PART 520—ORAL DOSAGE FORM NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 520 continues to read as follows:

Authority: 21 U.S.C. 360b.

■ 2. Section 520.1452 is amended by revising the heading of paragraph (d) and by revising paragraph (d)(2) to read as follows:

§ 520.1452 Moxidectin gel.

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(d) *Conditions of use in horses and ponies*—* * *

(2) *Indications for use*. For the treatment and control of large strongyles: *Strongylus vulgaris* (adults and L4/L5 arterial stages), *S. edentatus* (adult and tissue stages), *Triodontophorus brevicauda* (adults), and *T. serratus* (adults); small strongyles (adults): *Cyathostomum* spp., including *C. catinatum* and *C. pateratum*; *Cylicocyclus*. spp., including *C. insigne*, *C. leptostomum*, and *C. nassatus*; *Cyliocostephanus. spp*., including *C. calicatus*, *C. goldi*, *C. longibursatus*, and *C. minutus*; *Coronocyclus* spp., including *C. coronatus*, *C. labiatus*, and *C. labratus*; and *Gyalocephalus capitatus*; small strongyles: undifferentiated lumenal larvae; encysted cyathostomes (late L3 and L4 mucosal cyathostome larvae); ascarids: *Parascaris equorum* (adults and L4 larval stages); pinworms: *Oxyuris equi* (adults and L4 larval stages); hairworms: *Trichostrongylus axei* (adults); large-mouth stomach worms: *Habronema muscae* (adults); and horse stomach bots: *Gasterophilus intestinalis* (2nd and 3rd instars) and *G. nasalis* (3rd instars). One dose also suppresses strongyle egg production for 84 days.

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Dated: April 14, 2004.

Steven D. Vaughn,

Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 206

RIN 1010–AD04

Federal Oil Valuation

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: MMS is amending the existing regulations governing the valuation of crude oil produced from Federal leases for royalty purposes, and related provisions governing the reporting thereof. The current regulations became effective on June 1, 2000.

These amendments primarily affect which published market prices are most appropriate to value crude oil not sold at arm's length and what transportation deductions should be allowed.

DATES: *Effective date:* July 6, 2004.

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SUPPLEMENTARY INFORMATION:

I. Background

The MMS is amending the existing regulations at 30 CFR 206.100 *et seq.*, governing the valuation of crude oil produced from Federal leases for royalty purposes, and related provisions governing the reporting thereof. The current regulations became effective on June 1, 2000 (June 2000 Rule).

After conducting several public workshops, MMS issued a proposed rule that was published in the **Federal Register** on August 20, 2003 (64 FR 50088). The original comment period for this proposed rule closed on September 19, 2003. However, MMS received requests to extend the comment period and on September 26, 2003, MMS reopened the comment period until November 10, 2003 (68 FR 55556).

The amendments do not alter the basic structure or underlying principles of the June 2000 Rule. In proposing these amendments, the Department of the Interior reaffirmed that the value for royalty purposes of crude oil produced from Federal leases is the value at or near the lease. However, in determining value at the lease of production not sold under an arm's-length contract, MMS is not restricted to a comparison to arm's-length sales of other production occurring in the field or area. MMS may begin with a ''downstream'' price or value, and determine value at the lease by deducting the costs of transporting oil to downstream sales points or markets, or by making appropriate adjustments for location and quality.

Federal lessees are not obligated to sell crude oil downstream of the lease. Lessees are at liberty to sell production at or near the lease, even if selling downstream might have resulted in a higher royalty value for the production than selling it at the lease. If lessees do choose to sell downstream, the choice to sell downstream does not make otherwise non-deductible costs deductible (for example, marketing costs). *See Independent Petroleum Association of America, et al.* v. *DeWitt*, 279 F.3d 1036 (DC Cir. 2002), *cert. denied sub nom., Independent Petroleum Association of America, et al.* v. *Watson*, 537 U.S. 1105 (2003). In addition, MMS may choose to use downstream values when a lessee sells to an affiliate at or near the lease.

II. Comments on the Proposed Rule

Public comments received in response to the proposed rule favored most of the proposed changes. MMS received some negative comments regarding the proposed method for valuing California and Alaska crude oil, some of the specifications of allowable transportation costs, and changing the rate of return on undepreciated capital investments in calculating non-arms-length transportation allowances. We will group the comments received and the MMS responses generally according to the order of the substantive provisions of the rule (with related changes to definitions), with discussion of miscellaneous technical changes thereafter. MMS received comments on the proposed rule from 27 respondents.

A. Changing to NYMEX-Based Valuation and Determining the NYMEX Price To Use for Valuation—§ 206.103

MMS proposed using New York Mercantile Exchange (NYMEX)-based value with a roll as one of the measures of value for production not sold at arm's length in all areas except for California, Alaska, and the Rocky Mountain Region where MMS proposed to use NYMEX-based value without the roll. In the Rocky Mountain Region, NYMEX-based value without the roll would be used as the revised third benchmark (proposed to be redesignated as § 206.103(b)(3)). The base NYMEX price would be adjusted for location and quality differentials and actual transportation costs back to the lease.

Summary of Comments: Fifteen respondents submitted comments on the use of NYMEX pricing. There were several comments about our rationale for changing from a spot market index price to NYMEX and adjusting for location and quality differentials. Industry commenters generally supported using NYMEX, although they believe that spot market index prices are a workable starting point for valuation of oil not sold at arm's length. Some industry commenters believe that the NYMEX calendar month average is closer to the actual value of oil produced in the Rocky Mountain Region than the West Texas Intermediate (WTI) (Cushing, Oklahoma) spot prices prescribed as the third benchmark value in the June 2000 Rule. Industry comments were not opposed to retaining Alaska North Slope (ANS) spot prices as the basis for valuing oil produced in California and Alaska.

Industry commenters generally believe that the roll should not apply to oil produced in California, Alaska, or the Rocky Mountain Region. One industry group further suggested that the roll should not apply to oil produced in the Western Gulf of Mexico, or the San Juan Basin, or any other area that does not have a market center where physical exchanges occur between that market center and Cushing.

Industry believes that MMS should choose whether to include weekends and holidays in the calculation of the average NYMEX price, and is comfortable with MMS's choice to exclude them. Industry suggested that the three benchmarks and the alternative valuation provision for the Rocky Mountain Region are adequate.

State comments on the use of NYMEX were mixed. Two States supported the use of NYMEX. One State does not agree with using NYMEX as the third benchmark for the Rocky Mountain Region, and believes that non-arm's-length royalties should be determined by the affiliate's downstream sales price. The California State Controller's Office (SCO) strongly objected to using the adjusted NYMEX price for California and suggested retaining ANS spot prices. Several members of the California congressional delegation concurred with the California SCO comments.

MMS Response: MMS believes that, at this time, NYMEX futures prices probably represent a more reliable and better assessment of current oil values than spot prices. Use of the NYMEX price as the basis for royalty value has several advantages, not the least of which is the fact that the volume of transactions and the number of participants is so large that, at least theoretically, no one entity could manipulate the resultant price. This is an issue partly because of the recent publicity and questions about the information provided to spot price reporting services and the effect such potentially inaccurate information has on spot prices in general. In addition, there is only one NYMEX price, and it is available from any number of sources. There would be no question about the correct publication to use to obtain the applicable index price.

Further, various questions have arisen about the timing of application of index prices. Published spot prices for specific months generally represent the market's assessment of prices for crude oil delivered during that month, but determined between the 26th day of the month 2 months prior to the delivery month and the 25th day of the month immediately preceding the delivery month. MMS has reviewed the correlation between several public indicia of crude oil prices (*e.g.*, trading month spot prices, NYMEX prices, etc.) and the values actually used in paying royalties to MMS on crude oil sold at arm's length. This review demonstrated that calendar-month NYMEX prices (applying the roll, as discussed below, to production from areas outside the Rocky Mountain Region, California, and Alaska) have the highest correlation to reported arm's-length sales values of any publicly-available indices.

The June 2000 Rule used spot market index prices determined for the trading period that is closest to concurrent with the production month. However, this period is not consistent with the way industry does business. First, as explained above, the published spot market index price relevant to spot market deliveries during the production month is actually the price published the month before the month used to value the current month's production in the existing rule. For example, while the price determined in the period January 26 to February 25 may be the correct timing for spot sales at the market center for deliveries in March, that price may not reflect prices received in March for actual arm's-length sales by producers that are often made more contemporaneously with production. Second, the spot price used in the existing rule is not the price used for spot sales, but occurs 1 month later. It overlaps, but is not the same as, the production month. A price for production in March should be the most current and accurate information that a purchaser or seller would have at the time of production. The NYMEX prices are available on a real time basis to traders and, therefore, are the ones used most commonly to determine the base price of oil during the month of production. Comments received concur with the proposition that using the calendar month average of the daily NYMEX settlement prices will correlate more closely to prices received in the current production month than the index prices used in the existing rule.

A recent MMS review compared valuation of a common crude oil grade (Eugene Island) produced in the Gulf of Mexico using both the calendar month NYMEX price, with a roll (discussed below), and the spot market index price provisions of the existing crude oil valuation rule that became effective on June 1, 2000. The review found that the calendar month NYMEX price (with the roll) is advantageous to the public when futures prices in the out months are lower going forward (when the market is in ''backwardation''). Existing spot market index price provisions, or the use of NYMEX without the roll, are advantageous to the public when futures prices in the out months are higher going forward (when the market is in ''contango''). Using historical NYMEX data since the NYMEX oil market began in 1986, prices in the out months have been lower going forward approximately 60 percent of the time. Thus, taking a conservative and long-term approach to royalty valuation supports use of the NYMEX price with the roll.

MMS proposed to exclude weekends and holidays from the calculation of the average NYMEX price because NYMEX does not publish prices on those days. Commenters generally supported that choice and said that the agency should clearly choose either exclusion or inclusion. In addition, the WTI differential (based on WTI spot market prices) excludes weekends and holidays. In the final rule, MMS is adopting the proposal, and the rule excludes weekends and holidays from the calculation of the average NYMEX price.

MMS proposed the average NYMEX price as the basis for valuing oil produced in California and Alaska that is not sold at arm's length. MMS believes that choosing either ANS spot prices or NYMEX prices would lead to substantively the same result in royalty valuation over time. Publications that publish ANS spot prices also publish differentials between ANS and WTI crude oil at Cushing. The spot price for WTI at Cushing is similar to the NYMEX price. Thus, the NYMEX price adjusted by the differential between ANS and WTI at Cushing would yield a result very similar to ANS spot prices. After consideration of comments from the California SCO and related congressional comments, and because using ANS spot prices will be somewhat simpler than using NYMEX prices minus the WTI-ANS differential, MMS has decided to retain adjusted ANS spot pricing for valuing crude oil produced from Federal leases in California and Alaska.

As a result of moving to NYMEX pricing generally but retaining ANS spot pricing for oil produced in California and Alaska, the references to ''index price'' in several sections of the existing rule are replaced by a reference to ''ANS spot price.''

The comments received supported MMS's proposal to use NYMEX prices as the third benchmark for valuing oil produced from leases in the Rocky Mountain Region that is not sold at arm's length if the lessee does not have an approved tendering program. As in the proposed rule, the final rule retains the other three benchmarks for the Rocky Mountain Region from the existing rule.

MMS proposed applying a roll as an adjustment to the initial NYMEX prices for oil produced from leases outside the Rocky Mountain Region, California, and Alaska. One of the reasons that MMS proposed use of the roll was its own experience in selling crude oil taken as royalty in kind in the Gulf of Mexico under 43 U.S.C. 1353 and sold competitively to small refiners. MMS found that a substantial portion of the crude oil produced in the Gulf, and sold at arm's length was sold on the basis of a NYMEX price methodology, including the roll. MMS found that use of the roll resulted in increased return to the public on oil taken in kind and sold.

The roll is a commonly used measure of the trend of NYMEX prices for future deliveries in those areas. Prices reported for futures contracts on the NYMEX are not limited to deliveries in the prompt month as defined in this rule. Rather, trades could be made in March 2003 for deliveries in April 2003 or in several subsequent months. Due to the fact that the NYMEX prices are future price estimates and, therefore, inherently reflect increases or decreases in prices based upon expected trends, an adjustment to such estimates may be appropriate to extrapolate back to current price estimates, upon which royalty calculations are based. This adjustment factor is the roll, which is added to the initial NYMEX price when prices for the out months are in backwardation (to correct for the fact that the current price should be higher than the future price in this circumstance), and subtracted from the initial NYMEX price when prices for the out months are in contango (to correct for the fact that the current price should be lower than the future price in this circumstance). MMS proposed to add the roll to the initial NYMEX price used as the basis for royalty valuation, except for leases in the Rocky Mountain Region, California, and Alaska. As explained in the preamble to the proposed rule, the roll is not commonly used in transactions involving oil produced in the Rocky Mountain Region, California, or Alaska. For California and Alaska, the roll is irrelevant in the final rule because MMS is retaining ANS spot prices as the basis for royalty value. Commenters generally agreed that the roll should not be applied to oil produced in the Rocky Mountain Region, California, or Alaska.

