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The Billion-Dollar Federal Oil & Gas Royalty Dispute: Government Mooching or Industry Theft?

by

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I. INTRODUCTION

The oil and gas lease creates one of the more contentious contractual relationships. The relationship itself consists of conflicting goals driven by the lessor's passive noncost-bearing interest versus the lessee's active cost-bearing interest.[1] Perhaps the area of oil and gas law most prone to conflict is the calculation of royalty. This should not be surprising since the maximization of royalty is the lessor's primary concern once their lessee discovers oil or gas. Royalty maximization usually involves the lessor asserting their lessee is "cheating" them out of their royalty; the lessee's reply is that the lessor is merely "mooching" to get more than their entitlement under the terms of the oil and gas lease. Courts are being asked to determine whether cheating or mooching is taking place.[2]

The federal government, as lessor, seeks to maximize its oil and gas royalties from federal lands through the Minerals Management Service ("MMS"). The MMS is the agency within the Department of Interior that administers the calculation, payment, and distribution of royalties

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[1]I have analyzed the inherent conflicts between lessors and lessees in prior writings. *See* David E. Pierce, *Rethinking the Oil and Gas Lease*, 22 Tulsa L. J. 445, 459-60 (1987); David E. Pierce, *Coordinated Reservoir Development–An Alternative to the Rule of Capture for the Ownership and Development of Oil and Gas: Part I*, 4 J. Energy L. & Pol'y 1, 33-49 (1983).

[2]Recently, in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117 (D. D.C. 2000), the court struck down various royalty valuation regulations designed to facilitate government mooching against its oil and gas lessees. The court concluded: "Quite simply, upholding the Rule by endorsing the MMS' interpretation of the leases and regulations would place no logical limits on MMS' authority to rewrite the leases to the detriment of the lessees and the direct pecuniary benefit of the government." 91 F. Supp.2d at 130.

generated from federal and Indian lands.[3] In recent rulemaking efforts the MMS has revealed its basic agency mission to maximize royalty payments–arguably without regard for statutory or contractual limitations on the calculation of royalty.[4] Lessees would characterize this as regulatory-facilitated mooching.[5] The MMS would characterize it as clarification and refinement of the regulatory system to ensure the government receives the royalty to which it is entitled.[6] Some members of Congress view the MMS' actions as something long past-due to prevent outright theft by industry lessees.[7] Similar debates are taking place with regard to private royalties in courthouses throughout the country.[8] This article explores the cheater/moocher problem in the context of recent royalty calculation regulations adopted by the MMS to value oil produced from federal lands.[9] Although discerning the MMS' desire to mooch or prevent cheating requires case-by-case analysis, the underlying cause of these disputes does not, and can be explained by what I will call: the royalty value theorem.

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[3]30 C.F.R. § 201.100 (2000).

[4]The court in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117 (D. D.C. 2000), addressed these issues in the context of MMS regulations governing the valuation of natural gas for the calculation of royalties due federal and Indian lessors. "Amendments to Transportation Allowance Regulations for Federal and Indian Leases to Specify Allowable Costs and Related Amendments for Gas Valuation Regulations; Final Rule," 62 Fed. Reg. 65753 (December 16, 1997) [hereinafter "Final Gas Rule"].

[5]Although I am not aware of any lessee using the term "mooching" to describe the MMS' actions, the term encompasses any MMS efforts to obtain more royalty for the government through lease interpretations that go beyond what is required by statute, the lease, and valid existing regulations. In this context "mooch" means "to get or take . . . at another's expense . . . ." Webster's New Universal Unabridged Dictionary 1247 (1996).

[6]For example, in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117, 121 (D. D.C. 2000), the court characterized the MMS' actions as follows: "Thus, the NOPR [notice of proposed rulemaking] was billed as a 'clarification' which would 'provide specific guidance to lessees and royalty payors' as to which transportation cost components were deductible for purposes of royalty valuation in the wake of FERC Order 636."

[7]*See infra* text accompanying note 12.

[8]*E.g.*, Yzaguirre v. KCS Resources Inc., 2000 WL 822424, Case No. 05-97-02020-CV (Tex. Ct. App.–Dallas, June 27, 2000) (not designated for publication), *petition for review denied*, 44 Tex. Sup. Ct. J. 42, 2000 WL 1591059, Case No. 00-0829 (Tex. Oct. 26, 2000) (Justices Owen and Hecht dissenting), *rehearing granted, Oct. 26, 2000 order denying review withdrawn, review granted* (Jan. 11, 2001).

[9]"Establishing Oil Value for Royalty Due on Federal Leases; Final Rule," 65 Fed. Reg. 14022-14096 (March 15, 2000) [hereinafter "Final Oil Rule"].

II. THE ROYALTY VALUE THEOREM

Most disputes between royalty owners and their oil and gas lessees are predictable phenomena that can be explained by the "royalty value theorem:"

> ***When compensation under a contract is based upon a set percentage of the value of something, there will be a tendency by each party to either minimize or maximize the value.***

The oil and gas lease is a classic example. From the lessor's perspective, anytime they can obtain 1/8th of X+ instead of 1/8th of X, they will seek a share of X+. However, the lessee will resist because any amount in excess of X will reduce the lessee's net revenue interest under the lease. Basic contract law prohibits the lessor from demanding a 1/4th royalty when their lease provides for a 1/8th royalty. The specified fraction of royalty offers very little language that can be "interpreted" and therefore manipulated by parties to the agreement. However, the value component of the royalty equation has proven very susceptible to interpretation, and manipulation. When dealing with private lessors, the opportunity for interpretation/manipulation is generally confined to the language of the oil and gas lease and any documents that modify the lease, such as pooling agreements and division orders. However, when dealing with the federal government as lessor, the interpretation/ manipulation opportunity is magnified with the prospect for interpretation of: (1) statutory language; (2) contract language; and (3) regulatory language.

The legal positions advocated by the MMS may seem less convincing in light of the royalty value theorem: Are they being pursued to give legitimate effect to the parties' contract? or Are they an attempt to maximize royalty revenues in spite of the parties' contractual obligations? The royalty value theorem may also require that courts give less deference to MMS interpretations of the governing statutes, regulations, and contracts.[10] However, the lessee is not free from temptation under the royalty value theorem; to the extent lessees can lawfully minimize the value attributable to oil and gas it will similarly minimize the amount it owes in royalty, and taxes. Therefore, lessees will seek to value oil and gas for royalty purposes as close to the point of production as possible; before value has been added to the production through treatment and transportation. When the lessor is the federal government, a lessee's reasonable interpretation of its royalty obligations may give rise to regulatory punishment if its interpretation turns out to be incorrect. Presently it seems as though the entire industry is being vilified for pressing any lease interpretation that fails to maximize the government's side of the royalty value theorem.

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[10]When the government acts in a proprietary capacity, its interpretation of the governing statutes, regulations, and contracts will not be entitled to the level of deference its enjoys when acting in a purely regulatory capacity. *See infra* text accompanying note 47. The court in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117, 124 (D. D.C. 2000), observed: "Indeed, no deference is due an agency's interpretation of contracts in which it has a proprietary interest. . . . Similarly, an agency's interpretation of its own regulations is not entitled to deference when it will affect contracts to which the agency is a party."

III. THE OIL INDUSTRY–JUST ANOTHER TOBACCO COMPANY?

It is doubtful the royalty issues associated with federal lands will be resolved by compromise. The industry's approach will be to make the best of a "bad" situation and then determine whether to challenge the MMS's regulations.[11] The MMS's approach will be to prospectively maximize their position under the royalty value theorem while ensuring they do nothing that could weaken application of their valuation theories to past royalty obligations. Disputes concerning underpayment of past royalty obligations will not be a simple issue of statutory, contractual, and regulatory interpretation. Instead, the industry will be professionally demonized while the issues are presented in the context of fraud, conspiracy, and criminal conduct. For example, consider how some of our nation's highest-ranking politicians have characterized the issues:

> ***Under the current regulations governing crude oil royalty valuation for federal leases, a mountain of evidence has emerged demonstrating that federal oil and gas lessees, primarily the large, integrated corporations, have been cheating the American people out of hundreds of millions, if not billions, of dollars in royalties on federal oil and gas production.***[12]

The basic premise on which Senator Boxer operates is: if there is any theory under which the government could get more money for its royalty oil and gas, and the industry is not paying in accordance with that theory, they are guilty of criminal conduct. The validity of the government's theory doesn't matter–at least not at the demonization stage of the political process. At the demonization stage all you need is a willing accomplice in the media.

In his October 5, 1999 "Fleecing Of America" broadcast, Tom Brokaw revisits one of his earlier reports on the royalty valuation issue asking reporter Chip Reid "to bring us up to date on some of the most outrageous examples" of the "Fleecing Of America."[13] Mr. Reid observes: "Critics have long complained the oil companies don't pay enough in royalties because they are allowed to set the price for the oil they take. And those critics say they set the price too low."[14] Reid states:

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[11]The situation is "bad" because the MMS has the ability, through the rulemaking process, to unilaterally define and defend its position under the royalty value theorem. Although the industry can comment, its only real relief is through judicial review.

[12]Letter from Barbara Boxer and George Miller to Bruce Babbitt, dated July 30, 1998, commenting on the MMS proposed regulations on oil royalty valuation, p. 1 [hereinafter "Boxer Letter"].

[13]Transcript, October 5, 1999 NBC Nightly News, NBC-TV. Available through Video Monitoring Services of America, L.P., 330 West 42nd Street, New York, New York 10035.

[14]*Id.*

"Bottom line, taxpayers lose up to sixty-six million dollars a year, according to the government." This is followed by an observation by Danielle Brian, the Executive Director for the "Project On Government Oversight," that: "The government is being cheated. But what that really means is that the taxpayer is getting cheated."[15] Reporter Reid updates the continued "Fleecing Of America" stating:

> ***Last year, the Interior Department tried to fix that [industry cheating]. It forced the oil companies to pay fair market value, but last week, the Senate, led by Kay Bailey Hutchison of oil-rich Texas, said no. The oil companies can keep their prices. . . . The 'Fleecing of America' will continue.***[16]

NBC's Tom Brokaw would never waste his time reporting on the intricacies of upstream royalty valuation versus downstream valuation, the deduction of costs incurred to enhance a marketable product, or the law of corporate separateness. These subjects are the "truths" involved in the valuation debate; commentators like myself, other professors, and representatives on both sides of the issue, have been engaged in legitimate discourse on these issues for years.[17] But the truth on this subject does not play as well on national television as do lies of fraud, criminal conspiracy, and theft. This governmental/political propensity to cast legitimate contractual disputes as criminal corruption, when combined with a willing, superficial national media, creates enormous risk for any industry that comes within their sights. In such an environment the only real recourse is the courts.[18] However, one attempt at compromise proposed by the oil industry, and embraced in part by the MMS, is the take-in-kind program.

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[15]*Id.*

[16]*Id.*

[17]*E.g.*, David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 Eastern Min. L. Inst. 18-1 (1992).

[18]Attempts by the industry to avoid these disputes through settlement will be trumpeted as admissions of guilt. In the preamble to its Final Oil Rule the MMS notes:

> Recognizing that posted prices no longer reflected market value, State and private royalty owners in Alaska, California, Louisiana, New Mexico, and Texas brought lawsuits against several major oil companies over improper oil valuation and underpaid royalties. These lawsuits resulted in several oil companies paying additional royalties . . . .

Final Oil Rule, Preamble at 14023.

