Section 3

United States Department of the Interior

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FEB 12 1987

Memorandum

To: Director, Minerals Management Service

From: Associate Director for Royalty Management

Subject: Review of Analysis Titled "Crude Oil Royalty Valuation Monitoring System," by Bob Berman, Policy, Budget, and Administration

By memorandum of November 21, 1986, the Deputy Assistant Secretary, Policy, Budget, and Administration (PBA), suggested to you that further study be done of market-based approaches to royalty valuation under non-arm's-length conditions. He included an analysis dated November 28, 1986, by PBA's Bob Berman, who suggests the application of oil futures or spot prices as an alternative valuation methodology. Our comments on this analysis have been requested.

It is obvious that considerable thought and effort have gone into Mr. Berman's analysis. However, the inescapable conclusion is that, for purposes of oil royalty valuation, the application of futures and/or spot prices would be either contrary to existing law, lease terms, and regulations, or too impractical and nonspecific to administer. Listed below are our specific comments:

-- The Mineral Leasing Act of 1920 (Section 17(b) and (c)) states that royalty shall be based on the amount or value of production removed or sold from the lease. The Outer Continental Shelf Lands Act of 1953 (Section 6(a)(8)) states that royalty is due on the amount or value of production saved, removed, or sold. There can be little doubt that the value of production removed or sold was intended to be the current value, for which a futures price would be inapplicable.

-- Similarly, the various Federal and Indian leases require royalty on the amount or value of production removed or sold. Once again, futures prices would not, except coincidentally, reflect values of production sold currently.

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-- The existing regulations dealing with oil valuation, both onshore and offshore, address value of production, at the time of production or sale, for computing royalty. The regulations at 30 CFR 206.103 (onshore) state that, in the absence of good reason to the contrary, value based on the highest price paid or offered at the time of production for the major portion of like-quality products from the same field or area will be considered reasonable value. Similarly, the regulations at 30 CFR 206.150 (offshore) state that "Under no circumstances shall the value of production be less than the gross proceeds accruing to the lessee. . . ."

These regulations require leasehold oil production to be valued as of the time of production and/or sale. Hence, any attempt to apply a futures price for royalty value purposes would necessarily incorporate the market's assessment of the level of oil prices at some future date. Obviously the futures prices would not necessarily be reflective of current market price levels as required by regulation.

Though it may be suggested that current regulations could be changed to effect changes to royalty provisions of future leases, it is important to note that such rulemaking would need to conform with existing statutes. As previously mentioned, existing statutes indicate a royalty based on current value. Consequently, a change in statutory, as well as regulatory, language may be necessary to issue new leases with royalty provisions tied to futures values.

-- Application of spot prices in valuing non-arm's-length disposals of lease production would not be specific. Spot prices are available only for a limited number of "benchmark" domestic crudes delivered at specific points; e.g., West Texas Intermediate at Cushing, Oklahoma. It is not clear how spot prices would be adjusted for differences in quality or necessary transportation between that of the "benchmark" crude and that of the crude to be valued. An adjustment for differences in API gravity alone, for example, while a reasonable price adjustment mechanism for oil produced in the same field or area, does not necessarily reflect true value differences when comparing crudes from distant areas. The price differences in crude oil nationwide depend upon a host of factors not limited solely to gravity and transportation adjustments. Factors important to the establishment of value of a particular crude include the need for and availability of crude oil supply, the cost of transportation to the refinery, the chemical composition and refining characteristics of the crude oil, the cost to refine the particular crude, the mix of refined products derivable from the crude and their values, prices currently paid or offered for the same or comparable crudes, and other economic criteria. Posted prices, which exist in all the important producing areas, reflect all these considerations; "benchmark" spot prices, on the other hand, cannot relate these factors specifically to each producing area. The same is true for futures prices, which also relate to a few "benchmark" crudes only.

-- Mr. Berman's analysis speaks to "market-based" alternate valuation procedures; i.e., futures and/or spot prices. The implication that posted prices are not market prices is, of course, true to the extent that postings are offers to buy and do not always reflect prices actually paid. Postings are, however, driven by the market, are sensitive to market changes, and are adjusted as market conditions require. While posted prices may, on occasion, vary slightly from actual market prices, they are undoubtedly market based. The MMS would be hard pressed to defend a position that futures prices are better, more accurate, and more current measures of royalty value for current production than are concurrent posted prices.

-- Posted prices are widely available. They exist for nearly all fields and areas for which royalty valuation is necessary. Further, since a field posting relates to oil with the same general quality characteristics, quality-based price adjustments are simple and accurate. The same cannot be said for application of spot or futures prices for royalty valuation purposes.

-- A real inconsistency would develop if prices received under arm's-length conditions were accepted for royalty valuation purposes while futures prices were applied to non-arm's-length transactions. Two entirely different valuation standards would exist. (We agree that non-arm's-length transactions should receive a higher monitoring priority, and generally be investigated more thoroughly than arm's-length transactions. However, the standards to which each type of transaction is held should be as similar as possible.) If arm's-length prices are acceptable for royalty valuation purposes, a reasonable proxy for current non-arm's-length prices is not a futures price, but, rather, an assessment of what is currently being obtained under arm's-length conditions.

In summary, even though Mr. Berman's analysis is a scholarly study which provides insight into the workings of the oil futures market, we must disagree with the application of oil futures or spot prices as a basis for royalty valuation in non-arm's-length situations. We have ignored the fact that the study covered a relatively short period of time (15 months) during which extreme pricing volatility took place, and we have not discussed other, more minor disagreements we have with the study. More important is the basic conclusion that, even if the study results do indicate that oil futures prices "lead" posted prices, this has no bearing on our valuation responsibilities. For royalty valuation purposes, we must apply market value existing at the time of production or sale. Whether postings are considered to lag futures prices or not, postings represent current offers to purchase oil and are adjusted as necessary to conform to market conditions. Further, oil futures and spot prices are available on such a limited basis as to make price adjustments for quality and/or transportation extremely difficult, if not meaningless.

It has been our policy in non-arm's-length situations to verify that the posting or other price to be applied for royalty purposes is consistent with prevailing arm's-length prices. This policy is, we feel, rightly extended in the proposed oil royalty valuation regulations. The continued acceptance of arm's-length postings or contract prices is seen as the most equitable, most practical, and most easily administered method of royalty valuation available. The widespread existence and acceptance of posted prices make them much more applicable to specific cases than oil futures or spot prices, both in terms of timing and necessary adjustments.

Jerry D. Hill

Section 4

PRELIMINARY ANALYSIS OF THE DEPARTMENT OF INTERIOR, MINERALS MANAGEMENT SERVICE PROPOSED RULE ESTABLISHING OIL VALUE FOR ROYALTY DUE ON FEDERAL LEASES AND ON SALES OF FEDERAL ROYALTY OIL

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PREFACE

Barents Group LLC, a wholly owned subsidiary of KPMG Peat Marwick LLP, was retained by Gardere & Wynne, L.L.P., on behalf of a group of companies having significant crude oil production on Federal lands, to assist in analyzing the Department of Interior, Minerals Management Service (MMS) proposed rule establishing a new methodology for valuing oil for royalties due on Federal leases, and on the sale of Federal royalty oil (62 F.R. 3742, published January 24, 1997). These companies are interested in and affected by the MMS proposal.

For the purposes of this report, we have utilized certain terminology defined by MMS in its proposed rule, though we understand that these terms are not necessarily recognized or commonly used in the oil industry. The term "index pricing point" refers to the "physical location where an index price is established" – specifically, Cushing, Oklahoma, for the NYMEX futures price, and San Francisco and Los Angeles for the Alaska North Slope spot price. The term "market center" is defined by MMS as "a major destination point for crude oil sales, refining, or transshipment" – for example, St. James, Louisiana, and Guernsey, Wyoming. MMS has initially defined seven locations as market centers, including the "index pricing points." The term "aggregation point" is defined by MMS as "a central point where production from various leases or fields is aggregated for shipment to market centers or refineries – including, but not limited to, blending and storage facilities and connections where pipelines join." MMS proposes to publish periodically the aggregation points associated with each market center.

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EXECUTIVE SUMMARY

Barents Group LLC, a subsidiary of KPMG Peat Marwick LLP, was retained by Gardere & Wynne, L.L.P. on behalf of a group of companies having significant crude oil production on Federal lands, to assist in analyzing the Department of Interior, Minerals Management Service (MMS) proposed rule establishing oil value for royalty due on Federal leases, and on the sale of Federal royalty oil. In our preliminary analysis, we find that the benefits of greater simplicity and certainty anticipated by MMS from its proposed rule either would not be realized or would be smaller than expected. Implementation of the rule as proposed will come at substantial costs to the private sector, as well as to MMS itself. States, under the revenue sharing provisions of various Acts and where there is oil production on Federal lands, will share in the Federal government costs of implementing the proposed rule.

In this report, we consider various costs that would be imposed by the proposed rule and discuss problems with the proposed methodology for valuing oil for royalty purposes. In our analysis, we rely in part on interviews with and information gathered from six companies holding significant ownership in a large number of Federal leases. Four of the six companies account for approximately 19 percent of the royalty barrels produced on Federal lands during calendar year 1996 and for 20 percent of the total revenues collected during 1996. Of these four companies' production, 85 percent was from Federal offshore leases and the remaining 15 percent was from onshore leases.

Under the current MMS rules, the valuation of crude oil for royalty purposes is based on the concept of "gross proceeds" and divides transactions into two groups: arm's-length contracts and non-arm's-length contracts. Under arm's-length contracts, the royalty value is established based on the gross proceeds accruing to the lessee from selling the oil. If the oil is not sold under an arm's-length contract, then gross proceeds from the sale of the oil are calculated using one of five applicable benchmarks.

Under the proposed rule, the correlation between royalty value and "gross proceeds" is maintained for arm's-length contracts, but the definition of "arm's-length" is very limited. For the majority of sales which will be non-arm's-length sales, the proposed rule bases the value of oil for royalty purposes on an average of futures or spot sales prices. The royalty value of oil is calculated based on the monthly average of either the New York Mercantile Exchange futures price or the Alaska North Slope spot price, depending on where the oil is produced. In either case, particular adjustments are allowed for the quality of the oil, the location of the sale, and transportation costs. Under this rule, there would be no direct link between royalty values and actual contract prices for most transactions.