MMS does not agree with the suggestion of one commenter to apply the roll to production from the Gulf of Mexico that goes to market centers from which there are trades to Cushing, but not to production that goes to market centers from which there are not trades to Cushing. Determining which production from which leases goes to which market centers, and whether it is common for those market centers to have trades to Cushing, would add substantial administrative burden and cost to both royalty payors and the Government. Further, there was no explanation of why this alleged difference was relevant to applying the roll.

The proposed use of the roll also necessitated a corresponding proposed change to the definition of ''trading month.'' In § 206.101 of the existing rule, ''trading month'' is defined in terms of spot market sales. MMS proposed to change the definition of ''trading month'' to conform with NYMEX definitions and practice. It will be used only to calculate the roll. MMS received no comments opposing that change, and is adopting it in the final rule.

Based on the comments received, the final rule prescribes the NYMEX price with a roll as the royalty valuation basis for production from areas outside of the Rocky Mountain Region, California, and Alaska that is not sold at arm's length, and NYMEX with no roll as the third benchmark for production from the Rocky Mountain Region.

Additionally, in § 206.103(b), the paragraphs for the four benchmarks in the Rocky Mountain Region are renumbered (b)(1) through (b)(4) to correspond with the benchmark numbers as proposed. Industry supported the clarification.

While MMS expects the basic operation of the NYMEX market to be the same for the foreseeable future, it is not so clear that the roll will be a permanent feature of the marketplace. When MMS believes that using the roll is no longer a common industry practice, the MMS Director may terminate the use of the roll. However, the MMS Director may terminate the use of the roll only at the end of each 2-year period following the effective date of this rule, through notice published in the **Federal Register** no later than 60 days before the end of such 2-year period. Further, MMS also will have the option to redefine how the roll is calculated to comport with changes in industry practice, through notice published in the **Federal Register** no later than 60 days before the end of each 2-year period. MMS will explain its rationale when it publishes the notice. MMS believes that this flexibility is appropriate so that the valuation standards more closely reflect market developments. As proposed, MMS is adding at § 206.103(c)(2) the option to terminate or modify the roll at the end of each 2-year period after the effective date of this rule.

MMS sought comments in the proposed rule on allowing the use of the NYMEX price to value oil sold at arm's length in multiple sales downstream of the lease where the lessee does not first transfer to an affiliate and where ''tracing'' the production from the lease or unit to the specific sale is burdensome. MMS received positive comments from industry concerning the option to use an index-based value when a producer has numerous arm's-length sales downstream of the lease. Allowing producers to use NYMEX prices for these transactions might alleviate some administrative burden. However, we believe that royalty payments should be based on actual sale prices whenever possible. Also, under the existing regulations, producers have the option of petitioning MMS for alternative valuation procedures if they believe the administrative burden of tracing sales is excessive. In fact, MMS received requests for alternative valuation approvals to alleviate the tracing burden and is in the process of finalizing the requests. Based on these facts, MMS believes the existing regulations are working and do not need to be modified.

B. Adjusting the NYMEX Price for Transportation Costs and Location and Quality Differentials—§§ 206.109 and 206.112

1. Adjustments of NYMEX Prices to Market Centers Generally and Use of WTI Differentials

MMS proposed to adjust the base NYMEX price for location and quality differentials and actual transportation costs back to the lease. Using NYMEX prices necessitates adjusting values between market centers and Cushing (the location of the NYMEX price), because the value of the commodity (oil) varies by location and quality. Crude oil will be worth more the closer it is to 40 degrees API gravity, and the nearer it is located to markets or refineries. To adjust for the differences in location and quality, MMS proposed to use actual arm's-length exchange agreements, which are the market's valuation of the difference. MMS also proposed to allow the use of published differentials between the market center and Cushing when lessees do not actually exchange oil to Cushing at arm's length. In that connection, MMS proposed to add a definition of a new term, ''WTI differential,'' which is the term for that published differential. MMS also proposed to amend the definition of ''MMS-approved publication'' to include the WTI differential.

Summary of Comments: Ten respondents provided comments on adjusting the NYMEX price for transportation costs and location and quality differentials. The California SCO objected to adjusting the NYMEX price for quality and location in California by using the difference between the WTI spot price and the market center spot prices for crude oil. Additionally, the California SCO asserted that using a WTI differential fails to account for uplift in value due to location and gives industry a lower price. Another State believes that differentials should be allowed only if they are reasonable and actually incurred.

Industry commenters believe that requiring lessees to calculate a weighted-average arm's-length differential between a market center and Cushing could result in an unnecessary administrative burden and suggested that lessees should be allowed to use published WTI differentials in lieu of calculating their own location and quality differentials. Comments received from one trade publication indicated that restricting to a 2-year period the ability of lessees to change from one approved publication for WTI differentials to another is fundamentally anti-competitive. The commenter suggested allowing companies to choose a new publication every 90 days.

One commenter observed that there is a difference between the basis on which the WTI differential is calculated and the basis on which the NYMEX price is calculated. The commenter believed that this would lead to an inaccuracy in the adjustments to the NYMEX price. The concern arose principally because the WTI differential is the basis for adjusting the NYMEX price between the market center and Cushing (the location of the NYMEX price) if the lessee does not have an exchange agreement between the market center and Cushing. Additionally, the same commenter expressed concern that this difference would affect the use of the roll, because the prices incorporated in the roll calculation would all be determined on different basis months from the WTI differential that is used to adjust the NYMEX price.

MMS Response: As explained above, adopting the NYMEX price as the basis (or, in the Rocky Mountain Region, an alternative basis) for royalty valuation for oil produced from leases in areas other than California and Alaska and not sold at arm's length requires an additional adjustment beyond those in the current rule because the NYMEX price is defined only at Cushing for light sweet crude oil. Therefore, differentials from Cushing to other market centers are necessary. These differentials can be both positive and negative, depending on the quality and location of the alternative crude oil. They will also vary from month to month depending on relative market forces, *e.g.* tanker shortages in the Gulf, pipeline problems in Cushing, etc.

Under the final rule, the average of the daily NYMEX settlement prices published during the calendar month of production (including the roll, if applicable) at Cushing is adjusted to the market center by the differentials derived from the lessee's actual arm's-length exchange agreements between the market center and Cushing applicable to production during the production month. However, MMS believes that many lessees do not have arm's-length exchange agreements, for significant volumes of the oil they own at market centers, between Cushing and each market center to which they transport or exchange crude oil. If the lessee does not have arm's-length exchange agreements between a particular market center and Cushing for at least 20 percent of the oil it owns at that market center (as discussed further below), the adjustment to Cushing for the oil that is not exchanged at arms-length between that market center and Cushing would be the WTI published differential. (For the less than 20 percent of the lessee's oil that is exchanged at arm's-length between that market center and Cushing, the lessee will use the differential derived from the arm's-length exchange agreement(s).) If the lessee has arm's-length exchange agreements for more than 20 percent of the oil it owns at that market center, it may use the arm's-length differential for all of its oil at that market center. The lessee would then calculate a further adjustment from the market center to the lease.

MMS does not believe that it would be the best choice to allow lessees to use WTI differentials in lieu of calculating their own location and quality differentials when they have significant arm's-length exchanges. If actual arm's-length data is available, MMS believes that is preferable to using a published differential and more accurately represents the actual value of the lessee's oil.

With respect to the comment regarding the difference between the basis on which the WTI differential is calculated and the basis on which the NYMEX price is calculated, we recognize that the WTI differential is the average of the daily high and low differentials published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). For a given delivery month, the industry trade publications perform their price surveys for the WTI spot market price and determine differentials from the 26th day of the second month before the delivery month to the 25th day of the month preceding the delivery month. For the same delivery month, the NYMEX price, in contrast, is calculated on a different basis. As defined in the final rule, the NYMEX price is the calendar month of production average of the daily NYMEX settlement prices. MMS knows of no more contemporaneous published value that it could use that might give more accurate market differences.

MMS understands that the bases for calculating the WTI differential and the NYMEX price (and the roll) are not identical. However, as explained above, MMS believes that using the calendar month average NYMEX price is the most accurate measure of the base price of oil because it accounts for all the contemporaneous information available to traders during the production month. MMS also believes that using the WTI differential applicable to deliveries in the production month is the most accurate market measure of the expected difference in value between the market centers and Cushing.

MMS believes that over time, marginal losses from adjustments to the NYMEX price due to the difference in basis between the NYMEX price and the WTI spot market price (and, therefore, the WTI differentials) will be offset by marginal gains from those adjustments, and that the net effect should be immaterial. MMS believes these differences are not as important as the gain in public confidence from the use of NYMEX prices, which are less likely to be manipulated than index prices and are more easily obtained from a number of non-proprietary sources. Additionally, WTI differentials are not the preferred method of calculating the adjustment from Cushing to a market center; under the regulation they are to be used only when a lessee does not have significant actual arm's-length exchanges.

Changing from spot market index price-based valuation to NYMEX-based valuation and adding a definition for ''WTI differential'' also require a revision in the definition of ''MMS-approved publication.'' Under the existing rule, the term ''MMS-approved publication'' referred to which publications of spot market index price MMS would accept. Under the final rule, the term now refers to the publications MMS approves for determining WTI differentials and ANS spot prices (because ANS spot market pricing is retained for production from leases in California and Alaska).

MMS does not agree with the comment that lessees should be able to choose a new publication once every 90 days. In the final rule, §§ 206.103(a)(4) and 206.112(b)(2) do not permit lessees to choose an MMS-approved publication for ANS spot market prices or WTI differentials for any period less than 2 years, which is consistent with current practice. Using any period less than 2 years may be viewed as being more prone to market manipulation to the benefit of the lessee.

2. Adjustments to NYMEX Prices for Crude Oil Produced From Leases in the Rocky Mountain Region and California

MMS proposed adding a market center at Guernsey, Wyoming, for sweet crude oil produced from Federal leases in Wyoming, and requested comments regarding alternative valuation procedures, including differentials, in valuing sour crude produced from Federal leases in Wyoming. With regard to Wyoming sour grades, MMS asked whether it would be useful to include a market center for valuation of sour crude produced in the Rocky Mountain Region at Hardisty, Alberta, Canada (at which spot market prices for sour crude are published in trade publications), and adjust the Hardisty price for the cost of transportation from Casper, Wyoming (a typical delivery point) to Hardisty and from the lease to Casper. MMS also proposed adding possible market centers at Kern River for valuing San Joaquin Heavy produced from Federal leases in California and at Hynes Station on Line 63 for San Joaquin Light produced from Federal leases in California.

Summary of Comments: Wyoming opposed the suggested use of spot prices from Hardisty, Alberta, Canada, stating that Hardisty prices would be less accurate than using NYMEX prices at Cushing. The State also believed that the use of WTI differentials in general is not appropriate because they (like spot prices) potentially are susceptible to manipulation. The California SCO believed that the use of Hynes Station and Kern River as market centers would not increase accuracy in valuing production from Federal leases in California for Federal royalties.

Industry appeared to agree that there was no need to add Hardisty or Guernsey as new market centers. The two industry publications that submitted responses suggested that should MMS decide to use prices from Hardisty, Alberta, Canada, then their publications be utilized. Industry further recommended that MMS consider application of market center differentials such as Kern River and Line 63 to the ANS spot price to establish location and quality differentials between Long Beach and other market centers, should MMS decide to retain ANS pricing for Alaska and California production.

MMS Response: MMS agrees with the comments regarding the use of prices from Hardisty, Alberta, Canada, and Guernsey, Wyoming, and is not including either Hardisty or Guernsey as a market center at the present time. Using Hardisty as a market center would create a number of difficulties involved in making the adjustments back to the leases. MMS also agrees with the California SCO that the use of Kern River and Line 63 will not lead to improved accuracy at this time because of the apparently continued small volumes reported at those locations. Lessees who do not have their own exchanges of production from leases in the Rocky Mountain Region to Cushing, or of production from leases in California to Long Beach or San Francisco, may make proposals to MMS for adjustments.

