ECONOMIC ANALYSIS OF PROPOSED FEDERAL OIL ROYALTY VALUATION RULE UNDER EXECUTIVE ORDER 12866

Minerals Management Service
Department of the Interior
[63 FR 6113]

Table of Contents

I. Introduction 1

II. Need for the Proposed Action 2

III. Consideration of Alternate Proposals 4

IV. Proposed Rule 9

V. Rule Specifics 10

VI. Impacts of Proposed Rule 12

VII. Cost/Benefit Analysis 13
MMS-Incurred Costs 13
Industry Incurred Costs 14
Quantifiable Benefits 16
Offshore California 17
Onshore California 19
Offshore Gulf of Mexico 20
Onshore New Mexico 21
Rocky Mountain Area 22
Other Benefits 23
Overall Benefits 24

VII. Impact on Industry and Small Governments 24

VIII. Clear Writing of Regulation 24

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I. Introduction

The goal of this proposed rule is to establish royalty valuation methods that capture the true market value of crude oil produced from Federal leases, both onshore and offshore. Market value is a basic principle underlying royalty valuation. The Minerals Management Service's (MMS) current oil valuation rules, which have been in effect since March 1, 1988, rely heavily on oil posted prices to determine royalty value, particularly for oil not sold at arm's-length. However, the domestic crude oil market has moved away from posted prices to set market value. Accordingly, the current rules must be revised to assure that the Federal government receives market value for its crude oil production.

The proposed rule retains the principle that gross proceeds determine value for oil disposed of under an arm's-length contract. However, it substantively changes the valuation procedures for oil that is not sold arm's-length by abandoning reliance on posted prices as value determinants. It also defines separate valuation procedures for leases in three different geographical groupings -- California and Alaska, the Rocky Mountain area, and all other locations--to reflect the different crude oil market conditions and practices in each of these areas.

Almost one-fourth (23.7 percent in 1996) of the Nation's domestic crude oil production comes from Federal leases. Royalty rates on these leases typically range from 12.5 percent to 16-2/3 percent. In 1996 MMS collected more than $1.45 billion in royalty revenue from Federal oil production. By capturing the true market value of the public's oil resources, we expect this

rule to net an additional $66 million per year in royalties.

II. Need for the Proposed Action

Prior to the mid-1980's, posted prices were the primary mechanism for pricing crude oil in the United States; they represented prices oil purchasers were willing to pay for particular crude oils in specific areas. Because they often provided the basis for arm's-length purchases and sales, they were generally recognized as representative of market value and in turn provided the basis for both royalty and tax assessments. In recent years, however, posted prices have been increasingly criticized by a number of States (e.g., California, Colorado, New Mexico, and Texas[1]) as not being representative of the true market value of crude oil. This criticism is especially evident in California, where both the State and the City of Long Beach have reached settlement with several major oil companies over alleged undervaluation practices on State and City leases. Also, the interagency team set up by MMS to review the oil valuation issue in California concluded that for the relatively small volume of oil sold or purchased outright, payment of premiums above posted prices occurred frequently. The State of Texas (The State of Texas, et al., v. Chevron U.S.A. Inc., et al.) and private royalty owners in Louisiana (E.M. Lovelace, Jr., et al. v. Amerada Hess Corporation, et al.) have also settled with oil companies over undervaluation practices based on posted prices.

In June 1994, the Department of the Interior commissioned an interagency team to address possible underpayment of royalties on Federal crude oil production in California. In its report (*Final Interagency Report on the Valuation of Oil Produced from Federal Leases in California,* May 16, 1996), the team found that the bulk of California crude oil production was not sold. Rather, it was moved through intra-company transfers, straight exchanges between the integrated companies, and buy/sell contracts (a form of exchange). For the relatively small volume of oil that was sold or purchased outright, the team found that payment of premiums above posted prices commonly occurred. However, audits by both MMS and the State of California showed

[1]See Summit Resource Management, Inc.'s report to the State Lands Offices of Colorado, New Mexico, and Texas, *Crude Oil Royalty Payment Analysis*, February 21, 1995.

that most Federal royalty payments were based on postings. The team concluded that oil companies in California often receive gross proceeds higher than the posted prices for California crude oil.

The team also concluded that straight exchanges and, to a lesser degree, buy/sell contracts, are not arm's-length sales within the context of MMS regulations because they do not demonstrate opposing economic interests between the contracting parties. Rather, they found that companies conduct exchanges to obtain crude oil in locations that are more favorable to their refineries or other distribution systems. The straight (or barrel-for-barrel) exchanges reviewed by the team referenced at most only a location differential; the buy/sell exchanges commonly referenced posted prices. With respect to the latter, the team noted that the contracting parties can assign any price as long as there is a reciprocal valuation on the crude oil sent as well as the crude oil received. In short, the price(s) quoted in buy/sell exchange agreements--even between unrelated oil companies--is not necessarily the fair market value of the crude oil. The team ultimately recommended that MMS revise its oil valuation regulations to reduce reliance on posted prices.