The proposed rule would add to the existing information burdens imposed on Federal lessees (and their affiliates) by requiring all lessees (and their affiliates) who engage in "non-arm's-length" oil sales to file a new form providing details on every exchange and buy/sell agreement that they enter into. One form would have to be filed each year for each such transaction, regardless of whether it involved a disposition of oil from a Federal lease, State lease, or private land. Based upon the text of the proposed rule as compared to the instructions for the new form, it is unclear who would be required to file the form.

The costs of the new filing requirement would include:

- the cost of the filings,
- the cost to lessees (and their affiliates) of changing internal company administrative, accounting and record-keeping systems to capture and integrate the information to be filed – with serious implications for smaller companies that do not have automated contract administration systems, and
- the inequities resulting from the requirement to file information on all crude oil exchange and buy/sell agreements, regardless of whether the oil involved comes from a Federal, Indian, State or private property.

The issue of who must file is in need of clarification from MMS.

Most of the information that would be collected on the proposed Form MMS-4415 will not be usable for MMS' intended purpose of estimating "location/quality differentials" between "market centers" and "aggregation points." As a result, unnecessary costs will be imposed on both the private sector and MMS itself – the latter because it will have to process and analyze information relating to a large volume of transactions that will yield no benefits in terms of its objective of developing more reliable estimates of the market value of the oil produced from Federal lands.

In addition to the costs imposed by new information collection requirements, the proposed method for valuing oil contains serious numerous flaws that would result in uncertainties and additional costs for lessees and, in some cases, additional administrative costs to the Federal government. We identify seven distinct problems:

A. The methodology of using average spot price differences for establishing "locational price differentials" is problematic due to there being few transactions in some markets and the unevenness of contract volume over time. The proposed methodology will result in inaccurate location-based price adjustments and, thus, distorted estimates of value and will not accurately reflect quality factors.

B. "Location/quality adjustments" based on the proposed Form MMS-4415 will not be accurate or statistically valid. It will be difficult or impossible to derive from lessees' information filings reliable adjustments for the differences in the value of oil between any given "market center" and any "aggregation point."

C. Using "stale" price differentials based on the proposed Form MMS-4415 will not lead to accurate market valuations. The "location/quality adjustments" between "market centers" and "aggregation points" to be published by MMS would reflect a lag of a year or more, rather than conditions at the time a volume of oil is actually sold.

D. Changes in the treatment of transportation allowances will result in substantial compliance and administrative costs, and will create inequities. Additional costs will be incurred by pipeline companies, and competing shippers will not be treated consistently.

E. By assuming that there is a single crude oil price rather than a range of prices that reflect royalty values, the proposed MMS valuation methodology will have distributional impacts that have not been considered or addressed by MMS. Based on the proposed rule, averaging of the range of prices will be required, resulting in individual lessees being required to pay royalties on a value not related to the actual oil produced and sold from a given lease.

F. Obtaining contract information from and providing it to a separate affiliated company will be difficult at best. Substantial costs will be incurred by legally separate affiliates who will have to obtain information from others to complete Form MMS-4415.

G. The complex compliance considerations regarding what constitutes "like quality oil" will lead to uncertainty that increases the compliance cost of the proposed rule for lessees and MMS. The approximations inherent in the proposed valuation method together with the penalties defined in the rule will give lessees the incentive to request special calculations from MMS when their oil deviates only slightly from the valuation benchmarks.

Finally and of utmost importance, the proposed option of MMS' issuing an Interim Final Rule to be in force for one year before issuing a Final Rule would magnify the uncertainty and costs faced by lessees and the Federal government.

In summary, the proposed rule and its new methodology may increase Government revenues from Federal oil leases, but would do so only by imposing large administrative costs, uncertainty and inequities on the private sector. Lessees will face substantially higher costs and will be forced to pay royalties on unrealistic valuations that are not directly linked to oil they produce from a given lease or the transaction which produced the revenue related to the oil.

Preliminary Analysis of the Department of Interior, Minerals Management Service Proposed Rule Establishing Oil Value for Royalty Due on Federal Leases and on Sales of Federal Royalty Oil

1. INTRODUCTION

A new rule proposed by the Department of Interior, Minerals Management Service (MMS) establishing oil value for royalty due on Federal leases, and on the sale of Federal royalty oil, would impose substantial new costs both on Federal lessees and on MMS itself.[1] The benefits of greater simplicity and certainty anticipated by MMS from the proposed rule either would not be realized or would be smaller than MMS expects. In this report, we consider various costs that would be imposed by the proposed rule and discuss various problems and ambiguities with the proposed approach to valuing oil for royalty purposes. We also question the underlying rationale of selecting any single price to represent market value when many different values, within a reasonable range, can all be true arm's-length prices.

Six companies provided specific information to assist in the analysis, and other companies provided general comments.[2] These companies represent a diverse group of types and sizes of producers. Among this group are companies that (1) have some production, while still making large net purchases of crude oil to support refinery operations, (2) buy and sell actively in addition to producing and refining, (3) exclusively produce oil without having a refinery, and (4) produce roughly the same amount of crude as needed to run their refineries.

All six companies provided information on the effects of the proposed rule, and four companies provided production statistics. The four companies account for approximately 19 percent of the royalty barrels produced on Federal lands during calendar year 1996 and for 20 percent of the total revenues collected during 1996. Of these four companies' production, 85 percent was from Federal offshore leases and the remaining 15 percent was from onshore leases.[3] These companies are holders of 2,157 Federal leases under which they are responsible for paying Federal royalties. Of these 2,157 leases, they operate and pay royalties on 1,115 of the leases, and another person is designated to operate and remit royalties on the remaining 1,042 leases.

[1] All references to the proposed rule in this report, and page numbers shown in brackets, refer to 30 CFR Parts 206 and 208 as published in Federal Register, January 24, 1997, Volume 62, Number 16.

[2] These companies include: Chevron Corporation, Conoco Inc., Koch Industries, Inc., OXY USA Inc., Texaco Inc., and others.

[3] A very small percentage of total production was from Indian lands which is not covered by the proposed rule.

The costs to the oil industry of complying with the proposed rule will be discussed in three major sections. The Section 3 will discuss costs directly related to a new filing requirement, Section 4 will consider costs and uncertainties which will result from problems in the proposed new valuation method if implemented, and Section 5 will discuss the additional costs that would result if an Interim Final Rule were issued instead of a Final Rule.

This study is necessarily preliminary in nature because of the limited time available to complete it within the 60-day Office of Management and Budget (OMB) comment period. Time constraints dictated that our survey be restricted to a small number of sizable Federal leaseholders, and that we attempt to gather selected information from each company. Because of time considerations, our small sample cannot be considered representative, and we cannot make statements about the overall population of leaseholders. Nevertheless, we believe that the information presented provides considerable insight into the costs that would be imposed on the private sector by the proposed rule, as well as the serious limitations to the utility of the data that MMS proposes to collect.

As noted by MMS in its comments, the proposed rule has been determined to be "significant" under Executive Order 12866 Section 3(f)(4), because the OMB believes it raises "novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order." [Page 3750] Inadequate time was available in advance of the filing date to determine whether the proposed rule would impose costs sufficient to qualify it as an unfunded mandate under the Unfunded Mandates Act of 1995 (i.e., whether its total economic cost would exceed $100 million in any year), or whether the proposed rule would have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act. The April 28 due date for final comments does not allow sufficient time to adequately study the effects of a rule of this magnitude – one that affects crude oil transactions accounting for 24 percent of the Nation's crude oil production.

2. BACKGROUND

In this section, we provide background information relating to the proposed rule by describing data on Federal oil royalty payments from 1986 to 1996,[4] and by summarizing the current and proposed royalty valuation methodologies.

PRODUCTION AND ROYALTY TRENDS

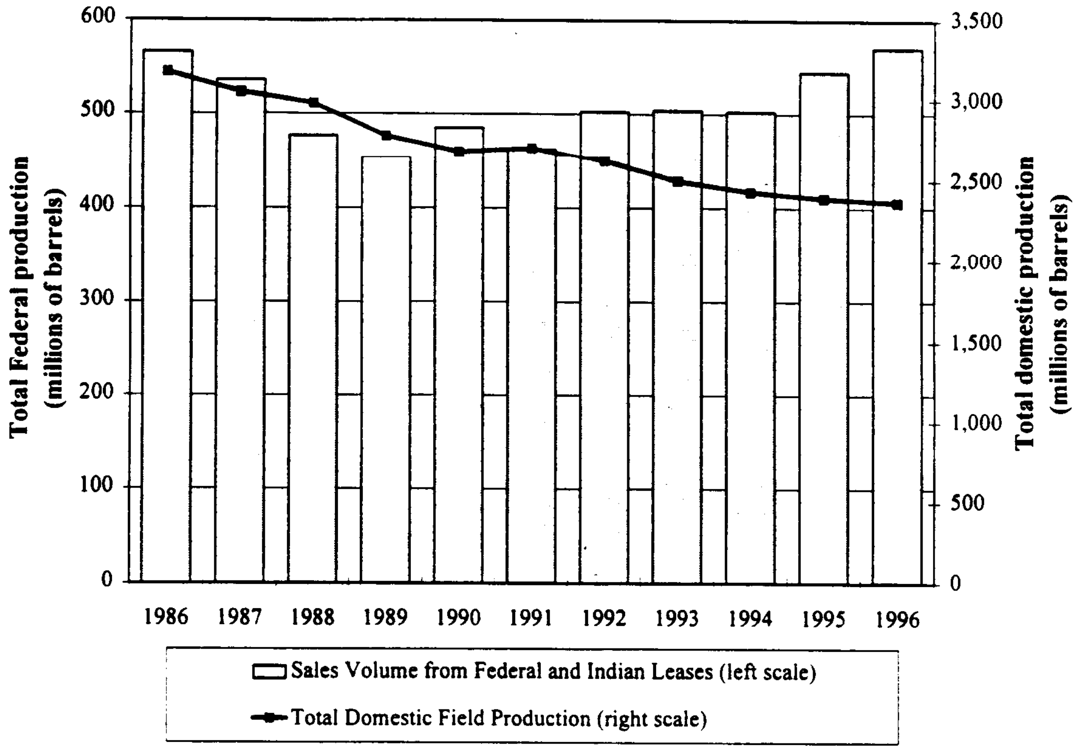
Production from Federal lands is reported annually by MMS. Three crude oil production categories are reported: from onshore properties, from offshore, and from Indian lands. While total domestic production has been declining at an average annual rate of 3 percent over the 1986 to 1996 period, crude oil production on Federal and Indian lands has begun increasing in recent years. Figure 1 shows the trends in both total domestic and Federal and Indian crude oil production. Beginning in 1992, Federal and Indian production began to diverge from the national trend. This increase in production is largely due to improved technology and increased offshore production on the Outer Continental Shelf.