3. Adjusting Values Between the Lease and the Market Center

The proposed rule retained the basic principles in the existing rule of adjusting value between the market center and the lease for location and quality and actual transportation costs. The proposed rule included two changes. First, the proposed rule (at § 206.112(b)) included a provision that if you transport or exchange (or both transport and exchange) at least 20 percent, but not all, of your oil produced from a lease to a market center, you must use the weighted average of the adjusted values of that oil to value oil not transported or exchanged to the market center. Second, the proposed rule deleted the provision (at existing § 206.112(c)) that allowed lessees to use market center values at locations other than market centers (primarily refineries).

MMS also proposed that if you transport your oil from the lease to a market center, and your oil has a higher or lower gravity and a higher or lower sulfur content than the crude oil for which a price is published at the market center, you should make an adjustment for quality even though you have no existing exchange agreements or quality banks. MMS proposed that in such circumstances, you would use appropriate posted price gravity tables to adjust the value of your produced crude for gravity differences from the market center benchmark crude, and use a factor of 2.5 cents per one-tenth percent difference in sulfur content to adjust for quality when you have neither exchange agreements nor quality banks to fully adjust the quality of your oil at the market center. MMS based this factor on our understanding of common sulfur bank adjustments for California.

Summary of Comments: Three respondents submitted comments on what adjustments and transportation allowances apply when valuing production using index pricing. An industry respondent agreed with the proposal to have a lessee base its adjustment for the portion of its production that does not go to the market center (*e.g.*, goes to a refinery) on the portion that goes to the market center, when it amounts to at least 20 percent of production. Industry commenters believed that the proposed sulfur adjustment was inadequate, and that it should be between $.50 and $1.00 per percent.

MMS Response: MMS made extensive changes to this section to clarify how and when to apply location and quality differentials and transportation allowances when calculating royalty value. MMS has changed this section to first show (in § 206.112(a)) how adjustments should be made between the lease and the market center, which applies regardless of whether NYMEX prices or ANS spot prices are used. Section 206.112(b) then shows how differentials should be calculated between the market center and Cushing when the NYMEX price is used as the basis of value.

The basic concepts of the proposed rule have been retained in the final rule. A lessee must use its arm's-length exchange agreements, if it has any, to determine the adjustment between the lease and market center or for any intermediate segments between those points. It may continue to use its actual transportation costs for any portion of the distance between the lease and market center over which oil is actually transported and not exchanged. If the lessee has an exchange agreement that is not at arm's length, the lessee must obtain MMS approval for using it as a location and quality adjustment. Until MMS approves a proposed location and quality differential, the lessee may use the location and quality differential in its non-arm's-length exchange agreement. If MMS prescribes a different differential, the lessee will need to adjust previously reported and paid royalties, together with appropriate interest payments or credits, based on the approved differential. To prevent ''double dipping,'' the lessee may not take both a transportation allowance and apply a location and quality differential between the same two points.

In the final rule, in § 206.112(a)(3), MMS has decided to retain the provision that requires a lessee to use its arm's-length exchange agreements that cover at least 20 percent of its production from the lease during the production month for the portion of oil from that lease for which the lessee does not have exchange agreements between the lease and the market center (or between some intermediate points). MMS believes that 20 percent is appropriate because it is greater than the royalty percentage under a typical onshore lease (12½ percent) or offshore lease (16⅔ percent).

Section 206.112(a)(4) of the final rule addresses the situation where a lessee does not transport or exchange at least 20 percent of its oil produced from the lease to a market center. In that instance, you would use paragraphs (a)(1) and (a)(2) to value the less than 20 percent portion (if any) that you transport or exchange (or transport and exchange) to a market center. For the remainder of your lease production, you must submit a proposal to MMS for a location and quality differential between the lease and the market center. You may use your proposed differential until MMS disapproves it. If MMS approves a different differential, you will need to adjust the previously reported and paid royalties, together with an interest payment or credit.

Paragraph (c) addresses situations in which an additional quality differential is appropriate. For instance, MMS understands from our royalty-in-kind program that the All America Pipeline uses a sulfur adjustment of 50 cents per full percent, after the first percent difference in sulfur. MMS believes that the typical sulfur content of oil produced from Federal leases is in the 1 to 3 percent range. Therefore, MMS will change its proposed use of a 2.5 cent per 0.1 percent adjustment to 5.0 cents per 0.1 percent sulfur unless MMS approves a higher adjustment. This adjustment would be similar to the factor used by the All America Pipeline and is consistent with the comments received from industry on common industry practice.

Our intent in rewriting § 206.112 was to clarify and simplify the existing rules. Certain technical issues were identified and evaluated to improve the effectiveness and efficiency of the rules by reducing litigation, assuring more contemporaneous compliance, reducing administrative cost to the Federal Government and lessees, and making Federal lands more attractive for development and leasing.

C. Transportation Cost Issues—§§ 206.110 and 206.111

1. Proposed Change to Rate of Return on Undepreciated Capital Investment—§ 206.111(i)(2)

MMS proposed an amendment to the regulations governing calculation of actual transportation costs in non-arm's-length situations by changing the allowed rate of return on undepreciated capital investment from 1.0 times the Standard & Poor's BBB bond rate to 1.5 times the Standard & Poor's BBB bond rate.

Summary of Comments: Two States commented specifically that 1.5 times the Standard & Poor's BBB bond rate is too high and does not reflect actual cost of capital. One State was particularly concerned that increasing the rate of return deduction would negatively impact State royalty income. It also believes the rate is not consistent with either MMS's former practice of rejecting the equity component of capital costs in determining a proper rate of return or with findings of the Energy Information Administration (EIA) that the rates of return are lower in the pipeline segment than in the exploration and production segment of the oil and gas industry. Specifically, the EIA found that the pipeline line of business averaged a return on investment approximately 50 percent of the return in the exploration line of business, and approximately 60 percent of the return in the oil and gas industry as a whole. This return was also slightly less than the Standard & Poor's BBB bond rate. Another State suggested a possible alternative to the proposal by applying the 1.5 times the Standard & Poor's BBB bond rate to pipelines constructed after the passage of the new regulations and retaining the 1.0 times Standard & Poor's BBB bond rate for existing infrastructure. Congressional commenters were concerned that the rate would negatively affect revenues.

Industry commenters asserted that 1.5 times the Standard & Poor's BBB bond rate was not sufficient. Based on a study from the American Petroleum Institute (API), industry argued that although pipelines are not as risky as drilling wells, some risk is involved, and that the cost of rate of return allowable should be between 1.6 and 1.8 times the Standard & Poor's BBB bond rate. Industry further suggests that non-pipeline-based transportation should be dealt with on a case-by-case basis.

MMS Response: MMS has examined some rates of return in the oil industry and believes that some weighted average rate of return considering both equity and debt is appropriate as an actual market-based cost of capital. An investor will choose to have a mix of debt and equity for many reasons, not the least of which is that companies that choose to finance their investments solely by debt will pay a higher interest rate due to the increased risk on the part of the creditor. Both debt and equity costs are actual costs of capital. The choice of Standard & Poor's BBB bond rate in 1988 was made, at least in part, in recognition of some equity component because the majority of companies with non-arm's-length transportation arrangements have debt costs lower than the Standard & Poor's BBB bond rate.

MMS continues to believe that establishing a uniform rate of return on which all parties can rely is preferable to the costs, delays, and uncertainty inherent in attempting to analyze appropriate project-specific or company-specific rates of return on investment. MMS, through its Offshore Minerals Management, Economics Division, has studied several years' worth of data for both non-integrated oil transportation companies and larger oil producers, both integrated and independent, that MMS believes are more likely to invest in oil pipelines. After a thorough review of the MMS and API studies, and consideration of the comments submitted by States and industry, we believe that the allowance for the rate of return on capital should be adjusted to 1.3 times the Standard & Poor's BBB bond rate. This number is the mid-point of the range suggested by the MMS study, which concluded that the range of rates of return appropriate for oil pipelines would be in the range of 1.1 to 1.5 times the Standard & Poor's BBB bond rate. MMS also believes that although there are some very high risks involved with certain oil and gas ventures, such as wildcat drilling, the risk associated with building and developing a pipeline to move oil that has already been discovered is much less and of a different nature. Both the MMS study and the data from EIA demonstrate that the market also perceives that the risk is lower in the transportation lines of business than in the exploration and production lines of business.

MMS believes that the study conducted by its Offshore Minerals Management Economics Division used the most relevant data for a reasonable period and is therefore the best source to decide on the appropriate rate of return. The fact that it also fell between the study cited by industry and the data cited by the State reaffirms our belief in its reasonableness.

2. Specific Transportation Cost Issues—§§ 206.110 and 206.111

(i) Arm's-Length Transportation

In § 206.110, MMS proposed to add new paragraphs (b) and (c) that would specify many of the costs incurred for transporting oil under an arm's-length contract that are allowable deductions and those that are not deductible, respectively. MMS believes some costs are directly related to the movement of crude oil to markets away from the lease. MMS proposed that the rule include specific costs of transportation that are allowable.

MMS also proposed to include specific costs as not being costs of transportation, either because they were costs of placing oil in marketable condition or costs of marketing, or otherwise simply not costs of transportation. They were proposed to be non-allowable as deductions from royalty value.

(ii) Non-Arm's-Length Transportation

In § 206.111, MMS proposed to add new paragraphs (b)(6) and (b)(7) that would specify many of the costs incurred for transporting oil under a non-arm's-length contract that are allowable deductions, but only to the extent they have not already been included in the actual cost calculation under paragraphs (d) through (j) of this section. MMS believes these costs are directly related to the movement of crude oil to markets away from the lease. MMS proposed that the rule include specific costs of transportation that are allowable.

MMS also proposed specific costs as not being costs of transportation, either because they were costs of placing oil in marketable condition or costs of marketing, or otherwise simply not costs of transportation. They were proposed to be non-allowable as deductions from royalty value.

(iii) Technical Correction to § 206.111(h)(5) Regarding Redepreciation

We proposed to modify existing § 206.111(h)(5) to delete the words ''who owned the system on June 1, 2000'' and replace them with the words ''from whom you bought the system'' to remedy an unintended consequence regarding depreciation when calculating a transportation allowance not involving an arm's-length transportation contract. The language in the June 2000 Rule would allow and require a second purchaser to go back to the depreciation schedule of the original owner, rather than continuing the depreciation of the first purchaser. This could result in either a higher or lower depreciable basis than was intended.

Summary of Comments: States were uniformly opposed to modification of the transportation allowances in the June 2000 Rule and most questioned whether MMS was proposing to designate marketing costs as transportation. One State suggested that MMS is acting contrary to its long-held policy, which does not allow the deduction of direct or indirect marketing costs. The State further suggests that expanding the cost deductions will not serve to streamline the audit process because it believes that the expanded transportation costs will inevitably lead to litigation. Another State commented that MMS has proposed allowing some costs which it traditionally has not allowed as transportation. The commenter requested that MMS insert a provision stating that reimbursements for any or all of these cost elements received by the lessee, its affiliate, or its marketing agent, be included either in gross receipts or included as offsets to the expenses incurred in calculating transportation allowances. No State pointed to a single specific cost listed as allowable in the proposed rule that MMS has ever considered to be marketing or non-transportation related.

Industry strongly supported the inclusion of specific transportation costs in the rule as a powerful tool for averting disputes arising out of lack of clarification of issues, but suggested that gauging and scheduling fees be included as deductible transportation costs.

MMS Response: MMS intends to clarify and simplify the existing rule to reduce litigation, assure more contemporaneous compliance, reduce administrative costs to the Federal Government and lessees, and make Federal lands more attractive for development and leasing. MMS does not believe it can eliminate all disputes, but clarity within the regulatory structure affords the benefits listed above. After clarifying the costs that would be considered to be gas transportation costs and those that would be considered not to be transportation costs in the amendments to the gas valuation regulations promulgated in 1997, one lawsuit resolved whether the lines that MMS had drawn were reasonable. That case, *Independent Petroleum Ass'n of America* v. *DeWitt*, 279 F.3d 1036, *cert. denied*, 537 U.S. 1105 (2003) upheld all of MMS's determinations, except one involving unused firm capacity charges. Regarding unused firm capacity charges, the court held that MMS had not sufficiently explained why they were not related to transportation. MMS believes that by more fully explaining the distinctions, its policy is more likely to be upheld.

