Reworking Activities are diligently pursued. If Production results from the Reworking Activities, this Lease will remain in effect for so long as there is Production in Commercial Quantities. If Reworking Activities result in a Dry Hole, LESSEE, at its option, has 60 days following the date the Dry Hole is Completed to begin Operations on a new well.

B. Definition.

As used in this Lease the term "Reworking Activities" means actual work is being conducted on the well in an effort to restore or increase Production.

93. 62 Blue Print Form, *supra* note 7, ¶ #6.

94. For example:

If operations for drilling are not commenced on said land . . . on or before one (1) year from this date, this lease shall terminate as to both parties, unless on or before one (1) year from this date lessee shall pay or tender to the lessor a rental of ——— Dollars ($——) which shall cover the privilege of deferring commencement of such operations for a period of twelve (12) months.

62 Blue Print Form, *supra* note 7, ¶ #4.

drilling or reworking" a well? If the lessee is not doing it, the lease automatically terminates. In Kansas, anything less than actual drilling is risky.[95]

Problems associated with the "operations" language can be solved by merely defining the term. The definition could favor either the lessor[96] or the lessee,[97] but its meaning would be clear, and both parties could avoid litigation.

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95. Herl v. Legleiter, 668 P.2d 200 (Kan. Ct. App. 1983). I have summarized the law in Kansas in previous writings noting:

> In *Herl v. Legleiter* the Kansas Court of Appeals suggests something less than actual drilling may be sufficient to satisfy a commencement clause. However, it appears where something less than actual drilling is being relied upon, the lessee should be required to demonstrate what amounts to an irrevocable commitment to conduct operations to completion, on the leased land. The best evidence of this, absent actual drilling on the premises, is an enforceable contract with a third party to drill a well on the leased land. However, the lessee runs a risk when something less than an appropriate rig is in place on the lease. Kansas cases indicate the lessee's good faith intent to commence and complete operations is immaterial. As the court in *Herl* notes: "[Lessee] . . . may in good faith have attempted to commence a well, but as a matter of fact the steps he took fell short of accomplishing what he was attempting to do."

1 PIERCE, KANSAS HANDBOOK, *supra* note 24, § 9.34, at 9-44 to 9-45. *But see* Petroleum Energy, Inc. v. Mid-America Petroleum, Inc., 775 F. Supp. 1420 (D. Kan. 1991) (dicta suggesting actions in preparation for drilling would be sufficient in Kansas).

96. A lessor-oriented clause could provide:

> 5. *EXTENSION BY OPERATIONS; DRY HOLES.* If, on the Termination Date, Operations are being conducted on the Leased Land, this Lease will extend beyond the Termination Date for so long as Operations are being diligently pursued. If Production results from the Operations, this Lease will remain in effect for so long as there is Production in Commercial Quantities. If Operations result in a Dry Hole, LESSEE, at its option, has 60 days following the date the Dry Hole is Completed to begin Operations on a new well. There is no limit on the number of Dry Holes LESSEE can drill under this Section. *As used in this Lease the following terms will have the indicated meaning: "Operations": The actual drilling of a well with equipment capable of drilling to the formation specified in the drilling permit.* "Dry Hole": A well not capable of Production in Commercial Quantities. "Completed": The date the drilling rig is removed from the well site.
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> 6. *EXTENSION BY OPERATIONS; REWORKING ACTIVITIES.* If Production in Commercial Quantities from the Leased Land ceases, regardless of the cause, LESSEE has 60 days following the date of such cessation to begin Operations or Reworking Activities in an effort to regain Production in Commercial Quantities from the Leased Land. If Operations are conducted within the stated period of time, LESSEE's rights will be governed by Section 5 of this Lease. If LESSEE commences Reworking Activities within the stated period of time, this Lease will remain in effect for so long as Reworking Activities are diligently pursued. If Production results from the Reworking Activities, this Lease will remain in effect for so long as there is Production in Commercial Quantities. If Reworking Activities result in a Dry Hole, LESSEE, at its option, has 60 days following the date the Dry Hole is Completed to begin Operations on a new well. *As used in this Lease the term "Reworking Activities" means actual work conducted on the well in an effort to restore or increase Production.*

97. A lessee-oriented provision could define "operations" to mean:

> Any action taken toward obtaining or regaining Production. This includes, without limitation, actual drilling or any act preparatory to drilling, such as any of the following: obtaining permits, contracting for drilling services, surveying a drill site, staking a drill site, building roads, clearing a drill site, or hauling equipment or supplies.

d. *Chasing Other Terminating Events: The Shut-In Royalty Clause*

The inability to market production at the end of the primary term can cause the lease to terminate in many states.[98] Responding to this problem, oil and gas developers began to include shut-in royalty clauses to ensure their leases could be maintained when they were unable to market production.[99] Most shut-in royalty clauses contemplate a total inability to market[100] and are limited to *gas* marketing problems. Most clauses also use language which indicates proper payment of shut-in royalty is a condition to the continued existence of the lease. A common form of shut-in royalty clause provides:

> [A]t any time, either before or after the expiration of the primary term of this lease, if there is a gas well or wells on the above land . . . and such well or wells are shut in before or after production therefrom, lessee or any assignee hereunder *may pay or tender* annually at the end of each yearly period during which such gas well or wells are shut in, as substitute gas royalty, a sum equal to the amount of delay rentals provided for in this lease for the acreage then held under this lease by the party making such payments or tenders, and *if such payments or tenders are made* it shall be considered under all provisions of this lease that gas is being produced from the leased premises in paying quantities.[101]

The "may pay" and "if" paid language can be interpreted as creating a special limitation on the lease grant.[102] This seems odd since a lessee will seldom if ever consciously want to surrender a producing lease.[103] The special limitation problem can be readily solved by structuring the clause as a covenant to pay instead of an option. A more difficult problem, however, is determining when the lessee can declare a well shut in. Most shut-in clauses are silent regarding the type of events that will justify placing the well in shut-in status.[104] It would appear to

98. *Compare* Elliott v. Oil Co., 187 P. 692 (Kan. 1920) (lease terminated when lessee completed gas wells capable of producing in paying quantities but was unable to produce gas due to a lack of market), *with* McVicker v. Horn, Robinson and Nathan, 322 P.2d 410 (Okla. 1958) (completion of gas well capable of producing in paying quantities will maintain the lease even though gas is not marketed).

99. *See generally* John S. Lowe, *Shut-In Royalty Payments*, 5 EASTERN MIN. L. INST. 18-1 (1984).

100. Tucker v. Hugoton Energy Corp., 855 P.2d 929 (Kan. 1993) (lessee cannot rely upon shut-in royalty clause when there is a "limited" market available for the gas). However, the lessee should not be forced to sell gas when a prudent operator would refrain from marketing.

101. 62 Blue Print Form, *supra* note 7, ¶ #3.(c).

102. *See, e.g.*, Amber Oil & Gas Co. v. Bratton, 711 S.W.2d 741 (Tex. Civ. App. 1986) (lessee accidentally paid shut-in royalty to wrong party, lease terminated). *But see* Gard v. Kaiser, 582 P.2d 1311 (Okla. 1978) (failure to comply strictly with shut-in clause will not result in automatic termination of the lease).

103. This is not like the delay rental payment situation where the lessee may actually intend to allow the lease to terminate by inaction. I doubt if lessees ever consciously go through the mental exercise of considering whether they want to make the $50 shut-in royalty payment or let a million-dollar asset terminate. This might be the case where the amount of the shut-in royalty payment approaches the value of the underlying lease; those cases, however, will not be litigated.

104. For example, in Tucker v. Hugoton Energy Corp. the shut-in royalty clause stated wells on the lease could be shut in when: "[G]as from a well or wells, capable of producing gas only, *is not sold or used for a period of one year* . . . ." Although the wells are capable of producing gas

be an easy task to address shut-in royalty problems by drafting a clause that avoids the use of special limitation language while specifying the types of events that will justify shut-in status.[105]

B. *Lessor Habendum Clause Concerns*

In addition to the lessor habendum clause issues discussed in conjunction with the cessation, commencement/operations/completion, and shut-in royalty clauses, the lessor will want to get the undeveloped

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in paying quantities, the court in *Tucker* indicated the lessee could not rely upon the shut-in clause—even though such gas "is not sold or used." Instead, the court held the lessee could rely upon the clause only when there is no available market for the gas. Tucker v. Hugoton Energy Corp., 855 P.2d 929, 934, 936 (Kan. 1993).