IV. TAKE THIS OIL "IN-KIND" (AND SHOVE-IT)

One way to avoid problems associated with the royalty value theorem is to adopt a royalty compensation mechanism that is not dependent on value. If royalty is paid by delivering a stated fraction of production to the lessor, the "value" of the production should not matter. If the lessor believes wellhead or field values are being artificially depressed, let the lessor take their production and see if they can do any better.[19] However, under the MMS's current approach to royalty valuation, taking in-kind will not survive where the lessor can share risk-free in the lessee's downstream business ventures. To the extent taking in-kind yields the government less value than the lessee obtains for its production at some downstream point, Senator Boxer and her followers would conclude the MMS employees responsible for the in-kind program were either incompetent, duped, or bribed.[20] Senator Boxer has already referred to these royalty-in-kind programs as "bogus" and just another attempt to "obscure the fact that the new [royalty valuation] rule is necessary because the industry has cheated the American people out of billions of dollars."[21] The simple fact is taking-in-kind will never be accepted by industry critics until the valuation issues discussed in the balance of this article are resolved. So long as MMS methodology for valuing royalty includes downstream values, any take-in-kind program that nets less than downstream values will be deemed

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[19]For example, in *United States v. General Petroleum Corp. of California*, 73 F. Supp. 225, 240 (C.D. Cal. 1946), *aff'd*, *Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950), the Secretary of Interior had elected to take the government's royalty in kind:

> The plaintiff-lessor did not accept the $1.65 price for its high-gravity oil from the foregoing property. It took its share of the oil for the year of April 1, 1929, to April 1, 1930, in kind and sold it to the Phillips Petroleum Company for $2.25 per barrel, a portion bringing $2.54 per barrel. Later this was purchased by Standard at a still higher figure.

[20]The demonization process creates problems for the MMS as well as the industry. Whenever a plaintiff in private litigation, or a relator in a *qui tam* action, comes up with a new theory on how they can obtain more royalty value, the pressure will be on agency personnel to aggressively pursue the theory–not because it is correct or appropriate, but because it can net a larger royalty–it satisfies the government's side of the royalty valuation theorem. Professional agency personnel (those who will be around after the next election), may be reluctant to adopt theories that: (1) they think will be difficult or impossible to defend; (2) they think will be difficult or impossible to administer; (3) they think are unfair; or (4) will make them look like fools for letting all that value get away from them–if indeed it should have been demanded all along. If agency employees are reluctant to embrace the new theories, they simply become one of the "demons" the process must destroy.

[21]Boxer Letter at 2.

will be deemed unacceptable.[22] Therefore, royalty calculation disputes between industry lessees and government lessors will continue until a few basic issues[23] are resolved regarding: the scope of the lessor/lessee relationship; the proper statutory basis for valuing production; the existence and scope of any implied obligation to market production; and the validity of transactions between corporate affiliates.

V. THE UNRESOLVED ISSUES

A. The Foundational Issue: When Does the Lessor/Lessee Relationship End?

1. Upstream/Downstream: Linear Royalty Analysis

The production, movement, treatment, and marketing of oil and gas are linear. Typically, as production moves away from the "upstream" wellhead point of extraction, investment is made by someone, and risks taken, in hopes of enhancing the value of the oil and gas as it moves in its "downstream" journey to ultimate consumption. Therefore, the value-added component of oil and gas is also linear, with an increase in value typically corresponding with an increase in investment, as the oil and gas move downstream from the wellhead. Before it can be determined whether, and to what extent, a lessor is entitled to participate in downstream oil and gas values, the *scope* of the

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[22]Of course, from the government's perspective this question provides the answer: delivery in-kind at the refinery or at a market center. Such an approach merely poses the valuation issue in a different context: *where* does the lessee discharge its in-kind delivery obligation versus *where* must the lessee determine value. However, the oil and gas lease form will typically be more helpful on this issue. For example, one on-shore federal lease form provides: "When paid in kind, production shall be delivered, unless otherwise agreed to by lessor, in merchantable condition *on the premises where produced* without cost to lessor." Form 3100-11 (October 1992), "Offer to Lease and Lease for Oil and Gas" (emphasis added).

[23]Issues that remain ripe for judicial action eighty years after enactment of the Mineral Leasing Act; issues that remain ripe for judicial action between private lessors and lessees after 140 years of experience under the oil and gas lease. In some instances courts have vacillated on the issue. *E.g., compare* Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970) *with* Wood v. TXO Production Corp., 854 P.2d 880 (Okla. 1992) and TXO Production Corp. v. Commissioners of the Land Office, 903 P.2d 259 (Okla. 1994) *with* Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203 (Okla. 1998); *compare* Scott v. Steinberger, 213 P. 646 (Kan. 1923), Voshell v. Indian Territory Illuminating Oil Co., 19 P.2d 456 (Kan. 1933), and Molter v. Lewis, 134 P.2d 404 (Kan. 1943) *with* Gilmore v. Superior Oil Co., 388 P.2d 602 (Kan. 1964) and Schupbach v. Continental Oil Co., 394 P.2d 1 (Kan. 1964) *with* Sternberger v. Marathon Oil Co., 894 P.2d 788 (Kan. 1995).

oil and gas lease relationship must be defined. At what point does the extracted oil and gas leave the sphere of influence of the oil and gas lease and enter into an arena in which the lessor and lessee no longer have any obligation to one another? When has the relationship, as to a particular barrel of oil or thousand cubic feet ("Mcf") of gas, run its course?[24] These questions must be answered before any sort of entitlement/moocher analysis can take place.

a. The Government's "Possessory" Approach

The government, and private lessors, take a *possessory* approach to defining the scope of the lessor/lessee relationship. If the lessee, or its affiliate, still *possesses* the oil or gas, or has the *right to possess* it at some later point in its downstream journey, it is still subject to the lessor/lessee relationship.[25] For example, the MMS relies upon a sale under an "arms-length" contract to define the point at which possession of produced oil leaves the lessee, thereby ending the lessor/lessee relationship with regard to that barrel of oil.[26] If an arms-length sale never takes place, various downstream index prices will be used to calculate royalty value.[27] However, if the lessee uses the oil in its refinery operation, I predict someday Senator Boxer and her followers will attack--as grossly negligent or criminally corrupt--the MMS's approach in this rule by demanding a royalty share in the gasoline product that remains in the lessee/refiner's *possession* prior to sale at the gasoline pump.[28] The royalty value theorem, combined with the possessory approach, necessitates the Senator Boxer attack: 1/8th of $1.50/*gallon* is better than 1/8th of $25.00/42-gallon *barrel*.

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[24]*See generally* David E. Pierce, *The Missing Link in Royalty Analysis: An Essay on Resolving Value-Based Royalty Disputes*, 5 Texas Wesleyan L. Rev. 185 (1999).

[25]The most dramatic illustration of the possessory approach is *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), where the valuation process began in Japan to calculate royalty due on gas extracted from a field in Alaska.

[26]30 C.F.R. § 206.102(a) (2000).

[27]30 C.F.R. § 206.103 (2000).

[28]Seeking royalty prices on refined gasoline is not as aggressive an approach as that taken by the MMS in *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), where royalty values were calculated on the value of gas in Japan after it had been extracted from a field in Alaska, transported to a liquefied natural gas plant, liquefied, loaded into special tankers and shipped to Japan, and then sold in its liquid form in Japan.

b. The Industry's "Functional" Approach

Industry lessees strenuously object to the possessory approach for defining the scope of the lease relationship. The industry seeks to employ a *functional* approach that defines the scope of the *lease* relationship by recognizing the basic function of the oil and gas lease: to authorize the lessee to enter, explore, and extract oil and gas from the leased land. The *function* of the lease is not to allow the lessor to share in a portion of the profits from the lessee's downstream investments in pipelines, compressors, processing plants, and other enterprises designed to enhance the value of oil and gas. The *function* of the lease is to permit extraction of the oil and gas that will trigger a royalty obligation at or near the point of extraction–regardless of the lessee's continued *possession* of the oil and gas.[29]

c. Analytical Difficulties with Each Approach

(1) The Possessory Approach

The possessory approach can result in fundamentally different royalty obligations–even when two lessees, producing under the same federal lease, are extracting oil and gas having the same intrinsic value. For example, assume Lessees ***A*** and ***B*** each own an undivided one-half interest in the same federal oil and gas lease. ***A*** takes its 50% of the oil and sells it in the field to ***B*** for $20.00/barrel. ***B*** takes its 50% of the oil and engages in various transactions, including exchanges and transportation, to get oil at its refinery. Oil at the market center closest to the leased land sells for $25.00/barrel. Assuming the MMS's transportation allowance would permit deduction of a $2.00/barrel transportation fee,[30] ***B*** will owe a royalty on $23.00/barrel while ***A***'s royalty will be valued using $20.00/barrel oil.[31] Is ***A*** cheating the government out of royalty on $3.00/barrel? Or,

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[29]In conjunction with a private royalty dispute, the author conducted a study of oil and gas leases used by a large producer throughout the State of Texas. A random sample of about 4% of the producer's Texas leases resulted in approximately 1,000 separate oil and gas lease documents for review. The lease sample consisted of many different types of lease forms, and customized lease documents, dating from 1927 to 1999. 98% of the sampled documents expressly provided for the lessee to "use" or purchase royalty production, or to sell production to an affiliate. This industry custom and practice recognizes that lessees often use, purchase, or sell royalty production in transactions that are not "arms-length" and which do not transfer "possession" away from the lessee. My study also revealed that in most situations where there is no arms-length transaction royalty will be determined using the market value of the production at the well, lease, or field, at the time it is extracted.

[30]30 C.F.R. §§ 206.109 to 206.118 (2000).

[31]If we assume the oil is produced from leases not located in California, Alaska, or the Rocky Mountain Region (Colorado, Montana, North Dakota, South Dakota, Utah, and

is this $3.00/barrel the government's "moocher margin" imposed on ***B*** for failing to sell its oil–relinquish *possession*--where it was produced?

There are many reasons why ***A*** may decide to market its oil in the field while ***B*** does not. ***A*** may not need the oil once it is extracted. ***A*** may find it more economically advantageous to simply sell its oil where produced and buy new oil at another location. ***A*** may have minimal quantities of oil in the field which would not justify the additional effort and investment to move it long distances. ***A*** may believe the price being offered for oil in the field is better than the price it could obtain downstream after considering the potential downstream risks and rewards. ***A*** may not want the hassle of dealing with the MMS's alternative valuation rules.

Under the MMS regulations, ***A*** is arguably in no way obligated to seek a market beyond the field of production.[32] ***A***, and ***B***, are free to enter into an arms-length sale of their oil once the oil is

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Wyoming), the value of the oil for royalty purposes will be based on the price established by the "market center" closest to the leased land. 30 C.F.R. § 206.103(c)(1). "Market center" is defined as "a major point MMS recognizes for oil sales, refining, or transshipment. Market centers generally are locations where MMS-approved publications publish oil spot prices." 30 C.F.R. § 206.101(2000). Separate valuation rules exist for oil produced in California and Alaska and oil from the "Rocky Mountain Region." 30 C.F.R. § 206.103(a) (2000) (California or Alaska) and 30 C.F.R. § 206.103(b) (2000) (Rocky Mountain Region)).

[32]Establishing Oil Value for Royalty Due on Federal Leases; Proposed Rule," 64 Fed. Reg. 73823 (Dec. 30, 1999) ("Lessees may market at the lease without breaching the duty to market."). The language of the final rule indicates the gross proceeds from an arm's-length sale will be used for calculating royalty unless the MMS finds the sale does not "reflect the reasonable value" due to a "[b]reach or your duty to market the oil for the mutual benefit of yourself and the lessor." 30 C.F.R. § 206.102(c)(2)(ii) (2000). However, this "reasonable value"/"duty to market" requirement is qualified by the following language:

> (A) MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.
>
> (B) The fact that the price received by the seller in an arm's length contract is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that the seller acted *unreasonably* or in *bad faith* in the sale of oil from the lease.

30 C.F.R. § 206.102(c)(2)(ii)(A) & (B) (2000) (emphasis added). The final rule essentially says a sale at the lease may be acceptable unless the MMS thinks it was "unreasonable" or not in accordance with its latest interpretation of the implied covenant to market. Not very reassuring. In *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117, 123 (D. D.C.

placed in "marketable condition."[33] Logically, if someone is willing to purchase the oil in an arms-length transaction, it is, by definition, in "marketable condition."[34] Therefore, a sale at the wellhead,

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2000), regarding the MMS's parallel gas valuation regulations, the court observed: "Interior does not contend that plaintiffs [lessees] have an obligation to sell gas downstream off the lease. In other words, Interior concedes that plaintiffs are free to sell or beneficially consume gas at the wellhead only, rather than pursue downstream sales."