MMS also commissioned a number of consultants (Innovation & Information Consultants, Inc.; Micronomics, Inc.; Reed Consulting Group; and Summit Resource Management, Inc.) to describe the domestic crude oil market and advise MMS on royalty valuation strategies. These consultants reported:

- Posted prices have not represented market value since at least 1986.

- Sales prices are often above posted prices and are linked, in some form, to market prices, such as spot or futures prices, or represent premia over posted prices.

- Major producers have few truly outright sales.

- Most major producers use buy/sell exchanges.

- There are regional differences in the domestic crude oil market, particularly on the West Coast and in the Rocky Mountain region, owing to differences in market concentration and availability of transportation options.

As explained by Innovation & Information Consultants, Inc. (*Crude Oil Marketing*, July 7, 1997), the domestic crude oil market has changed considerably over the past two decades. World shortages during the 1970's and the worldwide collapse of oil prices in 1986 led the petroleum industry away from long-term contracts with fixed prices. During the 1980's the petroleum industry began placing greater emphasis on spot transactions as a means of buying and selling crude oil in the United States. As integrated companies increasingly found themselves short of refinery feedstock, they became more active in the oil market. The emphasis placed on spot transactions and the consequent volatility of crude oil prices led to the development of a futures market for crude oil in the late 1980's and early 1990's. The wide publication of spot and futures prices by commercial reporting services has contributed to the use of these prices in structuring transactions.

III. Consideration of Alternate Proposals

MMS began the process of formulating new oil valuation regulations in December 1995 by publishing an Advance Notice of Proposed Rulemaking (Advance Notice) in the Federal Register (60 FR 65610). This Advance Notice requested comments on the need for changing the regulations to move away from reliance on posted prices. The Advance Notice also requested ideas on alternative valuation methods. In response to the Advance Notice, several States indicated that posted prices no longer reflected market value and that it would be appropriate to develop regulations that better reflect the market value of oil. Industry generally supported retention of posted prices for valuing oil not sold arm's-length, but declined to participate in the rulemaking process until their litigation involving similar issues was resolved. Realizing that this litigation could take years to conclude, we decided to proceed with the rulemaking process.

MMS formed a team comprised of individuals from MMS's Royalty Management Program and

Policy and Management Improvement office to write the proposed oil valuation regulations. Representatives from the State and Tribal Royalty Audit Committee and the Western States Land Commissioners also participated. MMS invited industry to participate as team members by contacting industry trade associations, but these groups declined to join.

The rulemaking team also consulted with a number of experts in crude oil marketing. These experts included crude oil brokers and refiners, commercial price reporting services, companies that market oil directly, and private consultants knowledgeable in crude oil marketing.

The consultants revealed areas where the 1988 oil valuation regulations could be improved, and they supported the concept of using index prices to value Federal oil with proper adjustments for location and quality. These experts agreed that the use of index pricing has several advantages over the current regulations for valuing oil not sold at arm's-length. For example:

- There is certainty in the price used to value the oil. Royalties more likely will be paid correctly initially, thereby reducing the burden of corrective billings.

- The companies will not require access to sales contracts from other producers in the field to determine the proper value.

- Audit will be confined to making sure that proper deductions were made and not on verifying that sales contract prices are comparable with the prices other producers are receiving for their oil.

- MMS will be assured that the public is receiving the fair market price for their oil.

After considering all the comments received on the Advance Notice of Proposed Rulemaking, MMS published a Notice of Proposed Rulemaking on January 24, 1997 (62 FR 3742). MMS held two public meetings in April 1997 (one in Denver and one in Houston) to hear comments on

the rule. Additionally, MMS received over 2,600 pages of written comments on the proposed rule. Based on a review of the comments, MMS revised the proposal in a July 3, 1997, supplementary proposed rulemaking (62 FR 36030). These changes were in response to comments that the original proposed rule was too restrictive in categorizing arm's-length sales. The original proposed rule in many cases would have required legitimate arm's-length sales to be valued as oil not sold at arm's-length, thereby forcing many small independent lessees to pay based on index prices when in fact their actual sales may have reflected market value.

Further, both industry and the States suggested many improvements to the rule. The States generally supported index pricing but differed in the specifics of how to calculate location and quality differentials. Industry almost universally suggested that we take our oil in kind.

Because the volume of comments on both proposals was substantial, we reopened the public comment period on September 22, 1997 (62 FR 49460), and requested comments on alternatives before proceeding with the rulemaking. The alternatives were:

Alternative 1 - Lessees would value oil not sold arm's-length based on prices they receive for outright sales of crude oil in the same region or area.