In 1996, crude oil production from Federal and Indian lands represented 24 percent of total oil production in the United States, with Federal offshore production accounting for 77 percent of this production. Under the lease contract between the U.S. Government (via the Secretary of the Interior) and the lessee, the lessee or its designee is required to pay a percentage of the production to the Federal government. Under the Minerals Leasing Act of 1920 and the Outer Continental Shelf Lands Act of 1953, royalties may be paid "in-value" or "in-kind." For Federal onshore lands, the customary royalty rate for oil is one-eighth of the production. For Federal offshore leases, the royalty rate generally ranges between one-sixth and one-eight of production, although there are also some nontraditional royalty arrangements. In 1996, Federal lessees (or their designees) paid $1.5 billion in crude oil royalties. Of that $1.5 billion, $1.2 billion was from Federal offshore oil, $232 million was from Federal onshore oil, and $45 million was from oil produced on Indian lands. Figure 2 shows Federal crude oil royalty payments by source for 1986 through 1996.

[4] An 11-year period is appropriate in this context because industry economics changed dramatically after oil prices crashed at the end of 1985.

Figure 1

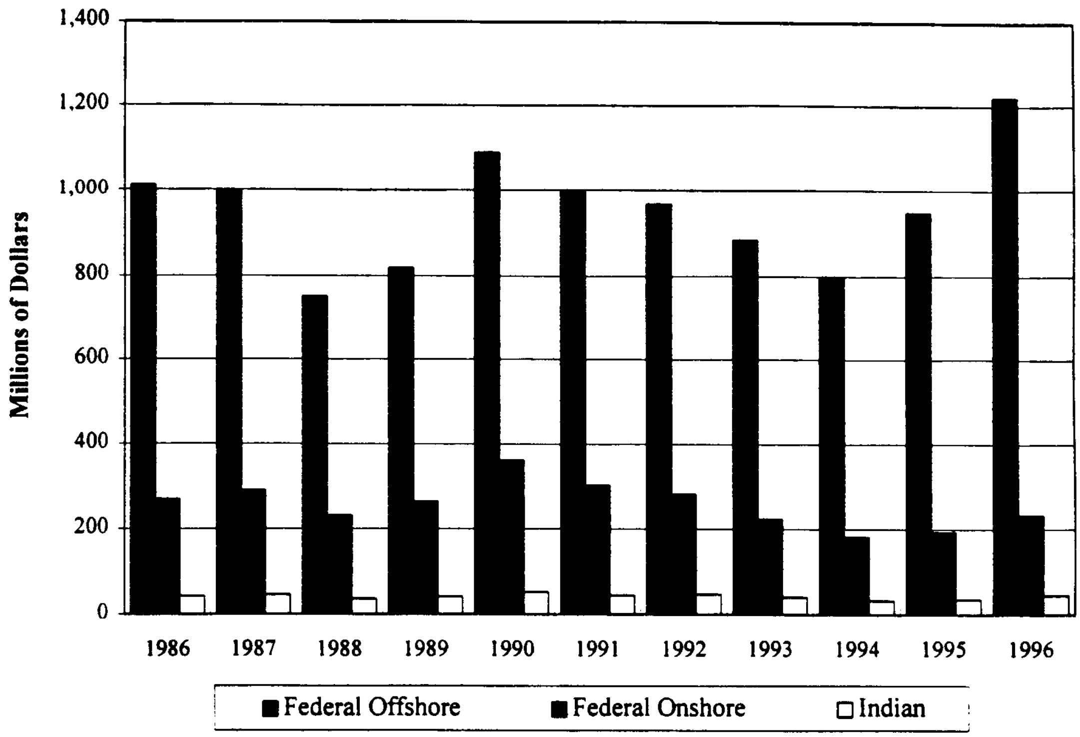
Total Domestic and Federal Crude Oil Production, 1986-1996[a]
(millions of barrels)



[a] 1996 Federal and Indian production figures are preliminary unpublished numbers from MMS.
Source: *Monthly Energy Review*, March 1997 and *Mineral Revenues 1995*

Figure 2

Royalties from Federal and Indian Crude Oil Leases, 1986-1996

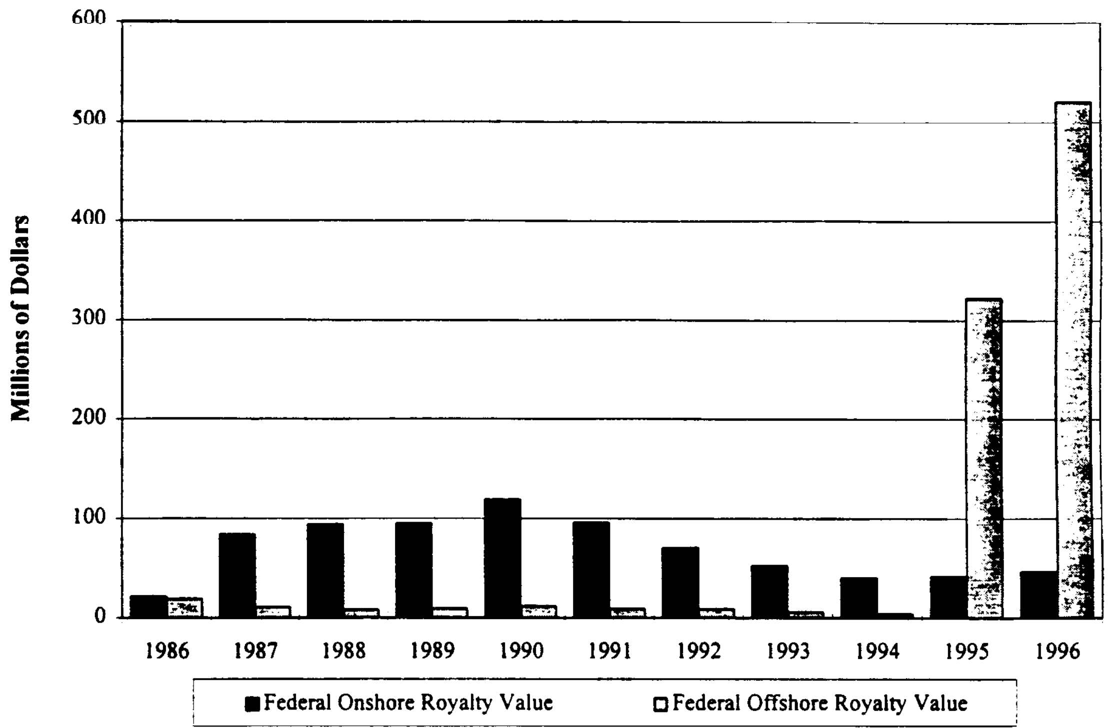


Source: *Mineral Revenues 1995* and preliminary 1996 data from MMS

Royalty oil taken in-kind from Federal leases totaled $566 million in 1996, about 37 percent of the total royalty amount. Of this $566 million, $45 million was produced on Federal onshore leases, and $521 million was from Federal offshore leases. Figure 3 shows the royalty value of oil taken in-kind from 1986 to 1996. While revenues derived from oil royalties taken in-kind from Federal onshore leases increased in 1996, the total number of onshore barrels sold declined by 5 percent. The increased royalty value resulted from higher oil prices. The number of barrels taken in-kind from Federal offshore leases increased dramatically in 1995 as five additional refiners joined the RIK program during the year. In 1996, the number of barrels taken in-kind from Federal offshore leases increased again, and the value of that oil also increased, along with oil prices generally (see Figure 4).

Figure 3

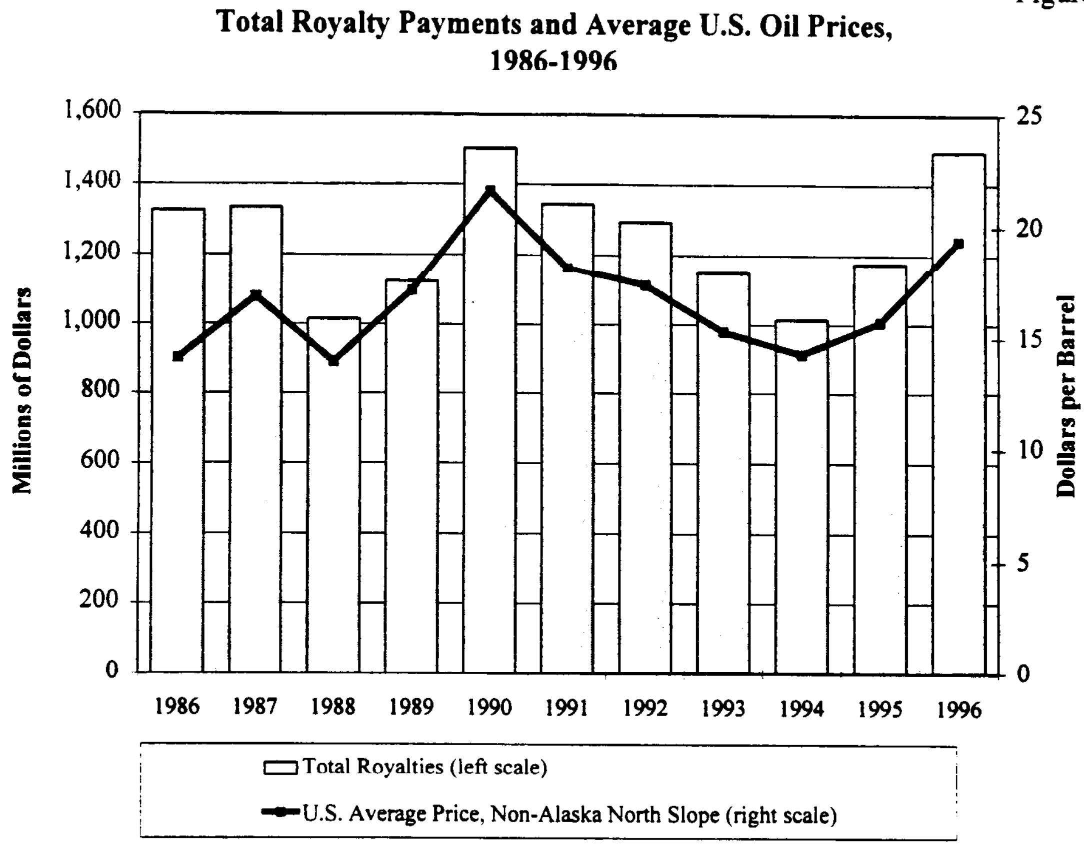
Royalty Value of Oil Taken In-Kind, 1986-1996