[33]The regulations define "marketable condition" as "oil sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area." 30 C.F.R. § 206.101 (2000). The regulations state:

> You must place oil in marketable condition *and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.* If you use gross proceeds under an arms-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.

30 C.F.R. § 206.106 (2000) (emphasis added). This is substantively identical to the terms of 30 C.F.R. § 206.152 (i) (2000) (federal gas valuation), and 30 C.F.R. § 206.153(i) (2000) (federal processed gas valuation), which were held to be unlawful in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp.2d 117, 130 (D. D.C. 2000), because not consistent with statutory authority or the federal lease form.

[34]As I have noted in prior writings regarding the implied covenant to market gas, under the pre-1990 gas regulatory regime the implied covenant to market was really nothing more than an implied obligation to "sell" extracted gas at the wellhead to the available pipeline purchaser. Consider the following analysis:

> Cases defining the implied covenant to 'market' under the traditional marketing scenario could take on a distorted meaning when applied to contemporary marketing scenarios. Under the traditional marketing scenario, the act of 'marketing' meant to sell the gas to a pipeline at or near the field where it was produced. Courts defined the lessee's duty as being simply to 'market the product once it is discovered' and to act as a prudent operator to obtain the best price for the gas when arranging a sale. However, the lessee has never been obligated to spend large sums of money to build pipelines or seek distant markets. In reality, the traditional implied covenant to market has been nothing more than an implied covenant to *sell* gas produced from the property at an acceptable price.

David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 Eastern Min. L. Inst. 18-1, 18-46 to 18-47 (1992) (citations omitted). However, consider Judge Prettyman's observations

in an arms-length transaction, would be acceptable marketing. Note that if ***B***, like ***A***, entered into an arms-length sale of its oil in the field for $20.00/barrel, ***B***'s royalty would be calculated using the $20.00 value; even though ***B*** may ultimately purchase oil at some downstream location at, for example, $22.00/barrel and then sell it further downstream for $25.00/barrel.[35]

What is the justification for treating ***A*** and ***B*** differently? What is the justification for treating ***B*** differently when it relinquishes possession of its oil at the well instead of at the refinery? One rationale offered by the MMS is that a competitive market at the lease does not exist. But the MMS follows this statement with several developments it acknowledges "may be seen as increasing the level of competition . . . ."[36] Also, this runs counter to the MMS authorizing the use of any arms-

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that an ability to "sell" oil and gas may not constitute "marketing":

> Theoretically, any gas–any 'production'–is 'marketable'. We can assume that, if the price were low enough to justify capital expenditures for conditioning equipment, someone would undertake to buy low pressure gas having a high water and hydrocarbon content. A lessee who sold unconditioned gas at such a price would, in a rhetorical sense, be fulfilling his obligation to 'market' the gas, and by thus saving on overhead he might find such business profitable. *There is a clear difference between 'marketing' and merely selling. For the former there must be a market, an established demand for an identified product.* We suppose anything can be sold, if the price is no consideration. *In the record before us there is no evidence of a market for the gas in the condition it comes from the wells.* The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content.

California Co. v. Udall, 296 F.2d 384, 387-88 (D.C. Cir. 1961) (emphasis added). In most instances there will be "an established demand" for oil and gas at or near the well where it is produced. It may be "worth" more at a downstream market, but this is due to the admittedly linear nature of oil and gas values: they are worth more as they move closer to the point of ultimate consumption. *See supra* text accompanying note 24.

[35]The MMS justifies calculating royalty on downstream values, instead of wellhead values, because their lessee's freely elect to market their oil and gas downstream from the wellhead. "Establishing Oil Value for Royalty Due on Federal Leases; Final Rule," 65 Fed. Reg. 14022, 14029 (March 15, 2000). The regulatory penalty placed on the lessee electing to market beyond the wellhead is two-fold: first, they are forced to share a portion of the enhanced values with the government; and second, they are forced to pay all non-transportation costs associated with procuring the enhanced downstream values. This sounds like mooching to me–unless a different result is mandated by statute or the lease contract.

[36]"Establishing Oil Value for Royalty Due on Federal Leases; Proposed Rule," 64 Fed. Reg. 73820 (December 30, 1999).

length transactions at the lease to calculate royalty. The MMS's real concern seems to be "the level of price transparency (i.e., the ability to discern the prices actually paid) at the lease or field or to simplify application of the existing oil valuation rules."[37] The MMS observes it is difficult to determine the value of oil when it is sold to an affiliate or when it is not sold at all, but rather is used by the lessee at some point downstream of the leased premises. However, the MMS's remedy for these perceived problems is to impose a greater royalty obligation on the lessee by using downstream market center spot prices to calculate oil values. Seeking a more workable technique to ascertain the "12 ½ per centum in amount or value of the production removed or sold from the lease"[38] is laudable. However, the industry will no doubt assert the MMS is using ease-of-administration as the basis for increasing the effective fractional royalty lessees pay on "production removed or sold from the lease."

The industry's argument will be that a lessee's downstream possession of oil or gas has little correlation to the required upstream inquiry into the "value of the production removed or sold from the lease." Merely because a new downstream number has become available for valuing oil and gas–spot prices–does not mean statutory and contractual royalty calculations can be changed to use the new number. Would this be the case if the new number typically yielded a *lower* royalty than comparable sales at the lease? Not likely.[39] Does the realization that the new number is typically *higher* than comparable sales at the lease mean comparable sales are not reflective of fair market value? Not necessarily. The only thing we can say for sure is that the new *downstream* number is not necessarily reflective of *upstream* values. They are different. Most courts that have confronted the problem of determining upstream values have expressed a preference for relying upon actual sales at or near the relevant location as opposed to trying to work back from a downstream sales point.[40]

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[37]*Id.*

[38]Section 17 of the Mineral Leasing Act provides for a royalty "in amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b) & (c) (1994).

[39]The MMS makes this clear when it requires royalty calculated on an affiliate's ultimate arm's-length sales price, but only "when the gas (or oil) marketed through the wholly-owned affiliate commands a *higher* price." Proposed Oil Rule, Preamble at 73823 (emphasis added).

[40]*E.g.*, Heritage Resources, Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996), *relying upon*, Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981) and Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 872 (Tex. 1968). Consider the following observation:

> The hierarchy of royalty valuation methods is intuitive. Market value is what a willing buyer and willing seller would agree upon under the circumstances. Where gas is actually sold at the wellhead in a transaction negotiated at the time of sale, all elements of the definition and the transaction are in congruity unless the sale is not at arms length or the parties act unreasonably; thus an actual sale at

(2) The Functional Approach.

The analytical difficulty with the functional approach is defining, for each lease, when the production process ends and downstream processes begin. When there is an arms-length sale of production on the leased premises, it is easy to define the end of the production process. This same approach could be used with sales to an affiliate. To protect the government from sweetheart deals that are not reflective of market value, the MMS could require the lessee engaging in the affiliate sale to submit information supporting the price used in the transaction. Perhaps the best evidence would be that the affiliate was purchasing similar production, in arms-length transactions, from unrelated third parties; or that third parties were purchasing at similar prices in arms-length transactions with other producers. Such information would provide the MMS with the price transparency it feels is lacking at the lease level. However, the MMS has expressly rejected such an approach,[41] which suggests the royalty value theorem is at work instead of a real concern about price transparency and ease-of-administration. The industry will assert that the MMS merely wants more money out of the lease relationship–not a more workable technique for calculating the royalty due.

The functional approach creates the most difficulty when the lessee fails to sell production at or near the location where it is produced. Most private leases anticipate this problem by providing expressly for a market-based royalty value whenever production is "used" by the lessee, "purchased" by the lessee, or sold to an affiliate.[42] Typically the royalty will be calculated as a share of the "market value" at the well. However, the MMS will attempt to avoid a functional approach for two reasons: (1) it will result in less royalty revenue than a downstream valuation approach; and (2) it will require a lease-specific analysis to determine value as opposed to using a more generic downstream valuation that can be applied to hundreds of leases.

> the wellhead is the best evidence of value. Comparable sales illustrate an available market and are strong evidence of value where there are no actual sales. The circumstances of comparable sales, however, will never be completely the same as circumstances at the wellhead. The work-back method is the hardest valuation method to use accurately because it begins furthest from the wellhead.

Eugene O. Kuntz et al., Cases and Materials on Oil and Gas Law 298 n.5 (3d ed. 1998).

[41]Proposed Oil Rule, Preamble at 73823.

[42]The vast majority of private lease forms employ a "market value" royalty measure to determine royalty obligations when no sale takes place at the lease, or when the sale is to the lessee or the lessee's affiliate.

2. The Scope of the Relationship Under the Mineral Leasing Act.

a. The Lessee's Burden; The Government's Advantage.

Compared to the lessee's position under private leases, the lessee has an uphill battle when attempting to define the scope of the lessor/lessee relationship under the Mineral Leasing Act and other federal leasing laws. First, the "at the well" language, so prevalent--and useful--in private leases,[43] is missing from the federal lease lexicon regarding royalty. Instead, royalty is based upon a percentage of the "amount or value of the production removed or sold from the lease."[44] Second, the lessee's royalty obligation will be governed primarily by statutory interpretation instead of contract interpretation.[45] Statutes define the base contractual obligation. This means that legislative history can play a major role in contract interpretation; typically a mixed proposition for both

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[43]*E.g.*, Sternberger v. Marathon Oil Co., 894 P.2d 788, 794-96 (Kan. 1995) (discussing significance of "at the well" language in calculation of royalty).

[44]Mineral Leasing Act of 1920, § 17(b) & (c), 30 U.S.C. § 226(b) & (c) (1994). The obvious issue is whether "removed . . . *from the lease*" and "sold *from the lease*" are federal analogues for "at the well." *See* United States v. General Petroleum Corp. of California, 73 F. Supp. 225 (C.D. Cal. 1946), *aff'd*, Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950). In *General Petroleum*, regarding the valuation location for natural gas, the court stated: "Natural-gas royalties are payable on the gas as it is produced at the well. It is the value of that gas which must be determined." *General Petroleum*, 73 F. Supp. at 254. When the deduction of gathering costs was addressed, the court adopted the lessee's proposition that "the government is only entitled to its share of the value of the wet gas at the well . . . ." 73 F. Supp. at 257. When the lessee tried to avoid paying royalties on gas it had produced, and then placed in storage awaiting sale, the court held:

> It is the court's view that the Secretary properly billed the lessees for gas royalties at the time the gas was produced at the leases, that is, before it left the field for storage. The Act, regulations and leases contemplate royalty payment to be made on the original production at the well. The royalty accrues as the gas is produced and on the amount so produced.

73 F. Supp. at 258. Concerning the valuation of royalty on crude oil, the parties agreed that "value" would mean "value at the wells" in the field where produced. 73 F. Supp. at 235 n.16. The court of appeals observed: "We take it that there is no dispute that notwithstanding the sketchy character of the leases, royalties were to be calculated at values at the wells, not at the pipe line destination . . . ." *Continental Oil*, 184 F.2d at 820.

[45]*E.g.*, Marathon Oil Co. v. Andrus, 452 F. Supp. 548, 550 (D. Wyo. 1978) (striking down Department's NTL-4 noting "[t]he powers of the Secretary are established and limited by the Mineral Leasing Act . . . and Regulations lawfully adopted pursuant thereto.").

parties.[46] Third, the MMS has the opportunity to set-the-stage for future disputes by promulgating regulations to implement its interpretation of the statutes.[47] Fourth, to the extent the statutes fail to clearly define the parties' obligations, the MMS's initial interpretation will be subject to a degree of deference by reviewing courts.[48]

b. What Does "Removed or Sold From the Lease" Mean?

The first step in determining when and where the lessor/lessee relationship ends with regard

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[46]*E.g.*, Gulf Oil Corp. v. Andrus, 460 F. Supp. 15, 17 (C.D. Cal. 1978) (relying upon legislative history to overturn Department's NTL-4 and noting the Department "apparently overlooked" the legislative history).

[47]Mineral Leasing Act of 1920, § 32, 30 U.S.C. § 189 (1994) ("The Secretary of the Interior is authorized to prescribe necessary and proper rules and regulations to do any and all things necessary to carry out and accomplish the purposes of this chapter . . . .").