Alternative 2 - Lessees would use the first applicable of a new series of benchmarks. The order of the benchmarks would be:

1. outright sales of like-quality crude from the same field or area as described in alternative 1.
2. the lessee's or its affiliate's arm's-length purchases from the producers at the lease in the field or area.
3. Outright arm's-length sales by third parties.
4. Prices published by MMS based on RIK sales.
5. Netback employing price information from the nearest market center or aggregation point.

Alternative 3 - MMS would establish value for geographic locations based on data it collects from individual payors.

Alternative 4 - Use flat rate differentials (cents per barrel or cents per mile transported) to deduct from the index price.

Alternative 5 - Use spot prices instead of NYMEX prices.

MMS held public workshops to discuss valuation alternatives in Lakewood, Colorado, on September 30 and October 1, 1997 (62 FR 50544); Houston, Texas, on October 7, 8, and 14, 1997 (62 FR 50544); Bakersfield, California, on October 16, 1997 (62 FR 52518); Casper, Wyoming, on October 16, 1997 (62 FR 52518); Roswell, New Mexico, on October 21, 1997 (62 FR 52518); and Washington, D.C. on October 27, 1997 (62 FR 55198). Additionally, we received hundreds of pages of written comments on the alternatives.

The workshops were useful in clarifying the alternatives and receiving feedback on the merits and viability of the various proposals. MMS used a number of suggestions from these workshops to refine the current proposal. We outline below our reasons for issuing the Further Notice of Proposed Rulemaking.

MMS received detailed comments on the use of tendering as a valuation methodology (Alternative 1). Tendering programs involve a company offering a percentage of its production from a given area for competitive sale. It then would use the prices received under the tendering program as royalty value for all its Federal the production in the area. MMS is not proposing tendering programs as the primary valuation methodology for several reasons. Tendering requires extensive monitoring and would add a significant audit burden to both MMS and industry. Its application is only useful where the lessee's production otherwise may not be sold at arm's-length and there is no nearby, independent measure of market value such as index. Further, some commenters indicated it is doubtful that many companies would desire the expense of creating a

tendering program that meets MMS approval. For these reasons, alternative 1 is not a potentially effective and reasonably feasable alternative to the proposed rule. However, we included tendering as the first valuation alternative for the Rocky Mountain Area because no published, reliable indicators of market value are readily available. The only spot price published in the Rocky Mountain Area is at Guernsey, Wyoming. We heard consistently that little oil is actually traded there, and the spot price is unreliable as a value indicator. However, in other areas of the country we have found spot prices to be viable indicators of value.

Based on experience under the current regulations, MMS considered alternative 2 as unworkable when applied to production from the entire country. Following benchmarks that rely on access to comperable arm's-length contracts would be costly and difficult to administer compared to the proposed rulemaking. The proposed rule will be much easier to administer and less costly for industry to comply with. The benchmarks are not a potentially effective and reasonably feasable alternative for parts of the country in which readily available and reliable indicators of market value exist.

However, MMS proposed a series of procedures for valuing production not sold at arm's-length in the Rocky Mountain region. This is because many commenters stated that index pricing could not be used as a reliable measure of value for this isolated market. Because the universe of lessees not transferring or selling their oil at arm's-length in the Rocky Mountain States is relatively small, MMS believes that these procedures are a workable solution absent a nearby, independent measure of market value such as index.

Workshop participants rejected alternative 3 (geographic pricing) as unworkable. The proposal would require lessees to indicate via Form MMS-2014 whether they disposed of their production under arm's-length or non-arm's-length transactions. The universe of arm's-length transactions would then be used by MMS to publish quality-adjusted prices for various Federal oil fields. Workshop participants expressed concerns that for many fields there would be insignificant quantities of arm's-length transactions to value the oil not sold arm's-length. Further, the

administrative burden on MMS to produce monthly data that non-arm's-length payors could use to value their royalties would be tremendous. Finally, MMS could not publish the price information in time for lessees not selling their oil arm's-length to report the correct royalty value 30 days after the month of production. With this in mind, MMS views alternative 3 as a non-feasible alternative.

Alternative 4 would eliminate the Form MMS-4415 filing requirement and instead would require MMS to rely on available information to publish location and quality differentials by zones or areas. These differentials would be in the form of rates-per-mile from leases to market centers, cents-per-barrel based on location, or a percentage of an index or spot price. This idea was rejected outright by industry participants as being non-feasible and less desirable than the reporting of actual differentials on Form MMS-4415. Under this further proposed rule, companies will be able to use actual differentials for oil exchanged between aggregation points and market centers.

Workshop participants judged alternative 5, using spot prices in the Gulf and Mid-Continent areas instead of starting with NYMEX futures prices for oil delivered at Cushing, Oklahoma, to be an improvement to the original proposed rule. In effect, using either price will give virtually the same result because the initial proposal included a location and quality differential from the spot price market center locations to Cushing, Oklahoma. This alternative thus eliminates one step in calculating differentials while effectively keeping the original principles intact. MMS adopted this alternative in the proposed rule. Spot prices play a significant role in crude oil marketing in terms of the basis upon which deals are negotiated and are readily available to lessees via price reporting services. Spot and spot-related prices drive the manner in which crude oil is bought and sold today in the United States.