In this rule, MMS does not modify its long-standing policy of not allowing as a deduction from gross proceeds the costs of placing production in marketable condition or costs of marketing production, including indirect or internal costs, or any other costs that are not necessary for the lessee to incur in order to move its oil. MMS believes that the costs it lists as transportation costs in the final rule are consistent with the reasoning that it has always followed in determining whether costs are for transportation or for something else.

In § 206.110(b), MMS identifies specific costs as allowable. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under § 206.110(b). The costs are:

(1) The amount that you or your affiliate pay under an arm s-length transportation contract or tariff. This is the base price paid to transport oil at arm's length. It has always been allowable as a transportation expense.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses. Pipeline losses are actual or theoretical reductions in the volume of oil that travels through a pipeline. Pipeline losses are the result of either real, physical losses, or errors in the measurement of the oil. The lessee or its

affiliate may incur the cost of a pipeline loss either by a reduction in the volume of oil, resulting in lower gross proceeds received, or by a reduction in the value of oil on which the lessee received payment. Again, this is specifically allowable under existing regulations because these fees must be paid to a pipeline owner if they are part of the fee structure.

(3) Fees paid for administration of a quality bank. Quality banks are the means by which the various shippers compensate each other if their oil is of higher or lower quality than the standard for the pipeline. Those shippers with higher quality oil receive a payment from the quality bank and those with lower quality oil must pay into the bank. Those payments are not usually taken into account to determine the value of the oil for Federal royalty purposes due to the provisions of § 206.119. The fees allowed in this paragraph are fees paid to the person who administers the quality bank, not the payments made or received in adjusting the qualities of the injected oils. These banks are usually administered by pipeline owners, but may be administered by third parties. MMS is changing the final rule language by eliminating the phrase ''to a pipeline owner'' to acknowledge the fact that sometimes these fees may be paid to other persons who administer the quality bank. These fees are allowable because they are costs that are required to be incurred in order to ship oil through the pipeline to which they apply, and are not costs of placing the oil in marketable condition.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. Some oil pipelines require that shippers leave oil in the pipeline so that the pipeline is full. Oil will not flow through the pipeline unless it is filled. The oil that the shipper (lessee) owns in the pipeline is, in effect, inventory that cannot ever be sold as long as the shipper uses the pipeline to transport its oil. If a shipper is required to maintain inventory, it loses the time value of money on the value of that oil for every month it is maintained in the line. For lines that do not require the shippers to maintain line fill, the pipeline owner will own the oil that fills the line and will charge the shipper as part of the arm's-length price or tariff a cost at least equal to its capitalized costs. In order to treat lessees who ship through pipelines that require shippers to maintain line fill the same as lessees who ship through pipelines in which the owner provides line fill, MMS is allowing a deduction equal to the capitalized costs of the line fill—the monthly value of the oil that the shipper owns that serves as line fill times the rate of return.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees. Allowable costs (5) through (8) are all fees paid, as part of the cost of moving oil, to various persons who perform intermediate services associated with physical movement of oil. Specifically, the final rule allows fees paid to terminal operators for loading or unloading oil, fees paid for short-term storage incidental to transportation, fees paid to pump oil from one system or vehicle to another, and fees paid to physically move oil through a hub because they are costs incurred to move oil. Even short-term storage, if it is required by the transporter and not incurred for marketing purposes, is a cost associated with the movement of oil. MMS does not intend to allow any costs associated with marketing to be deducted. Therefore, the regulation limits storage costs to those required by transporters and limits transfer fees to those needed to physically move the oil, but disallows fees that merely transfer title—which is clearly a cost of marketing.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation. These payments account for the fact that when high-gravity oil is mixed with lower-gravity oil, the volume of oil in the pipeline shrinks. If the charge is levied because your oil is of a significantly different quality than the other oil in the system, it is allowable as a transportation deduction because it affects the overall ability of the pipeline to transport oil. You may not deduct charges to adjust the quality of the oil to meet pipeline standards because that would be a cost of placing the oil in marketable condition.

(10) Costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain. MMS believes that this is a cost that the lessee or its affiliate must incur to obtain the pipeline's transportation service, and therefore is a cost of moving the oil. It is not incurred for marketing purposes or to put the oil in marketable condition, but is paid solely to procure transportation services. Again, MMS will allow only the capitalized costs, when that is all that is appropriate, or a one-time expense, if that is appropriate. These costs should only include the currently allocable costs applicable to the Federal lease. MMS believes that shippers generally use two different means of assuring creditworthiness. The first involves a deposit or advanced payment in which the shipper incurs only the costs associated with the time value of money because it receives its deposit back. The other involves actual out-of-pocket costs to obtain a letter of credit, guarantee, or surety bond. MMS believes that these two means should be accounted for differently in calculating your transportation allowance.

For example, in the first case, if you make a cash deposit of 2 months of the expected transportation charges (say $50,000), and transport 100,000 barrels per month, of which 75,000 barrels are from a Federal lease, you must calculate the cost as follows:

Multiply the deposit by the monthly rate of return, calculated by dividing the rate of return specified in § 206.111(i)(2) by 12, and multiply that result by the proportion of total production from each Federal lease. In this example, if the Standard & Poor's BBB bond rate was 8 percent, the allowable monthly rate would be

$$\left(\frac{.08 \times 1.3}{12} = .009\right),$$

and that would be multiplied by the amount of the deposit to get the monthly cost, which would be $450. Then you could include the share of that applicable to the Federal lease (75,000/100,000) = ¾. So you could include $337 as an allowable transportation cost for as long as the $50,000 is on deposit (and the other factors remain unchanged).

In the second case involving the expense of a letter of credit or other surety, if you pay your bank $5000 as a non-refundable fee for a letter of credit, you can include the proportion allocable to Federal production in the month that fee is paid, and then never again.

MMS does not allow deduction of costs that are not actual costs of transporting oil. A new § 206.110(c) lists the costs that MMS believes are clearly not related to the transportation of oil. These are:

(1) Fees paid for long-term storage (more than 30 days). Fees paid for long-term storage are due to a marketing choice and are not a necessary transportation cost.

(2) Administrative, handling, and accounting fees associated with terminalling. Similarly, administrative fees associated with terminalling are not allowable because MMS believes that they are associated with administrative costs that are the lessee's obligation.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees. Non-allowable costs for title and terminal transfer fees and fees paid to avoid title and terminal transfer fees are associated with changes in ownership rather than movement and therefore are not costs of transportation.

(5) Fees paid to brokers. Fees paid to brokers are treated similarly to items (3) and (4) above, because they are also costs associated with changes in ownership.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production. Non-allowable costs (6) and (7) relate to scheduling, nominating, and accounting for sale and movement are internal costs that the lessee is required to provide at no cost to the lessor.

(8) Gauging fees. Gauging fees are simply costs of measuring the volume of oil, which have traditionally been the responsibility of the lessee.

Section 206.111 specifies how to calculate non-arm's-length transportation allowances. In § 206.111(b)(6), MMS proposed certain costs as allowable costs of transportation as follows:

(i) Volumetric adjustments for actual (not theoretical) line losses.

(ii) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill.

(iii) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(iv) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(v) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

Several of these costs are the same as the costs allowed under § 206.110(b) for arm's-length transportation described above. For example, MMS will allow lessees who transport through a non-arm's-length arrangement to deduct the cost of carrying line fill on their books and will allow fees paid to non-affiliated terminal operators and hub operators associated with physical movement of oil. MMS is also adding a new cost parallel to these costs. If a lessee pays a non-affiliated quality bank administrator, those costs are comparable to those incurred by arm's-length shippers.

MMS will also allow certain costs similar to the costs allowed for arm's-length shippers. For example, MMS will allow volumetric losses, instead of fees, that cover shrinkage when high-gravity petroleum is mixed with low-gravity oil. Similarly, actual volumetric changes in line volume, whether they are losses or gains are allowable (or required to be added) for non-arm's-length shippers, in lieu of allowing fees for actual or theoretical line losses for arm's-length shippers.

The costs identified as not being allowable for arm's-length shippers in § 206.110(c) are also not allowed as transportation costs for shippers that transport their oil through non-arm's-length arrangements. In addition, MMS has specified that theoretical line losses are not allowable, because they are not actual costs to shippers who ship through non-arm's-length arrangements. The following have been designated as non-allowable transportation costs under § 206.111(b)(7):

(i) Fees paid for long-term storage (more than 30 days).

(ii) Administrative, handling, and accounting fees associated with terminalling.

(iii) Title and terminal transfer fees.

(iv) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(v) Fees paid to brokers.

(vi) Fees paid to a scheduling service provider.

(vii) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(viii) Theoretical line losses; and

(ix) Gauging fees.

The final rule retains the lists of allowable and unallowable costs in §§ 206.110 and 206.111 because MMS believes they properly draw the line between those expenses that are needed for the movement of oil and those expenses that are incurred for some other purpose.

The final rule adopts the proposed rule's changes to § 206.111(h)(5) related to redepreciation as proposed. When we amended the rules in March 2000, we intended the revisions regarding depreciation in the current rule to permit, one time only, a new depreciation schedule based on your purchase price when you purchase a transportation system from a previous owner. If a transportation system were sold more than once, subsequent purchasers would have to maintain the then-existing depreciation schedule.

However, existing paragraph (h)(5) says ''if you or your affiliate purchase a transportation system at arm's length after June 1, 2000, from anyone other than the original owner, you must assume the depreciation schedule of the person who owned the system on June 1, 2000.'' But if A were the original owner and still owned the system on June 1, 2000, and subsequently sold the system to B after June 1, 2000, who in turn sold it to C, the rule as written says that C would have to assume original owner A's depreciation schedule. This was not MMS s intent. To be consistent with the intended result, C should assume B's depreciation schedule in this situation.

Therefore, to reflect the original intent, MMS is modifying § 206.111(h)(5) to delete the words ''who owned the system on June 1, 2000'' and replace them with the words ''from whom you bought the system.'' This change will enable C in the example above to assume the depreciation schedule of B based on B's purchase price of the transportation system and subsequent reinvestment.

D. Treatment of Joint Operating Agreements—§§ 206.102 and 210.53

MMS proposed to remove the presumption that sales to a co-lessee under a joint operating agreement (JOA) are not at arm's length. The proposal required changing the reporting instructions in 30 CFR § 210.53 with respect to sales under JOA to facilitate review and audit of these transactions.

Summary of Comments: A State respondent opposed the treatment of JOAs as arm's-length transactions. The State declared that MMS's treatment in the 2000 preamble was consistent with the practical realities of the ''proceeds'' received by co-lessees under JOAs. Co-lessees are working interest owners. As such, they share in costs that royalty owners do not incur. The nature of the very lease interests between a royalty owner and a working interest owner differ. Co-lessees, in essence, are given a ''deduction'' benefit, which they would not receive if their royalty were calculated under the non-arm's-length rules.

The respondent from industry agreed with the proposed changes, but requested that the language under § 210.53(1)(c) be amended from ''each working interest owner'' to ''the working interest owners.'' The change in wording would provide for a second reporting line but not more, easing reporting burdens.

MMS Response: MMS does not believe there should be a presumption that transactions under JOAs are sales or not sales. Neither does MMS believe that there should be a presumption that transactions under JOAs are at arm's length or are not at arm's length. When a party to a JOA, who is not the operator, allows the operator to dispose of the non-operator's share of oil production in exchange for the consideration provided under that agreement, MMS recognizes that some of these arrangements may be sales of the production. Holding that a disposition under a JOA is not a sale, while a disposition under a sales contract, with identical terms, is treated as a sale, would be a case of form over function. MMS believes that it is the substance of the transaction, rather than the form, that determines whether a transaction is treated as arm's length or not.

MMS believes that, when a contract of whatever form results in the Federal royalty owner sharing in costs that are not properly sharable, the definition of gross proceeds together with the exceptions in § 206.102(c)(2) provide sufficient tools for MMS to assure that the lessor will not share in costs that are not properly shareable. If the operator is providing marketing services to its co-lessees, the MMS may require that they be provided at no cost to the lessor, regardless of whether the oil is disposed through the JOA or through a sales contract.

MMS's current practice is to include detailed reporting guidance in the ''Minerals Revenue Reporter Handbook''. MMS decided that specific reporting guidance for JOA's should not be included in our regulations. MMS agrees with industry that having the designee report a separate line for each working interest owner on the Form MMS–2014, Report of Sales and Royalty Remittance, is not needed. Therefore, MMS is not modifying § 210.53 as proposed but will modify the Minerals Revenue Reporter Handbook to require a designee to report, on the Form MMS–2014, one line for the share of the production the designee purchased from the working interest owners at arm's length and report on separate lines the required information for the remaining shares of the production valued (1) as an arm's-length sale by you or your affiliate under § 206.102; or (2) at an index price under § 206.103.