[48]*See, e.g.*, Mesa Operating Limited Partnership v. U.S. Dept. of Interior, 931 F.2d 318, 322 (5th Cir. 1991), *cert. denied*, 502 U.S. 1058 (1992) (applying Chevron, U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837, 843 (1984), in holding that MMS's order requiring payment of royalty on certain reimbursed NGPA § 110 "post-production" costs was a permissible interpretation of its authority under the Outer Continental Shelf Lands Act.). However, courts may be less inclined to grant MMS interpretations deference when its actions are more proprietary as opposed to regulatory. For example, when the MMS interprets its ability to control pollution on the OCS, it is acting in a purely regulatory capacity and would be entitled to maximum deference. However, when the MMS is interpreting statutes that impact reciprocal property rights of the government and those entities with which it deals, its interpretations may be unduly influenced by its proprietary interests as opposed to regulatory interests. For example, in *United States v. General Petroleum Corp. of California*, 73 F. Supp. 225 (C.D. Cal. 1946), *aff'd*, *Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950), the trial judge discussed the administrative agency's unique relationship as lessor/regulator stating:

> In resolving the foregoing issues [whether posted prices reflected the market value of oil in the field] it must be remembered that the government's role is taken to be no different from that of any private lessor or proprietor, for while the Kettleman Hills lands involved are public mineral lands, and as such until their disposition are under the supervision and control of Congress, the government as to such lands acts in a proprietary capacity, and treats with them in the same way as does the private landowner.

73 F. Supp. at 234 (footnotes omitted).

to produced oil and gas is to examine the statutory language for guidance.[49] The Mineral Leasing Act provides for a royalty based upon the "amount or value of production removed or sold from the lease . . . ."[50] The task will be to determine whether the removal of oil and gas "from the lease" indicates the point at which the lessor/lessee relationship terminates with regard to that barrel of oil or Mcf of gas. The lessee will contend a sale of oil or gas at the lease, or removal from the lease either for use by the lessee, or sale by the lessee at some downstream location, is the critical royalty-defining event; and the event that terminates the lessor/lessee relationship as to production that has been sold or removed. The MMS will rely upon its marketing obligation and gross proceeds rules to extend the lessor/lessee relationship to locations often far removed "from the lease."[51]

To resolve this issue the parties will have to first look to the relevant statutes for guidance. For example, the Mineral Leasing Act of 1920, as amended ("MLA"), contains several provisions that must be examined. First, section 17 of the MLA sets out the base obligation to pay a royalty "in amount or value of the production removed or sold from the lease."[52] Section 36 of the MLA gives the government the option to take its royalty in "oil or gas" and further authorizes the government to sell its royalty oil and gas at the "market price".[53] Section 28 seeks to ensure a gateway from the wellhead to marketing outlets by making all pipelines having rights-of-way through federal lands common carriers.[54] Section 27 seeks to control the unlawful restraint of trade in oil and gas "to

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[49]Independent Petroleum Ass'n of America v. Armstrong, 91 F. Supp.2d 117, 124 (D. D.C. 2000) ("In all its actions, an agency is constrained by the statutory authority given by Congress. Thus, where Congress has spoken to a particular matter, Congress' plainly expressed intent governs.").

[50]Mineral Leasing Act of 1920, § 17(b) & (c), 30 U.S.C. § 226(b) & (c) (1994).

[51]In *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), the MMS was successful at using its gross proceeds rule to push the valuation of natural gas produced in Alaska downstream to a sale of liquified natural gas in Japan. Although the court purported to agree that valuation should be "at the lease," it held the gross proceeds rule converted the "at the lease" language to merely the end-point where you work back to in determining deductions from gross proceeds obtained in Japan. 604 F. Supp. at 1386.

[52]*Id.*

[53]MLA § 36, 30 U.S.C. § 192.

[54]MLA § 28(r), 30 U.S.C. § 185(r) states, in part:

> (1) Pipelines and related facilities authorized under this section shall be constructed, operated, and maintained as common carriers.
>
> (2)(A) The owners or operators of pipelines subject to this section shall accept, convey, transport, or purchase without discrimination all oil or gas

control the price or prices thereof . . . ."[55] Therefore, the MLA provides the government with a royalty based upon a share of production, or the value of production. The Act also seeks to ensure there are free and open markets for production the government may take in-kind and for production that is removed or sold by the government's lessee.

The MLA's legislative history, and the history of the other federal leasing statutes, assist in determining where Congress intended the lease relationship to end following extraction of oil and gas. Industry custom and usage at the time of enactment, and amendment, may also assist in understanding the context in which Congress used the terms: "in amount or value of the production removed or sold from the lease." Other critical portions of the MLA's royalty provisions were clearly influenced by industry custom and practice–most notably the government's share of

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delivered to the pipeline without regard to whether such oil or gas was produced on Federal or non-Federal lands.

(B) In the case of oil and gas produced from Federal lands or from the resources on the Federal lands in the vicinity of the pipeline, the Secretary may, after a full hearing with due notice thereof to the interested parties and a proper finding of facts, determine the proportionate amounts to be accepted, conveyed, transported or purchased.

(3)(A) The common carrier provisions of this section shall not apply to any natural gas pipeline operated by any person subject to regulation under the Natural Gas Act or by any public utility subject to regulation by a State or municipal regulatory agency having jurisdiction to regulate the rates and charges for the sale of natural gas to consumers within the State or municipality.

(B) Where natural gas not subject to State regulatory or conservation laws governing its purchase by pipelines is offered for sale, each such pipeline shall purchase, without discrimination, any such natural gas produced in the vicinity of the pipeline.

(4) The Government shall in express terms reserve and shall provide in every lease of oil lands under this chapter that the lessee, assignee, or beneficiary, if owner or operator of a controlling interest in any pipeline or of any company operating the pipeline which may be operated accessible to the oil derived from lands under such lease, shall at reasonable rates and without discrimination accept and convey the oil of the Government or of any citizen or company not the owner of any pipeline operating a lease or purchasing gas or oil under the provisions of this chapter.

[55]MLA § 27(k), 30 U.S.C. § 184(k) states, in part:

[I]f the lands or deposits subject to the provisions of this chapter shall . . . form the subject of any contract or conspiracy in restraint of trade in the mining or selling of . . . oil . . . gas . . . entered into by the lessee . . . to control the price or prices thereof . . . the lease . . . shall be forfeited by appropriate court proceedings.

production: "12½ per centum" which was no doubt derived from the then-prevalent industry standard of ⅛th. Since the statutes have never been interpreted and applied to address the precise issue of when the lease relationship terminates, this appears to be a ripe area for new analysis, and argument.

If statutory interpretation does not resolve the issue, the next step will be to look to the oil and gas lease contract.[56] For purposes of discussion, I will refer to Form 3100-11 (October 1992), "Offer to Lease and Lease for Oil and Gas", that is employed to lease on-shore federal lands (the "1992 Form").[57] The lease language concerning the scope of the lessor/lessee relationship is sparse. However, the in-kind royalty provision states: "When paid in kind, production shall be delivered, unless otherwise agreed to by lessor, in merchantable condition *on the premises where produced* without cost to lessor."[58] The free-market and market-access provisions of the MLA are expressly incorporated into the 1992 Form as follows:

> Lessor reserves the right to ensure that production is sold at reasonable prices and to prevent monopoly. If lessee operates a pipeline, or owns controlling interest in a pipeline or a company operating a pipeline, which may be operated accessible to oil derived from these leased lands, lessee shall comply with section 28 of the Mineral Leasing Act of 1920.[59]

The third source of guidance on when the lease relationship terminates will be the applicable regulations. Regulations take on particular importance since many of them are incorporated into the oil and gas lease contract. For example, the 1992 Form provides:

> Rights granted are subject to applicable laws, the terms, conditions, and attached stipulations of this lease, the Secretary of Interior's regulations and formal orders in effect as of lease issuance, and to regulations and formal orders hereafter promulgated when not inconsistent with lease rights granted or specific provisions of this lease.[60]

The lease language distinguishes between regulations in existence at the time the lease is entered into

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[56]Since the oil and gas lease form, that becomes the contract, is the product of regulation, statutory interpretation plays a unique role because it may negate a contractual term, created by regulation, which runs counter to legislative intent.

[57]Form 3100-11 (October 1992), "Offer to Lease and Lease for Oil and Gas."

[58]1992 Form at § 2 (emphasis added).

[59]1992 Form at § 10.

[60]1992 Form, front page.

and those adopted afterwards. This dichotomy relies upon the lessee's assent: the lessee assented to regulations in existence at the time the lease was signed. If a subsequent regulation attempts to change the lessee's rights under the lease, it will not be binding on the lessee absent new assent. I predict the courts will also have to address situations where the lessee may have assented to a regulation that was contrary to the underlying statute. Presumably such assent would be invalid.[61]

The regulations will also trigger their own interpretive problems. For example, the MMS regulations state:

> (b) If the regulations in this subpart are inconsistent with:
> (1) A Federal statute;
> (2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation; or
> (3) An express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, or lease provision will govern to the extent of the inconsistency.[62]

Apparently this provides a regulatory basis to avoid a finding that the regulation is contrary to law. To the extent the regulation is contrary to law, it will be interpreted so as to avoid the conflict.

Among the potential conflicts are those that arise when a lessee removes oil or gas from the leased premises for a downstream use, including a downstream sale. Will the lessee be obligated to pay royalty on the downstream value instead of the value when removed from the lease? The gross proceeds provisions of the Proposed Oil Rule, in many situations, require a royalty calculated on downstream values;[63] so do the alternative index pricing provisions for non-arm's-length transactions.[64] If the lessor/lessee relationship, with regard to this produced oil, ended once it was removed from the lease, then the lessee would argue that royalty should be calculated on the value

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[61]In a case involving the proper valuation of production for royalty purposes, the trial judge indicated the lessee would be bound by lease provisions only if they were authorized by the Mineral Leasing Act. United States v. General Petroleum Corp. of California, 73 F. Supp. 225, 250 (C.D. Cal. 1946), *aff'd*, Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950) ("the lessees are bound by the Secretary's determination of values of gas and gasoline *if* the Mineral Leasing Act expressly or impliedly authorized the Secretary to include such section in the leases, and *if* he validly exercised such reserved power by his orders . . . .") (emphasis added).

73 F. Supp. at 250.

[62]30 C.F.R. § 206.100(b) (2000).

[63]30 C.F.R. § 206.102(a) (2000).

[64]30 C.F.R. § 206.103 (2000).

of the oil when it was removed. Such an approach avoids issues concerning the deduction of costs and the payment of royalty on "services" instead of "production." Lessees will argue such an approach guarantees the government its entitlement to a royalty based upon the market value of the production at the time it was "removed . . . from the lease"–without regard for what the lessee does with the production.[65] However, the major problem in such cases will be ascertaining the market value of the oil at the lease; a fundamentally different issue from identifying the scope of the lease relationship.

B. How Should Production be Valued?

When the government does not take its royalty in kind, the Mineral Leasing Act requires the lessee to pay a royalty measured by the "value of the production removed or sold from the lease."[66] The current lease form gives the MMS the authority to "establish reasonable minimum values on products after giving lessee notice and an opportunity to be heard."[67] The statutory goal of the government is to have its royalty calculated using a fair market value for oil and gas produced from the leased lands.[68] The current MMS/industry debate focuses on whether the MMS's regulatory actions are designed to achieve Congress' *statutory* "market value" goal or to achieve the MMS's *regulatory* goal of maximizing government income under the royalty value theorem.

The role of the government in securing its statutory market value goal is illustrated by the

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[65]*E.g.*, United States v. General Petroleum Corp. of California, 73 F. Supp. 225, 258 (S.D. Cal. 1946), *aff'd*, Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950) (natural gas removed from lease and placed in storage triggered royalty obligations "on the original production at the well").

[66]MLA § 17(b) & (c), 30 U.S.C. § 226(b) & (c) (1994).

[67]1992 Form at § 2.