105. A lessee-oriented shut-in royalty clause might provide:

SECTION 7. UNABLE TO MARKET PRODUCTION

If the Leased Land is capable of Production in Commercial Quantities, but LESSEE elects not to market Production because of Inability to Access a Market, Unacceptable Terms, or Market Conditions, and this Lease is not being maintained by the terms of another Lease Clause, this Lease will be deemed to be Shut-in.

The duration of this Lease will extend beyond the Termination Date for so long as a Shut-in well exists on the Leased Land.

If LESSEE is relying upon this Section to extend the Lease beyond the Termination Date, and Production is Shut-in for 90 consecutive days, LESSEE will pay to LESSOR $—— as an Advance Royalty. If Production remains Shut-in, LESSEE will pay LESSOR $—— for each period of 90 consecutive days Production is Shut-in following the initial 90-day period. LESSEE will pay any Advance Royalty due under this Section within a reasonable time following the close of the Shut-in period entitling LESSOR to Advance Royalty. LESSEE's failure to properly pay the Advance Royalty will make the LESSEE liable for the amount due but will not operate to terminate this Lease.

a. "Inability to Access a Market" means: The unavailability of an acceptable mode of transportation to deliver Leased Substances to a buyer.

b. "Unacceptable Terms" means: Offered contract terms which are not reasonable when compared with terms of existing contracts with other producers similarly situated to LESSEE. If comparison is not possible, then any term which a reasonable person in LESSEE's position would find unacceptable. The terms may relate, for example, to an offer to buy, gather, transport, treat, process, or market Leased Substances.

c. "Market Conditions" means: The market price being offered for a Leased Substance is such that a reasonable person in LESSEE's position, having the power to do so, would refrain from marketing the Leased Substance.

d. "Shut-in" means: A well capable of Production which is not being produced.

e. "Advance Royalty" means: A payment made under this Section which LESSEE can recoup, dollar-for-dollar, from future royalty payable to LESSOR. LESSEE can recoup Advance Royalty only to the extent there is future royalty payable to LESSOR from which the recoupment can be made.

The following clause addresses some of the same issues from the lessor's perspective:

7. UNABLE TO MARKET PRODUCTION; SHUT-IN ROYALTY. If the Leased Land is capable of Production in Commercial Quantities, but LESSEE is unable to market Production, LESSEE may Declare one or more wells on the Leased Land to be Shut-In. The duration of this Lease, as to the specific surface area and formation(s) attributed to the Shut-In well by the terms of this Lease, will extend beyond the Termination Date for so long as the Shut-In well exists on the Leased Land and LESSEE complies with the terms of this Section. Upon Declaring a well Shut-In, LESSEE will pay LESSOR $1000.00 as a Shut-In Royalty which will entitle LESSEE to keep the well Shut-In until the end of the calendar year in which the well is Declared Shut-In, or until LESSEE is able to market gas, whichever occurs first. In no event will LESSEE exercise its rights under this Section when it may result in drainage of Leased Substances from the Leased Land. As used in this Lease the following terms will have the indicated meaning: "Declare": LESSEE provides LESSOR with a written notice stating Production from a well on the Leased Land is Shut-In. "Shut-In": A well capable of Production in Commercial Quantities which is not being produced and marketed.

portions of the leased property back from the lessee as soon as the primary term expires. Typically this is accomplished through a variant of what is commonly called a Pugh clause.[106] The following clause is designed to return to the lessor all surface and subsurface areas that are not associated with production from a well as of the expiration of the primary term of the lease:

> 3. *REVERSION OF LEASED LAND.* Notwithstanding any other provision of this Lease, immediately following the Termination Date the surface area covered by the Lease will be automatically reduced to include only the portion of the Leased Land which is counted for participation purposes in production from any Pooled Unit, if Pooled.[107] For portions of the Lease that are not Pooled,

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106. *See generally* Bibler Brothers Timber Corp. v. Tojac Minerals, Inc., 664 S.W.2d 472 (Ark. 1984) (discussing what a Pugh clause is, and is not). The Pugh clause, also called a "Freestone rider" in Texas, was originally used to narrow the effect of the pooling clause by providing that at the expiration of the primary term of the lease, only acreage actually being credited with a share of pooled unit production would be perpetuated beyond the primary term. LOWE, NUTSHELL, *supra* note 19, at 256-58.

However, the Pugh clause can also be used to reduce the scope of the lessee's grant even when none of the leased acreage has been pooled or unitized. As I have noted in previous writings:

> A Pugh clause limits the leasehold area to be held by production. Although the grant may cover a large block of land, the Pugh clause operates, in conjunction with the habendum clause, to limit the area perpetuated by production to the spacing, proration, or pooling unit where the producing well is located. Acreage outside the designated area, although covered by the lease, will not be maintained beyond the primary term unless a producing well is located on such acreage. However, to be effective, the Pugh clause must "explicitly" provide for this limited effect of production from a designated unit of acreage by "obvious, clear and direct" language. . . .
>
> The Pugh clause can also apply to specified depths or formations beneath the leased land. This is referred to as a "horizontal" Pugh clause. A horizontal Pugh clause limits the perpetuating effect of the producing well to the geologic formation where production is obtained, or depths from the surface to the base of the deepest formation penetrated by a well. The "vertical" Pugh clause limits the surface acreage, the *geographic* area, maintained by a producing well. The horizontal Pugh clause limits the subsurface formations, the *geologic* area, maintained by a producing well. . . .

1 PIERCE, KANSAS HANDBOOK, *supra* note 24, at 12-6.

107. This clause would be coordinated with a lessor-oriented pooling clause such as the following:

> 8. *POOLING.* LESSEE has the right to Pool the Leased Land with other lands so long as a reasonable geological basis exists to justify the resulting Pooled Unit. A Pooling Declaration will be used to establish the Pooled Unit. A Pooled Unit can include all or any part of the Leased Land and pertain to any Leased Substance. Production of any Leased Substance from any land which is included in a Pooled Unit formed pursuant to this Section is deemed, for purposes of this Lease, to be Production from the Leased Land. For purposes of this Lease, any action taken or occurring on a Pooled Unit is deemed to be action taken or occurring on the Leased Land. This includes any action or event required to extend this Lease under Sections 4, 5, 6, or 7. The act of creating a Pool comprised of the Leased Land and other lands will not create any sort of cross-conveyance of rights between the LESSOR and other interest owners in the Pooled Unit. Instead, each party will retain sole ownership in the particular tract they contribute to the Pooled Unit. If a Pooled Unit is created under this Section, LESSOR's Royalty associated with the Pooled Unit will be reduced in the proportion Leased Land surface acreage included in the Pooled Unit bears to the total surface acreage comprising the Pooled Unit. As used in this Lease the following terms will have the indicated meaning: "Pool": Combining acreage only to the extent necessary to comply with the minimum acreage requirements imposed by the applicable drilling, spacing, or prorationing laws. "Pooled Unit": The geographic and geologic area described in the Pooling Declaration. "Pooling Declaration": A written document which describes the surface and subsurface areas covered by the Pooled Unit, the applicable

the surface area covered by the Lease will be reduced to include only the portion of the Leased Land which is necessary to obtain a full allowable under prorationing laws and to meet the minimum requirements for the applicable drilling or spacing unit associated with each well on the Leased Land. After the Termination Date the subsurface area covered by the Lease will be reduced to include only those formations from which Production is being obtained in Commercial Quantities. After the Termination Date, all surface and subsurface areas not otherwise held by Production as contemplated by this Section shall automatically revert to LESSOR. If a surface area and formation is held by Production in Commercial Quantities from a well on the Termination Date, but subsequently Terminates pursuant to the terms of this Lease, the surface area and formations associated with the well will automatically revert to LESSOR. If at the Termination Date LESSEE is pursuing Operations as contemplated by this Lease, the determination of the surface area and formations that will revert to the LESSOR will be delayed until the results of such Operations are known. Upon Termination of any portion of the Leased Land, LESSEE, within 15 days of the Termination, will properly file for record a document that identifies and expressly releases the terminated areas and formations of the Leased Land.

C. *The Habendum "Covenant"?*

As we have seen, the special limitation aspect of the habendum clause causes problems for the lessee in several contexts. Would it be possible to substitute a covenant-based regime for the special limitation created by the typical lease habendum clause? If so, the lease would actually move toward a more general statement of the underlying relationship instead of becoming a more detailed version of leases of the past. Consider the following formulation of a different approach to the lease habendum clause:

If, prior to the Termination Date of this Lease, LESSEE discovers Leased Substances on the Leased Land, LESSEE agrees to diligently develop, produce, and market the Leased Substances for the mutual benefit of LESSOR and LESSEE. The duration of this Lease will be extended beyond the Termination Date to permit LESSEE to extract Leased Substances from the Leased Land, and the Lease will not terminate until one of the following events occurs:
(1) LESSEE elects to terminate the lease; or
(2) LESSOR's royalty received under the lease for any calendar year period (January through December) following the Termination Date does not exceed $5,000 and LESSEE fails to pay to LESSOR, within thirty days following receipt of LESSOR's billing, the differ-

drilling, spacing, or prorationing laws which necessitate creating the Pool, the Leased Substances covered by the Unit, LESSOR's proportionate share of Pooled Unit production, and the date and time the Pooled Unit becomes effective. The Pooling Declaration will be effective when filed for record. LESSEE will provide LESSOR with a copy of the Pooling Declaration within 5 days after it is filed for record.