Source: *Mineral Revenues 1995* and preliminary 1996 data from MMS

Royalty payments in-kind and in-value are clearly linked to the price of crude oil. Figure 4 shows the trends in the average first purchase price of crude oil for the U.S. (less Alaska North Slope crude). During this period, prices peaked in 1990, corresponding to the Persian Gulf War, and began rising again in 1995.

Figure 4



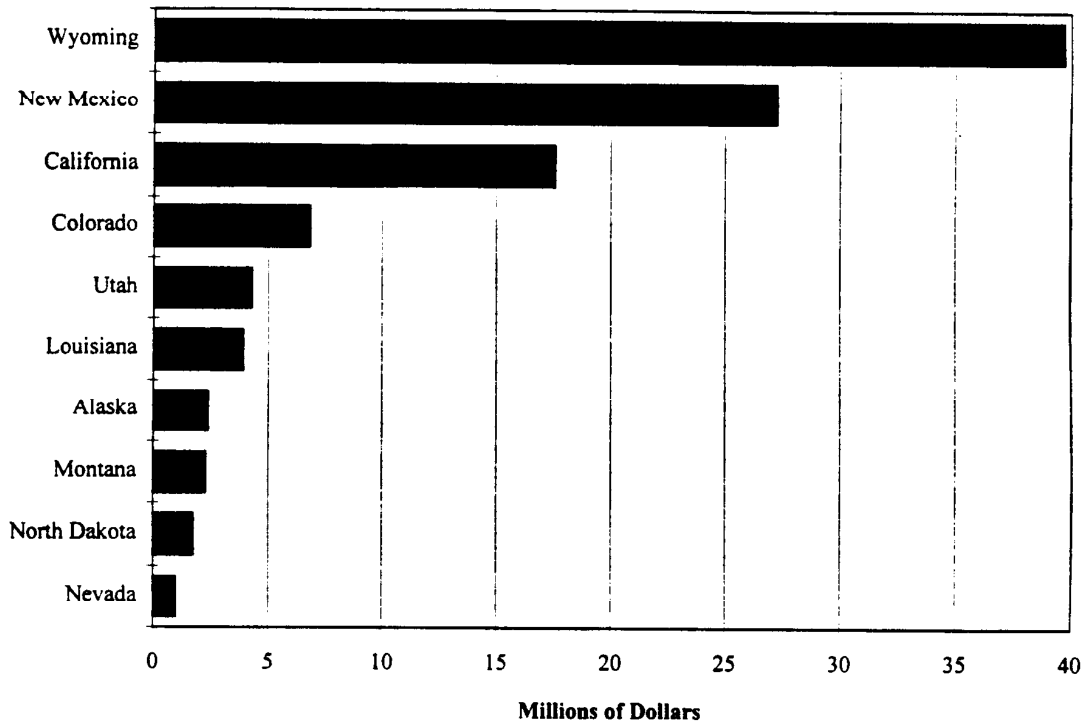
Source: *Petroleum Marketing Monthly*, March 1997; *Mineral Revenues*, 1995; and preliminary 1996 data from MMS.

Under the Mineral Leasing Act, and the Mineral Leasing Act for Acquired Lands, states are paid 50 percent (generally 90 percent in the case of Alaska) of the lessees' payments for lease bonuses, royalties, late-payment interest, and rentals of public lands within mineral-producing states. Certain states with offshore production receive distributions equal to 27 percent of royalties under Section 8(g) of the Outer Continental Shelf Lands Act. The states actually receive a distribution of revenues net of the costs of administering mineral leases. As a result of the Omnibus Budget Reconciliation Act of 1993, MMS recovers 50 percent of the Federal Government's mineral leasing program administrative costs before disbursement to the states. As a result of these provisions, states will share MMS' costs of implementing any new rule.

In 1996, $108.9 million or 24 percent of royalties collected from mineral leases was distributed to mineral-producing states from both offshore and onshore mineral activity. The Mineral Leasing Act of 1920 provides that states whose boundaries encompass Federal public domain mineral leases share in the revenue from those leases. Of these royalty distributions to the states, $8.4 million were offshore oil royalties, and $100.4 million were onshore oil royalties. The ten largest royalty-earning states represent 98 percent of the national total. Figure 5 shows the top ten states in descending order.

Figure 5

Oil Royalty Revenues of Ten States with the Highest Royalty Distributions, 1996



Source: Preliminary 1996 data from MMS

THE CURRENT RULE

The valuation of crude oil for royalty purposes is currently governed by a 1988 rule.[5] The valuation methodology is based on the concept of "gross proceeds" accruing to the lessee. Simply stated, the lessee pays the Federal government a royalty based on the price received for the oil at or near the well. The rules divides sales transactions into two groups: arm's-length contracts and non-arm's-length contracts. Under arm's-length contracts, the royalty value is established based on the gross proceeds accruing to the lessee; the gross proceeds concept reflects the consideration received by the Federal lessee from selling the oil.

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[5] 53 FR 1218-1222, January 15, 1988.

If the oil is transferred in a non-arm's-length disposition to a "marketing affiliate," a defined term meaning an affiliate of the lessee which purchases only production from the lessee, the royalty value is established as the gross proceeds received by the lessee's affiliate in its first arm's-length sale.

If the oil is not sold under an arm's-length contract, then gross proceeds from the sale of the oil are calculated using the first applicable of the following five benchmarks:

1. the lessee's contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of like-quality oil in the same field, provided these are comparable to other posted prices or sales contract prices;
2. the arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same field;
3. the arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same area or nearby area;
4. prices received for arm's-length spot sales of significant quantities of like-quality oil from the same field (or same area) with adjustments for other matters unique to the circumstances of the lease or salability of the oil; or
5. a net-back method or any other reasonable method.

In using any of the above methods for both arm's-length and non-arm's-length contracts, the lessee may deduct a transportation allowance equal to the "reasonable, actual costs" of transporting the oil (Section 206.104). In certain circumstances, the lessee may use Federal Energy Regulatory Commission ("FERC") or State tariffs instead of transportation costs calculated using an MMS methodology.

The new rules proposed by the Department of the Interior, Minerals Management Service specify a very different approach for determining the value of oil for royalty purposes.

PROPOSED RULE

In this section, we discuss the new reporting requirements and valuation methodology that have been proposed by MMS.

Proposed Reporting Requirement

The proposed rule states that a new form, MMS-4415, must be filed by all Federal lessees (or their affiliates) for all of their crude oil production sold, regardless of whether the oil was produced and sold from Federal, State, or private lands. The form must initially be submitted no later than two months after the effective date of the proposed rule and then by October 31 of the year in which the rule takes effect and by October 31 of each succeeding year (proposed 30 CFR 206.105(c)(3)).

The form must be filed annually for each contract that includes an exchange or buy/sell arrangement. MMS defines a "buy/sell arrangement" as an agreement to deliver oil to a specified location in exchange for oil deliveries at another location which specifies prices to be paid at each exchange point. The arrangement may appear to be two separate sales within the same agreement (proposed 30 CFR 206.101). MMS defines an "exchange agreement" as a type of buy/sell, except that oil prices are not specified explicitly (except perhaps for explicit dollar adjustments to account for differences in the quality or location of the volumes exchanged). Arm's-length sales are not required to be reported on the new form.

The proposed rule requires that "*All* Federal and Indian lessees (or their affiliates as appropriate) would initially submit Form MMS-4415 ..." [page 3749, emphasis added]. The rule makes no exception for *lessees* who have only arm's-length transactions. In addition, it is not clear who will file the Form on an ongoing basis – the lessee or the person designated by a lessee as the royalty payors? The text of the proposed rule itself associates the reporting obligation exclusively with the *lessee* (and its affiliates). However, the instructions attached to the proposed Form MMS-4415 refer only to the royalty *payor* [page 3758]. Also, in its analysis of the paperwork burden to be imposed by the new Form, MMS bases its estimate of the burden on the number of royalty payors. The critical issue of who must file is in need of clarification from MMS.

Proposed Valuation Methodology

For arm's-length sales (where the lessee or their affiliate has not also purchased crude within the previous two years, does not have a call on production, and has not entered into an exchange agreement), the proposed rule would retain the concept of gross proceeds as the royalty value of oil. MMS states that, "Valuation of production sold under arm's-length contracts would essentially stay the same, but the number of transactions considered to be actual sales at arm's length would be limited." [page 3743] All other sales (which would likely include the vast majority of Federal oil royalty sales) would be subject to a new methodology in which royalty value is linked to either the New York Mercantile Exchange (NYMEX) futures price for West Texas Intermediate at Cushing, Oklahoma, or the Alaska North Slope (ANS) spot price, depending on the location of production. Such transactions include exchange agreements, reciprocal buy/sell agreements, non-arm's-length transactions, and sales to an affiliated refiner. The rule would not apply to production from Indian lands.