[68]Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950). The court in *Continental Oil* found:

> We have previously noted that the Leasing Act itself refers to royalty as a percentage (in amount or value of the production). We have also noted the references in the lease to the term (value) . . . .
>
> We are therefore of the opinion that the trial court was right in its interpretation of the leases as requiring royalty to be based upon actual, true or market value of the oil.

184 F.2d at 816-17.

Kettleman Hills posted price dispute. During the early 1930s the Secretary of Interior became convinced that prices posted by integrated oil companies in the Kettleman Hills field did not reflect the market value of the oil produced from the field.[69] The Secretary responded by issuing an order requiring government lessees to pay royalty based upon "the highest posted price in California for crude oil of equal or lower gravity . . . ."[70] The trial court held the Secretary lacked authority to establish a minimum price for the calculation of oil royalty.[71] However, the court indicated the Secretary had the authority to reject royalty calculations on values that did not represent market value.[72] Therefore, although the Secretary could not unilaterally designate what would be *deemed* market value, the Secretary could take the necessary action to *ascertain* market value.

Since the Secretary's minimum price did not reflect market value, the court had to independently evaluate the posted prices to determine whether they reflected market value. The court's first step in the analysis was to:

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[69]United States v. General Petroleum Corp. of California, 73 F. Supp. 225, 232 (S.D. Cal. 1946, *aff'd*, Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950).

[70]*General Petroleum*, 73 F. Supp. at 232.

[71]*Id.* at 238, *aff'd*, *Continental Oil*, 184 F.2d at 810. However, in *United States v. Ohio Oil Co.*, 163 F.2d 633 (10th Cir. 1947), *cert denied*, *Ohio Oil Co. v. United States*, 333 U.S. 833 (1948), the court upheld a minimum price order established by the Secretary of Interior for the Lance Creek field setting oil values at $1.02/barrel when the lessee was selling oil under contract for $0.77/barrel. However, the court noted the Secretary's order was based upon factors that were relevant to determining the market value of the oil at issue. *Ohio Oil*, 163 F.2d at 642. The court's opinion seems to indicate the lessee's real complaint was that it was locked into a long-term oil sales contract that was signed to induce a purchaser to build a pipeline to the field. 163 F.2d at 641. Apparently the current market value for oil in the field exceeded the proceeds paid to the lessee under its oil sales contract. *See also* Wilbur v. Texas Co., 40 F.2d 787 (D.C. Cir. 1930) (dicta stating Secretary of Interior had authority to disapprove lessee's oil sales contract with third-party purchaser when the oil sales price was found to be inadequate; case dismissed because production purchaser lacked standing to contest Secretary's order), *cert. denied*, Texas Co. v. Wilbur, 282 U.S. 843 (1930).

[72]The court observed:

> The Secretary was not left without recourse when, in his opinion, the prevailing market price of oil did not reflect its true or reasonable market value. He could disapprove the sale of oil at such prices and prevent the establishment of those prices as an apparent basis of royalty value-determination.

General Petroleum, 73 F. Supp. at 236.

> [D]etermine whether or not the posted prices truly reflect reasonable market value. If they do, then defendants have properly accounted for plaintiff's oil royalties. Plaintiff [Secretary of Interior] contends vigorously that they do not, and asserts and assumes the burden of proving that there was absent in the period in question a competitive, open market for crude oil at Kettleman Hills.[73]

The court found that posted prices in the Kettleman Hills field did not reflect market values because they placed an artificial ceiling on the ability to increase crude oil prices as gravity increased; ceilings which were not used in other fields producing similar crude oil with similar gravity ranges.[74] The court noted that determining market value is a factual inquiry.[75] The essential fact the court had to determine was the market value of oil, at the well, in the Kettleman Hills field.[76] Because all

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[73]*General Petroleum*, 73 F. Supp. at 238.

[74]*Id.* at 239-40.

[75]The court observed:

> In any event it may be considered with other evidence in determining whether the prices prevailing in a market reflected true market value or whether they were artificial and not the result of supply and demand. *Each case must be judged on its own facts.*

General Petroleum, 73 F. Supp. at 240.

[76]The trial court noted that the "lessees are obligated to return to the government the specified percentage of the reasonable market value at Kettleman Hills of the oil produced." *General Petroleum*, 73 F. Supp. at 235. The court footnotes this statement with the observation: "It was agreed at the pre-trial conference that 'value' means value at the wells at Kettleman Hills." *Id.* at n.16. Natural gas values were also involved in *General Petroleum*; the court stated: "Natural-gas royalties are payable on the gas as it is produced at the well. It is the value of that gas which must be determined." *General Petroleum*, 73 F. Supp. 254. The court noted again: "The Act, regulations and leases contemplate royalty payment to be made on the original production at the well. The royalty accrues as the gas is produced and on the amount so produced." *General Petroleum*, 73 F. Supp. 258. The court of appeals considered the "at the well" issue in evaluating the lessee's argument that its oil should be valued using its lower gravity after it has been transported out of the field as opposed to its higher gravity when produced. Apparently the oil, due to evaporation and other physical changes, would have a lower gravity in the pipeline than at the lease. The court rejected the lessee's argument stating:

> We take it that there is no dispute that notwithstanding the sketchy character of the leases, royalties were to be calculated at values at the wells, not at the pipe line destination, and we think the court was not obliged to take into consider the

production from the Kettleman Hills field was sold pursuant to the challenged posted prices, the court looked to other fields in the area to try and identify comparable sales. Relying upon evidence provided primarily by industry witnesses, the court compared the relative location, distillation qualities, and transportation and marketing outlets for crude oil from area fields.[77] The court concluded: (1) the industry's Kettleman Hills field posted prices did not reflect market value from July 1, 1931 through August 29, 1935;[78] (2) the minimum price the Secretary sought to impose did not reflect market value;[79] (3) the alternative value argued for by the Secretary did not reflect market value;[80] and (4) the alternative value argued for by the industry did not reflect market value.[81] Instead, the court found market value to be something more than what the industry advocated, and something less than what the Secretary advocated. Apparently the royalty value theorem was in full operation.

What about the non-integrated producer that innocently sells its oil at the below-market posted prices?[82] Will its royalty obligation be limited to the proceeds it receives from its purchaser?

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factors here mentioned.

Continental Oil, 184 F.2d at 820.

[77]*General Petroleum*, 73 F. Supp. at 241.

[78]*General Petroleum*, 73 F. Supp. at 249. However, the court found that the posted prices for the remainder of the period at issue, from August 29, 1935 through July 1, 1939, reflected market value; being comparable with adjusted prices paid in other area fields. *Id.*

[79]Using the information provided by the district court's opinion, the "highest price posted" standard imposed by the Secretary's order would have resulted in a price approximately 9% greater than that found by the court. *General Petroleum*, 73 F. Supp. at 242, Table D (using $1.05/barrel Santa Fe Springs field price as opposed to the $0.959/barrel Kettleman Hills field price.).

[80]The Secretary argued for a transportation allowance of 2¢ instead of the 10¢ allowance adopted by the court. *Continental Oil*, 184 F.2d at 815.

[81]The industry argued for a transportation allowance of 17.64¢ instead of the 10¢ allowance adopted by the court. *Continental Oil*, 184 F.2d at 819.

[82]The court observed:

> The record shows and the court found that there was no evidence to indicate that Continental in any manner participated in any rigging of the market or in any practices designed to establish posted prices below the reasonable or true values of the oil. Continental was obliged to sell the oil for what it could get.

The court in *Continental Oil* answers this question by noting that the federal oil and gas lease creates a "market value" royalty obligation, not a "proceeds" obligation:

> We are therefore of the opinion that the trial court was right in its interpretation of the leases as requiring royalty to be based upon actual, true or market value of the oil. . . .
>
> We have then a contract which in terms obligates the lessee to pay a stated percentage of the value of the production. This is an undertaking which the lessee assumed without any express limitation or qualification. Whatever the percentage may be, the lessee must in any event pay a sum calculated with respect to the true value.[83]

From the Kettleman Hills cases it can be concluded that the MMS's primary regulatory task is to ensure their lessees are paying royalty based upon the "market value" of the oil and gas produced and removed from the lease. Regulatory requirements imposed by the MMS should be designed to assist in ascertaining market value. Kettleman Hills suggests the appropriate markets for royalty valuation are markets "at the well" where the oil or gas is produced. The market value analysis requires a review of the specific facts that impact the value of production at the well. Any attempts by the MMS to define, administer, or streamline the royalty valuation analysis must be guided, and limited, by a legitimate search for the market value of the oil and gas produced and removed from the lease. In the Kettleman Hills cases the Secretary's oil valuation regulation was struck down because it merely attempted to impose a royalty value standard (highest posted price in California) without having any relationship to the market value of the actual production at issue. However, the court upheld the Secretary's orders regarding gas and gas liquids valuation because their intent and purpose was to identify the market value of the gas and gas liquids.[84] Closely

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Continental Oil, 184 F.2d at 816.

[83]*Continental Oil*, 184 F.2d at 817. The court held Continental Oil had underpaid $128,261.50 in crude oil royalties which represented the difference between Continental Oil's "proceeds" and the court's "market value" determination. 184 F.2d at 807. This was also the apparent dilemma of the lessee in *United States v. Ohio Oil Co.*, 163 F.2d 633 (10th Cir. 1947), *cert. denied*, *Ohio Oil Co. v. United States*, 333 U.S. 833 (1948) (lessee locked into long-term contract to sell oil for $0.77/barrel when current market price for oil in the field was $1.02/barrel).

[84]For example, the court found: "In our opinion the net realization order was made in an effort to carry out the Secretary's *duty to collect royalty on the basis of value* and it was a proper exercise of the Secretary's reserved power to determine value for royalty purposes." *Continental Oil*, 184 F.2d at 821 (emphasis added). This search for the value of *production* for royalty purposes is further illustrated by the court's deduction of gathering expenses to adjust gas values to reflect the wellhead value of the *gas* instead of the value or the *gas plus the value of the*

associated with the "value" of production is the issue of what sort of "production" the lessee must make available for valuation.

C. What Sort of "Production" Must the Lessee Make Available to be "Removed or Sold from the Lease"?

This issue is typically stated in terms of the lessee's marketing obligations. What must the lessee do with the oil and gas it extracts in order to comply with its royalty obligation of "12½ per centum in amount or value of production removed or sold from the lease"? Often times resolution of the scope-of-the-relationship issue discussed in subsection A. will also resolve the issue posed in this subsection. This is also a major battleground for the royalty value theorem. Because production values tend to increase in a linear fashion as production moves away from the wellhead,[85] the MMS will seek to push the point of royalty valuation as far downstream from the wellhead as possible. Tools used by the MMS to accomplish this task include: (1) the gross proceeds rule;[86] (2) affiliate

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gathering service. *General Petroleum*, 73 F. Supp. at 254, 257.

[85]*See supra* Part IV.A.1.

[86]The major impact of the gross proceeds rule is it ensures royalty valuation events will not take place near the wellhead unless the production is actually sold at the wellhead. The physical removal of the oil and gas from the lease, under the gross proceeds rule, will not trigger a royalty valuation event. I predict this rule will be directly challenged by the industry as contrary to the express terms of § 17 of the Mineral Leasing Act which specifies a royalty on the "value of production removed or sold from the lease . . . ." The industry will argue that if the production is not "sold" at the lease, but rather is "removed . . . from the lease" and sold or used at some downstream location, the proper measure of royalty, *under the Mineral Leasing Act*, is the market value of the production at the time it left the leased premises. The MMS will place primary reliance on *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), which gave effect, with a vengeance, to the MMS's gross proceeds rule. However, perhaps the most interesting aspect of the trial court's opinion, and that of the panel of 9th Circuit judges that affirmed, is that nowhere was the critical § 17 Mineral Leasing Act language mentioned. Instead the district court judge relied upon the general policy statement that the Mineral Leasing Act was intended "'to promote wise development of natural resources and to obtain for the public reasonable financial returns on assets belonging to the public.'" 604 F. Supp. at 1380. The judge also noted General Accounting Office reports, the Linowes Commission findings, and general legislative findings surrounding enactment of the Federal Oil and Gas Royalty Management Act of 1982, concerning the incompetence of the government in policing its oil and gas lease revenues. 604 F. Supp. at 1380-81. Although none of these matters had anything to do with whether royalty values should be worked-back from Japan, they apparently influenced the trial judge's decision regarding the MMS's gross proceeds rule. The situation was aggravated by the 9th Circuit's one paragraph summary affirmance of the trial judge's gross proceeds/work-back analysis. 807 F.2d at 765-66.

rules;[87] and (3) marketing rules.[88] The MMS's limitation on the deduction of costs is designed to magnify the impact of downstream valuations to maximize the government's benefits under the royalty value theorem.