> ence between the royalty paid during the calendar year and $5,000.[108]

The key to making this approach acceptable to the lessor is the clause providing the lessee with an economic incentive to voluntarily terminate the lease when production becomes marginal. It is somewhat similar to the delay rental concept, but applied to the secondary term of the lease instead of the primary term. The lessor could also police the slothful lessee through enforcement of the express covenant to "diligently develop, produce, and market the Leased Substances for the mutual benefit of LESSOR and LESSEE."

Such a covenant-based approach would eliminate the need for a cessation clause, shut-in royalty clause, force majeure clause, and other savings clauses. There would be no paying quantities limitation. However, depending upon how the term "discovers" is defined, the lessee will still need a commencement/operations/completion clause to allow the lease to continue based on development that is commenced, but not completed, prior to the termination date. The downside for the lessor is that it gives up its special limitation club. However, policing the lease under the special limitation approach often, of necessity, polarizes the parties into an "all-or-nothing" position that tends to promote litigation. Under a covenant-based approach, the lessor can demand payment of a liquidated sum of money. If the lessee fails to pay, the lease terminates. There are no involved factual issues, such as are encountered in a paying quantities or cessation dispute. The facts required to make a case would be relatively simple: (1) How much was paid in royalty? (2) How much was due in order to maintain the lease?[109] (3) Did the lessor properly bill the lessee for the difference? (4) Did the lessee pay the required amount within the 30-day time frame?

IV. The Royalty Clause: Can't We All Just Get Along?

Disputes under the royalty clause can be placed into five general categories: (1) Issues concerning the events that will trigger a royalty obligation; (2) Issues concerning valuation of the base royalty obligation; (3) Costs that can be deducted from the base royalty obligation to arrive at the royalty due; (4) Payment issues; and (5) Unstated obli-

108. Since the oil and gas lease may last for decades, the lessor may want to tie the required payment to an inflation index. An alternative formulation might tie termination to the lessee's development activities by providing that the lease will terminate when:

> Extraction of Leased Substances has ceased for a period of 180 days and LESSEE, after demand by the LESSOR, does not thereafter engage in good faith activities to further explore, develop, produce, or market, as may be required to resume the extraction and sale of Leased Substances. Any termination of the Lease pursuant to this subsection will be considered a forfeiture and not the product of a special limitation.

109. The difference between the stated payment and the royalty paid during the calendar year.

gations of the lessor and lessee that emanate from the express lease terms and tend to permeate all the other issues. Each issue arises out of radically varying judicial interpretations of the lease royalty clause,[110] interpretations which typically have a monumental economic impact on the parties to the lease.

The royalty clause is deceptively simple.[111] Its simplicity has been used by courts in many instances as a reason to base their decisions on principles other than the intent of the parties as gleaned from the express terms of the lease.[112] As with other contracts and conveyances, once they are left open to the interpretation process courts will often use the opportunity to "define" the rights and obligations of the parties to achieve "equity" in a particular case or to pursue broader judicially defined policies. Once a party to the lease discovers that the perceived equities or the court's policy goals do not coincide with its interests, the party needs to fashion future leases in a way that will deny the court an opportunity to "interpret" the lease. Usually it is the lessee who is trying to limit the court's interpretive license.

A. *Defining the Royalty-Triggering Events*

The take-or-pay royalty disputes have highlighted the need for greater precision in defining what will, and will not, trigger the lessor's

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110. For example, the supreme courts of Kansas, Montana, and Texas have held that the term "market value" in the gas royalty clause requires a calculation using the *current* market value of gas—even though the lessee is bound by a long-term contract to sell gas to a third party at a different price. However, the supreme courts of Arkansas, Louisiana, and Oklahoma have held under such circumstances that "market value" is equal to the proceeds received by the lessee under its long-term sales contract—at least where the lessee obtained the best price and terms available for the gas *at the time the gas contract was made*. *Compare* Lightcap v. Mobil Oil Corp., 562 P.2d 1 (Kan. 1977), *cert. denied*, 434 U.S. 876 (1977); Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978); and Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968); *with* Hillard v. Stephens, 637 S.W.2d 581 (Ark. 1982); Henry v. Ballard & Cordell Corp., 418 So. 2d 1334 (La. 1982); and Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981).

111. For example, one common royalty clause provides:

> The royalties to be paid by lessee are: (a) on oil, and other liquid hydrocarbons saved at the well, one-eighth of that produced and saved from said land, same to be delivered free of cost at the wells or to the credit of lessor in the pipe line to which the wells may be connected; (b) on gas, including casinghead gas and all gaseous substances, produced from said land and sold or used off the premises or in the manufacture of gasoline or other products therefrom, the market value at the mouth of the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale . . . .

62 Blue Print Form, *supra* note 7, ¶ #3.

112. For example, courts have traditionally used various "canons of construction" to "interpret" the oil and gas lease against the lessee and in favor of the lessor. *See generally* Bruce M. Kramer, *The Sisyphean Task of Interpreting Mineral Deeds and Leases: An Encyclopedia of Canons of Construction*, 24 TEX. TECH L. REV. 1, 105-08 (1993). Often this can be attributed to the judges' unstated belief that the expressed agreement is "unfair" to the lessor. However, traditional contract doctrine would not allow the court to invalidate the parties' agreement. Instead, the terms of the agreement are deemed unambiguous but nevertheless subject to interpretation to give effect to the parties' expressed meaning; meaning ascertained by the court from its analysis of the "four corners" of the document. *See generally* Pierce, *Rethinking the Oil and Gas Lease*, *supra* note 2, at 453-55.

entitlement to royalty.[113] When the lease fails to expressly address the issue, lessees run the risk that courts will use more nebulous concepts such as "implied covenants" and "cooperative ventures" to determine whether the royalty owner gets its share of the $20,000,000 paid to the lessee by the gas purchaser.[114] The ultimate royalty-triggering event should be gas flowing through the valves at the wellhead. However, when leases provide for royalty based upon contract "proceeds"[115] disputes are certain to arise over whether such things as severance tax reimbursements, gathering and compression reimbursements, and take-or-pay payments are "proceeds" or something else. Additionally, under the new gas marketing regime it is often impossible to trace a party's gas to a particular contract in order to identify the proceeds.[116]

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113. *See generally* Bruce M. Kramer, *Royalty Obligations Under the Gun—The Effect of Take-or-Pay Clauses on the Duty to Make Royalty Payments*, 39 INST. OIL & GAS L. & TAX'N 5-1 (1988); Richard C. Maxwell, *Oil and Gas Royalties—A Percentage of What?* 35 ROCKY MTN. MIN. L. INST. 15-1 (1988); Michael P. Pearson & Richard D. Watt, *To Share of Not To Share: Royalty Obligations Arising out of Take-or-Pay or Similar Gas Contract Litigation*, 42 INST. ON OIL & GAS L. & TAX'N 14-1 (1991).

114. *E.g.*, Frey v. Amoco Production Company, 603 So. 2d 166, 170 (La. 1992) (lessors entitled to share in lessee's $20.9 million "non-recoupable take-or-pay payment"). *See also* Klein v. Jones, 980 F.2d 521, 531 (8th Cir. 1992) (applying Professor Harrell's "cooperative venture" analysis to claim for royalty on take-or-pay payments).

115. This would also include market value royalty provisions in states like Oklahoma that equate "market value" with a lessee's contract proceeds. Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981).