Royalty valuation at the lease for non-arm's-length transactions is proposed as follows: Where oil is transferred to an affiliate who later sells it at arm's length,[6] the value of the oil for royalty purposes will be either

1. the affiliate's arm's-length resale price (provided that neither the lessee nor its affiliate also purchases oil), or
2. a "monthly average" of the NYMEX futures price (for non-California and non-Alaska oil) or ANS spot price (for oil produced in California or Alaska), adjusted for location and/or quality differentials.

For all other cases (i.e., where the lessee or its affiliate refines the oil or disposes of it in a non-arm's-length transaction), the value of the oil at the lease for royalty purposes will be

1. for oil not produced in California or Alaska, a "monthly average" of the NYMEX futures price, adjusted for location and/or quality, or
2. for production in California and Alaska, the "monthly average" spot price for ANS oil delivered in California (either at San Francisco or Los Angeles), adjusted for location and/or quality.

Three adjustments to the "monthly average" NYMEX futures price are described by MMS:

1. a "location/quality differential" between the "index pricing point" (for example, West Texas Intermediate at Cushing, Oklahoma) and the appropriate market center (for example, Light Louisiana Sweet at St. James, Louisiana), calculated as the difference between the average monthly spot prices published in an MMS-approved publication for the respective locations;
2. a "location/quality differential" between the "market center" and a "major aggregation point" for oil from various sources, as either published by MMS or contained in the lessee's arm's-length exchange agreement (this adjustment would be based on the data collected on Form MMS-4415); and
3. the actual costs of transportation (as determined under existing valuation rules) from the "aggregation point" to the lease, or from the "market center" to the lease if the oil flows directly to a "market center."

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[6] Using MMS' definitions, "Arm's-length contract means a contract or agreement between independent, nonaffiliated persons with opposing economic interests regarding that contract. Two persons are affiliated if one person controls, is controlled by, or is under common control with another person. Based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: ownership over 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol. MMS may rebut this presumption if it demonstrates actual or legal control, as through interlocking directorates. MMS may require the lessee to certify the percentage of ownership or control. Aside from the percentage ownership criteria, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. To be considered arm's-length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed." (Sec. 206.101 Definitions)

The proposed rule raises many issues, which we have grouped into two main categories:

- The costs directly related to the proposed new information filing requirements, and
- The costs, inequities, and uncertainty arising from flaws and problems in the proposed method for valuing oil.

The first category of costs will be discussed in Section 3, and the second category will be discussed in Section 4.

3. COSTS IMPOSED BY PROPOSED FORM MMS-4415

The proposed rule would impose substantial costs on Federal lessees, their affiliates, and their designees, as well as create substantial additional costs for MMS itself. Much of the cost will arise from requirements to file detailed information about oil transactions that will be of little or no use to MMS under its proposed royalty valuation methodology. Even the information that would be of use to MMS would be difficult to interpret and could not serve as the basis for statistically valid estimates. MMS has not reported to OMB or quantified any additional cost other than that imposed by the proposed Form MMS-4415. In this section, we briefly review the reporting requirements of Federal oil leaseholders under current law, review and critique MMS' estimate of the reporting cost under the proposed rule, and consider the costs imposed by the new filing requirement. In Section 4 of the report we will discuss some of the problems with and ambiguities of the proposed valuation methodology.

CURRENT REPORTING COST

Under current information reporting rules related to Federal oil royalties, three forms must be filed on a monthly basis with MMS. Lessees (or their designees) must file Form MMS-2014, "Report of Sales and Royalty Remittance," for each lease with the sales quantity, the sales value, the royalty quantity, and the royalty value. The form allows the reporting of information on multiple leases. Form MMS-3160 "Monthly Report of Operations" requires onshore well operators to report the location of each well; its production status; the volumes produced of oil, gas, and water; and the disposition of each product. A separate report, the "Oil and Gas Operations Report," also requires the reporting of production volumes by offshore wells. These latter two reports, when matched with Form 2014, are used by MMS to test royalty payments for completeness and accuracy.

Under the Paperwork Reduction Act of 1995, Federal agencies must report to the Office of Information and Regulatory Affairs (OIRA) of the OMB on the burdens imposed by their active information collections. According to information filed by MMS with OIRA, MMS has estimated that filings of Form MMS-2014 imposed 240,600 hours of labor costs on lessees in 1996, based on a total of 3,036,000 responses filed in that year (or an average of 253,000 forms per month). Information reported on the time cost imposed by Form MMS-3160 was grouped together with other forms and was not available separately.

Under the proposed rule, all of the reporting requirements of the current rule would remain intact, with the added requirement of completing Form MMS-4415 for each exchange agreement and buy/sell contract falling within the purview of the rule. Therefore, the proposed rule does not appear to be consistent with the goals of the Paperwork Reduction

Act. As mentioned above, MMS has not provided any analysis of the impact of the proposed rule on other reporting requirements.

MMS ESTIMATE OF COST OF NEW REPORTING REQUIREMENT

MMS has estimated that the private-sector reporting cost imposed under the proposed rule would amount to approximately $800,000 per year (Fed. Reg. Vol. 62, No. 16 at 3750). They arrive at this figure as follows: MMS estimates that there are approximately 2,000 royalty payors on Federal leases, and that the average royalty payor has 64 sales contracts and exchange agreements from which information will need to be extracted. They further assume that it will take 15 minutes for a lessee to gather the relevant information and to complete proposed Form MMS-4415 ("Oil Location Differential Report") – which must be filled out for each exchange and buy/sell agreement. These assumptions lead to an estimate of 32,000 hours per year of effort by lessees as a whole. Assuming average labor costs of $25 per hour leads to the estimate of $800,000 per year.

MMS further asserts that the record-keeping cost attached to the new rule would be minimal. Specifically, in its "Supporting Statement for Paperwork Reduction Act Federal Rule" filed with OMB, MMS states that

> *... minimal additional expense [will be] incurred by respondents or recordkeepers resulting from the collection of information. The information requested is information that the payors will already keep on file for tax and personal accounting purposes. We do not anticipate that any additional capital or start-up costs will be needed to provide the requested information. Furthermore, the total operational and service costs of providing the information should also be minimal because this information should already be maintained. Additionally, MMS anticipates a minimal amount of new equipment and supplies will be needed by the payors.* [page 4, para. 13]

In subsequent sections of this report, we will explain the results of our preliminary investigation, which contradict all of the points made by MMS in this passage.

First, however, it is important to note that MMS provides no support in its comments for the assumptions underlying its estimated time cost. Specifically, it gives no support for the three key assumption of 64 filings (on average) per royalty payor, 15 minutes of effort per filing, and $25 per hour of labor effort. According to our preliminary analysis, the MMS estimate is too low because these assumptions are too low. MMS does not take into account the practical difficulties in obtaining the required information that may not already exist – especially sulfur content and actual transportation costs. In particular, MMS assumes that all of the information required to fill out each Form MMS-4415 is readily available and systematically maintained by lessees/payors in the normal course of business. This is not the case.

The hourly labor cost assumed by MMS is significantly lower than the compensation assumed for its *own* employees who would analyze the data submitted. In its "Supporting Statement for Paperwork Reduction Act Federal Rule" submitted to OMB, MMS assumed that GS-9 employees would collect, sort and file the documents at a cost of approximately $29 per hour, and that GS-12 analysts would analyze and publish the data at a cost of approximately $43 per hour. Lessees would need to assign skilled professional analysts who are capable of understanding the various contracts and other sources from which information must be extracted in completing Form MMS-4415. Surely, such an analyst in the private sector would not cost less than a GS-9 Federal employee as MMS has assumed. One of the companies surveyed reported that the average salary, with benefits, of an appropriately skilled professional would amount to $75,105 per year, or $36 per hour (assuming 52 weeks per year and 40 hours per week). In addition, given the size of new workload volume imposed on lessees, it would be appropriate to allocate overhead costs to this effort, which the same company reported as $8,040 per year. Due to time constraints, our preliminary survey data did not allow an assessment of the number of forms that will actually have to be filed per year by the average lessee, or the average time required to complete each form.

As mentioned above, MMS has not reported or quantified costs in addition to the cost imposed by Form MMS-4415. For example, the implications of the new reporting requirement for the other forms that must be filed have not been analyzed. It is foreseeable that the proposed Form MMS-4415 could have substantial implications for the information required on Forms MMS-2014 and MMS-3160, and the Oil and Gas Operations Report. Changes to these filings triggered by the new requirement would result in additional costs to lessees and MMS.

FURTHER COSTS RELATED TO PROPOSED FORM MMS-4415

In order to obtain information regarding the expected costs of the proposed reporting requirements, we conducted a limited survey of six significant oil producers who are Federal lessees. In conducting this survey, we asked each company to perform two tasks: First, we asked them to attempt to complete Form MMS-4415 for two or more transactions, and to provide an assessment of the process noting any problems that arose (e.g., problems in obtaining the required information or difficulties in interpreting what information was required). Second, we asked them to identify any significant changes that would be required to their administrative and information systems and processes to enable them to complete the forms for all of their contracts in effect for a filing year. Due to the ambiguities in MMS' instructions and the lack of ready access to some of the required information, no company was able to perform a complete analysis or develop a full cost estimate for this second part in the time permitted by the OMB comment period. Nevertheless, we were able to collect useful information on the nature of the changes required to be made by these companies.

We also interviewed several company representatives to determine their understanding of the requirements of the proposed rules. The survey and interview process identified a number of important concerns with ambiguities in the proposed reporting requirement. We have identified four major issues related to the new filing requirement that should be addressed before MMS proceeds:

A. most of the information collected on Form MMS-4415 will not be usable for and will not achieve the intended purpose of obtaining reliable market price adjustments for oil quality and delivery location;

B. the new form would impose major systems costs to change internal company administrative, accounting, and record-keeping systems to capture and integrate new information – with serious implications for smaller companies that do not possess automated royalty reporting or contract administration systems;

C. Form MMS-4415 will be burdensome on the industry and will require a much greater effort to complete than is anticipated by MMS; and

D. the new filing requirement would be inequitable in that it would impose burdens on individual lessees and their affiliates that would bear no clear relationship to the number of federal leases held or the volume of oil sold.

We discuss each of these issues in turn.