In summary, the proposed method is a reasoned, practical solution to establishing royalty valuation methods that capture the true market value of crude oil produced from Federal leases. The alternaitves mentioned above were deemed to be less desirable and more costly to implement

than the proposed rule. For these reasons MMS determined that they are not feasable alternatives or effective means to achieve the same results as the proposed rule.

IV. Proposed Rule

The MMS is proposing further changes to its proposed rules published in the Federal Register on January 24, 1997 (62 FR 3742), and July 3, 1997 (62 FR 36030), by amending the regulations governing the royalty valuation of crude oil produced from Federal leases. These changes are in response to comments received on the January 24 and July 3, 1997, notices as well as the comments received on the September 22, 1997 (62 FR 49460), request for public comment on alternative valuation procedures and the comments given at the workshops discussing alternatives. The proposed changes would further modify the eligibility requirements for oil valuation under arm's-length transactions; add valuation criteria for valuing oil produced in the Rocky Mountain Area and not sold arm's-length; and clarify the information collection requirements using a new form titled Federal Federal Oil Location Differential Report, Form MMS-4415.

V. Rule Specifics

When oil is sold by the lessee or its affiliate under an arm's-length contract, royalty value is the gross proceeds accruing under that contract with four exceptions:

1. If MMS determines that any arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, MMS may require oil sold under that contract to be valued either as if not sold arm's-length, or at the total consideration received.

2. If MMS determines that the value does not reflect the reasonable value of the production due to either:

   (a) misconduct by or between the parties to the arm's-length contract; or

   (b) breach of duty to market the oil for the mutual benefit of the lessee and the

lessor,

MMS may require the oil to be valued as if not sold arm's-length.

3. When oil is disposed of under an exchange agreement, MMS also may require the oil to be valued as if not sold arm's-length. However, if the lessee enters into one or more arm's-length exchange agreements, and following those exchanges the oil is disposed of in an arm's-length transaction, the arm's-length sale may be the proper value. The lessee may adjust that value for any location or quality differential or other adjustments received or paid under the arm's-length exchange agreement(s). But if MMS determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, MMS may require valuation of the oil under the proposed methodology for oil not sold arm's-length.

4. When oil is disposed of in the exercise of a noncompetitive crude oil call, MMS requires the oil to be valued as if it is not sold arm's-length.

When oil is not sold under an arm's-length contract, royalty valuation is based on the geographic location of the lease, as follows:

California and Alaska

Value would be the average of the daily mean Alaska North Slope (ANS) spot prices published in any MMS-approved publication during the calendar month preceding the production month. The lessee must adjust the value for applicable location and quality differentials, and may adjust it for transportation costs.

Rocky Mountain Area (Utah, Colorado, Wyoming, Montana, North Dakota, and South Dakota)

Value would be based on the first applicable of a series of benchmarks:

1. The highest price bid for tendered volumes is the value of production from leases in the area the tendering program covers. The tendering program must offer at least 33 1/3 percent of the lessee's or its affiliate's production from both Federal and non-Federal leases in that area, and the lessee must receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

2. The volume-weighted average of gross proceeds under the lessee's or its affiliates arm's-length contracts for the purchase or sale of production from the field or area. The total volumes purchased or sold under those contracts must exceed 50 percent of the lessee's and its affiliate's production from both Federal and non-Federal leases in the same field or area.

3. The average of the daily NYMEX futures settle prices at Cushing, Oklahoma, for the light sweet crude oil contract for the prompt month that is in effect on the first day of the month preceding the production month. The lessee must adjust the value for applicable location and quality differentials, and may adjust it for transportation costs.

<u>For the Rest of the Country (other than California, Alaska, and six-State Rocky Mountain Region)</u>

Value would be the monthly average of the daily mean spot price for:

a. the market center nearest the lease where the spot price is published in an MMS-approved publication,
b. the crude oil most similar in quality to the lessee's oil, and
c. deliveries during the production month.

The lessee may adjust the value for applicable location and quality differentials, and may adjust for allowable transportation costs.

VI. Impacts of Proposed Rule

The MMS concludes that the proposed oil valuation regulations would result in an annual increase in Federal oil royalties of approximately $66 million. MMS and industry will realize administrative savings because of reduced complexity in royalty determination and payment. Specifically, the proposed rule would result in:

- simplification of pricing, coupled with certainty,
- reductions in valuation determinations and litigation,
- reduction in industry compliance costs, and
- receipt of market value of oil produced from Federal leases.