E. Limit on Grace Period for Reporting Changes—§ 206.121

MMS proposed a technical correction to the regulation at § 206.121 that permitted a grace period for reporting and paying royalties after the June 2000 Rule became effective to give royalty payors adequate time to change their systems. We proposed to end-date the grace period for such adjustments, because we consider 3 years to be sufficient time to have reported and paid royalties under the regulations published in 2000.

Summary of Comments: One State commented that, if MMS decides to add a new grace period in the final rule, it should retain the system change requirement associated with the rule. Industry comments supported the elimination of the grace period associated with the June 2000 Rule, and recommended the implementation of a new grace period for the final rule primarily to account for system changes associated with the potential re-definition of JOAs.

MMS Response: MMS agrees that the grace period from the June 2000 Rule should be discontinued. We consider 3 years to be sufficient time to have reported and paid royalties under the June 2000 Rule. Further, since we received no requests for relief after the June 2000 Rule was published, MMS does not believe that implementation of a new grace period is necessary. This is especially true given the fact that we have modified the treatment of working interest owners under JOAs in the final rule to alleviate reporting of each interest owner's production. Therefore, § 206.121 is removed from the final rule.

F. Other Technical Changes

In addition, MMS proposed making a technical change to the definition of ''affiliate'' in § 206.101. MMS proposed changing paragraph (2) of the definition of ''affiliate'' by striking the words ''of between 10 and 50 percent'' and substituting therefore the words ''10 through 50 percent'' because the current definition does not specify the treatment of a situation in which one person owns exactly 50 percent of another person.

Summary of Comments: Industry supported the redefinition of affiliate.

MMS Response: Based on the comment received and the need for clarification, MMS is modifying the definition of ''affiliate'' in § 206.101(2) as proposed.

II. Procedural Matters

1. Summary Cost and Royalty Impact Data

Summary of Comments: MMS received comments questioning the following: (1) MMS assumptions used regarding the percentage of arm's-length sales and the percentage of not-at-arm's-length sales in the analysis, and (2) MMS assumptions on allowances. One State and several congressional commenters questioned (3) why revenue impacts published in the proposed rule were ranges instead of single figures.

MMS Response: On the question of assumptions of percentages of arm's-length sales and the percentage of not-at-arm's-length sales in the analysis, MMS provides the following information. At the time of the proposed rulemaking, MMS estimated the percentage of arm's-length sales and the percentage of not-at-arm's-length sales at 50 percent each. MMS did not use ''Sales Type Code'' data reported by companies on the Form MMS–2014, Report of Sales and Royalty Remittance. We have recently reviewed data reported using the ''Sales Type Code'' on the Form MMS–2014 from October 2002 to March 2003 and found that 70 percent of crude oil produced from Federal leases was reported as being sold at arm's length and 30 percent was reported as being not sold at arm's length. However, because the ''Sales Type Code'' is a new reporting requirement and because the reported data has not yet been audited, MMS believes that 50 percent is a better estimate of the actual amount of crude oil that is not sold at arm's-length.

On the question of assumptions on allowances, MMS provides the following information. When MMS was researching the revenue impacts associated with the proposed rule, we considered three variables associated with the transportation-related changes to the existing regulations: (a) Whether allowances are at arm's length or not at arm's length, (b) the range of the cost components, and (c) the amount of production taken in kind.

Regarding the first variable (a), since 1996, MMS has not collected forms which indicate if allowances are at arm's length or not at arm's length. In preparing the proposed rule, certain assumptions were made concerning actual impacts to revenues.

MMS assumed 50 percent of transportation allowance transactions were at arm's length and that 50 percent were not at arm's length. MMS does not collect data on whether allowances are at arm's length. MMS does collect data on whether sales are at arm's length, but there is no relationship between the type of sale and the type of allowance.

Regarding the second variable (b), MMS also assumed that certain costs, such as the cost of a letter of credit, would range from $.02 to $.05 per barrel. Because of uncertainty associated with the exact amount of each deductible cost, MMS chose to publish a range of possible effects rather than an average. This explains why revenue impacts published in the proposed rule were ranges instead of single figures.

Regarding the third variable (c), because production taken in kind is not subject to the transportation regulations in the proposed rule, oil taken in kind has the potential to significantly affect the total of transportation allowances reported. MMS applied high (77 percent) and low (19 percent) range factors for production taken in kind to account for scenarios at either extreme, to demonstrate the potential range of revenue impacts.

Summarized below are the estimated costs and royalty impacts of this rule to all potentially affected groups: industry, the Federal Government, and State and local governments. The costs and the royalty collection impacts are segregated into two categories—those accruing in the first year after implementation of this rule and those accruing on a continuing basis each year thereafter.

A. Industry

(1) *Expected Royalty Increase—NYMEX-based valuation applied to oil not sold at arm's length.*

Under this rule, industry will value oil based on a market price that more closely represents the true value of the oil. We believe this may result in industry paying additional royalties compared to the Federal oil valuation rule that became effective June 1, 2000. Provided below are estimates of any significant increased royalties.

This rule maintains many of the provisions of the June 2000 Rule including the concept of separate valuation methodologies linked to different production locations. This analysis is divided into the two areas affected by these changes. They include the Rocky Mountain Region, and the ''Rest of the Country,'' including the Gulf of Mexico. Since we retained the use of ANS spot prices for California and Alaska, we removed the royalty impacts of using NYMEX pricing in California and Alaska from the analysis. This analysis highlights the impacts of modifying the pricing provisions and methodologies. The allowed adjustments for transportation and quality as outlined in the June 2000 Rule also will change somewhat, and some additional corresponding analysis is included.

''Rest of the Country''

In valuing production not sold under an arm's-length contract, the June 2000 Rule employed the spot market index price of the oil most closely associated with the production, with appropriate adjustments for location and quality. The timing of the spot market that corresponds with the production month was the quoted average from an MMS-approved publication from the 26th day of the month prior to the current production month to the 25th day of the current production month. For example, December royalty production was valued using the spot quotes for the oil most similar in location and quality from November 26th through December 25th.

The new methodology for the ''Rest of the Country,'' as discussed earlier, is the NYMEX Calendar Month Average daily settlement price with the roll and a quality and location differential. This method uses a trading month quality and location differential (found in MMS-approved publications and based on spot price quotes) applied to the average of the daily NYMEX prices, excluding weekends and holidays, during the production month for deliveries during the prompt month as defined in this rule. For example, for the month of December, assume a producer seeks to value production whose characteristics are closely related to Light Louisiana Sweet (LLS) crude oil. The grade differential established over the period October 26 through November 25 will be applied to the average of the daily NYMEX prompt month prices published for each day in the month of December. The grade differential is the WTI spot price for the period October 26–November 25 less the LLS spot price for the same period. Assuming the WTI value is $29.00 per barrel and the LLS value is $28.00 per barrel, the differential is $1.00 per barrel.

The forward roll is added to the calendar month average NYMEX value and is determined by adding ⅔ of the difference between the average daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production and the average of those prices for deliveries during the next succeeding month plus ⅓ of the difference between the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production and the average of those prices for deliveries during the second month following the month of production as specifically defined in the rule. Assuming the roll calculation results in a value of +$.30 per barrel, the calculated royalty value, assuming the NYMEX calendar month average price is $29.50 per barrel, is $28.80 per barrel (including both the roll and the differential). It is calculated as follows for all royalty production not disposed of at arm's length in the month of December:

(NYMEX Calendar Month Average + roll)—(Spot average WTI − Spot Average LLS)

($29.50 + $.30) − ($29 − $28) = $28.80 per barrel for December royalty production valued as not sold under an arm's-length contract.

We compared prices under NYMEX adjusted for the roll and the grade differential discussed above with prices calculated under the June 2000 Rule based on spot prices at each of the market centers applicable in the ''Rest of the Country''—*e.g.*, Midland, Texas; St. James, Louisiana; and Empire, Louisiana. We found that over the period April 2000 through December 2002, or the period from approximately when the June 2000 Rule became effective through the end of calendar year 2002, the adjusted average monthly NYMEX price with the roll (adjusted from Cushing to each of these market centers) exceeded the monthly average spot prices for these market centers by an average of $.31 per barrel. We also performed this comparison back to the beginning of 1999 and found that the difference is slightly higher over the entire period January 1999 through December 2002. We chose the $.31 per barrel increment as the basis for our royalty impact estimates.

In estimating the impact of a change to NYMEX valuation, we made several assumptions in addition to the $.31 per barrel increment. We assumed that 50 percent of all Federal barrels would be valued under the non-arm's-length provisions, that the offshore royalty rate is one-sixth and the onshore royalty rate is one-eighth, and that volumes taken in kind would vary from 50,000 barrels per day to 180,000 barrels per day.

The 50,000 includes only barrels currently taken in the small refiner program, and the 180,000 includes small refiner volumes plus barrels currently going to the Strategic Petroleum Reserve. We then subtracted the volumes taken in kind and applied the $.31 per barrel figure to the remaining barrels assumed to be valued under the non-arm's-length provisions. We estimate increased costs to industry in the form of higher royalty payments of $4,303,913 to $11,658,663 per year.

Rocky Mountain Region

Determining the impact of the final rule from the June 2000 Rule methodology for valuing oil not sold at arm's length in the Rocky Mountain Region is difficult. This is largely because there is no prescribed formula currently in place, but rather a series of benchmark procedures that lessees apply on an individual basis. The new methodology for the third benchmark is the NYMEX Calendar Month Average daily settlement price with appropriate differentials, but without the roll discussed above. This method uses a trading month differential (found in MMS-approved publications and based on spot price quotes) applied to the average of the daily NYMEX prices, excluding weekends and holidays, published for each day during the production month for deliveries during the prompt month as defined in this rule. This methodology will apply only if the lessee has no MMS-approved tendering program and elects to value production based on NYMEX prices rather than the volume-weighted average of gross proceeds received under arm's-length contracts. Where the third benchmark applies, valuation of Wyoming Sweet will rely on differentials between WTI at Cushing and the lease. For example, for the month of December, assume a producer seeks to value production for Wyoming Sweet crude oil. The grade differential established over the period October 26 through November 25 will be applied to the average of the daily NYMEX prompt month prices published for each day in the month of December. For December production, the average value of Wyoming Sweet against WTI determined October 26th through November 25th applied to the NYMEX calendar month average becomes the basis of value:

(Trading month WY Sweet spot oil assessment − Spot WTI assessment) + NYMEX calendar month average.

We compared prices under NYMEX adjusted for the grade differential (without the roll) with prices calculated under the existing rule based on spot prices at Cushing. We used the same time period, April 2000 through December 2002, as we did for the ''Rest of the Country.'' Over this period, the monthly average spot price exceeded the adjusted average monthly NYMEX price by about $.06 per barrel. We also performed this comparison back to the beginning of 1999 and found that the adjusted NYMEX price exceeded the monthly average spot price by about $.02 per barrel over the entire period January 1999 through December 2002. To illustrate the highest potential cost to industry, we chose the $.02 per barrel increment of NYMEX over spot as the basis for our benefit and cost estimates.

In estimating the impact of a change to NYMEX valuation, we made several assumptions in addition to the $.02 per barrel increment. First, we assumed that 50 percent of all Federal barrels would be valued under the non-arm's-length provisions. Then, because there are four non-arm's-length benchmarks in the Rocky Mountain Region and only the third benchmark will rely on NYMEX prices, we assumed that 25 percent of all Federal barrels that are valued under the benchmarks will be valued under each of the benchmarks; therefore, only 25 percent of those barrels will rely on NYMEX prices. (None of the other three benchmarks will change.) Consequently, 12½ percent of all Federal barrels will be valued under the third non-arm's-length benchmark. We also assumed that the royalty rate is one-eighth, and that volumes taken in kind (these are from Wyoming only) would be about 4,000 barrels per day. We then subtracted the volumes taken in kind and applied the $.02 per barrel figure to the remaining barrels assumed to be valued under the non-arm's-length provisions. We estimate higher royalty payments to be about $11,738 per year.