1. The MMS Approach.

The MMS's marketing obligations are designed to complement its gross proceeds rule. If the lessee could merely sell oil or gas at the first opportunity, it would typically yield lower gross proceeds than if it were required to sell after conditioning the oil or gas and undertaking various marketing efforts. The hope is that the lessee's net revenue interest in the production stream from a lease, and other leases they may have in the area, will cause the lessee to engage in business ventures downstream of the wellhead by investing in its production to try and realize downstream profits not available at the wellhead. The gross proceeds rule, combined with the affiliate rules, effectively allow the government to participate in these downstream profits; rules limiting the deduction of costs ensure the government gets an even better deal than its lessee. The entire system is designed to avoid a royalty based upon the market value of the production when it is removed from the lease. The MMS treats the market value at the well as the "floor" for royalty valuation and relies upon the gross proceeds, affiliate, and marketing rules to establish the royalty it will demand.

Under the MMS's regulation the lessee is required to "place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government."[89] To determine whether the rule is designed to accurately define market value, as opposed to being designed to manipulate the royalty value theorem, consider the following scenario:

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[87]The affiliate rules magnify the impact of the gross proceeds rule by extending downstream the arm's-length transaction for royalty valuation. But for the gross proceeds rule, there would be no need for affiliate rules. Lessees will argue that since the Mineral Leasing Act requires a market value–as opposed to proceeds–measure to calculate royalty, it should not matter what the lessee does with the oil and gas once it is produced. Use of the production by the lessee, sale to itself or an affiliated company, or sale to a third party should all result in the same market value measure for calculating the royalty due.

[88]The focus of marketing rules is to require the lessee to do something with the production once it is removed from the lease. The industry response will be that once production is removed from the lease the critical royalty-valuation event has already taken place–triggering a royalty based upon the market value of the production removed. The MMS argument requires the lessee to prepare a "marketable product" and, more recently, requires that the "marketable product" be marketed "for the mutual benefit of the lessee and the lessor . . . ." 30 C.F.R. § 206.106 (2000).

[89]30 C.F.R. § 206.106 (2000).

- There is an active, competitive market for the purchase of oil at the well where produced.
- The wellhead price for oil in the area is $20.00/barrel.
- Oil from the Federal 1-5 Well is being marketed by the lessee, Acme Oil Company, for $20.00/barrel at the well.
- Acme sells the oil at the wellhead to Third-Party Gathering Company.
- Third-Party Gathering Company collects the oil and delivers it to Third-Party Purchasing Company at a centralized delivery point in the field of production.
- Purchasing Company pays Gathering Company $21.00/barrel for the oil at Purchasing Company's interstate pipeline connection in the field.
- There is an active, competitive market for the purchase of oil at Purchasing Company's centralized delivery point, which is $21.00/barrel.
- Purchasing Company takes the oil, combines it with other oil, and transports it to a refinery where it is sold to Third-Party Refining Company for $25.00/barrel.
- There is an active, competitive market for the purchase of oil at Refinery Company's refinery, which is $25.00/barrel.

Acme is obligated to pay 12½% of the "value of the production removed or sold from the lease."[90] If Acme pays 12½% of $20.00, will the MMS complain? Yes. The MMS will demand royalty based upon 12½% of $21.00 contending that Acme could not avoid its marketing obligation to move ("gather") its oil within the field of production. Had Acme fulfilled its marketing obligation it could have delivered the oil to the "better" market at Purchasing Company's interstate pipeline connection in the field. The MMS's regulation states:

> If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.[91]

The MMS will likely argue that a prudent operator in Acme's position would have paid to move its oil to Purchasing Company's interstate pipeline connection to obtain $21.00/barrel for its oil.

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[90]MLA § 17(b) & (c), 30 U.S.C. § 226(b) & (c) (1994).

[91]30 C.F.R. § 206.106 (2000).

This analysis is also supported by the MMS's "gross proceeds" rule which allows the MMS to disregard the gross proceeds and apply a downstream price when:

> MMS determines that the value [sales price] . . . does not reflect the reasonable value of the production due to . . .
>
> (ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.
>
> (A) MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's length contract.
>
> (B) The fact that the price received by the seller in an arm's length transaction is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market *unless MMS finds additional evidence that the seller acted unreasonably* or in bad faith in the sale of oil from the lease.[92]

The MMS would most likely conclude Acme acted "unreasonably" because it sought to avoid paying to gather the oil to the intrastate pipeline connection.[93] The MMS would argue the government is losing $0.125/barrel in royalty (12½% of $1.00) because Acme failed to properly market its oil by paying to have it gathered to the $21.00/barrel market in the field.

The MMS relies, in part, on *California Co. v. Udall*[94] to support its marketable condition requirement.[95] In *California Co.* the lessee contracted to sell gas produced from federal lands to Southern Natural Gas Co. at a price of 12¢/Mcf. However, to meet the contract delivery specifications for some of the gas, the lessee incurred the following per Mcf charges: 0.3¢ gathering, 4.5¢ compression, and .25¢ dehydration. These charges were deducted from the 12¢/Mcf contract price and royalty was paid on the balance remaining: 6.95¢/Mcf. The Secretary of Interior demanded that royalty be calculated on the 12¢/Mcf contract proceeds without any deduction for gathering,

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[92]30 C.F.R. § 206.102(c)(2) (2000) (emphasis added).

[93]This would seem to particularly be the case when the MMS expressly denies its lessees a deduction for gathering expenses. *See* 30 C.F.R. § 206.109(a) (2000) (allowing deduction of transportation costs that are "not gathering"). "Gathering" is defined as "movement of lease production to a central accumulation or treatment point . . . off the lease . . . ." 30 C.F.R. § 206.101 (2000).

[94]296 F.2d 384 (D.C. Cir. 1961).

[95]Proposed Oil Rule, Preamble at 73822.

compression, and dehydration.[96] After noting the parties agreed the term "value"[97] meant "fair market value",[98] the court focused on the meaning of the word "production."[99] The court stated the issue as follows:

> Does it ["production"] mean the raw product as it comes from the well, no matter what its condition? Or does it mean that product readied for the market in and to which it is being sold?[100]

The lessee stipulated that it had a duty to market the gas.[101] The Secretary contended that "since the lessee was obliged to market the product, he was obligated to put it in marketable condition; and that the 'production' was the product in marketable condition."[102] The court ultimately rests its holding on a burden-of-proof finding. The Secretary had presented factual evidence to believe that the gas was not marketable until it had been produced, gathered, dehydrated, and compressed for delivery

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[96]California Co. v. Seaton, 187 F. Supp. 445, 446-47 (D.C. 1960), *aff'd*, California Co. v. Udall, 296 F.2d 384 (D.C. Cir. 1961).

[97]The court was focusing on § 17 of the Mineral Leasing Act which provides for a royalty based upon the "value of the production". *California Co.*, 296 F.2d at 386-87.

[98]The trial court also observed that "the term 'value of production' does not defy interpretation and there is authority for its close identification with a market or contract price." *Seaton*, 187 F. Supp. at 449. The trial court concluded there was a rational basis for the Secretary equating the 12¢/Mcf contract price to the "value" required by the statute because the contract, under these facts, supported the Secretary's determination of gas values. The court cautioned, however:

> This is not to suggest that he [the Secretary] take the easy way out and compute royalty on the contract price, which includes some, but not uniform m.c.f. costs of preparing the gas for production or marketing, merely because it involves less work for the Supervisor.

187 F. Supp. at 453. So long as the Secretary is pursuing the statutory "value", and is relying upon evidence that is relevant to ascertaining that value, the court will not second-guess the Secretary's conclusions. In this case the conclusion was the 12¢/Mcf contract price equaled the royalty "value" mandated by § 17 of the Mineral Leasing Act.

[99]*California Co.*, 296 F.2d at 387.

[100]*Id.*

[101]*Id.*

[102]*Id.*

to the gas purchaser. The lessee simply failed to prove the gas was marketable in its ungathered, undehydrated, and uncompressed state. The trial court observed: "The lessee has not shown that the gas can be marketed at the pressure with which it comes from the wells."[103] The court of appeals found:

> In the record before us there is no evidence of a market for the gas in the condition it comes from the wells. The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content.[104]

Therefore, it appears the "marketable product" approach for federal leases is much like that under the law of Colorado,[105] Kansas,[106] and Oklahoma[107] where a case-by-case factual inquiry will be required to ascertain the "marketable" status of the production.

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[103]*Seaton*, 187 F. Supp. at 451.

[104]*California Co.*, 296 F.2d at 388.

[105]Garman v. Conoco, Inc., 886 P.2d 652, 659, 661 (Colo. 1994) (lessee has obligation to produce a marketable product but once a marketable product is obtained any additional costs to enhance the value of the gas may be deducted to calculate royalty; when production becomes marketable is a question of fact); Rogers v. Westerman Farm Co., 986 P.2d 967 (Colo. App. 1999), *appeal to Colorado Supreme Court pending*, (gas was found to be marketable at the wellhead although lessee gathered, dehydrated, and compressed the gas to obtain a higher downstream sales price; lessee was entitled to deduct gathering, dehydration, and compression costs when paying lessor royalty based upon the downstream sales price).

[106]Sternberger v. Marathon Oil Co., 894 P.2d 788, 799-800 (Kan. 1995) (lessee has duty to produce a marketable product but once a marketable product is obtained reasonable costs incurred to enhance the value of the marketable gas can be deducted in calculating royalty). The court in *Sternberger* also noted that the gas was in fact marketable at the wellhead, even though no gas was being sold at the well. Nevertheless, the court held the lessee was entitled to deduct its gathering expenses, which were incurred beyond the wellhead, because the lease provided for a royalty valuation at the well.

[107]Mittlestaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1208, 1210 (Okla. 1998) (lessee has a duty to provide a marketable product at the wellhead or leased premises; "a royalty interest may bear post-production costs of transporting, blending, compression, and dehydration, when the costs are reasonable, when actual royalty revenues increase in proportion to the costs assessed against the royalty interest, when the costs are associated with transforming an already marketable product into an enhanced product, and when the lessee meets its burden of showing these facts.").

2. The Industry Response.

The probable industry response to the MMS's marketing requirements will be to try and ensure all costs associated with enhancing production once it is produced will be deductible when calculating royalty.[108] From a conceptual point of view, this asks for too little. The foundational question should be whether the lessor/government is entitled to share in any benefits (whether gross or net profits) downstream of the royalty valuation point specified by statute. If the Mineral Leasing Act and related federal leasing statutes require a royalty based upon the "*value* of the production removed or sold *from the lease*", then the marketing obligation is quite clear: extract oil and gas and move it off the lease. Nothing more would be required. Extraction and removal trigger an obligation to pay the market value of the production that was removed from the lease. The relevant value would be the value at the lease. The gross proceeds a lessee received in a sales transaction would be relevant only to the extent they provide evidence useful for calculating the market value of production at the lease. The industry will rely upon the *General Petroleum* case to support each of these arguments.[109]

The industry will also rely upon the court's analysis in *Independent Petroleum Ass'n of America v. Armstrong*[110] which made several helpful findings. First, the court found: "The longstanding interpretation of 'value of production,' one recognized by Interior (at least until the present matter) and affirmed by the courts, is that it refers to the value of oil or gas *at the wells*."[111] The court then noted this "at the well" interpretation limits the government's royalty rights: "Thus, it is well-recognized that the government's royalty interest is limited to the value of production at the lease or wellhead, not in value enhancements resulting from downstream activities."[112] Second,

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[108]*See generally* Joyce Colson, *Upstream, Midstream, Downstream–The Valuation of Royalties on Federal Oil and Gas Leases*, 70 Colorado L. Rev. 563, 575 (1999) ("Is it reasonable to impose an implied duty to market on a lessee whereby the lessor reaps the benefit of increased value resulting from valuation at a midstream or downstream point without paying any associated costs?").