As discussed in Section VII., MMS will incur minimal additional costs with the implementation of the rule. The administrative costs to industry are a result of the proposed information collection, Form MMS-4415, Federal Oil Location Differential Report. As discussed above, under the proposed rule, valuation of oil not sold under an arm's-length contract often relies on published indices or spot prices that lessees must adjust for locational differentials between the market center and the aggregation point or lease. (Also, transportation allowances between the lease and aggregation point or market center, as well as certain quality adjustments, would be permitted.) Federal lessees and their affiliates would be required to give MMS specific information from their various oil exchange agreements and sales contracts applicable to Federal production. From this data, MMS would calculate and publish representative location differentials for lessees' use in reporting in various areas. Generally only the integrated payors with either a refinery, marketing capability, or both will be required to complete the form. We discuss the detailed industry impacts in Section VII.

VII. Cost/Benefit Analysis

MMS-Incurred Costs

MMS will incur minimal additional costs to administer the proposed rule. However, some of the

specific aspects of the rule will require MMS to redirect personnel resources for implementation. The largest cost will be associated with data collection, analysis, and publication of differentials. The raw data for this effort will be collected via the proposed Form MMS-4415. MMS estimates the annualized cost of determining differentials as follows:

- We estimate that it will require a team of two GS-9 employees a total of approximately 60 hours annually to collect, sort, and file the documents associated with this information collection. Only existing office equipment and space will be used. Using an hourly wage of $14.73 plus 25 percent for benefits and an additional 10 percent for overhead and support, we estimate the cost to be $2,430.45.
- We also estimate that it will require a team of four GS-12 analysts approximately 120 hours each to analyze and publish the data annually. Only existing office equipment and space will be used. Using an hourly wage of $21.36 plus 25 percent for benefits and an additional 10 percent for overhead and support, we estimate the cost to be $14,097.60. The total Federal Government cost estimate of collecting and analyzing the information is $16,528.05 annually.

Additional costs associated with the rule such as subscriptions to commercial reporting services and other monitoring costs are expected to be minimal.

Industry Incurred Costs

Industry will pay MMS additional royalties under the proposed rule compared to what it paid under the current regulations. However, industry will now value oil based on a market price that more closely represents the true value of the oil. This is not an additional cost incurred by industry but rather a reflection of the market value upon which royalties should have been based on under the current regulations. The additional administrative costs to industry are a result of the proposed information collection, Form MMS-4415, titled "Federal Oil Location Differential Report." We estimate that the total initial burden for all respondents is 4,597.5 hours at a cost of $160,912.50. The number of exchange agreement contracts involving aggregation points and market centers required to be reported under this proposed rule is considerably less than required under the January 24, 1997, proposed rule. While we recognize that the initial reporting burden

will still be sizable, it is reasonable to expect that the burden in succeeding years will be less because of efficiencies gained from the initial filing of Form MMS-4415. Our estimate is for the initial reporting burden and is based upon review of industry comments on the initial, supplemental, and further proposed rulemakings; comments made at the public meetings and workshops; and consultation with MMS auditors about their review of exchange agreement contracts examined in their work.

While MMS requires that only aggregation point to market center exchange agreement contracts be reported, we anticipate that companies will have to sort through their exchange agreement contracts before the relevant exchange agreement contracts can be compiled and the required information extracted and reported. Federal lessees required to file this information will generally have annual total domestic production (Federal and non-Federal) in excess of one-million barrels of crude oil. (Fifty-nine lessees had annual total domestic production in excess of one-million barrels of crude oil in 1996.)

We estimate that large companies (i.e., a company with over 30 million barrels annual domestic production, which included 13 Federal lessees in 1996) will each have approximately 1,000 exchange agreement contracts to review to identify the relevant contracts needed for reporting under this proposed rule. Of those contracts, we estimate that each large company will have to report on 100 exchange agreements. We estimate that the reporting burden for a large company is 185 hours including 80 hours to aggregate the exchange agreement contracts to a central location, 80 hours to sort the exchange agreement contracts, and 25 additional hours to extract the relevant information and complete Form MMS-4415 (1/4 hour to complete each form). We estimate the total reporting for the 13 large companies is 2,405 hours (185 hours x 13 large companies); using a per-hour cost of $35, the total cost is $84,175.

We estimate that mid-sized companies (i.e., those with between 10 and 30 million barrels of annual domestic production, which included 11 Federal lessees in 1996) will each have approximately 250 exchange agreement contracts to review to identify the relevant contracts

needed for reporting under this proposed rule. Of those contracts, we estimate that each mid-sized company will have to report on 25 exchange agreements. We estimate that the reporting burden for a mid-sized company is 106.25 hours including 60 hours to aggregate the exchange agreement contracts to a central location, 40 hours to sort the exchange agreement contracts, and 6.25 additional hours to extract the relevant information and complete Form MMS-4415 (1/4 hour to complete each form). For the 11 mid-sized companies, we estimate the total burden as 1,168.75 hours (106.25 hours x 11 mid-sized companies); using a per-hour cost of $35, the total cost is $40,906.25.