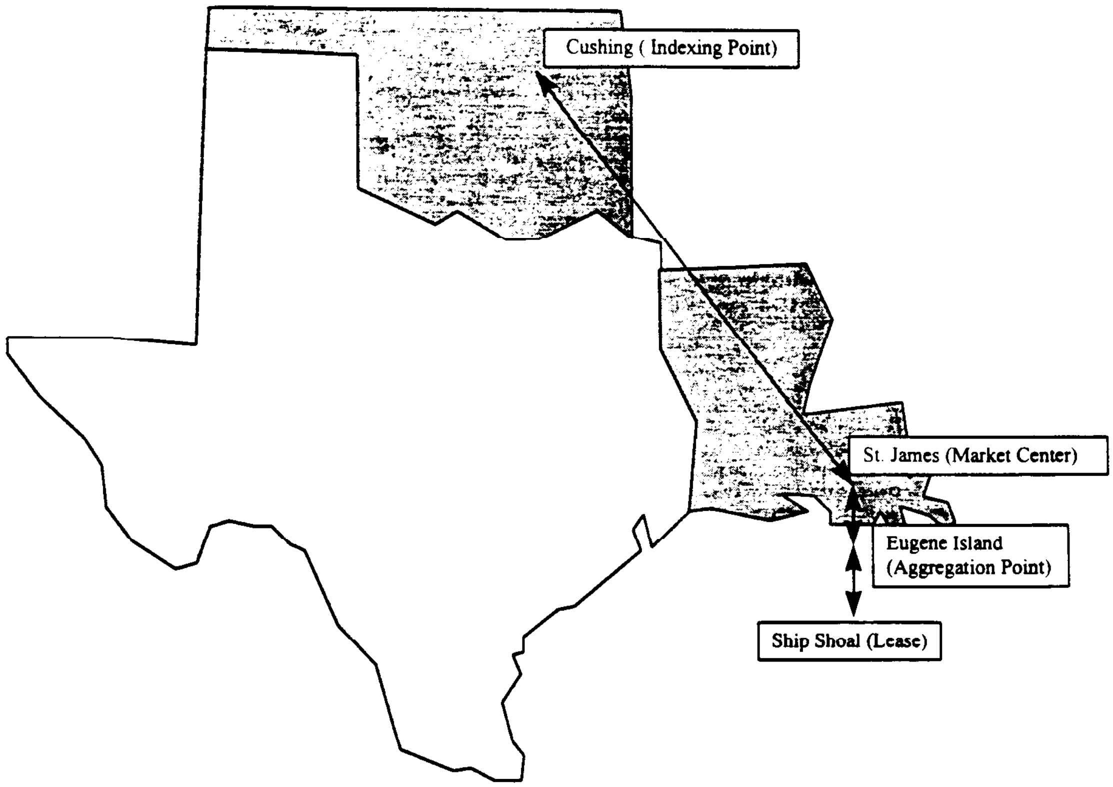
A. Most of the information collected on Form MMS-4415 will not be usable for the intended purpose of estimating market "location/quality value differentials" between "aggregation points" and "market centers."

MMS will receive a large number of forms which will have no use for the proposed valuation scheme. The stated purpose of collecting data from lessees (and their affiliates) is to develop a set of price adjustments between "aggregation points" and major "market centers." According to the proposed rule, MMS plans to rely on spot prices to adjust for location and quality differentials between Cushing, Oklahoma, (the NYMEX futures "index pricing point") and other major market centers. As a result, those companies with contracts covering transactions between those points will have provided data that will make no contribution to MMS' intended objectives. Similarly, many transactions occur between leases and MMS-designated aggregation points. Because the only allowed adjustment between these points will be for the direct cost of transportation, and because the relevant cost is the "actual cost," as defined by MMS, rather than industry averages, none of the Forms MMS-4415 filed for these transactions will help MMS to achieve its stated objectives.

Consider, as well, a transaction in which the producer delivers crude from the lease directly into a "market center." Valuation of such oil under the proposed rule (assuming the transaction is not arm's length) would require adjusting the NYMEX average futures price to the particular "market center" based on spot prices, and deducting the producer's "actual cost" of transportation to the market center, so the information filed on MMS-4415 for this

Figure 6

Example of Crude Oil Transactions Between Ship Shoal and Cushing



In fact, a great many more combinations occur in actual U.S. markets. For example, crude oil is also trucked to St. James from onshore leases and stored in tanks together with offshore crude. Crude from both sources could be combined and exchanged in a single transaction for crude at another location. At that location, it is impossible for the purchaser of the crude to know where it came from, or even whether it came from one or more Federal leases. Indeed, this combined stream of crude oil could be exchanged a number of times between not only these locations, but many others, with MMS wishing to have a Form MMS-4415 filed for each separate contract. MMS' purpose, however, is only to attempt to collect reliable data on the "location/quality differential" between the "market center" and an aggregation point, so most buy/sell and exchange contracts – all of which will be burdensome to report – will be ignored.

In summary, MMS proposes to impose a very large data collection and reporting requirement in order to collect data for a very limited subset of all transactions. Information regarding all other kinds of contracts would represent wasted effort on the part of both lessees (and their designees) and MMS staff – the former would file much useless information, and the latter would have to process, record, analyze, and weed out the useless information.

B. The new form would impose major systems costs to change internal company administrative, accounting, and record-keeping systems to capture and integrate new information – with serious implications for smaller companies that do not have automated contract administration systems.

As noted earlier, in MMS' statement to OMB regarding the costs of the proposed rule, MMS stated that they "... do not anticipate any additional capital or start-up costs will be needed to provide the requested information."[7] Our interviews and supplementary information provided by companies, led us to conclude otherwise. It was clear from the information we gathered that the new rule would require significant changes in the companies' contract information and administrative systems. None of the companies maintain all of the information required on a single system, and some information needed to complete Form MMS-4415 simply is not currently collected or does not exist. In some cases, different pieces of information are held by different legal entities (such as in the case of a production company and a marketing company that are separate corporations under common control). Substantial systems design and reprogramming will be required to link existing systems, at a minimum. Some company systems were designed by consulting firms that will need to be hired to make modifications required by the MMS proposal. One company reported that this additional reporting requirement will likely make their existing system obsolete. Absent this requirement, they would continue to use the existing system, but the proposed new filing requirement is expected to force them to expend tens of millions of dollars to replace their system.

Smaller companies, such as small production and marketing companies do not have sophisticated computerized systems for storing and integrating the kinds of royalty reporting and sales contract information that they would be required to track under the proposed rules. Either they would incur large costs of manually tracking the information or would have to invest in a new automated system.

A different set of problems arises in the case of small producers or producers with small working interests whose production is sold by the well operator under a joint operating agreement. In many instances, the lessee merely receives the proceeds from the operator and is unaware of the specific terms of the crude oil sales. The operator may sell the lessee's production through a buy/sell or exchange agreement, which will trigger an obligation under the proposed rule for the lessee to file a Form MMS-4415. Under this circumstance, however, the lessee will have either no or insufficient knowledge on which to make the filing.

If a purchaser is currently paying royalties and filing the Form MMS-2014 on the lessee's behalf, the added responsibility for filing the new form may be viewed as excessive. The purchaser may decide either to begin charging the lessee for assuming this additional task or,

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[7] "Supporting Statement for Paperwork Reduction Act Federal Rule," para. 13.

alternatively, decide it is simply not worth the headache and require the lessee to take on both the payment and Form MMS-4415 reporting responsibilities directly. Either way, the small producer faces additional costs and effort.

The companies we surveyed reported a number of problems locating the required data. The first problem encountered by all of the companies was the lack of data on sulfur content, one of the important components of quality requested on the form. Generally, sulfur content simply is not available on a lease-by-lease basis. While this information is important to the refinery when the crude is received, the crude received has been commingled before reaching the refinery so that it requires testing at the entrance to the refinery rather than at the lease. In order to report data on sulfur as proposed, companies would be required to go through a process of collecting samples, sending them to a laboratory for testing, developing a new system or modifying an existing system to link sulfur content to the lease, and to link the sulfur with the contract after the crude leaves the lease. This is not a small requirement.

In addition, as crude enters multiple pipelines and is mixed with other crude from other leases, it loses any direct connection with its original sulfur content. Thus a buyer taking crude out of the pipeline may receive crude with a different sulfur content than was put into the pipeline at the lease. Under the proposed rule, companies might be required to pay for two analyses of sulfur content in order to complete the new form. While some pipelines maintain quality banks to adjust for differences in gravity, it is not common industry practice to make adjustments for sulfur content as suggested by MMS. For example, sweet crudes (sulfur less than 0.5 percent) and sour crudes (sulfur of 0.5 percent or more) are generally not commingled, but various types of sweet crude are blended together in transportation systems, as are various types of sour crude. As a result, purchasers generally only know that the crude they are buying has a general character based on the area or field of origin rather than a specific sulfur content.

As noted earlier, MMS has stated its belief that all of the information to be requested on Form MMS-4415 is readily available. The information we received from companies indicated that this was not the case. Some of the specific data-gathering problems reported by individual companies are as follows:

1. Current information related to volume at title transfer locations is not readily available in the lessee's royalty reporting or contract information system and will have to be retrieved from financial systems and records.

2. Information on the sulfur content of oil delivered and received at title transfer locations is not generally available. Some such information might be found through a manual search of paper files for each property. Where such information does not exist, tests will have to be administered at a laboratory cost of about $18 per sample. This cost is substantially understated because it does not include the cost of collecting a sample, shipping it to a testing center, recording the results, and modifying computer systems to store and retrieve the data.

3. The actual API gravity adjustments are not readily available and will have to be calculated and/or retrieved from financial records.

4. The "actual cost," as defined by MMS, of transporting crude oil from the property to "market centers" is not currently tracked. A procedure and data system would have to be developed to gather, analyze, and record this data.

5. Some of the required information currently is not maintained in any system and will need to be acquired or derived. One company reported that they did not currently maintain a contracts system electronically and would have to develop one in order to complete Form MMS-4415 on an ongoing basis. Our sample was comprised primarily of large companies; we would expect such problems to be even more common among smaller companies.