116. The problem is illustrated by the following hypothetical:

> [A]ssume a lessee has acquired leases covering three different tracts of land, each owned by a different mineral owner. In June of 1992 the lessee enters into three different gas contracts. None of the contracts commit any reserves from the leased land. Instead, the lessee agrees to deliver to each purchaser a stated volume of gas. The lessee plans to obtain the volumes required to perform its gas sales contracts from its three leases, leases it might acquire in the future, and by purchasing gas from other producers in the area. The three contracts have the following terms:
>
> Contract #1. Two-year term, fixed price of $2.10/Mcf, and a daily delivery obligation of between 500 and 750 Mcf per day.
>
> Contract #2. Six-month term, variable price of 15% above a designated published field (spot) price, and a daily delivery obligation of between 500 and 750 Mcf per day.
>
> Contract #3. Thirty-day term, price agreed upon five days before the month of delivery, volumes not to exceed 10,000 Mcf per day. Assume the parties agree upon $0.90/Mcf as the price for deliveries accepted during the month of July. Assume for all the gas contracts the sales point is at the same designated point on an interstate pipeline. The lessee measures all the gas produced from each lease at the wellhead. The gas from the lessee's leases is commingled in a gathering system that serves several other leases in the area. From the gathering system the gas is delivered to the interstate pipeline where it is transported to the sales point designated in the lessee's gas contracts. The lessee also purchases other gas along the pipeline to meet its sales needs.
>
> Assuming each of the lessee's leases provides for a 1/8th royalty, which lessor gets 1/8th of $2.10/Mcf? Which lessor gets 1/8th of $0.90/Mcf? Which lessors have their wells shut in when the lessee's purchasers fail to take gas under their contracts? Can the lessee choose to declare a "pool" of gas from which it markets and pay royalty based upon the "weighted average price of gas"—the "WAPOG"? Suppose the lessee pays in excess of $1.00/Mcf to acquire third-party gas to meet its gas sales obligations, can the lessee credit the $2.10/Mcf contract to it's third party gas? This series of questions demonstrates a few of the problems associated with the lessee's new marketing freedom. Courts grappling with these problems must initially look to traditional gas royalty valuation jurisprudence in an attempt to resolve issues arising in a very nontraditional gas market.

One drafting technique to deal with the take-or-pay problem would be to state that the lessor either will, or will not, share in any reimbursement or take-or-pay payments made by the gas purchaser to the lessee. However, would such a clause include a "reservation charge" paid to a lessee under a two-part demand/commodity rate for gas?[117] Arguably, a broader approach to the issue is needed to ensure that the underlying problem is addressed instead of merely its latest manifestation. Perhaps a better approach would be to totally divorce calculation of the lessor's royalty from the lessee's contractual arrangements with gas purchasers. This would also mean departing from a "proceeds" basis for calculating royalty in favor of a market value or some other measure. A departure from a "proceeds" royalty may make sense when, as under contemporary gas marketing scenarios, it is no longer possible to identify the proceeds.

B. *Defining the Base Royalty Obligation—The Gross and Net of it All*

1. *Oil—Does the Royalty Owner Really Want an In-Kind Royalty?*

The base royalty obligation for oil is typically expressed as a fractional share of the oil produced.[118] Courts have uniformly held such leases give the lessor an ownership interest in a portion of the oil produced.[119] Since lessors seldom do anything with their share of the oil, the lessee will market the lessor's share of oil production along with the lessee's share. However, most lease forms are silent concerning the lessee's authority to sell the lessor's share. This raises title uncertainties for the lessee and the oil purchaser. The oil purchaser will seek to solve its title problems by obtaining a division order from the lessor. The limited authority addressing the issue indicates the lessee has an implied right to sell the lessor's oil when the lessor fails to

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David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 EASTERN MIN. L. INST. 18-1, 18-7 to 18-9 (1992) (footnote omitted).

117. James Hardwick and Kevin Hayes describe the "reservation charge" term contract as follows:

> These contracts impose on the seller a maximum delivery obligation but give the buyer flexibility in its purchase volumes. Such contracts provide for a two-part rate, first a reservation fee payable on the maximum quantity available regardless of the quantity nominated by the buyer and second, a commodity charge based on the volume nominated and taken. The commodity charge may track the spot price and the reservation fee is frequently a percentage of the commodity charge. Thus, the buyer pays for its flexibility and the seller is compensated for its delivery obligation by the reservation charge.

James C.T. Hardwick & J. Kevin Hayes, *Gas Marketing Royalty Issues in the 1990s Part I*, 8 OIL & GAS L. & TAX'N REV. 243, 244 (1993).

118. *See* 62 Blue Print Form, *supra* note 7, ¶ #3(a) ("[O]n oil, and other liquid hydrocarbons saved at the well, one-eighth of that produced and saved . . . .").

119. *E.g.*, Shreveport-El Dorado Pipe Line Co. v. Bennett, 290 S.W. 929 (Ark. 1927).

arrange to take it in kind.[120] This will generally result in a sale of lessor's oil at the market price at the time the oil is run from the storage tanks into the purchaser's truck or pipeline.[121]

As a practical matter, the primary benefit of an in-kind oil royalty is the leverage a tort claim in conversion offers when the lessee, purchaser, or others fail to respect the lessor's ownership interest in produced oil. In many cases the benefits of the "tort" action will be outweighed by the benefits of a longer "contract" statute of limitation. Eliminating the in-kind oil royalty would eliminate the need for crude oil purchasers to obtain a division order from the lessor.[122] More importantly, the lessor, by retaining merely a right to be paid in cash for a share of oil production, may be able to more effectively defend against environmental liabilities associated with owning a share of the produced oil.[123] Therefore, the mineral owner should consider negotiating for a royalty clause that provides for payment of the market value of a share of the produced oil instead of an actual share of the oil.

2. *Gas—How Many "Business Activities" Does the Royalty Owner Get to Share In?*

A fundamental problem concerning the gas royalty clause is determining the lessee business activities in which the lessor is entitled to participate. Although the lessor may be entitled to a share of the "proceeds" or "market value" derived from the production of gas, courts have had a difficult time defining the limits of the business activities that constitute "production" and are therefore subject to the royalty obligation. Conceptually the lessee can be viewed as either

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120. Cook v. Tompkins, 713 S.W.2d 417, 420-21 (Tex. Civ. App. 1986) (implied contract theory); Wolfe v. Texas Co., 83 F.2d 425, 430-31 (10th Cir. 1936), *cert. denied*, 299 U.S. 553 (1936) (alternative theories of implied contract, agency, and ratification). *See* David E. Pierce, *Resolving Division Order Disputes: A Conceptual Approach*, 35 ROCKY MTN. MIN. L. INST. 16-1, 16-5 to 16-17 (1990) [hereafter Pierce, *Resolving Division Order Disputes*].

121. *See generally* RESTATEMENT (SECOND) OF AGENCY § 61(1) (1958) (agent has authority to sell at the "market price" when no price specified). Under a contract (non-agency) theory, the lessee would have the right to sell the oil at the current market price. Cook v. Tompkins, 713 S.W.2d 417, 420-21 (Tex. App. 1986); Wolfe v. Texas Co., 83 F.2d 425, 430 (10th Cir. 1936), *cert. denied*, 299 U.S. 553 (1936); Pierce, *Resolving Division Order Disputes*, *supra* note 120, at 16-1, 16-10 to 16-11, 16-14 to 16-15.

122. Pierce, *Resolving Division Order Disputes*, *supra* note 120, at 16-1, 16-50 to 16-52.

123. As I have noted in a previous writing:

> [T]he lessor should consider changing the typical right-to-take-in-kind oil provision to a contractual right to share in production proceeds. Although liability for ownership of the produced *product* has not yet been imposed in environmental cases, a right to a share of the actual production makes it conceptually easier to try and characterize the lessee as the lessor's contractor for development purposes. Since lessors seldom actually market their share of oil, it may be better to not have the right to take oil in kind. This is one area where the potential benefits of environmental structuring may outweigh the revenue-collection benefits associated with ownership of a fractional share of the oil.

Pierce, *Structuring Routine Oil and Gas Transactions*, *supra* note 6, at 174.

participating in several distinct business activities with respect to the same gas or a single business activity. To the extent a business activity enhances the value of the produced gas, the lessor will want to participate. Traditionally the issue has arisen in disputes concerning the lessee's deduction of costs associated with its various business activities and has been addressed in the context of the lessee's implied covenant to market.[124] The more basic inquiry is whether the lessor should be able to share in the product of the lessee's various business activities at all.

Today most gas production operations can be divided into four distinct business activities. The first business is the extraction of gas from the ground. The lessor is clearly entitled to participate in the benefits of this activity and disputes seldom arise if the extracted gas is sold to a third party at the wellhead. If the gas is not sold at the wellhead, it will proceed to a second business activity, which we can call "gathering." Gathering may include separation, dehydration, compression, and movement to a central point in the field. If the gas is sold at the wellhead, the lessor will not participate in the incremental benefits of this activity.[125] However, if the gas is sold at a central point in the field after the gathering function has taken place, the lessor will participate in the benefits associated with gathering. Most disputes in this area have focused on whether the lessee can deduct gathering-related costs prior to calculating the royalty due on gas proceeds or values derived from the gathering business activity.[126]

The third business activity is "marketing." As used in this discussion, "marketing" refers to the activity associated with enhancing the value of an already saleable product. It must be distinguished from the more traditional connotation given the term with regard to the implied covenant to "market." For example, a lessee's traditional marketing obligation to its lessor can be discharged by a sale of the gas at the wellhead or the terminus of the gathering system. However, the lessee may decide to invest additional entrepreneurial efforts to

124. Wood v. TXO Production Corp., 854 P.2d 880, 882 (Okla. 1992) (on-lease compression costs are not deductible; court discusses many of the cases).