[109]United States v. General Petroleum Corp. of California, 73 F. Supp. 225, *aff'd*, Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950).

[110]91 F. Supp.2d 117 (D. D.C. 2000).

[111]91 F. Supp.2d at 125 (emphasis by the court).

[112]*Id.* The court completed its analysis stating:

> Accordingly, the government's royalty interest on the value of production may not include proceeds received by lessees that are attributable to matters other than gas production. . . . In light of these established principles, the court finds untenable MMS' present position that it has the authority to define value to include

the court found that "a duty to market gas at no cost may not be reasonably implied from the four corners of the lease agreements."[113] Again, the court found the lease language focuses the lessee's obligations, and reciprocal rights, at the well:

> [H]aving reviewed the applicable lease forms, the court finds no reasonable support for MMS' position that the leases obligate lessees to market gas at no cost to the lessor. To the contrary, the lease forms enumerate the various production- and royalty-related duties and rights without any mention of marketing or sale of gas beyond the lease or wellhead.[114]

D. The "Prudent Operator" Under Federal Oil and Gas Leases.

Under private leases the "prudent operator" is an objective standard used to define what a reasonable operator would do under the circumstances.[115] The legal standard–not the limitations and capabilities of the individual to which the standard is being applied–defines what must be done. Therefore, if a prudent operator would drill a protection well, we do not inquire into the financial ability of our particular operator to accomplish the task. It simply does not matter when defining the conduct required to satisfy the prudent operator standard. Courts have also refused to consider the lessee's business interests that are external to the oil and gas lease. For example, in *Amoco Production Co. v. First Baptist Church of Pyote*[116] it was immaterial for defining the lessee's marketing obligations to a particular lessor that other lessors in the field may benefit from the lessee's course of action. Similarly, in *Amoco Production Co. v. Alexander*[117] the lessee's implied development obligations to a particular lessor could not be limited because it may negatively impact

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> downstream costs unrelated to production of the gas.

Id. The court's observations illustrate the basic difference between a royalty on "oil" of "gas" and MMS attempts to obtain a royalty on "costs" or money the lessee spends to enhance oil or gas.

[113]91 F. Supp.2d at 128.

[114]*Id.* at 129.

[115]*E.g.*, Brewster v. Lanyon Zinc Co., 140 F. 801, 814 (8th Cir. 1905) ("Whatever, in the circumstances, would be reasonably expected of operators of ordinary prudence, having regard to the interests of both lessor and lessee, is what is required.").

[116]579 S.W.2d 280 (Tex. App. 1979), *writ ref'd, n.r.e.*, 611 S.W.2d 610 (Tex. 1981) (per curiam opinion).

[117]622 S.W.2d 563 (Tex. 1981).

the lessee's other lessors in the field. The *Alexander* case also defines the lessee's implied obligations using the "single lease analysis" which means: "Amoco owed the Alexanders the duty to do whatever a reasonably prudent operator would do *if the Alexanders were its only lessor in the field.*"[118] The fact-specific, and contract-specific, nature of the implied covenant analysis was explained by the court as follows:

> Amoco's responsibilities to other lessors in the same field do not control in this suit. This lawsuit is between the Alexanders and Amoco on the lease agreement between them and the implied covenants attaching to that lease agreement. The reasonably prudent operator standard is not to be reduced to the Alexanders because Amoco has other lessors in the same field.[119]

The foregoing principles establish that the definition of prudent operation should not vary with the individual capabilities, limitations, and business interests of the lessee. Keeping these principles in mind, consider the following scenario:

- Acme Oil Company owns a federal lease covering the North ½ of §30; Major Oil Company owns a federal lease covering the South ½ of § 30.
- Acme is a small non-integrated oil company; Major is a large integrated oil company.
- The terms of Acme's lease with the government are identical to those between Major and the Government.
- Each lease provides for assignment;[120] Acme could assign its lease to Major and Major could assign its lease to Acme.

Will Acme's marketing obligations be the same as Major's marketing obligations? With a single-lease analysis in place for defining express obligations, and an objective prudent operator standard in place for defining implied obligations, it should not matter "who" the lessee is to define what the lessee must do to comply with its lease obligations. If this were not the case, then every single lease would require the examination of extrinsic evidence to define lease obligations–based upon the unique situation of the current lessee. Therefore, it should not matter, in defining lease obligations, whether a particular lessee also owns gathering, treating, processing, refining, or other post-lease facilities, has existing contractual relationships that gives it access to such facilities, or, as discussed

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[118]Amoco Production Co. v. Alexander, 622 S.W.2d 563, 570 (Tex. 1981) (emphasis added).

[119]*Id.* at 569.

[120]Mineral Leasing Act § 30a, 30 U.S.C. § 187a (1994) ("any oil or gas lease issued under the authority of this chapter may be assigned . . . subject to the final approval by the Secretary").

in the following section, has affiliates that own such facilities.

E. Does the Mineral Leasing Act Negate Basic Principles of Corporate Law?

Is it permissible for the MMS to treat a good faith sale[121] of oil or gas to an affiliated company different from a good faith sale to a non-affiliated company? At the heart of this question is the extent to which the MMS can disregard the basic concept of corporate separateness. To illustrate the issue, as it will most likely be presented to the courts by lessees, assume the following facts:

- Acme Refining Company owns all the stock in Acme Production Company but is unrelated to Independent Oil Company.
- Acme Production and Independent Oil own adjacent oil and gas leases on federal lands; they produce oil that is identical in quality and quantity.
- Independent Oil sells oil to Acme Refining at the lease for $20.00/barrel.
- Acme Production sells oil to Acme Refining at the lease for $20.00/barrel.
- Acme Refining takes the oil from the leases and, through a series of investments and transactions, aggregates a large volume of oil at a market center where it is selling for $25.00/barrel.

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[121]The MMS does not inquire into whether the affiliate transaction is in fact proper or improper. 30 C.F.R. § 206.103 (2000). Instead, it effectively deems all such transactions improper by disregarding the corporate separateness of the affiliated companies. As noted by the MMS in the Preamble to the Oil Valuation Rule:

> If the lessee first transfers to a wholly-owned or wholly-commonly-owned affiliate who then resells at arm's length downstream, it is still true that the producing entity could have sold its production at the point and at the price its affiliate did, instead of using the wholly-owned affiliate arrangement. It is perfectly proper to value the production of a producer who markets through a wholly-owned affiliate at a higher level than the production that other producers sell at arm's length in the first instance, when the gas (or oil) marketed through the wholly-owned affiliate commands a higher price.

Proposed Oil Rule, Preamble at 73823.

- Acme Refining sells one-half of the oil for $25.00/barrel and moves the rest to its refinery where it is used in its refining process.

- Assume that under MMS transportation allowances, the MMS will allow Acme Production a $2.00/barrel transportation fee/location differential.

- The MMS demands royalty from Independent Oil based upon a $20.00/barrel oil value making Independent Oil's royalty $2.50/barrel (12½% x $20).

- The MMS demands royalty from Acme Production based upon a $23.00/barrel oil value making Acme Production's royalty $2.875/barrel (12½% x $23).

- There has been no wrong-doing by the Acme entities; there is no basis for "piercing the corporate veil" or otherwise refusing to recognize the corporate separateness between Acme Refining and Acme Production–other than the MMS's oil valuation regulations.

- Compared to Independent Oil, Acme Production's effective royalty percentage is 14.375% instead of 12.5%.

- Acme Production challenges the MMS's valuation because it results in a royalty that is not reflective of "12½ per centum in amount or value of the production removed or sold from the lease" and the MMS's valuation disregarding the corporate separateness of Acme Production and Acme Refining is not "reasonable."

1. MMS Concerns Regarding Affiliate Transactions.

The obvious concern the MMS has with affiliate transactions is the lessee's ability to manipulate the sales price[122] when the producing company sells to an affiliated purchasing company. The traditional approach for policing affiliate transactions would be through the audit process to determine if the prices being paid by a purchasing affiliate are representative of market value at the

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[122]This sales price defines the "gross proceeds" that form the basis for calculating the government's royalty. 30 C.F.R. § 206.102 (2000) ("The value of oil . . . is the gross proceeds accruing to the seller under the arm's-length contract . . . ."). "Gross proceeds" is defined as "the total monies and other consideration accruing for the disposition of oil produced." 30 C.F.R. § 206.101 (2000). "Arms-length contract" is defined as "a contract or agreement between independent persons *who are not affiliates* and who have opposing economic interests regarding that contract." *Id.* (emphasis added). "Affiliate" is defined broadly to include ownership of over 50% of the voting stock in an entity with a presumption of control arising when there is ownership of between 10 and 50% of the voting stock. *Id.*

point of sale.[123] Presumably the same techniques used to test an arm's length sale would be used to test an affiliate sale. The basic issue in each case is the value of the production at the point of sale. However, the technique used by the MMS to address affiliate transactions is to disregard them altogether by treating the affiliate purchasing company's sale of production as the only relevant transaction for royalty purposes.

2. Corporate Separateness and the Supreme Court.

Corporations were invented to isolate and control business risks. Frequently, for example, a properly-advised corporate client will use subsidiary corporations to conduct various business enterprises to isolate the risk of one line of business from another. Justice Souter recently noted, in an unanimous Supreme Court opinion:

> It is a general principle of corporate law deeply 'ingrained in our economic and legal systems' that a parent corporation (so-called because of control through ownership of another corporation's stock) is not liable for the acts of its subsidiaries. . . . 'A corporation and its stockholders are generally to be treated as separate

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[123]For example, in *Shell Oil Co. v. Babbitt*, 125 F.3d 172, 175 (3d Cir. 1997), the MMS sought records from Shell Western E & P, Inc. (the federal lessee) and its parent company, Shell Oil Co. (the purchasing company) "to determine whether the non-arm's length price Shell paid Shell Ex [Western] was acceptable for royalty valuation purposes." The court held:

> MMS is entitled to documents which will allow it to determine if Shell Ex is undervaluing oil for royalty purposes by first transferring it to Shell. Whether or not that is so, we are satisfied that for auditing purposes Shell must disclose the records the State requested.

125 F.2d at 178. However, the court was careful to note:

> We conclude by emphasizing that our ruling is narrow. We do not find that MMS can impute the proceeds received by Shell to Shell Ex. We will leave the determination of that issue to a case in which it is presented. Thus, we agree with Shell that this appeal 'does not directly concern the proper value of royalties on oil produced from [Shell Ex's] 32 leases.'

Id. See, also, Santa Fe Energy Products Co. v. McCutcheon, 90 F.3d 409 (10th Cir. 1996) (Federal Oil and Gas Royalty Management Act authorized MMS to require purchaser affiliated with federal lessee/producer to provide documents relating to purchaser's resale of production purchased from affiliated purchaser).

entities.'[124]

Typically, the corporate separateness between affiliated companies will be disregarded only when there is a factual basis for piercing the "corporate veil."[125] An administrative agency, executing its statutory programs, must respect principles of corporate separateness unless Congress expressly authorizes it to disregard basic corporate law concepts. For example, the Supreme Court in *Bestfoods* had to determine whether the Environmental Protection Agency ("EPA") was authorized to disregard the corporate separateness of a wholly-owned subsidiary under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA").[126] CERCLA is the classic "remedial" statue designed to effect the cleanup of sites where hazardous substances pose a potential danger to public health and the environment. Because of its remedial goals, courts have been willing to interpret it broadly. The statute itself imposes strict liability on broad classes of persons "[n]otwithstanding any other provision or rule of law . . . ."[127] The question posed in *Bestfoods* is whether CERCLA's broad strict liability concepts would apply to various entities notwithstanding basic concepts of corporate law that treat affiliated companies as separate legal entities.