We estimate that smaller companies (i.e., companies with less than 10 million but greater than one million barrels of annual domestic production, which included 35 Federal lessees in 1996) will each have approximately 50 exchange agreements to review to identify the relevant contracts needed for reporting under this proposed rule. Of those contracts, we estimate that each small company will have to report on 5 exchange agreements. We estimate that the burden for a small company is 29.25 hours including 20 hours to aggregate the exchange agreement contracts to a central location, 8 hours to sort the exchange agreement contracts, and 1.25 additional hours to extract the relevant information and complete Form MMS-4415 (1/4 hour to complete each form). For the 35 small companies, we estimate that the burden is 1,023.75 hours (29.25 hours x 35 smaller companies); using a per-hour cost of $35, the total cost is $35,831.25

We estimate that the total initial burden for all respondents is 4,597.5 hours at a cost of $160,912.50. We expect the annual burden to decline somewhat as industry becomes more familiar with the reporting requirements.

Quantifiable Benefits

Process/Analysis

We divided the analysis of quantifiable benefits into three sections, consistent with the three geographic divisions of the proposed rule:

- California (both onshore and offshore)

- Offshore Gulf of Mexico (this also includes onshore New Mexico, Texas, and Louisiana)
- Rocky Mountain Area

For each of the geographic areas, we compared the royalty paid in 1996 for oil and condensate either directly to MMS or through the small refiner royalty-in-kind program to what would be required under the proposed valuation requirements. We examined each month of 1996 separately. The year 1996 was chosen because it:

- Is the last complete year in which all months of data were available.
- Represents a typical production year with no major market interruptions.
- Reflects data incorporating most of the edits and corrections performed by the exception processing modules in MMS's Auditing and Financial System/Production Accounting and Auditing System[2].

We focused on the onshore leases only in California, Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming because they account for about 94 percent of total onshore Federal oil production. For offshore California and the Gulf of Mexico, we used 100 percent of the oil volumes and values for this analysis.

When examining the payments received from Federal onshore and offshore leases, we grouped all the royalty reporters into five separate categories:

1. Major integrated producers with refinery capacity
2. Large, independent producers/marketers with refinery capacity
3. Large, independent producers/marketers with no refinery capacity
4. Small, independent producers with refinery capacity
5. Small, independent producers with no refinery capacity

Specific Area Analysis

[2]However, 1996 data is still unaudited and significant adjustments may be made at a later date.

Offshore California

Under both the current and further proposed rules, the value of production sold by a lessee or its affiliate under an arm's-length contract would be valued on the gross proceeds received under that contract. But the proposed rule would require value of oil not sold at arm's-length to be based on the average of the daily mean Alaska North Slope (ANS) spot prices published in an MMS-approved publication during the calendar month preceding the production month. The lessee must adjust the value for applicable location and quality differentials, and may adjust it for transportation costs. We believe that all large, independent producers/marketers with no refinery capacity (Category 3) and small independent producers (Category 5) would continue to value crude as they always have (via arm's-length gross proceeds). Therefore, we did not include them in the analysis. We examined the other three categories of royalty producers using the following procedure:

- We grouped all production by unit (i.e. Beta, Santa Ynez, etc.).
- We determined a weighted average gravity for each unit.
- We made gravity adjustments to equate the Unit oil to the 27° API ANS oil. This was done using Chevron's California posted price gravity adjustment scale in effect during the month of production.
- We subtracted a location differential from the ANS value in Los Angeles to arrive at a value at the lease. We used the following per-barrel location differentials relying on several sources, including the City of Long Beach and consultant reports:

  Beta: $0.20

  Pitas Point: $0.35

  Point Hueneme: $0.35

  Point Pedernales: $0.75

  Rocky Point: $2.60

  Santa Clara: $0.35

  Santa Ynez: $1.80

- We subtracted sulfur penalties from the ANS price where appropriate. These penalties were based on All-American Pipeline sulfur bank adjustments and consultant reports. We used a

value of $0.65 for each percent sulfur above the benchmark ANS sulfur content of one percent. The per-barrel values used are:

Beta: $1.69

Point Pedernales: $2.53

Rocky Point: $1.81

Santa Ynez: $2.08

- We then compared, for each month in 1996, (1) the location and quality-adjusted ANS price to (2) the actual price reported by each royalty reporter on Form MMS-2014 less any transportation allowances reported on Form MMS-2014. We then multiplied this incremental value by the royalty quantities reported on the Form MMS-2014 to arrive at an overall net gain or loss associated with the proposed rulemaking.