Assuming information is available or can be obtained, current systems will have to be modified at considerable expense to enable companies to efficiently complete Form MMS-4415. Financial systems will have to be merged with royalty reporting and contracts systems; downstream systems will have to be modified to interface with upstream systems; pricing systems would have to be modified to interface with aggregation systems. Making such modifications will require large initial investments in system design and programming time.

C. Form MMS-4415 will be burdensome to the industry, will require a much greater effort to complete than is anticipated by MMS, and will result in data of questionable utility to MMS.

Our survey of Federal lessees and interviews with company representatives revealed that gathering the information required for the proposed form would be much more time consuming than the 15 minutes assumed by MMS. Numerous difficulties and ambiguities were identified that would not only increase the effort required by lessees, but would reduce the information value of the data received by MMS. Furthermore, the filing requirement would impose disparate costs on different lessees entirely out of proportion to the number of leases each lessee owns or volume of oil each produces. Here, we summarize and discuss some of these issues.

1. In reviewing the transactions recorded on Form MMS-4415 by the companies we surveyed, we encountered cases of exchange and buy/sell transactions in which the information reported on the form will be either ambiguous or entirely useless to MMS in computing "location/quality" value differentials. For example, one company reported a buy/sell transaction where they sold 17 barrels of one kind of crude oil to another party and bought 100 barrels of another kind. In such a case, the difference between the financial flows on the buy and sell sides of the contract will represent the influences of both the (large) difference in volumes transacted and the difference in location and quality of the two volumes transacted. To add to the complication, this

single transaction was part of an "evergreen" contract in which balancing-up of the buy and sell volumes occurred over time, though as distinct transactions. In the case at hand, several additional buy/sell transactions occurred under the same contract for different qualities of crude at different locations. The sum of these individual transactions (distributed over time) were equal on the buy side and the sell side. However, for any given buy/sell transaction, MMS will find it difficult or impossible to develop meaningful oil price differentials using the data reported from the individual transactions. MMS would be required not only to link all the survey forms related to an individual contract, but also to make a variety of assumptions about how the individual components of the transaction were valued – something even the companies involved might not be able to do with accuracy. While MMS appears to assume that all transactions for a single contract during a given year can be combined on one Form MMS-4415, variations over time in the quality, location and quantity of crude sold by exchange, as well as pricing revisions, may necessitate separate forms for some transactions under the same contract.

2. Instructions are not clear and do not address many issues with the result that there is the potential for serious misinterpretations of the form's requirements (in addition to the ambiguity mentioned earlier over who must file). These misinterpretations could well render the results meaningless unless substantial additional guidance is provided. As a simple example, one company, when completing the form simply checked the relevant location boxes without specifying the name of the location. If MMS were to receive this form, they would need either to discard it or to follow up with the company to request more information. Because this company would have already provided hundreds of forms, following this approach would, at a minimum, require substantial additional time for both the company and MMS.

3. The payment basis for a particular property on a contract can change numerous times per year, and a form would presumably have to be filed for each change. To complicate matters further, contracts can cover multiple properties and have multiple delivery points, so that a Form MMS-4415 would have to be filed for each delivery point associated with each property. For example, a given contract may involve five properties and have three delivery points, requiring 15 forms to be filed. If this same contract is amended for the bulk delivery three times during the year, the number of forms to be filed triples to 45 per reporting period for the single contract.

4. The cost of transporting oil from the lease to title transfer points or MMS designated "market centers" is not generally available for particular exchanges or buy/sell transactions. Transportation costs are not generally tracked on a transaction-by-transaction basis. Therefore, the actual delivery of oil from a particular property lease may not be determinable, and numerous assumptions would be required to estimate a cost of transportation.

5. It is not clear how and where to report specific charges and costs (i.e., location differentials and gathering/handling charges) that are included in the contract but are

not identified on the form as adjustments. In some cases such charges are explicit, while in others they are incorporated into the price for which the crude is sold.

6. There is a lack of uniformity in the use of location names. Different names appear to mean different things to different companies. Thus, two companies may report comparable transactions at the same location (such as an "aggregation point"), but MMS may not realize this fact if the two companies use different names for the same location.

D. The new filing requirement would place very different costs on different lessees that are not related at all to the number of leases they own or the volume of oil they produce from a given lease.

As noted previously, the new form would have to be filed for all barrels sold through an exchange or buy/sell contract by a leaseholder during a filing year, regardless of whether the particular transactions involved Federal lease oil. It is easy to see how this requirement will lead to costs being imposed on different lessees that are unrelated to and entirely out of proportion to the importance of Federal leases in their operations. Indeed, companies would be required to consider whether to continue conducting transactions involving Federal oil if the proposal is adopted because of the sizable reporting cost involved in the filing requirements. Consider, for example, two similar onshore leaseholders, each with production of 1,000 barrels per day, and each operating 50 leases with an average daily production rate of 20 b/d per lease with all oil disposed of through the same number of exchange or buy/sell contracts. Now, suppose the first leaseholder produces exclusively from leases on Federal lands and the second leaseholder produces from one Federal lease at 20 b/d and from 49 private leases for the remaining 980 b/d of production. Under the proposed rule, both leaseholders will face equal reporting costs.

In addition, the reporting costs imposed on different companies will depend on the structure of their contracting arrangements, independently of how may leases they hold. Reporting would be required for many different kinds of contracts ranging from long-term evergreen contracts where single contracts covering large volumes of crude oil may last for years, to spot transactions where more than 100 contracts might be written each month by a typical large integrated company. For example, two companies with the same number of Federal leases, producing the same volume of oil from those leases, will have vastly different reporting costs if one tends to engage in a few long-term evergreen contracts with large customers, while the other tends to engage in a large number of contracts with many small customers.

4. OTHER COSTS AND PROBLEMS OF THE PROPOSED RULE

In addition to the paperwork and related costs that will be imposed by the proposed additional information collection, the MMS proposal for valuing oil contains numerous flaws and problems that would result in additional costs and uncertainties for lessees and, in some cases, additional administrative costs for MMS. In the following, we discuss seven distinct problems that deal with the statistical validity of the proposed valuation methodology, changes in the treatment of transportation allowances, and other ambiguities and difficulties. A key issue that will be emphasized is that neither the spot-price-based "location" adjustments mandated by MMS, nor the MMS-calculated "location/quality" adjustments will reflect actual market transactions that relate to the actual oil produced and sold from the Federal lease.

A. The use of average spot price differences for establishing locational price differentials is problematic due to low volume in some markets and the unevenness of transactions over time.

MMS is attempting to introduce certainty to royalty valuation through a process that involves averaging of prices across each month. This methodology introduces distortions into the valuation process that can adversely affect lessees or MMS. The proposed valuation, which involves spot prices and NYMEX futures prices averaged over a one-month period, implicitly assumes that equal weighting of prices from all days is a valid approach. However, due to the unevenness of transaction volumes across a given month, prices observed on different days may not have the same information content. For example, if on average a spot transaction occurs in a particular location for a particular quality of crude only once per week, then the spot price observed on the day of the transaction will reflect supply and demand conditions on that day. However, prices on days when no transactions occurs will generally be listed as the price of the most recent transaction and, thus, will not reflect any changes in market conditions that have occurred since that last transaction. Averaging spot prices across all these days (i.e., giving equal weight to days when transactions occur and days when none occur) will result in a distorted measure of the average market value of crude over the month. This is more than a theoretical possibility, especially given that spot market activity during any given month may be most concentrated in the days leading up to the expiration of futures contracts. Furthermore, averaging spot prices over a month will do nothing to reduce the measurement error induced by low or uneven transaction volumes.

To see this, consider the following simplified example: Suppose that the "true" spot market price of Light Louisiana Sweet crude at St. James is \$20.00/bbl on March 1 and falls at a constant rate of \$0.05 per calendar day, ending at \$18.50 on March 31. If spot transactions occur on March 1 and every seventh day thereafter, then the time path of the spot price will follow a stair-step pattern, while the "true" price will show a continuous decline. The true average market price of Light Louisiana Sweet crude at St. James will be $19.25/bbl, while the average spot price will be $19.39/bbl (14 cents higher). In this case, it is clear that the lessee will suffer, because the spot price measurement error will distort the relationship between prices at St. James and Cushing. Of course, the lessee could benefit under other market circumstances. The error will be greater the less frequent are spot transactions in the given market center and the more (and more suddenly) the market value of the crude changes over the month.

A reasonable solution to this averaging bias would be to compute volume-weighted averages of spot prices. With a weighted average, greater weight would automatically be given to those days where price discovery in the market was greatest, and thus to those prices where the information content is greatest. However, this will not be possible in practice because spot transaction volumes are not available from any published source.

In addition to the above problems with averaging *per se*, the proposed rule is unclear on how the averaging of spot prices is to be done in practice. MMS will approve several publications for spot price quotes, and it is unclear from the rule which publication or publications a lessee should use in any given instance. For example, if a lessee needs to calculate spot price differentials for West Texas Intermediate at Cushing, OK, and Midland, TX, it is unclear whether it should use prices from Platt's, Telerate or Petroflash, or all of these. Should lessees or their designated royalty payors subscribe to all approved publications relevant to their businesses (at a nontrivial cost) and shop among them for the average prices at each market center that would be most beneficial to the Government? Is the lessee free to shop among them for the price that would be most beneficial to itself? Or will it be required to take an average from among all approved publications quoting the relevant spot price? The rule provides no guidance on these questions.

B. "Location/quality adjustments" based on MMS-4415 will not be accurate or statistically valid.

There are serious questions regarding the statistical validity of the proposed method for capturing quality, location and transportation adjustments in the valuation process. The proposed rule indicates that MMS proposes to develop and publish a set of location/quality differentials between major "aggregation points" and "major market centers" based upon the information provided by lessees, their affiliates and/or their designees on Form MMS-4415. However, it may not be possible to derive statistically valid differentials based on such information because the adjustments contained in actual sales, exchange, and buy/sell agreements represent several factors that can be impossible to disentangle.

It is important not simply to average together all transactions between a given market center and aggregation point over a given year because the overall average will confound the effects of location, gravity, sulfur content, and even transportation costs (in addition to time, as discussed in point C below). Instead, in order for the differentials to be meaningful adjustments for market valuation, MMS will need to develop a schedule that provides incremental allowances for gravity and sulfur differences for each market center/aggregation point pair. It may not be possible to do this with an adequate degree of statistical precision based on the data provided on Form MMS-4415.