125. Instead, the wellhead purchaser of the gas will derive whatever benefit is associated with the enhanced value of the gas at the terminus of the gathering system. The "value" associated with the gathering system could come from the ability to demand beneficial purchase terms from well owners connected to the system, the ability to control and aggregate a larger package of gas, and the profit associated with the enhanced value of the gas when it is brought to a more centralized marketing point in the field.

126. The expense that has received the most attention by the courts is compression. *Compare* Wood v. TXO Production Corp., 854 P.2d 880 (Okla. 1992); Hanna Oil and Gas Co. v. Taylor, 759 S.W.2d 563 (Ark. 1988); Schupbach v. Continental Oil Company, 394 P.2d 1 (Kan. 1964), and Gilmore v. Superior Oil Company, 388 P.2d 602 (Kan. 1964); *with*, Merritt v. Southwestern Electric Power Co., 499 So. 2d 210 (La. Ct. App. 1986); and Martin v. Glass, 571 F. Supp. 1406 (N.D. Tex. 1983). *See also* Ashland Oil & Refining Company v. Staats, Inc., 271 F. Supp. 571, 575 (D. Kan. 1967).

attempt to earn a profit on its gas beyond the profit that could be earned at the wellhead. This "marketing" activity may include aggregating several supplies of gas,[127] seeking buyers for the gas, and transporting, storing, and delivering the gas.[128] The marketing activity may also consist of entering into contracts with third parties to provide these marketing services.

The fourth business activity is "processing." During processing valuable liquids and liquefiables are removed from the gas stream. Typically processing will take place at a point removed from the wellhead because gas supplies must be aggregated to amass the volumes necessary to make the activity profitable. As with the gathering and marketing business activities, processing typically enhances the value of the gas.[129] As with the other activities, a substantial amount of entrepreneurial capital is devoted to the activity; the increased value of the gas is comprised of the lessee's capital investment plus the enhanced value of the gas resulting from the investment—the profit.

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127. Some gas supplies may be leased to the lessee; the lessee might also purchase gas from third parties or obtain control over other supplies by operating gathering systems or processing plants.

128. As I have observed in another recent commentary:

> The US gas marketing system has changed considerably during the past five years. Under the old gas marketing regime, lessees sold their gas production at or near the field where it was produced. Under the new marketing regime, lessees often sell their gas at points far removed from the field of production after considerable value has been added by treating, compressing, gathering, packaging, and transporting the gas. . . .
>
> Prior to 1985, lessees were generally required to market their gas at or near the field of production since they could not access the pipeline grid to move their gas to distant markets. Since 1985, the function of the pipeline system has gradually shifted from purchasing and reselling gas to the transportation of gas for third parties, including gas producers. Now it is possible for a lessee, in an effort to maximize the return for itself and its lessor, to compress, gather, transport, and deliver gas to customers anywhere on the pipeline grid. However, this means the lessee will often be adding considerable value to the gas as it is moved from the wellhead to the ultimate consumer.

David E. Pierce, *The New US Gas Marketing Regime and its Impact on Royalty Calculations*, 12 OIL & GAS L. & TAX'N REV. 26 (1994).

129. Processing potentially enhances the value of the gas in two ways. First, gas containing excessively high levels of natural gas liquids cannot be efficiently shipped on pipelines. Therefore, some gas requires processing before it can be transported or marketed to the end user. Second, the value of the unprocessed gas stream is generally less than the value of the extracted gas liquids and the resulting residue gas. Gas liquids, such as ethane, butane, propane, and natural gasoline can be tanked and transported by truck to myriad markets and sold at favorable prices when compared to the value of the unprocessed gas. However, the profitability of processing is impacted by two factors: (1) The cost of the feedstock—natural gas, and (2) the price of oil which tends to define the price the processed liquids will bring. As the price of gas increases, the processing profit margin decreases. As the price of oil decreases, the processing profit margin decreases. As one commentator has observed:

> [W]ith the drop in crude prices, liquid product prices, until recently, dropped closer to the cost of natural gas. Given most predictions that natural gas prices are expected to increase relative to oil prices, it can be expected that the processing of gas for liquids will only become less profitable. There will be periods when such processing will be very profitable because of price spikes due to crude oil price increases.

Arthur J. Wright, *Gas Plants and Gathering Systems*, *in* PRACTICAL NATURAL GAS MARKETING SHORT COURSE 8-33 (Rocky Mtn. Min. L. Found. 1993).

Naturally, lessors want to share in any business activity that makes their royalty interest more valuable—particularly if the activity is risk-free to the lessor. Lessees often allow the lessor to share in all four business activities: extraction, gathering, marketing, and processing.[130] By the very nature of the royalty clause the lessor shares in the *gross* receipts or value generated by the extraction activity. With some notable exceptions,[131] lessors have generally been permitted to share in only the *net* receipts or values generated by the gathering, marketing, and processing business activities. However, the courts have not clearly defined the basis for determining whether the lessor should participate in any business activity other than extraction. In most instances, the lessee simply permits the lessor to share in the benefits of other business activities—perhaps unconsciously or because of administrative convenience. However, this may change as lessees begin to assume many of the gathering, marketing, and processing business activities formerly provided by the pipelines that purchased the gas—particularly if lessees are unable to recoup a proportionate share of such costs from their lessor.

When identifying the lessee business activities the lessor is entitled to participate, courts may be influenced by lease language addressing related matters. For example, assume the lessor has a lease provision prohibiting the deduction of:

> "[E]xpenses of production, gathering, dehydration, compression, transportation, manufacturing, processing, treating, or marketing of gas, oil, or any liquefiable hydrocarbon extracted therefrom."[132]

Could such language in the lease be an indication that if the lessee engages in these additional activities the lessor is entitled to participate? Lessees bound by such a clause may deny the lessor a "free ride" in the lessee's other business activities by structuring the sale of production at the wellhead. However, could such language be an indication that the lessee *must* engage in these additional activities to the extent it would maximize the value of each party's interest?[133]

Other language in the lease may answer some of these questions. For example, if the lease provides for a royalty calculated on the value or proceeds of production at the wellhead, the lessee would have no duty to engage in any post-extraction activities. The only business the

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130. *See, e.g.,* Matzen v. Hugoton Production Co., 321 P.2d 576 (Kan. 1958) (lessee was paying royalty on the sale of gas after its value had been enhanced at a processing plant).

131. *E.g.*, West v. Alpar Resources, Inc., 298 N.W.2d 484 (N.D. 1980).

132. This language comes from a royalty clause modification recommended for lessors. Hinton, *Negotiating Oil and Gas Leases for the Lessor*, *supra* note 3, at 58.

133. Once the lessor establishes a right to share in post-extraction business activities, the issue would arguably become whether a prudent operator in the lessee's position would pursue the other business activities to enhance the value of production from the lease.

lessor will participate in is the extraction business.[134] If the lease provides for a royalty calculated on the value or proceeds of production without tieing the valuation to the wellhead, pipeline, or other objective point in the process, other language in the lease may take on greater importance. For example, a royalty clause requiring the payment of gross proceeds or gross value without designating a valuation point, coupled with a clause restricting the deduction of costs associated with the business activities of gathering, marketing, and processing, would provide the lessor with a strong argument for sharing in each of the lessee's business activities—expense free. Such language may also expand the scope of the lessee's "implied" marketing obligations to the lessor. The lessee may be required to at least evaluate these other business activities.[135]

Under today's radically changed marketing regime,[136] lessees, for royalty purposes, will elect to take one of two approaches to marketing their gas:

> 1. Permit the lessor to share in all phases of their business activities, regardless of whether the lessor receives a fraction of the gross or net receipts generated by the activity; or 2. Treat the gas as having been sold, and the royalty obligation determined, at or near the wellhead. This may be accomplished by a sale to a third party, an affiliate, or the lessee.[137]

The lessee's ability to pursue one course of action over the other will depend upon the express terms of the royalty clause. However, considering the new complexity of the gas marketing regime the lessee will generally favor executing a sale or valuation, for royalty purposes, at or near the wellhead[138]—unless a radically different approach to the calculation of royalty is taken.[139]

If the lease provides for a royalty based upon the market value of the gas as produced at the wellhead, the identity of the "buyer," and indeed the lack of an actual sale, should not matter. To the extent the parties can identify a current value for the gas when produced, the commodity value should define the royalty obligation without regard

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134. However, the subsequent business activities may become relevant if it is necessary to calculate wellhead values or proceeds employing a work-back method.