Using the procedures in the further proposed rule, we estimate a 1996 revenue gain of:

- Category (1): $11,800,300.80
- Category (2): $ 508,119.28
- Category (4): $ 269,146.73

Onshore California

We arrived at a monthly price at the lease by taking the ANS spot price less a gravity deduction from Chevron's posted price adjustment scale in effect at the time of production to Midway-Sunset specifications (from ANS at 27° API to Midway-Sunset at 13° API, monthly range from $.10 to $.25 per degree or total deduction from $1.40 to $3.50 per month) less a $0.75 transportation charge from the Midway-Sunset field to Los Angeles area refineries (average tariff rate for the Four Corners Pipeline). Midway-Sunset production is roughly 80 percent of all Federal onshore California production, and another 10 percent of the Federal onshore California production comes from the same general area and is similar quality crude. Since nearly all of the Federal royalty oil from onshore California is from the Midway-Sunset field, we felt analyzing only this field would be sufficient for our analysis.

We compared the monthly ANS unit price adjusted to the lease to the unit prices for categories 1,

2, and 4 as reported on the Form MMS-2014. We then multiplied any difference between the adjusted ANS price and the price that was actually reported by the royalty quantity to compute a new royalty amount. As with the offshore case, we assumed there would be no revenue impact for the large independent producers/marketers (Category 3) or the small independent producers (Category 5), as they would continue to pay on the gross proceeds they receive from arm's-length sales.

Using the procedures in the further proposed rule, we estimate a 1996 revenue impact of:

- Category (1): $536,894.69
- Category (2): $ -13.16
- Category (4): $ 8,651.16

Offshore Gulf of Mexico

The proposed rule would require the value of oil not sold arm's-length to be based on the average of the daily mean spot price (1) for the market center nearest the lease where spot prices are published in an MMS-approved publication, (2) for the crude oil most similar in quality to the lessee's oil; and (3) for deliveries during the production month. The lessee must adjust the value for applicable location and quality differentials, and may adjust it for transportation costs.

There are three different spot prices published for Gulf of Mexico oil: Eugene Island (35° API, .84 percent sulfur), Heavy Louisiana Sweet (32° API, .3 percent sulfur) and Light Louisiana Sweet (37.5° API, .3 percent sulfur). When the lessee applies a spot price, quality and location adjustments will be allowed.

Production sold by a lessee or its affiliate under an arm's-length contract would be based on gross proceeds received under that contract. We believe that all large, independent producers/marketers with no refinery capacity (Category 3) and small independent producers with no refinery capacity (Category 5) would continue to value crude as they always have; therefore, they were not included in the analysis. We examined the other three categories using the

following procedure:

- We categorized the production by area (i.e. Green Canyon, High Island, etc.).
- We assigned each area the spot price that most accurately represented the oil from that field.
- We calculated weighted average gravities for each area.
- We made gravity adjustments to the spot price using Shell Oil Company's offshore oil posted price adjustment scale in effect at the time of production.
- We deducted location differentials from the spot price for the actual movement of the oil from its first onshore location to the spot market. This value was based on FERC tariffs in effect for transport from major onshore gathering points to the spot market centers.
- We then compared the location and quality-adjusted spot price to the value reported on the Form MMS-2014 for each month in 1996.[3] Any difference was then multiplied by the royalty quantity for each lease and aggregated.

Under the proposed rule, we estimate a 1996 revenue gain of:

- Category (1): $43,517,498.99
- Category (2): $ 4,750,376.13
- Category (4): $ 1,341,782.66

Onshore New Mexico

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[3]MMS compared the price reported on Form MMS-2014 to the location and gravity-adjusted spot price at the first onshore delivery point, assuming that all payors reported a royalty due line (Transaction Code 01) representing the value at the onshore delivery point and a separate transportation allowance line (Transaction Code 11) representing the costs of transporting the oil to shore. That is, MMS compared (1) the onshore spot price, adjusted for the actual reported gravity at the lease, to (2) the price reported by the payor for the royalty due line without deducting any reported transportation allowance for that line. If a payor incorrectly netted their transportation allowance from the royalty due, or if the payor sold their oil at the lease and incurred no transportation to move the oil to shore, MMS acknowledges that the revenue impact estimate for the Gulf of Mexico may be overstated. However, if a payor does not report a separate transportation allowance on Form MMS-2014, MMS has no way of knowing the costs of transporting the production to shore to equate the reported price to the onshore spot price. Absent any other reasonable alternatives, MMS chose this methodology recognizing that the revenue impact could be overstated.

For New Mexico, we arrived at a monthly price at the lease by taking the West Texas Intermediate at Midland spot price less a $0.19 charge for transportation and quality from the lease to the aggregation point and a $0.25 charge from the aggregation point to Midland, Texas. These values came from both the actual per-barrel rates charged by pipelines in the area and additional allowances related to transportation and quality.

We compared (1) the monthly adjusted Midland spot price at the lease to (2) the Category 1, 2, and 4 unit prices less any transportation allowances reported on the MMS Form-2014. This per-barrel incremental difference was then multiplied by the reported royalty quantity to compute the theoretical royalty gain or loss. There would be no revenue impact for the large independent producers/marketers without refinery capacity (Category 3) or the small independent producers without refinery capacity (Category 5) as they would continue to pay on gross proceeds accruing from their arm's-length sales.