(2) *Expected Royalty Decrease—Increased Allowable Costs.*

(i) *Increase Rate of Return in non-arm's-length situations from 1 times the Standard and Poor's BBB bond rate to 1.3 times the Standard and Poor's BBB bond rate.*

MMS does not routinely collect detailed allowance information, such as affiliation between the payor and transporter or the cost components used to calculate a non-arm's-length allowance rate. Therefore, we had to make several broad assumptions in order to estimate the impact of this rule. We assumed that 50 percent of all allowances are non-arm's-length. We also assumed that over the life of the pipeline, allowance rates are made up of ⅓ rate of return on undepreciated capital investment, ⅓ depreciation expenses, and ⅓ operation, maintenance and overhead expenses. During FY 2001, royalty payors reported transportation allowance deductions of $45,363,394 for Federal oil production. Based on our assumptions, if ⅓ of the allowance deductions are non-arm's-length, then $22,681,697 of the total allowances fell in this category. If ⅓ of the allowance is made up of the rate of return, this equals $7,560,565. Therefore, we estimate that increasing the basis for the rate of return by 30 percent could result in additional allowance deductions of $2,268,169 ($7,560,565 × .30). Our review of transportation allowances deducted from oil royalties in the States of Wyoming, Colorado, Utah, and New Mexico revealed minimal amounts reported for onshore leases. Therefore, we assumed that virtually this entire increase will impact offshore royalties only.

(ii) *Line Loss as a component of a non-arm's-length transportation allowance.*

For offshore production, the estimate is based on the total offshore oil royalties for FY 2001 of $2,069,450,791. We assumed that 50 percent of all allowances are non-arm's-length, and that oil pipeline losses are 0.2 percent of the volume of the production. Therefore, before making the further adjustments discussed below, we estimated this change could result in additional transportation allowances of $2,069,451 per year ($2,069,450,791 × .50 × .002). For onshore production, we used total onshore oil royalties for FY 2001 of $252,575,890. We assumed that 50 percent of all allowances are non-arm's-length, and that oil pipeline losses are 0.2 percent of the volume of the production. Therefore, before making the further adjustments discussed below, we estimated this change could result in additional transportation allowances of $252,576 per year ($252,575,890 × .50 × .002).

We also recognize that substantial volumes of offshore production are taken in kind and are not subject to the regulations regarding transportation. We estimated that between 50,000 barrels of oil per day (BOPD) and 180,000 BOPD may be taken in kind. The wide variance in this estimate is caused by the approximately 130,000 BOPD which may be taken in kind and placed into the Strategic Petroleum Reserve. Based on daily offshore Federal royalty share of 222,100 BOPD, the amount of oil transportation subject to these regulations could range from a high of 77 percent of the royalty share of production to a low of 19 percent of the royalty share of production. [(222,100 − 50,000) / 222,100 = 77 percent; (222,100 − 180,000) / 222,100 = 19 percent]. Applying the high and low range factors for oil taken in kind, this could result in additional transportation allowance deductions for offshore leases ranging from $393,196 ($2,069,451 × 19 percent) to $1,593,477 ($2,069,451 × 77 percent) per year.

(iii) *Quality Bank Administration Fees as a component of an arm's-length and a non-arm's-length transportation allowance.*

For offshore oil production, our estimate is based on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We also estimated that quality bank administrative fees were $.002 per barrel. We estimated that allowing such fees could result in additional offshore transportation allowances of $162,133 (81,066,567 × $.002) per year before considering the effects of oil taken in kind. Applying the high and low range factors for oil taken in kind, this could result in additional transportation allowance deductions ranging from $30,805 ($162,133 × 19 percent) to $124,842 ($162,133 × 77 percent) per year. For onshore production, we used the onshore royalty volume for FY 2001 of 9,496,181 barrels. Allowing such fees could result in additional allowances of $18,992 (9,496,181 × $.002).

(iv) *Line Fill as a component of an arm's-length and a non-arm's-length transportation allowance.*

For offshore oil production, our estimate is based on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We estimated that line fill costs ranged from $.02 to $.05 per barrel. We then estimated that this factor could result in additional transportation allowances of $1,621,331 (81,066,567 × $.02) to $4,053,328 (81,066,567 × $.05) before considering the effects of oil taken in kind. Applying the high and low range factors for oil taken in kind, this could result in additional offshore transportation allowance deductions ranging from $308,052 ($1,621,331 × 19 percent) to $3,121,062 ($4,053,328 × 77 percent) per year. For onshore production, we estimated that this factor could result in additional transportation allowances of $189,924 (9,496,181 × $.02) to $474,809 (9,496,181 × $.05).

(v) *The cost of a Letter of Credit as a component of an arm's-length transportation allowance.*

Again, we assumed that 50 percent of allowances are at arm's length. We again based the estimate on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We estimated that letter of credit costs ranged from $.02 to $.05 per barrel. We thus estimated that this could result in additional transportation allowances of $810,666 (81,066,567 × $.02 × .5) to $2,026,664 (81,066,567 × $.05 × .5). Applying the high and low range factors for oil taken in kind, this could result in additional offshore transportation allowance deductions ranging from $154,027 ($810,666 × 19 percent) to $1,560,531 ($2,026,664 × 77 percent) per year. For onshore production, we estimated that this factor could result in additional transportation allowances of $94,962 (9,496,181 × $.02 × .5) to $237,405 (9,496,181 × $.05 × .5).

(vi) *Royalty Reduction Summary, items (i)–(v)—Additional Deductions for Allowances.*

We estimate that between $3,154,249 and $8,668,081 in additional transportation allowances could be deducted in determining Outer Continental Shelf lease royalties based on an increased rate of return and permissibility of line losses for non-arm's-length allowances; permissibility of quality bank administration fees and line fill costs for both arm's-length and non-arm's-length allowances; and permissibility of letter of credit costs for arm's-length allowances. Also, for these same items, we estimate that between $556,454 and $983,782 of additional transportation allowances may be deducted in determining onshore Federal lease royalties.

(3) *Net Expected Change in Royalty Payments from Industry.*

We estimate a net expected change in royalty payments from industry of $1,311,743. That amount is calculated by the sum of the Royalty Increase for the Rocky Mountain Region ($11,738) plus the mid point value of the ''Rest of the Country'' ($7,981,288) plus the mid point value of the Royalty Decrease for Increased Allowable Costs (−$6,681,283).

(4) *Expected Range of Royalty Impact on Industry.*

We estimate the expected range of the royalty impact on industry is −$5,336,212 to $7,959,698. The low end of that range is the sum of the Royalty Increase for the Rocky Mountain Region ($11,738) plus the lowest impact for the ''Rest of the Country'' ($4,303,913) plus the highest impact of the Royalty Decrease for Increased Allowable Costs (−$9,651,863). The high end of that range is the sum of the Royalty Increase for the Rocky Mountain Region ($11,738) plus the highest impact for the ''Rest of the Country'' ($11,658,663) plus the lowest impact of the Royalty Decrease for Increased Allowable Costs (−$3,710,703). For example, $11,738 + $4,303,913 −$9,651,863 = −$5,336,212 is the low range impact for Industry.

(5) *Cost—Administrative.*

(i) *System Modifications to reflect NYMEX pricing basis.*

We believe that any increases in administrative costs related to the changes in non-arm's-length valuation procedures will be minimal. These procedures involve NYMEX prices, which are readily available at no cost from numerous sources. They also involve determination of spot price differentials at various locations. We believe that anyone who used the non-arm's-length provisions of the June 2000 Rule already has access to the needed publications and exchange agreements. For some lessees, modification of computer programs related to royalty calculation and payment may be needed. We think that only about 50 of the approximately 800 Federal oil royalty payors will use the non-arm's-length provisions and thus might need to do some reprogramming. Using an estimated cost of $5,000 for each such payor to do its reprogramming, the added one-time cost will be $250,000.

(ii) *Location Differential under § 206.112(c)(1).*

We anticipate that, in a very few cases, companies may request approval of proposed differentials when less than 20 percent of the crude oil is transported or exchanged from the lease. These requests must: (1) Be in writing; (2) identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases; (3) completely explain all relevant facts, including informing MMS of any changes to relevant facts that occur before MMS responds to a request; (4) include copies of all relevant documents; (5) provide the company's analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) suggest the proposed differential. We estimate that there will be two such requests annually. We estimate the annual burden for these requests will be 660 hours (2 x 330), including recordkeeping. Based on a per-hour cost of $50, we estimate the cost to industry is $33,000.

B. State and Local Governments

This rule will not impose any additional burden on local governments. MMS estimates that States impacted by this rule may experience changes in royalty collections as indicated below:

(1) *Expected Royalty Increase—From Use of NYMEX Pricing.*

States receiving revenues from offshore OCS Section 8(g) leases will share in a portion of the estimated additional $4,303,913 to $11,658,663 in royalties that will accrue annually from the ''Rest of the Country,'' under this valuation methodology. Based on each OCS Section 8(g) State's share of total offshore royalties for FY 2001 and their OCS Section 8(g) disbursement percentage, we estimate the States' OCS Section 8(g) share to be between $26,363 and $71,119. Onshore States will receive additional revenue of $317,682.

For the Rocky Mountain Region, we estimate an increase in the States' share of royalty revenues of about $5,869 per year.

(2) *Expected Royalty Decrease—Allowable Costs: Increased Rate of Return and Inclusions of Line Loss, Quality Bank Administration Fees, Line Fill and Letters of Credit as components of allowance costs.*

(3) *Net Expected Change to Royalty Payments to States.*

We estimate that the net expected change to royalty payments to the States is −$55,553. That amount is calculated by the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the mid point value of the ''Rest of the Country'' ($366,423) plus the mid point value of the Royalty Decrease for Increased Allowable Costs (−$42,786 for OCS 8(g) States and −$385,059 for all States).

(4) *Expected Range of Royalty Impact on States.*

We estimate the expected range of the royalty impact on States would be −$204,773 to $93,628. The low end of the range is the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the lowest impact for the ''Rest of the Country'' ($344,045) plus the highest impact of the Royalty Decrease for Increased Allowable Costs (−$62,756 and −$491,891). The high end of the range is the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the highest impact for the ''Rest of the Country'' ($388,801) plus the lowest impact of the Royalty Decrease for Increased Allowable Costs (−$22,815 and −$278,227).

C. Federal Government

Because many of the changes in this rule are technical clarifications and others are relatively minor changes to the valuation mechanisms, the impacts to the Federal Government should be minimal, especially in administration.

(1) *Expected Royalty Increase—from use of NYMEX pricing.*

The Federal Government will receive an estimated $4,303,913 to $11,658,663 in royalties each year from the ''Rest of the Country,'' of which affected States will receive a portion. We estimate the Federal share of offshore royalties to be between $3,642,186 and $10,952,180 and the Federal share of onshore royalties at $317,682. For the Rocky Mountain Region, we estimate an increase in royalty revenues of about $5,869 per year of the estimated additional $11,738 in royalties accruing to production in the affected States.

(2) *Expected Royalty Decrease—Allowable Costs: Increased Rate of Return and Inclusions of Line Loss, Quality Bank Administration Fees, Line Fill and Letters of Credit as components of allowance costs.*

We estimate that between $3,710,703 and $9,651,863 per year in additional transportation allowances may be deducted in calculating Federal royalties. Of that, between $22,815 and $62,756 is attributed to OCS 8(g) States and between $278,227 and $491,891 per year is attributed to all other States.

(3) *Net Expected Change in Royalty Payments to the Federal Government.*

We estimate a net expected change in royalty payments to the Federal Government of $1,367,296. That amount is calculated by the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the mid point value of the ''Rest of the Country'' ($7,614,865) plus the mid point value of the Royalty Decrease for Increased Allowable Costs (−$6,253,438).

(4) *Expected Range of Royalty Impact on the Federal Government.*

We estimate the expected range of the royalty impact on the Federal Government is −$5,131,479 to $7,866,070. The low end of that range is the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the lowest impact for the ''Rest of the Country'' ($3,959,868) plus the highest impact of the Royalty Decrease for Increased Allowable Costs (−$9,097,216). The high end of that range is the sum of the Royalty Increase for the Rocky Mountain Region ($5,869) plus the highest impact for the ''Rest of the Country'' ($11,269,862) plus the lowest impact of the Royalty Decrease for Increased Allowable Costs (−$3,409,661).

(5) *Cost—Location Differential under § 206.112(c).*

We anticipate that companies may request approval of proposed differentials when they transport or exchange less than 20 percent of the crude oil from the lease. In processing these requests, MMS must: (1) Respond in writing; (2) verify for all leases involved, the record title or operating rights owners of those leases, and the designees for those leases; (3) completely explain all relevant facts; (4) obtain copies of all relevant documents; (5) analyze the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) potentially defend our determination. For the above written requests, we estimate that there will be two responses annually. We estimate that the annual burden for these requests is 660 hours (2 × 330), including recordkeeping. Based on a per-hour cost of $50, we estimate the cost to the Federal Government is $33,000.