135. In most instances, if the other business activities would enhance the value of the lessee's share of production, the lessee will either undertake the investment to engage in the activity or structure its marketing transactions to obtain the services from third parties who have made the investment. If the lessee attempts to structure the transaction to foreclose the lessor from these benefits, while the lessee enjoys them directly or through affiliated entities, the lessor may be able to rely upon the express royalty terms and the implied marketing covenant to police such conduct.

136. *See supra* note 128.

137. Conceptually, since the lessee already owns all the gas under the typical form of gas royalty clause, the lessee cannot "sell" it to itself. Instead, the lessee is agreeing to, in effect, pay royalty based upon the current market value for the gas at the time it is produced.

138. This will make it more difficult for a court to construe "at the wellhead" to mean anywhere "on the lease." *See, e.g.,* Gilmore v. Superior Oil Co., 388 P.2d 602, 606 (Kan. 1964).

139. *See infra* text accompanying notes 152-164.

to what the lessee actually does with the gas. However, what the lessee does with the gas may impact the lessor's implied marketing covenant rights. For example, if the lessee commits gas from a well to a gas contract providing for a relatively high price for gas but unduly limiting the purchaser's obligation to take gas, the market value royalty owner may have a basis for complaint. Essentially the lessee has committed the lessor's property to provide a purchaser with back-up gas supplies. The higher price would be indicative of a rolled-in reservation fee in exchange for the lessee making the gas supply available to the purchaser. However, this arrangement negatively impacts the lessor because it artificially limits the amount of gas that will be run from the property on which a market value royalty could be paid. The lessee is obtaining a benefit (the reservation fee reflected by the higher gas price) to the detriment of the lessor (commitment of the reserves without an obligation to take). The lessee may be able to remedy the situation by providing in its gas contract for the right to market all gas not actually taken by the purchaser.

Another way to deal with the problem would be to pay the lessor its royalty based upon the higher contract proceeds instead of the lower current market value. This raises the issue of whether a lessee would prefer drafting a "proceeds" or a "market value" basis for calculating the royalty obligation. Commentators differ over the benefits of a market value royalty approach. For example, after examining the checkered past of the clause one commentator concluded:

> Significant business risks are incurred with market value leases. To this author, there is very little to be gained by market value royalty provisions for either the lessor or the lessee. While market value clauses provide an opportunity to take advantage of falling or rising prices vis a vis long-term contract prices, that advantage is far outweighed by the potential liability for additional royalties caused by market value lease terms. Both parties are subject to great uncertainty regarding whether sales proceeds received are adequate and great burdens to demonstrate what "market value" really means for a given lease. Although these royalty clauses have been used for decades, perhaps it is time to convince industry management and mineral owners that their best interests are served by lease royalty clauses that do not rely upon market value. Decades of market value jurisprudence illustrate its inadequacies.[140]

I have arrived at a different conclusion:

> Probably the most desirable form of royalty clause for the lessee today is a market value royalty clause which requires payment of royalty based upon current market values. If interpreted by courts in light of present marketing realities, a current market value

140. Mary Viviano Laitos, *Current Lease Royalties Under Market Value Royalty Clauses—What is Market Value?*, THE LANDMAN 9, 18 (Sept./Oct. 1992). *See also* John S. Lowe, *Negotiating Oil and Gas Leases for the Lessee*, 1 NATURAL RESOURCES & ENV'T 6, 58 (1985).

> royalty calculation provides the lessee with maximum flexibility to market the gas to or through affiliates, through marketing pools, or any other arrangement. It is also imminently fair to the royalty owner, who will receive, with the emerging spot-pricing network, the market value the lease requires regardless of what the lessee does with the gas.[141]

From the lessee's perspective, the market value clause allows for discharge of the royalty obligation using what is becoming a very objective standard: spot gas prices that can be adjusted as necessary to account for the location of the gas in relation to the reference point for the reported price. When the lease ties the market value calculation to a specified location, such as the wellhead, gathering line terminus, delivery point on an intrastate or interstate pipeline, tailgate of a processing plant, or a central marketing point used by spot price reporting services, the market value of the gas commodity should be readily calculable. The primary benefit of the market value measure is it permits the lessee total freedom to do whatever it wants with the gas without regard for how its gas transactions[142] impact the lessor's royalty. It can pool the gas with other gas supplies and make sales to several buyers without concern for matching supplies with specific contracts or how the weighted average price for gas sold from a pool correlates to individual royalty obligations.[143]

The lessor should be satisfied with such an approach since it gives the lessor what it has probably always wanted: a share of the market value of gas as it is produced without regard for the lessee's contractual relationships with affiliates or third parties. If the lessor wants to participate in some of the lessee's post-extraction businesses, the location of the valuing point can be adjusted downstream from the wellhead.[144]

The one area where the lessee's actions can adversely impact market value royalty is when it enters into agreements that restrict the rate of production from the lease. To the extent the well is not producing at its full allowable—and therefore not achieving the full current market value royalty potential—the lessor may be able to challenge the lessee's actions. However, the lessee's conduct will be tested under a prudent operator standard which considers not only the interests of the lessor, but also the interests of the lessee.[145]

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141. David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 EASTERN MIN. L. INST. 18-1, 18-51 (1992).

142. The lessee's post-extraction businesses.

143. *See generally* Pierce, *Royalty Calculation in a Restructured Gas Market*, *supra* note 141, at 18-1, 18-51 to 18-53.

144. If the lessee is unwilling to calculate royalty on processed gas values, the lessor may be able to negotiate for a larger fractional share of royalty valued at the wellhead. For example, the lessor might negotiate for a 1/4th royalty "at the wellhead" in lieu of a 1/8th royalty on gas values determined somewhere beyond the wellhead.

145. For example, in Brewster v. Lanyon Zinc Co. Judge Van Devanter noted:

If the lessee plans to commit the gas to a long-term contract, the lessee should do what lessees should have done back in the 50s, 60s, 70s, and 80s: discuss the matter with the lessor and obtain the lessor's consent to accept the proceeds under the long-term contract and memorialize the lessor's consent in an amendment to the oil and gas lease. As I have noted in previous writings:

> Perhaps the greatest problem for lessees under the royalty clause, and the oil and gas lease in general, is determining when it is necessary, or advisable, to include the lessor in the lease operation decision-making process. For example, most market value royalty problems could be avoided if the lessor, at the time a gas contract was being entered into, joined in the gas sales contract. If the lessor is consulted when the gas purchase contract is offered,[146] they may commit to the contract and be willing to sign the necessary lease amendment so royalties can be calculated according to the contract proceeds.[147]

If the lessor is unwilling to cooperate, the lessee should negotiate with the gas purchaser for an excess royalty clause or a release provision that would permit the lessee to sell sufficient gas outside of the long-term contract to meet its market value royalty obligations.

The lessor's approach to the royalty clause should reflect the inherently passive nature of the lessor's participation. Not unlike the owners of nonexecutive mineral interests, nonparticipating royalty interests, and overriding royalty interests, the lessor is, to a large extent, at the mercy of the lessee when it comes to the machinations of the marketplace. Since courts have uniformly held the typical oil and gas relationship does not give rise to fiduciary obligations,[148] the lessor must rely upon the express terms of the oil and gas lease to protect its interests.[149] Therefore, the lessor will seek to prepare a royalty clause that defines the royalty obligation with reference to objective standards that cannot be readily manipulated by the lessee. As with any arm's-length non-fiduciary transaction, the passive party must draft as though the other party will do nothing right, will deny any wrong-

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> It is only to the end that the oil and gas shall be extracted with benefit or profit to both that reasonable diligence is required. Whether or not in any particular instance such diligence is exercised depends upon a variety of circumstances . . . . Whatever, in the circumstances, would be reasonably expected of operators or ordinary prudence, having regard to the interests of both lessor and lessee, is what is required.

Brewster v. Lanyon Zinc Co., 140 F. 801, 814 (8th Cir. 1905).

146. Presumably if the terms being offered were good enough to warrant the lessee's acquiescence, it should be good enough to entice the lessor to enter the agreement. In any event the lessor will lack the benefit of knowing what the future holds for the price of gas when it evaluates the contract terms at the front-end of the deal.