The facts in *Bestfoods* illustrate just how far the Supreme Court is willing to go to protect basic concepts of corporate law. Ott Chemical Co. (Ott I) had been manufacturing chemicals at a plant in Michigan from 1957 to 1965. CPC International Inc. ("CPC") wanted to buy Ott Chemical so it incorporated an entity also named Ott Chemical Co. (Ott II). Ott I then sold all its assets to Ott II in exchange for CPC stock.[128] Ott II continued manufacturing chemicals at the site until 1972 when CPC sold Ott II to Story Chemical Company. Story operated the site until its bankruptcy in 1977.[129] Afterwards, Michigan environmental officials found the Ott/Story site "littered with

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[124]United States v. Bestfoods, 524 U.S. 51, 61 (1998).

[125]As noted by Justice Souter in *Bestfoods*:

> But there is an equally fundamental principle of corporate law, applicable to the parent-subsidiary relationship as well as generally, that the corporate veil may be pierced and the shareholder held liable for the corporation's conduct when, inter alia, the corporate form would otherwise be misused to accomplish certain wrongful purposes, most notably fraud, on the shareholder's behalf.

524 U.S. at 62.

[126]CERCLA §§ 101 to 405, 42 U.S.C. §§ 9601 to 9675 (1994).

[127]CERCLA § 107(a), 42 U.S.C. § 9607(a) (1994).

[128]524 U.S. at 56.

[129]*Id.* at 57.

thousands of leaking and even exploding drums of waste, and the soil and water saturated with noxious chemicals."[130] The necessary cleanup to remedy the hazardous conditions at the Ott/Story site was estimated by the EPA to cost "well into the tens of millions of dollars."[131] At the time the EPA began looking for liable parties, the Ott I and Ott II entities were defunct and Story was bankrupt.[132] Therefore, EPA had a strong incentive to impose liability on CPC as the parent of the Ott II wholly-owned subsidiary.

Another group of corporate affiliates were also involved with the Ott site. In 1977 Aerojet-General Corp. arranged for the purchase of the Ott site from Story's trustee in bankruptcy. However, recognizing the substantial risk associated with the contaminated site, Aerojet did not want to expose its general corporate assets to the undertaking. Therefore, Aerojet, like CPC, created a wholly-owned subsidiary, Cordova Chemical Company, to purchase the former Ott site.[133] In 1981 the EPA began to focus on the former Ott site and in 1989 brought suit against CPC, Aerojet, the Cordova entities, and an individual, Arnold Ott.[134] The major targets of the EPA's efforts were Aerojet, as the parent corporation of the Cordova entities, and CPC, as the parent corporation of the Ott II entity; after all, the cleanup was projected to cost "tens of millions of dollars," the Ott entities were defunct, and the Cordova entities apparently lacked the "tens of millions" necessary to perform the cleanup.[135] Unless the EPA could impose liability on CPC and Aerojet, the cleanup costs would presumably require that the EPA draw upon the Superfund–meaning taxpayers would pick up the tab.

With these equities stacked in the EPA's favor, it was a particularly bold move for the Supreme Court to hold that the corporate separateness of CPC and Aerojet must be respected absent: (1) a factual basis for piercing the corporate veils that separate them from their wholly-owned subsidiaries; or (2) a clear statutory basis expressed in CERCLA that principles of corporate separateness should be ignored. The district court, and the court of appeals, each held there was no basis to "pierce the corporate veils" that existed between CPC and Ott II, and Aerojet and Cordova.[136] Therefore, the issue before the court was whether CERCLA provided a statutory basis

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[130] *Id.*

[131] *Id.*

[132] *Id.* at 58.

[133] Cordova Chemical Company in turn created a wholly-owned subsidiary, Cordova Chemical Company of Michigan, to manufacture chemicals at the site. 524 U.S. at 57.

[134] 524 U.S. at 58.

[135] Arnold Ott settled with the EPA prior to trial. 524 U.S. at 58 n.6.

[136] The Court observed:

> Applying Michigan veil-piercing law, the Court of Appeals decided that

for disregarding the corporate separateness of CPC/Ott II and Aerojet/Cordova. Finding CERCLA lacked the necessary language addressing the issue, the Court held:

> CERCLA is thus like many another congressional enactment in giving no indication 'that the entire corpus of state corporation law is to be replaced simply because a plaintiff's cause of action is based upon a federal statute' . . . and the failure to speak to a matter as fundamental as the liability implications of corporate ownership demands application of the rule that '[i]n order to abrogate a common-law principle, the statute must speak directly to the question addressed by the common law,' . . . .[137]

3. Do the Federal Leasing Laws "Speak Directly" to the "Liability Implications of Corporate Ownership"?

I predict the answer to this question will go a long way towards answering the government's "sixty-six million dollar" question posed in Tom Brokaw's "Fleecing Of America" segment.[138] The challenge for MMS and industry combatants will be to determine whether the Allotted Lands Leasing Act of 1909,[139] Mineral Leasing Act of 1920,[140] Right-of-Way Leasing Act of 1930,[141]

> neither CPC nor Aerojet was liable for controlling the actions of its subsidiaries, since the parent and subsidiary corporations maintained separate personalities and the parents did not utilize the subsidiary corporate form to perpetuate fraud or subvert justice.

524 U.S. at 60. This holding was not challenged by any of the parties on appeal. 524 U.S. at 63 n.9.

[137]524 U.S. at 63. The Court noted: "Although this respect for corporate distinctions when the subsidiary is a polluter has been severely criticized in the literature, . . . nothing in CERCLA purports to reject this bedrock principle, and against this venerable common-law backdrop, the congressional silence is audible." 524 U.S. at 62.

[138]Transcript, October 5, 1999 NBC Nightly News, NBC-TV ("Bottom line, taxpayers lose up to sixty-six million dollars a year, according to the government."). Available through Video Monitoring Services of America, L.P., 330 West 42nd Street, New York, New York 10035.

[139]25 U.S.C. § 396 (1994).

[140]30 U.S.C. §§ 181-287 (1994).

[141]30 U.S.C. §§ 301-306 (1994).

Omnibus Indian Mineral Leasing Act of 1938,[142] Acquired Lands Leasing act of 1947,[143] Outer Continental Shelf Lands Act of 1953,[144] Indian Mineral Development Act of 1982,[145] Federal Oil and Gas Royalty Management Act of 1982,[146] Federal Onshore Oil and Gas Leasing Reform Act of 1987,[147] Royalty Simplification and Fairness Act of 1996,[148] or other applicable federal laws, provide clear authority for the MMS's disregard of the separate and distinct corporate existence of affiliated entities.

V. CONCLUSION.

There should not be any dispute among the parties that the MMS can take appropriate action to ensure federal, state, and tribal governments are not being cheated out of the royalty due them under the federal leasing system. The problem is determining what action is appropriate considering the lessee's statutory obligation, and reciprocal right, to pay royalty based upon the "value of the production removed or sold from the lease." All regulatory and interpretive efforts are built upon the obligation to pay, and the right to pay, the value of production when it is "removed or sold from the lease." As noted above, the first task will be to define the scope of the lessor/lessee relationship. Once this is determined, the scope of the lessee's marketing obligation can be properly defined, along with the prudent operator standard that will be imposed on federal lessees. The courts may also have to consider, in the obligations/rights context, the validity of contractual lease terms that have been defined by regulations, accepted by lessees, but not necessarily consistent with the governing statutes. Finally, the courts will have to consider the role of corporate law under the Mineral Leasing Act and the other federal leasing statutes, in light of the United States Supreme Court's holding in *United States v. Bestfoods*.[149]

To date, it appears the MMS's regulations have been driven by the royalty valuation theorem and a desire to use downstream price indexes to generically calculate royalty obligations. Since the use of such indexes also optimize the lessor's position under the royalty valuation theorem, the

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[142] 25 U.S.C. §§ 396a-396g (1994).

[143] 30 U.S.C. §§ 351-360 (1994).

[144] 43 U.S.C. §§ 1331-1356 (1994).

[145] 25 U.S.C. §§ 2101-2108 (1994).

[146] 30 U.S.C. §§ 1701-1757 (1994).

[147] Pub. L. No. 100-203 (1987).

[148] Pub. L. No. 104-185 (1996)

[149] 524 U.S. 51 (1998).

MMS's position has been presented as a necessity for determining "value" while avoiding the potential for cheating by lessees.[150] The industry will respond that such prophylactic efforts are: (1) a sham to obtain a greater fraction of the value than authorized by statute; (2) perhaps effective to ease the MMS's royalty administration, but not permissible when they impinge upon the lessee's basic statutory royalty rights; and (3) unnecessary because more precise measures exist to address lessee-cheating risks without altering the lessee's underlying royalty obligations/rights. As the MMS and the industry join these issues in litigation, the precise allegations and concerns of the MMS may actually assist in defining the limits of its regulatory authority. The MMS's royalty valuation concerns can be placed in two categories: (1) general manipulation of oil and gas markets so that prices offered and paid are not competitive; and (2) the use of exchanges, affiliate transactions, and other devices to create an artificial price for production that is not representative of its market value.

If the MMS desires to use downstream indexes to calculate royalty,[151] perhaps the best approach would be to negotiate individually with its lessees to arrive at a mutually acceptable index-based standard that reflects the "value" of production as it is removed from the lease. This would avoid having to trace what the lessee does with the production and would provide an objective standard that could be easily policed. For example, the parties could individually investigate various indexes that have been in existence for several years and identify those that could, with proper adjustments, serve as an analog to production values at the lease. The next step would be to negotiate the index discount factor that will be used in lieu of comparable sales at the lease. Assume a historical analysis of wellhead prices in the field, compared to the targeted index, reveal that a 20% discount would be appropriate. Therefore, the parties could agree that until either party elects to terminate the agreement, royalty settlements under their oil and gas lease would be based upon 80% of the chosen index price. Although the agreement would be open to adjustment at any time, any royalty obligation accruing while the agreement is in place would be governed by the agreement.

Realistically, the royalty value theorem, combined with the tendency to demonize the parties' contractual disputes, offers little hope for resolution of the issues short of further judicial action. Settlement, in the current climate, also seems ill-advised.[152] The situation is also aggravated by a

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[150]Courts have acted to protect the lessee's royalty "rights" when the government has taken action to increase the royalty beyond what is required by statute or contract. *See, e.g.*, Gulf Oil Corp. v. Andrus, 460 F. Supp. 15, 17 (C.D. Cal. 1978) (rejecting government's attempt to obtain royalty on production that is not "removed" from the leased premises); Marathon Oil Co. v. Andrus, 452 F. Supp. 548, 553 (D. Wyo. 1978) (rejecting government's attempt to impose royalty obligation on oil and gas that is unavoidably lost or used in lease operations).

[151]I have been a big fan of index pricing for royalty calculation and first advocated it in 1992. David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 Eastern Min. L. Inst. 18-1, 18-52 (1992).

[152]Settlements on these issues often have a lingering negative legal impact, particularly on the industry party. For example, in *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1386

remarkable lack of "controlling legal authority" to guide the parties. I predict the parties will be active in the coming years trying to develop "controlling legal authority." Until then, we are left with the basic statutory mandate that lessees pay the government royalty based upon the ***"value of the production removed or sold from the lease."***

(D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), Marathon got whipsawed by Judge Fitzgerald who relied, in part, upon Marathon's prior settlement to justify using liquified gas sales in Japan to value gas at the well in Alaska. The judge observed:

> Obviously the February 1981 settlement agreement demonstrates that the price paid for gas by Alaska Pipeline on its long-term contract failed to provide reasonable value for purposes of computing royalty on that portion of the gas delivered to the LNG plant for sale in Japan. . . . Thus Marathon's argument that 'the "gross proceeds" received by the lessee from the sale of [the LNG] with its enhanced values in a distant market are not indicative of the value of the raw material feedstock gas produced at the lease' has a hollow ring. Since January 1, 1980, the effective date of the settlement agreement, Marathon paid royalties based on a 'value' derived from the sales price in Japan. Marathon expressly agreed to this method in the February 1981 settlement agreement. Marathon cannot now credibly argue that landed sales price in Japan is irrelevant to the reasonable value for purposes of computing royalties.

No good deed goes unpunished.