D. Summary of Royalty Impacts and Costs to Industry, State and Local Governments, and the Federal Government

In the table, a negative number means a reduction in payment or receipt of royalties or a reduction in costs. A positive number means an increase in payment or receipt of royalties or an increase in costs. For the purpose of calculation of the net expected change in royalty impact, we assumed that the average for royalty increases or decreases will be the midpoint of this range.

SUMMARY OF COSTS AND ROYALTY IMPACTS

Description	Costs and royalty increases or royalty decreases	
	First year	Subsequent years
A. Industry:		
(1) Royalty Increase from use of NYMEX pricing	Rocky Mountain Region: $11,738 ''Rest of the Country'': $4,303,913 to $11,658,663.	Rocky Mountain Region: $11,738. ''Rest of the Country': $4,303,913 to $11,658,663.
(2) Royalty Decrease—Increased Allowable Costs	−$3,710,703 to −$9,651,863	−$3,710,703 to −$9,651,863.
(3) Net Expected Change in Royalty Payments from industry [1]	$1,311,743	$1,311,743.
(4) Expected Range of Royalty Impact [2]	−$5,336,212 to $7,959,698	−$5,336,212 to $7,959,698.

SUMMARY OF COSTS AND ROYALTY IMPACTS—Continued

Description	Costs and royalty increases or royalty decreases	
	First year	Subsequent years
(5) Administrative Cost—Modification of Systems and Submittal of Location Differential Requests.	$283,000	$33,000.
B. State and Local Governments:		
(1) Royalty Increase—Increased Royalty Revenue in Terms of the States' Share of Federal Royalties from use of NYMEX pricing.	Rocky Mountain Region: $5,869	Rocky Mountain Region: $5,869.
	''Rest of the Country'': $344,045 to $388,801.	''Rest of the Country'': $344,045 to $388,801.
(2) Royalty Decrease—Increased Allowable Costs in Terms of the States' Share of Federal Royalties.	OCS § 8(g) States: −22,815 to −62,756.	OCS § 8(g) States: −22,815 to −62,756.
	All Other States: −278,227 to −491,891.	All Other States: −278,227 to −491,891.
(3) Net Expected Change to Royalty Payments to States [1]	−55,553	−55,553.
(4) Expected Range of Royalty Impact [2]	−204,733 to 93,628	−204,733 to 93,628.
C. Federal Government:		
(1) Royalty Increase—Increased Royalty Revenues Net of the States' Share from use of NYMEX pricing.	Rocky Mountain Region: 5,869	Rocky Mountain Region: 5,869.
	''Rest of the Country'': 3,959,868 to 11,269,862.	''Rest of the Country'': 3,959,868 to 11,269,862.
(2) Royalty Decrease—Increased Allowable Costs Net of the States' Share.	−3,409,661 to −9,097,216	−3,409,661 to −9,097,216.
(3) Net Expected Change in Royalty Payments to the Federal Government [1].	1,367,296	1,367,296.
(4) Expected Range of Royalty Impacts [2]	−5,131,479 to 7,866,070	−5,131,479 to 7,866,070.
(5) Cost of Administering Location Differential Requests	33,000	33,000.

[1] The value is the sum of the Royalty Increase for the Rocky Mountain Region plus the mid point value of the ''Rest of the Country'' plus the mid point value of the Royalty Decrease for Increased Allowable Costs.

[2] The low range impact is the sum of the Royalty Increase for the Rocky Mountain Region plus the lowest impact for the ''Rest of the Country'' plus the highest impact of the Royalty Decrease for Increased Allowable Costs. The high range impact is the sum of the Royalty Increase for the Rocky Mountain Region plus the highest impact for the ''Rest of the Country'' plus the lowest impact of the Royalty Decrease for Increased Allowable Costs. For example $11,738+$4,303,913+($9,651,863)=($5,336,212) is the low range impact for Industry.

2. Regulatory Planning and Review, Executive Order 12866

Summary of Comments: One State suggested that the revenue impacts that would result constitute a significant regulatory action under Executive Order 12866.

MMS Response: This rule does constitute a significant regulatory action under Executive Order 12866, but not because of the potential revenue impacts. It constitutes a significant regulatory action because it may raise novel legal or policy issues.

In accordance with the criteria in Executive Order 12866, this rule is not an economically significant regulatory action, as it does not exceed the $100 million threshold. The Office of Management and Budget has made the determination under Executive Order 12866 to review this rule because it raises novel legal or policy issues.

1. This rule will not have an annual effect of $100 million or adversely affect an economic sector, productivity, jobs, the environment, or other units of Government. MMS evaluated the costs of this rule, and estimates that industry might incur additional administrative costs of approximately $283,000 in the first year of implementation, and $33,000 in additional administrative costs in subsequent years. The Federal Government might incur $33,000 each year in additional administrative costs.

2. This rule will not create inconsistencies with other agencies' actions.

3. This rule will not materially affect entitlements, grants, user fees, loan programs, or the rights and obligations of their recipients.

4. This rule will raise novel legal or policy issues.

3. Regulatory Flexibility Act

The Department of the Interior certifies this rule will not have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). The rule applies primarily to large, integrated producers who either refine their oil or sell their oil to affiliated marketers. Small producers will continue to pay their royalties based on the proceeds they receive for the sale of their oil to third parties as they have done since 1988.

Your comments are important. The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions in this rule, call 1–800–734–3247. You may comment to the Small Business Administration without fear of retaliation. Disciplinary action for retaliation by an MMS employee may include suspension or termination from employment with the Department of the Interior.

4. Small Business Regulatory Enforcement Act (SBREFA)

This rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule:

1. Does not have an annual effect on the economy of $100 million or more. See the above Analysis titled ''Summary of Costs and Royalty Impacts.''

2. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

3. Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

5. Unfunded Mandates Reform Act

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*):

1. This rule will not significantly or uniquely affect small governments. Therefore, a Small Government Agency Plan is not required.

2. This rule will not produce a Federal mandate of $100 million or greater in any year; *i.e.*, it is not a significant regulatory action under the Unfunded Mandates Reform Act. The analysis prepared for Executive Order 12866 will meet the requirements of the Unfunded Mandates Reform Act. See the above Analysis titled ''Summary of Costs and Royalty Impacts.''

6. Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings), Executive Order 12630

In accordance with Executive Order 12630, this rule does not have significant takings implications. A takings implication assessment is not required.

7. Federalism, Executive Order 13132

In accordance with Executive Order 13132, this rule does not have federalism implications. A federalism assessment is not required. It will not substantially and directly affect the relationship between the Federal and State governments. The management of Federal leases is the responsibility of the Secretary of the Interior. Royalties collected from Federal leases are shared with State governments on a percentage basis as prescribed by law. This rule will not alter any lease management or royalty sharing provisions. It will determine the value of production for royalty computation purposes only. This rule will not impose costs on States or localities.

8. Civil Justice Reform, Executive Order 12988

In accordance with Executive Order 12988, the Office of the Solicitor has determined that this rule will not unduly burden the judicial system and does not meet the requirements of §§ 3(a) and 3(b)(2) of the Order.

9. Paperwork Reduction Act of 1995

The Office of Management and Budget (OMB) has approved a new collection of information contained in this rule, entitled 30 CFR 206, subpart C, Federal Oil under 44 U.S.C. 3501 *et seq.*, and assigned control number 1010–0157. The total hour burden currently approved under 1010–0157 is 1,608. The information collection applies only to §§ 206.103(b)(4), 206.112(a)(1)(ii), 206.112(b)(3), and 210.53(a) and (b) of this rule and the burden hours are allocated equally to each section. OMB approval of this collection expires October 31, 2006. We received comments from industry, but there were no changes in the information collection from the proposed rule to the final rule. We will use the information collected to ensure that proper royalty is paid on oil produced from Federal onshore and offshore leases.

Submit your comments on the accuracy of this burden estimate or suggestions on reducing the burden to Sharron L. Gebhardt, Lead Regulatory Specialist, Chief of Staff Office, Minerals Revenue Management, MMS, PO Box 25165, MS 320B2, Denver, Colorado 80225. If you use an overnight courier service, the MMS courier address is Building 85, Room A–614, Denver Federal Center, Denver, Colorado 80225. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

10. National Environmental Policy Act (NEPA)

This rule deals with financial matters and has no direct effect on Minerals Management Service decisions on environmental activities. Pursuant to the Department of the Interior Departmental Manual (DM), 516 DM 2.3A (2), § 1.10 of 516 DM 2, Appendix 1 excludes from documentation in an environmental assessment or impact statement ''policies, directives, regulations and guidelines of an administrative, financial, legal, technical or procedural nature; or the environmental effects of which are too broad, speculative or conjectural to lend themselves to meaningful analysis and will be subject later to the NEPA process, either collectively or case-by-case.'' Section 1.3 of the same appendix clarifies that royalties and audits are considered to be routine financial transactions that are subject to categorical exclusion from the NEPA process.

11. Government-to-Government Relationship With Tribes

In accordance with the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951) and DOI DM 512 DM 2, we have evaluated potential effects on federally recognized Indian tribes. This rule does not apply to Indian leases. However, these changes may have an impact on Indian leases. As such, by **Federal Register** notice (68 FR 7086) dated February 12, 2003, MMS reopened the comment period on the January 2000 supplementary proposed rule for valuing crude oil produced from Indian leases. The comment period closed on April 14, 2003. MMS will determine how to proceed with that rulemaking based on comments received, taking into account our trust responsibilities and safeguarding the competitiveness of Indian leases.

12. Effects on the Nation's Energy Supply, Executive Order 13211

In accordance with Executive Order 13211, this regulation does not have a significant adverse effect on the Nation's energy supply, distribution, or use. The changes better reflect the way industry accounts internally for its oil valuation and provides a number of technical clarifications. None of these changes should impact significantly the way industry does business, and accordingly should not affect their approach to energy development or marketing. Nor does the rule otherwise impact energy supply, distribution, or use.

13. Consultation and Coordination With Indian Tribal Governments, Executive Order 13175

In accordance with Executive Order 13175, this rule does not have tribal implications that impose substantial direct compliance costs on Indian tribal governments.

14. Clarity of This Regulation

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this rule easier to understand, including answers to questions such as the following:

(1) Are the requirements in the rule clearly stated?

(2) Does the rule contain technical language or jargon that interferes with its clarity?

(3) Does the format of the rule (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity?

(4) Would the rule be easier to understand if it were divided into more (but shorter) sections? A ''section'' appears in bold type and is preceded by the symbol ''§ '' and a numbered heading; for example, § 204.200.

(5) What is the purpose of this part?

(6) Is the description of the rule in the ''Supplementary Information'' section of the preamble helpful in understanding this rule?

(7) What else could we do to make the rule easier to understand?

Send a copy of any comments that concern how we could make this rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street NW., Washington, DC 20240.

List of Subjects in 30 CFR part 206

Continental shelf, Government contracts, Mineral royalties, Natural gas, Petroleum, Public lands—mineral resources.

Dated: March 17, 2004.

Chad Calvert,

Acting Assistant Secretary for Land and Minerals Management.

■ For the reasons set forth in the preamble, subpart C of part 206 of title 30 of the Code of Federal Regulations is amended as follows:

PART 206—PRODUCT VALUATION

■ 1. The authority for part 206 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

■ 2. Section 206.101 is amended to:
■ a. Revise the introductory text and paragraph (2) of the definition of ''affiliate.''
■ b. Remove the definitions of ''index pricing'' and ''index pricing point.''
■ c. Revise the definitions of ''MMS-approved publication'' and ''trading month.''
■ d. Add definitions of ''NYMEX price,'' ''prompt month,'' ''roll,'' and ''WTI differential.''

The revisions and additions read as follows:

§ 206.101 What definitions apply to this subpart?

* * * * *

Affiliate means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

* * * * *

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, MMS will consider the following factors in determining whether there is control under the circumstances of a particular case:

* * * * *

MMS-approved publication means a publication MMS approves for determining ANS spot prices or WTI differentials.