147. 1 PIERCE, KANSAS HANDBOOK, *supra* note 24, § 11.21, at 11-27. *See also* Pierce, *Rethinking the Oil and Gas Lease*, *supra* note 2, at 462-63.

148. *E.g.*, Waechter v. Amoco Production Co., 537 P.2d 228, 248 (Kan. 1975), *adhered to*, 546 P.2d 1320 (Kan. 1976).

149. Although lessors also obtain substantial benefits from "implied" covenants, such covenants emanate from the express terms of the lease. Implied covenants are also bound-up by factual issues which typically require protracted litigation to define and resolve.

doing, will take advantage of its superior position at every turn, and when finally caught in the act will, of course, be judgment-proof.[150]

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150. Keeping these goals in mind, consider the following royalty clause:

SECTION 8. ROYALTY. LESSEE will pay to LESSOR a Royalty as follows:

A. LESSOR's Share of Production Proceeds.

An amount of money equal to 3/16ths of the Current Market Value of all Leased Substances and Component Substances produced from the Leased Land, or a Pooled Unit in which all or a part of the Leased Land is included. If LESSEE, or any affiliate or contractor of LESSEE, Processes a Leased Substance, LESSEE will pay to LESSOR an amount of money equal to 3/16ths of the Current Market Value of the Products obtained from processing or 3/16ths of the Current Market Value of the Leased Substance, whichever results in the largest current payment of Royalty to the LESSOR.

B. Costs.

LESSOR's Royalty will not be subject to any expense, charge, or deduction relating to developing, producing, operating, treating, dehydrating, gathering, compressing, or marketing Leased Substances. LESSEE will be solely responsible for costs associated with putting Leased Substances into a marketable condition and moving them to a Centralized Marketing Point. However, reasonable costs associated with marketing production beyond a Centralized Marketing Point can be deducted by LESSEE in calculating Royalty. If LESSEE Processes a Leased Substance, and LESSOR is paid Royalty on the Products obtained from processing, LESSEE is entitled to deduct its reasonable actual costs of processing to calculate Royalty, but in no event will LESSEE be permitted to deduct processing costs that exceed 20% of the value of the Products obtained from processing.

C. Taxes.

Properly assessed taxes, levied against LESSOR's Royalty, can be deducted from LESSOR's Royalty to reimburse LESSEE or any third party that has properly paid such taxes.

D. Payment.

Payment of Royalty will be made within 90 days following initial production from a well completed on the Leased Land (or a Pooled Unit in which all or part of the Leased Land is included). Royalty on subsequent production from the well will be made no later than 60 days following the end of the calendar month in which Leased Substances are produced from the well. Any amount not paid when due under this Subsection will bear interest at an annual percentage rate of 18%, compounded monthly. With each Royalty payment LESSEE will provide LESSOR with the necessary information that will enable LESSOR to ensure that their Royalty has been properly calculated.

Whenever LESSEE receives payment from a third party for production subject to Royalty under this Lease, LESSEE will place all amounts due LESSOR in a separate trust account until it is distributed to LESSOR. With regard to Royalty due LESSOR, LESSEE will be held to the standard of a trustee in all matters concerning its receipt, protection, payment, and accounting. LESSOR is given the right, at all reasonable times, personally or through representatives, to inspect and copy the books, accounts, contracts, records, and data of LESSEE pertaining to any matter within the scope of this Lease.

E. Division Order.

Since title to all Leased Substances Produced under this Lease will be in LESSEE, LESSOR will not be required to execute any sort of division order or similar document for Royalty payments made by LESSEE. If Royalty payments are to be made directly to LESSOR by a third party purchaser, LESSOR may elect to negotiate a division order with the third party purchaser or require that all payments be made to LESSEE, whereupon LESSEE will make all distributions to LESSOR pursuant to the terms of this Lease.

F. Definitions.

As used in this Lease the terms listed below will have the following meaning:

1. Royalty. The compensation payable to LESSOR pursuant to the terms of this Lease.

2. Current Market Value. The market value of production, at a Centralized Marketing Point, at the time it is removed from the Leased Land (or a Pooled Unit in which all or part of the Leased Land is included) or the Gross Proceeds received by the LESSEE in a sale of production, whichever results in the largest current payment of Royalty to the LESSOR.

So far I have suggested refinements to the terms of the traditional royalty clause that lessors and lessees might negotiate over. The focus is on attempting to more clearly define the business activities in which the lessor can participate, the basis for deducting costs associated with such activities, and a valuation formula that maximizes the lessor's income whether using a proceeds or market value measure.[151] However, such an approach tends to merely respond to the inherent problems of the clause instead of attempting to solve the problems.

C. *A Possible "Solution" to the Royalty "Problem"*

The function of royalty is to compensate the lessor for permitting the lessee to develop the lessor's mineral interest. The goal has been to compensate the lessor with a share of the income generated by the sale of extracted minerals. Traditionally, compensation has been a share of the proceeds generated by an actual sale of the extracted minerals—or a share of their market value. The traditional approach to lessor compensation hasn't worked well. Whether a proceeds or market value measure of royalty is used, determining the royalty due has been the source of unceasing dispute and litigation. As noted in previous sections of this article, disputes have arisen over identifying the "proceeds" that will trigger a royalty obligation, the proper stage of the business activities at which value or proceeds will be determined, costs that can be deducted prior to calculating the royalty, and the lessee's implied marketing obligations. Fundamental changes in

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3. *Gross Proceeds.* The total consideration received by LESSEE from a sale of production to a third party purchaser.

4. *Centralized Marketing Point.* A centralized point at or near the field of production where Leased Substances can be readily sold and/or transported to third parties. For gas, a centralized marketing point is the point on an intrastate pipeline or interstate pipeline where the gas has left the field gathering system and entered the pipeline transportation system. For oil, a centralized marketing point is the point where oil is delivered to a purchaser's pipeline or other centralized crude collection point operated by the purchaser or a third party.

5. *Products.* All marketable substances obtained from the processing or treatment of a Leased Substance, to include, without limitation, hydrocarbon liquids and residue gas.

6. *Processes.* A Leased Substance is separated into various products or otherwise treated or altered to enhance its value or marketability.

151. Under the restructured gas marketing regime, I have previously offered the following suggestions for lessors to consider:

> With regard to new leases, what should the royalty clause look like? From an analysis of the *Tara* and *Vela* line of cases, it would be beneficial for the lessor to have the royalty calculated on the basis of "current market value of the gas or the gross proceeds received by the lessee, *whichever results in the largest current payment of royalty to the lessor.*" The lease should define the costs that can be deducted prior to calculating the royalty due. The lease should also specify the lessee's marketing obligations. For example, will the lessee be obligated to market the gas for the best price possible, making full use of all marketing outlets available to it?

Pierce, *Calculating Royalty in a Restructured Gas Market*, *supra* note 141, at 18-1, 18-50.

the gas marketing system have compounded the traditional royalty problems.[152]

1. *The Basic Goal*

Any attempt to "solve" the royalty clause problem will require an alternative approach that compensates the lessor while avoiding the demonstrated inadequacies of the existing system. From the lessor's perspective, the primary goal should be to select an objective basis for calculating royalty that the lessor can effectively police on a monthly basis. Ideally, the lessor would like to be able to obtain a report of the previous month's total production volume, apply a "royalty price" to it, multiply it by its fractional share, and arrive at a number that should equal the amount of the lessee's check. The ability to objectively calculate the royalty due would aid the lessor and the lessee by eliminating disputes and hard feelings over unexplained deductions, adjustments, and valuation formulas that may require interpretation of complex gas contracts with third parties.

The only additional policing the lessor would need to do would be to ensure the lessee was producing the well at its maximum capacity. The lessor would obtain information from the state concerning the well's ability to produce and its assigned allowable. If the well isn't being operated at or near its allowable, the lessor will be entitled to an explanation. This would address the implied marketing covenant part of the royalty equation and could also be expanded to address gas balancing problems.[153] The lessee's marketing duties could be made more definite if the lease expressly required the lessee to endeavor to maintain production from any well on the lease equal to its maximum efficient rate or, if the well is subject to a government-imposed allowable, the maximum allowable rate of production. If the lessee wants to engage in a seasonal marketing program, the lessee should consult the lessor and obtain the lessor's consent or provide expressly for such a program in the royalty clause.

If more than one lessee has an interest in the well, gas balancing problems will occur. Even though the lessees may have elaborate gas balancing provisions in their operating agreement or a separate gas balancing agreement, these contracts will not determine the rights as between the impacted lessees and their respective lessors.[154] Perhaps the fairest approach would be to permit the lessor to be paid its roy-

152. Pierce, *Calculating Royalty in a Restructured Gas Market*, *supra* note 141, at 18-1, 18-3 to 18-9.

153. *See generally* David E. Pierce, *The Law of Disproportionate Gas Sales*, 26 TULSA L.J. 135, 168-172 (1990).