In addition, similar to the problem of low transaction volume in spot markets discussed in point A above, the proposed rule could result in differentials between some "market centers" and "aggregation points" being determined by just a few crude exchange contracts. This can occur if, for example, transactions in a market segment can include large volumes where crude is delivered from the companies' properties to their own refineries without actually being subject to a sale or exchange agreement. In such cases, the differentials calculated and published by MMS based on Form MMS-4415 will be of dubious statistical validity – they will be based on small samples and will not reflect information about a significant segment of market activity.

C. Using "stale" price differentials based on Form MMS-4415 will not lead to accurate valuations.

MMS would publish its calculations of "location/quality differentials" between market centers and major aggregation points just once per year, based on the annual filing of Form MMS-4415. This means that in any given month the royalty value calculated for a volume of lease crude will be based on local market conditions that prevailed up to a year ago, or more. In reality, prices fluctuate constantly based on continual changes in local supply and demand factors. For example, an increase in refining capacity in one location could have an impact on either location or quality differentials that would be reflected in the MMS-calculated allowances with a one-year lag. Similarly, the initiation of production from a significant new field – especially one whose crude has characteristics that are significantly different from the types typically sold in the local market – could significantly alter value relationships among different kinds of crude in the local market or between the local market and other markets.

By mandating that the oil industry base monthly royalty payments on annualized price differential estimates from the prior year that do not reflect current market conditions, MMS is imposing significant risks on the lessees. Changes in price differentials relative to the previous year could be either in the Federal government's favor or in an individual lessee's favor. There is no reason to believe that these gains and losses would average out for any individual lessee, so that lessees will be left unnecessarily exposed to a new risk unrelated to their own commercial transactions.

In general, then, the "location/quality differentials" to be published by MMS will not represent accurate adjustments that reliably bring NYMEX-based valuations in line with the range of market values of the oil that is sold by Federal leaseholders. They will provide a cloudy picture of the quality and location adjustments implicit in the terms of exchange and buy/sell contracts, and they will be too old to reflect current market conditions when the oil is actually sold.

D. Changes in the treatment of transportation allowances will result in substantial compliance and administrative costs, and will create inequities.

The proposed rule eliminates the lessee's ability under current rules to apply for the use of Federal Energy Regulatory Commission (FERC) and State-approved tariffs when computing Federal royalties. Rather, lessees are required to use actual costs, even though in its section-by-section analysis of the proposed rule, MMS asserts that "MMS is not proposing to change the existing methods to calculate transportation allowances." [p. 3747] This requirement results in substantial compliance and administrative costs and creates inequities: substantial costs will be incurred by many pipeline companies, and competing shippers will not be treated consistently.

Interstate oil pipeline carriers must file tariffs with FERC. Since 1994, these tariffs are generally computed using an indexing methodology that eliminates the need to maintain records based on actual costs. The proposed rule would require companies to undertake the reconstruction of actual costs at substantial expense. The establishment of cost-based tariffs is a highly labor intensive process and often requires incurring outside consulting and legal fees that FERC was able largely to eliminate through regulatory action undertaken in 1993. Through the proposed rule, MMS effectively would eliminate all the cost savings that the FERC achieved in this area.

The disallowance of FERC or state tariffs does not extend to shippers actually paying such tariffs to unaffiliated pipelines. As a result, those shippers owning an equity interest in a pipeline would be required to use a cost allowance calculated according to the MMS rule, while competitors could deduct higher actual tariffs for shipments through the same pipeline.

E. By assuming a single crude oil price rather than a range of market prices that reflect actual arm's-length transactions, the valuation methodology will have distributional impacts that have not been considered by MMS.

In addition to the problems discussed above with calculating meaningful averages, the averaging methodology will have distributional implications that MMS apparently has not fully considered. The implicit assumption underlying the proposed rule is that apart from location and quality differences, there is a single market price for crude oil. While our report is not intended to discuss at length the crude oil pricing issues raised by the proposed rule, we disagree with this fundamental assumption.

As defined in the proposed rule, an arm's-length contract "means a contract or agreement between independent, nonaffiliated persons with opposing economic interests regarding that contract." [Sec. 206.101 Definitions] On any given day, different independent, nonaffiliated persons in the same location will arrive at different prices for otherwise comparable crude oil. These prices will reflect not only general market conditions, but also the particular needs of the buyer and the seller. If a buyer needs to acquire an incremental supply of crude oil with typically the case that personnel from different affiliates had little knowledge of the operational characteristics of systems maintained by other affiliates.

The MMS proposal would impose the need to integrate these systems. Typically, upstream systems do not have any information on what happens to the crude oil after it leaves the lease, while downstream systems typically have little information on the source of the crude oil. Thus, to complete the form, a downstream affiliate must have access to such information as MMS lease numbers, lease locations, production rates, gravity at the lease, and sulfur that would generally reside with an upstream affiliate – although data on sulfur content rarely exist. Conversely, if the upstream affiliate must develop the information necessary to complete the form, it must have access to a great deal of contractual and pricing information that resides with downstream affiliates.

As a result, integrating information systems between affiliates (if it is permissible on a legal basis to do so) to capture the accounting information necessary to complete Form MMS-4415 will lead to substantial costs.

G. The complex compliance considerations regarding what constitutes "like quality oil" will lead to uncertainty that increases the cost of the proposed rule for both lessees and MMS.

Under proposed paragraph (c)(1)(iii), section 206.105, when a lessee's production is not actually moved to a "market center" but is instead moved directly from the lease to its ultimate disposal site (e.g., a refinery), the proposed rule requires the lessee to calculate a "location differential" based on "the market center nearest the lease where there is a published spot price for crude oil of like quality to your oil. Like-quality oil would mean oil with similar chemical, physical, and legal characteristics." [page 3748] For example, MMS considers West Texas Sour and Wyoming Sour to be "like crudes" for this purpose. MMS gives the example of a Wyoming Sour crude producer who transports its oil directly to a refinery without accessing any MMS-defined aggregation points or market centers. According to MMS, "in this case West Texas Sour crude at Midland, Texas, might represent the crude oil/market center combination nearest to the oil produced." However, MMS gives no instruction as to how close in quality two crudes must be in order to be considered "like" each other for royalty valuation purposes. For example, suppose the producer delivers Wyoming Sour with an average gravity of 34° and sulfur of two percent to its refinery, and the West Texas Sour sold spot at Midland has an average gravity of 38° and sulfur of one percent. According to the new rule, the producer must base royalty payments on the spot-price differential between West Texas Intermediate at Cushing and the West Texas Sour at Midland, which is of higher quality than the lessee's own oil.

MMS does make some accommodations for situations such as this: Under proposed paragraph (c)(4), "if a MMS calculated differential does not apply to a lessee's oil due to location and quality differentials, the lessee must request MMS in writing to calculate a location and quality differential that applies to its oil." However, MMS gives no guidance as to how "unlike" the market center oil the producer's oil must be before either it is permitted to apply for a special calculation or it is obligated to apply. The uncertainty created by the "like quality" language of the rule will create an incentive for lessees to request special calculations for small differences between their oil and that typically sold at the nearby market center, in order to avoid the risk of either overvaluation or undervaluation – both of which could involve real monetary costs [page 3749]. The requests for exceptions driven by small quality and location differences will not only impose additional filing costs on lessees, but will impose corresponding increases in the workload and paperwork burden of MMS as it processes and responds to the requests. Uncertainty over the appropriate valuation could also lead to a greater need for MMS to conduct costly compliance audits.

5. COSTS OF ISSUING AN INTERIM FINAL RULE

In its general description of the proposed rule, MMS states that it "may publish an Interim Final Rule while it further evaluates the methodology in this proposed rule. This approach would provide the flexibility to do a revision after the first year without a new rulemaking." [page 3743]. Issuing an Interim Final Rule, rather than a Final Rule, could magnify the compliance costs to lessees and the paperwork burden on MMS. The assumed flexibility that MMS would get in testing and changing the rule would come at a cost that MMS does not recognize in its analysis of the proposed rule. If the rule is initially issued on an interim basis, lessees will incur all of the costs discussed above of installing and adjusting their administrative operations and systems to comply with the Interim Rule and then, after one year, will have to incur some of the same kinds of costs again to comply with any changes MMS decides to implement when issuing its Final Rule. The option of issuing an Interim Final Rule would be costly and disruptive and would not serve MMS' stated objective of adding "more certainty to the valuation of oil produced from Federal lands." [page 3742]

6. CONCLUSIONS

Our preliminary analysis of the proposed valuation and reporting rule shows that (1) it would likely impose annual administrative costs on lessees that will be higher than MMS claims; (2) there would be significant one-time costs of adapting information and administrative systems to support the new filing requirements; (3) flaws and ambiguities in the valuation methodology will result in additional costs, inequities and uncertainty; and (4) the benefits of greater simplicity and certainty that MMS claims it will obtain from the new rule will be much smaller than it appears to believe.

The costs directly related to the new reporting requirement will include both the recurring effort required to fill out Form MMS-4415 for each exchange or buy/sell agreement, and the one-time costs of adapting companies' information and administrative systems to collect and maintain appropriate data items. Certain information that will be required on the proposed form (such as sulfur content, gravity, and transportation costs) are not maintained by companies in their extant information systems. In some cases, significant effort and cost would be expended to develop the required information.

In addition, seven distinct problems were identified dealing with the statistical validity of the proposed valuation methodology, changes in the treatment of transportation allowances, and various ambiguities in the proposed rule. Neither the spot-price-based location adjustments nor the MMS-calculated location/quality adjustments will reliably reflect the actual market values of crude oil transactions being conducted by lessees. These problems will lead to additional costs and uncertainty being imposed on the private sector. The option of issuing an Interim Final Rule in advance of the Final Rule would magnify the costs and uncertainty expected under the proposed rule.

In summary, the rule may increase government revenues from Federal oil leases, but would do so only by imposing large administrative costs, uncertainty and inequities on the private sector. Lessees will face substantially higher costs and will be forced to pay royalties on unrealistically high valuations that are not directly linked to their actual sales.