Estimated 1996 revenue gains under the further proposed rule for onshore New Mexico are:

- Category (1): $305,449.75
- Category (2): $331,159.89
- Category (4): $138,682.17

Rocky Mountain Area

We determined that calculating monthly values by State for the three valuation criteria could not be complete due to lack of information. It is difficult to estimate what unit value a tendering program would have yielded, nor is it easy to estimate how much production would be offered for sale. It is also difficult to determine the volume-weighted average price of a lessee's arm's-length sales and purchases from a field/area or whether that volume met the 50 percent threshold since we could not determine what sales or purchases were arm's-length. We could not determine a location/quality differential from Cushing, Oklahoma, to the fields/areas of each State due to lack of such transaction information.

In order to arrive at a fair market price that approximated arm's-length sales (i.e. attempting to mirror the proposed valuation criteria), we utilized the monthly weighted average unit value per barrel for the large and small independent producers/marketers with no refining capacity (categories 3 and 5). Those prices were usually higher than any of the three refiner's (categories 1, 2, 4) unit prices. We decided that this calculated arm's-length price would be a conservative, yet reasonable proxy for unit value.

We were unable to split the oil volumes into sweet and sour crudes, so we assumed that the lessees grouped into the five categories produced proportional volumes of sweet and sour crudes. Since we utilized unit prices that had already been adjusted for quality, we did not make any further quality adjustments.

For Colorado, Montana, North Dakota, Utah, and Wyoming we took the monthly weighted average unit price for the large and small independent producers/marketers with no refining capacity (Categories 3 and 5) and compared that price to each individual lessee unit price in each of the refiner Categories (1, 2, and 4) as reported on Form MMS-2014. The price difference per barrel was multiplied by the royalty quantity to compute the theoretical royalty gains or losses. We assumed there would be no revenue impact for the large independent producers/marketers (Category 3) or the small independent producers (Category 5), as they would continue to pay on gross proceeds.

Estimated 1996 revenue gains under the further proposed rule for the Rocky Mountain Area (see Appendix A for actual by-State breakdown) are:

- Category (1): $1,958,450.90
- Category (2): $ 248,640.10
- Category (4): $ 381,596.97

Other Benefits

MMS and industry will realize administrative savings because of reduced complexity in royalty

determination and payment. Specifically, the proposed rule would result in:

- Simplification of pricing, coupled with certainty,
- Reductions in valuation determinations and litigation,
- Reduction in industry compliance costs, and
- Receipt of market value of oil produced from Federal leases.

Overall Benefits

The total impact of the proposed rule by using the 1996 comparison as a baseline is expected to result in the following additional revenue amounts:

- Category (1): $58,118,595.13
- Category (2): $ 5,838,282.24
- Category (4): $ 2,139,859.69

Grand Total: $66,096,737.06

VII. Impact on Industry and Small Governments

As stated above, this regulation has minimal impact on industry. The entire source of additional costs to industry is related to the proposed Form MMS-4415. We estimate that the total initial burden for all respondents is 4,597.5 hours at a cost of $160,912.50. Additional information relating to the impact of this form has been filed with the Office of Management and Budget via the Paperwork Reduction Act. This regulation will not significantly or uniquely affect small Governments. This includes State, local and tribal governing authorities. MMS generally shares its oil royalties when Federal land is located in a particular State. The only expected impact in such cases will be additional revenue.

VIII. Clear Writing of Regulation

MMS advocates clear writing in all its documents. We have trained virtually all MMS employees in "plain English" concepts, and have included these concepts in all our recent regulatory revisions. In 1996, MMS won Vice President Gore's Hammer Award for pioneering efforts to write regulations in plain English. We wrote this further proposed rule in plain English including reordering, renumbering, and adding sections for ease of reference. Although this rule deals with technically complex issues, we made every effort to write it as clearly as possible.

Appendix A

Rocky Mountain Area

Increase in Royalties by Category and State

	Increase in Royalties					Total Rocky
Category	CO	MT	ND	UT	WY	Mountain area
1-Maj Int Ref	$ 47,672.79	$ 509,586.90	$ 240,076.57	$ 61,873.43	$ 1,099,241.21	$ 1,958,450.90
2-Large Ind Ref	$ 4.96	$ 9,288.29	$ 90,492.27	$ 1,948.18	$ 146,906.40	$ 248,640.10
4-Small Ref	$ 4,359.82	$ 414.69	$ 78,977.22	$ 2,175.74	$ 295,669.50	$ 381,596.97
Totals	$ 52,037.57	$ 519,289.88	$ 409,546.06	$ 65,997.35	$ 1,541,817.11	$ 2,588,687.97
Volumes that are valued less than Arm's-length Sales unit value	97,379.17	250,509.61	372,969.90	92,468.72	1,311,866.72	2,125,194.12
$ increase/bbl	$0.53	$2.07	$1.10	$0.71	$1.18	$1.22