154. This assumes the lessors have not agreed to be bound by the terms of the balancing mechanism worked out by their lessees in operating or gas balancing agreements.

alty on volumes actually produced from the well, when produced—regardless of which working interest owner is marketing gas from the well.[155] Once the lessee begins to market gas from the well, it would be permitted to defer payment of royalty on all, or an agreed percentage, of the gas produced until the lessor's royalty account, on an MMBtu basis, is balanced.[156]

2. *Index-Based Royalty*

The interests of the lessor and lessee coincide when it comes to clarity in the royalty clause. The lease should reflect who "won" and who "lost" the negotiation of such issues as *how* royalty will be valued and *where* in the marketing process the valuation will be made. However, instead of specifying marketing obligations and getting into deduction issues, it may be preferable for the parties to agree that the royalty will be based on a readily ascertainable index which values gas at a specified location on an interstate pipeline. Simply applying a negotiated factor to this index base would eliminate the need for workback calculations to adjust a stated spot price to the corresponding value of gas at the wellhead or gathering line terminus. Think about how nice it would be if the lessor (and lessee) could pick up a copy of *Inside FERC's Gas Market Report*, *Natural Gas Intelligence Gas Price Index*, *Gas Daily*, or the local newspaper, multiply the selected index price by the royalty fraction and the produced volumes, and arrive at the royalty due—no valuations, no workbacks, no deduction of costs required.

Negotiations under such an index royalty approach would focus on the proper fraction, price index, and a backup valuation technique in the event the index becomes unavailable. For example, assume the lessor wants a "3/16ths royalty." The lessee may be willing to pay the lessor 3/16ths of the market value of gas *at the wellhead*. However, if the lessor wants 3/16ths of the spot price at a major marketing point on Williams Natural Gas Company's pipeline,[157] the lessee may refuse

155. The volumes would be proportionately reduced to reflect only the lessee's working interest share in the well.

156. The lessor may want to spread the lessee's make-up period over an extended period of time to ensure the lessee does not engage in opportunistic seasonal marketing detrimental to the lessor. For example, if the lessee had a right to balance on a current MMBtu-for-MMBtu basis, it could refrain from taking gas during the Summer months when spot prices are generally low, putting the lessor in an "overproduced" status as to royalty, thereby allowing the lessee to retire the imbalance by taking its "makeup" MMBtus during the Winter months when prices are high. The lessor can counter this activity by providing that a relatively small percentage of future lessee takes can be designated as makeup gas. For example, the lease could provide that only 25% of production will be credited to retire the lessee's imbalance. In this manner, if the lessee decides to engage in seasonal marketing, the lessor will be able to share in 75% of the current gas values. It also extends the duration of the makeup period thereby giving the lessor the time value of the gas to be made up plus some current income from the non-makeup gas.

157. As quoted for the month by a selected price reporting service.

to give a 3/16ths royalty since the quoted spot price may reflect rolled-in value associated with gathering, compressing, treating, and transportation. The lessee will argue this requires the fractional share to be adjusted downward or a different index selected[158] that more accurately reflects value at the wellhead. However, the lessor may counter by suggesting the index needs to be revised upward to account for the value of the liquid hydrocarbons, helium, and sulphur that the lessee is able to extract from the raw gas stream.

The end result is that the parties will ultimately agree on a fraction, say 5/32nds, and an index, say the monthly index price for spot gas delivered to Williams Natural Gas Co. (Texas, Oklahoma, Kansas) as reported in *Inside F.E.R.C.'s Gas Market Report.* If the lessee produced 20,000 MMBtus in December 1993 from the lease, the royalty due the lessor would be $7,031.25.[159] If the same amount of gas is produced in January 1994, using the same index, the royalty due the lessor would be $6,062.50.[160] The differing royalty reflects the differing value of gas purchased during the December and January bid periods. In addition to selecting an index, the royalty clause should also make it clear that the selected index price will not be adjusted to account for any costs, including production taxes. The lessee should agree to pay and discharge all severance and other production taxes associated with the production of gas from the leased land. Since the valuation for severance tax purposes will, in most cases, be different from the index used for payment of royalty, it would be better for the parties to deal with the tax burden through adjustments to the index price, if necessary, instead of using an index price less severance taxes.[161] For example, the parties might agree on a royalty based upon 98% of the reported index price to account, in part, for the lessee's agreement to pay all taxes associated with production.

The major weakness of using a pricing index in an oil and gas lease is that the lease may outlive the selected index. The selected index may no longer reflect market values, or the index may cease to exist as marketing patterns and techniques change, and as companies providing such services go out of business. However, it would seem

158. The parties could also use the stated index price minus an amount of money to account for the location value of the gas at the chosen pricing point. The same result could be achieved by specifying payment of a percentage of the selected index price. The percentage basis more easily accounts for system wide inflation.

159. $2.25 x (5/32 x 20,000) = $7031.25.

160. The January 1994 index price for gas delivered to Williams Natural Gas Co. (Texas, Oklahoma, Kansas) was $1.94 compared to the December 1993 index price of $2.25. *See Prices of Spot Gas Delivered to Pipelines, Dec. 1*, INSIDE F.E.R.C.'S GAS MARKET REPORT, Dec. 3, 1993; *Prices of Spot Gas Delivered to Pipelines, January 1*, INSIDE F.E.R.C.'S GAS MARKET REPORT, Jan. 4, 1994.

161. Once numbers based upon wellhead valuations of production are introduced into the equation, much of the objectivity is lost and the lessor must evaluate another set of transactions to determine whether the severance tax deduction is proper.

that a carefully selected market-based index has as much of a chance of keeping pace with increases in demand, operating costs, and other factors impacting the parties as would the lessee's contracts with third parties or the more traditional market value calculations. If the index fails, alternate indexes can be specified and in any event a current market value at the wellhead or some other point can be included as a backup.[162] Index failures might also be addressed through arbitration to select a comparable replacement index.

In selecting an index, lessors and lessees can gather historical information on prices reported by various pricing indices. Prices generated under the various indices can be compared with actual royalty payments that have been made in the past in similar transactions to determine how royalty values under various indices compare. This should assist the parties in identifying the optimal indices and the adjustments that might be required to achieve the desired royalty compensation. The ultimate goal of each party should be to select an index that reflects the current value placed on the gas commodity in a relevant market area.

The index approach also offers an opportunity to improve the royalty calculation process under existing leases. Lessors and lessees may want to renegotiate the royalty clause in existing leases to arrive at a more objective standard for calculating royalty. As this article demonstrates, the vast majority of leases create a number of unresolved issues concerning the proper calculation of royalty. Since royalty litigation is often a "winner-take-all" proposition, lessors and lessees alike may prefer to focus their efforts on improving the royalty calculation process prospectively. For example, a lessee holding several leases in an area may want to experiment with offering to amend existing royalty clauses to provide for an index-based royalty. If the parties are not comfortable with a permanent change, they could agree to operate under the new system for a designated period of time, such as three to five years. At the end of the period the parties could evaluate how the selected index worked, whether the lessee was able to avoid any administrative costs, and whether the underlying lessor/lessee relationship was improved.[163]

The index pricing concept may also prove to be a superior approach to calculating oil royalties. As noted in a previous section, the typical lessor, in my opinion, gains very little by having an in-kind

162. Although the backup valuation may be at a different fractional share to reflect the location adjustment.

163. The lessor should also achieve administrative costs savings in being able to readily confirm it has received what it is entitled to under the lease agreement—without the aid of accountants, frequent calls to the lessee or gas purchaser, or an attorney.

royalty on oil.[164] Instead of arguing over transportation charges, wrangling with crude oil purchasers over division orders, and wondering if any "premiums" are being paid to the operator of the well to commit or continue selling their crude to a particular purchaser, why not require the lessee to pay the lessor a stated fraction of an index price used for trading crude oil?

V. Conclusion: Better Luck Next Century

It is doubtful the basic relationship of lessor and lessee will be replaced as we enter the second century of oil and gas jurisprudence. Although environmental concerns may dictate that developers purchase the minerals and surface in fee in certain situations, the oil and gas lease is probably here to stay. Therefore, it is essential that we continuously improve existing lease clauses to incorporate the teachings of the past. More importantly, lease disputes should be carefully evaluated to determine if we are effectively addressing the underlying cause of problems associated with the relationship.

164. *See supra* text accompanying notes 118-123.