* * * * *

NYMEX price means the average of the New York Mercantile Exchange (NYMEX) settlement prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows:

(1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the prompt month corresponding to each such day; and

(2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

* * * * *

Prompt month means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

* * * * *

Roll means an adjustment to the NYMEX price that is calculated as follows:

Roll = .6667 × ($P_0 - P_1$) + .3333 × ($P_0 - P_2$), where: P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month; P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is March. March was the prompt month (for year 2003) from January 22 through February 20. April was the first month following the month of production, and May was the second month following the month of production. P_0 therefore is the average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 22 and February 20. P_1 is the average of the daily NYMEX settlement prices for deliveries during April published for each business day between January 22 and February 20. P_2 is the average of the daily NYMEX settlement prices for deliveries during May published for each business day between January 22 and February 20. In this example, assume that P_0 = $28.00 per bbl, P_1 = $27.70 per bbl, and P_2 = $27.10 per bbl. In this example (a declining market), Roll = .6667 × ($28.00 − $27.70) + .3333 × ($28.00 − $27.10) = $.20 + $.30 = $.50. You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is July. July 2003 was the prompt month from May 21 through June 20. August was the first month following the month of production, and September was the second month following the month of production. P_0 therefore is the average of the daily NYMEX settlement prices for deliveries during July published for each business day between May 21 and June 20. P_1 is the average of the daily NYMEX settlement prices for deliveries during August published for each business day between May 21 and June 20. P_2 is the average of the daily NYMEX settlement prices for deliveries during September published for each business day between May 21 and June 20. In this example, assume that P_0 = $28.00 per bbl, P_1 = $28.90 per bbl, and P_2 = $29.50 per bbl. In this example (a rising market), Roll = .6667 × ($28.00 − $28.90) + .3333 × ($28.00 − $29.50) = (−$.60) + (−$.50) = −$1.10. You add this negative number to the NYMEX price (effectively a subtraction from the NYMEX price).

* * * * *

Trading month means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, *www.nymex.com*, in which case the NYMEX definition will apply.

* * * * *

WTI differential means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

(1) *Example.* Assume the production month was March 2003. Industry trade publications performed their price surveys and determined differentials during January 26 through February 25 for oil delivered in March. The WTI differential (for example, the West Texas Sour crude at Midland, Texas, spread versus WTI) applicable to valuing oil produced in the March 2003 production month would be determined using all the business days for which differentials were published during the period January 26 through February 25 excluding weekends and holidays (22 days). To calculate the WTI differential, add together all of the daily mean differentials published for January 26 through February 25 and divide that sum by 22.

(2) [Reserved]

■ 3. In § 206.103, paragraphs (b), (c), (d), and (e) introductory text, (e)(1)(ii), and (iii) are revised to read as follows:

§ 206.103 How do I value oil that is not sold under an arm's-length contract?

* * * * *

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options for valuing your production under different factual situations. You must consistently apply paragraph (b)(1), (b)(2), or (b)(3) of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease or a portion of the lease is not part of a unit or communitization agreement) that you cannot value under § 206.102 or that you elect under § 206.102(d) to value under this section.

(1) If you have an MMS-approved tendering program, you must value oil produced from leases in the area the tendering program covers at the highest winning bid price for tendered volumes.

(i) The minimum requirements for MMS to approve your tendering program are:

(A) You must offer and sell at least 30 percent of your or your affiliates' production from both Federal and non-Federal leases in the area under your tendering program; and

(B) You 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.

(ii) If you do not have an MMS-approved tendering program, you may elect to value your oil under either paragraph (b)(2) or (b)(3) of this section. After you select either paragraph (b)(2) or (b)(3) of this section, you may not change to the other method more often than once every 2 years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new 2-year period.

(2) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliates' production from both Federal and non-Federal leases in the same field or area during that month.

(ii) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliates' arm's-length purchases or sales to the same gravity as that of the oil produced from the lease.

(3) Value is the NYMEX price (without the roll), adjusted for applicable location and quality differentials and transportation costs under § 206.112.

(4) If you demonstrate to MMS's satisfaction that paragraphs (b)(1) through (b)(3) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the MMS Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.* (1) Value is the NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under § 206.112.

(2) If the MMS Director determines that use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula used by industry to calculate the roll changes, MMS may terminate or modify use of the roll under paragraph (c)(1) of this section at the end of each 2-year period following July 6, 2004, through notice published in the **Federal Register** not later than 60 days before the end of the 2-year period. MMS will explain the rationale for terminating or modifying the use of the roll in this notice.

(d) *Unreasonable value.* If MMS determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, MMS may establish reasonable royalty value based on other relevant matters.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.*

(1) * * *

(ii) You must value your oil under this section at the NYMEX price or ANS spot price; and

(iii) You believe that use of the NYMEX price or ANS spot price results in an unreasonable royalty value.

* * * * *

■ 4. In § 206.104, the section heading, the introductory text of paragraph (a), and paragraphs (a)(3), (c), and (d) are revised to read as follows:

§ 206.104 What publications are acceptable to MMS?

(a) MMS periodically will publish in the **Federal Register** a list of acceptable publications for the NYMEX price and ANS spot price based on certain criteria, including, but not limited to:

* * * * *

(3) Publications that use adequate survey techniques, including development of estimates based on daily surveys of buyers and sellers of crude oil, and, for ANS spot prices, buyers and sellers of ANS crude oil; and

* * * * *

(c) MMS will specify the tables you must use in the acceptable publications.

(d) MMS may revoke its approval of a particular publication if it determines that the prices or differentials published in the publication do not accurately represent NYMEX prices or differentials or ANS spot market prices or differentials.

■ 5. In § 206.109, paragraph (b) is revised to read as follows:

§ 206.109 When may I take a transportation allowance in determining value?

* * * * *

(b) *Transportation allowances and other adjustments that apply when value is based on NYMEX prices or ANS spot prices.* If you value oil using NYMEX prices or ANS spot prices under § 206.103, MMS will allow an adjustment for certain location and quality differentials and certain costs associated with transporting oil as provided under § 206.112.

* * * * *

■ 6. Section 206.110 is amended by:

■ A. Revising paragraph (a);

■ B. Redesignating existing paragraphs (b) through (e) as paragraphs (d) through (g); and
■ C. Adding new paragraphs (b) and (c).

The revisions and additions read as follows:

§ 206.110 How do I determine a transportation allowance under an arm's-length transportation contract?

(a) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred as more fully explained in paragraph (b) of this section, except as provided in paragraphs (a)(1) and (a)(2) of this section and subject to the limitation in § 206.109(c). You must be able to demonstrate that your or your affiliate's contract is at arm's length. You do not need MMS approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

* * * * *

(b) You may deduct any of the following actual costs you (including your affiliates) incur for transporting oil. You may not use as a deduction any cost that duplicates all or part of any other cost that you use under this paragraph.

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid for administration of a quality bank.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(i) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 206.102 or § 206.103, as applicable; and

(ii) Multiply the value calculated under paragraph (b)(4)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 206.111(i)(2) by 12.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(10) Costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain.

(c) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

* * * * *

■ 7. Section 206.111 is amended by:
■ A. Revising the section heading and paragraph (a);
■ B. In paragraph (b), revising the introductory text and adding new paragraphs (b)(6) and (b)(7);
■ C. Revising paragraph (h)(5); and
■ D. Revising paragraph (i)(2).

The amendments read as follows:

§ 206.111 How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?

(a) This section applies if you or your affiliate do not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. Calculate your transportation allowance based on your or your affiliate's reasonable, actual costs for transportation during the reporting period using the procedures prescribed in this section.

(b) Your or your affiliate's actual costs include the following:

* * * * *

(6) To the extent not included in costs identified in paragraphs (d) through (j) of this section, you may also deduct the following actual costs. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(i) Volumetric adjustments for actual (not theoretical) line losses.

(ii) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you as a shipper to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(A) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 206.102 or § 206.103, as applicable; and

(B) Multiply the value calculated under paragraph (b)(6)(ii)(A) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 206.111(i)(2) by 12.

(iii) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(iv) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(v) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(vi) Fees paid to a non-affiliated quality bank administrator for administration of a quality bank.

(7) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(i) Fees paid for long-term storage (more than 30 days).

(ii) Administrative, handling, and accounting fees associated with terminalling.

(iii) Title and terminal transfer fees.

(iv) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(v) Fees paid to brokers.

(vi) Fees paid to a scheduling service provider.

(vii) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(viii) Theoretical line losses.

(ix) Gauging fees.

(h) * * *

(5) If you or your affiliate purchase a transportation system at arm's length after June 1, 2000, from anyone other than the original owner, you must assume the depreciation schedule of the person from whom you bought the system. Include in the depreciation schedule any subsequent reinvestment.

(i) * * *

(2) The rate of return is 1.3 times the industrial bond yield index for Standard & Poor's BBB bond rating. Use the monthly average rate published in ''Standard & Poor's Bond Guide'' for the first month of the reporting period for which the allowance applies. Calculate the rate at the beginning of each subsequent transportation allowance reporting period.

* * * * *

■ 8. Section 206.112 is revised to read as follows:

§ 206.112 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?

This section applies when you use NYMEX prices or ANS spot prices to calculate the value of production under § 206.103. As specified in this section, adjust the NYMEX price to reflect the difference in value between your lease and Cushing, Oklahoma, or adjust the ANS spot price to reflect the difference in value between your lease and the appropriate MMS-recognized market center at which the ANS spot price is published (for example, Long Beach, California, or San Francisco, California). Paragraph (a) of this section explains how you adjust the value between the lease and the market center, and paragraph (b) of this section explains how you adjust the value between the market center and Cushing when you use NYMEX prices. Paragraph (c) of this section explains how adjustments may be made for quality differentials that are not accounted for through exchange agreements. Paragraph (d) of this section gives some examples. References in this section to ''you'' include your affiliates as applicable.

(a) To adjust the value between the lease and the market center:

(1)(i) For oil that you exchange at arm's length between your lease and the market center (or between any intermediate points between those locations), you must calculate a lease-to-market center differential by the applicable location and quality differentials derived from your arm's-length exchange agreement applicable to production during the production month.

(ii) For oil that you exchange between your lease and the market center (or between any intermediate points between those locations) under an exchange agreement that is not at arm's length, you must obtain approval from MMS for a location and quality differential. Until you obtain such approval, you may use the location and quality differential derived from that exchange agreement applicable to production during the production month. If MMS prescribes a different differential, you must apply MMS's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(2) For oil that you transport between your lease and the market center (or between any intermediate points between those locations), you may take an allowance for the cost of transporting that oil between the relevant points as determined under § 206.110 or § 206.111, as applicable.

(3) If you transport or exchange at arm's length (or both transport and exchange) at least 20 percent, but not all, of your oil produced from the lease to a market center, determine the adjustment between the lease and the market center for the oil that is not transported or exchanged (or both transported and exchanged) to or through a market center as follows:

(i) Determine the volume-weighted average of the lease-to-market center adjustment calculated under paragraphs (a)(1) and (a)(2) of this section for the oil that you do transport or exchange (or both transport and exchange) from your lease to a market center.

(ii) Use that volume-weighted average lease-to-market center adjustment as the adjustment for the oil that you do not transport or exchange (or both transport and exchange) from your lease to a market center.

(4) If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to MMS an adjustment between the lease and the market center for the portion of the oil that you do not transport or exchange (or both transport and exchange) to a market center. Until you obtain such approval, you may use your proposed adjustment. If MMS prescribes a different adjustment, you must apply MMS's adjustment to all periods for which you used your proposed adjustment. You must pay any additional royalties owed resulting from using MMS's adjustment plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(5) You may not both take a transportation allowance and use a location and quality adjustment or exchange differential for the same oil between the same points.

(b) For oil that you value using NYMEX prices, adjust the value between the market center and Cushing, Oklahoma, as follows:

(1) If you have arm's-length exchange agreements between the market center and Cushing under which you exchange to Cushing at least 20 percent of all the oil you own at the market center during the production month, you must use the volume-weighted average of the location and quality differentials from those agreements as the adjustment between the market center and Cushing for all the oil that you produce from the leases during that production month for which that market center is used.

(2) If paragraph (b)(1) of this section does not apply, you must use the WTI differential published in an MMS-approved publication for the market center nearest your lease, for crude oil most similar in quality to your production, as the adjustment between the market center and Cushing. (For example, for light sweet crude oil produced offshore of Louisiana, use the WTI differential for Light Louisiana Sweet crude oil at St. James, Louisiana.) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(3) If neither paragraph (b)(1) nor (b)(2) of this section applies, you may propose an alternative differential to MMS. Until you obtain such approval, you may use your proposed differential. If MMS prescribes a different differential, you must apply MMS's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(c)(1) If you adjust for location and quality differentials or for transportation costs under paragraphs (a) and (b) of this section, also adjust the NYMEX price or ANS spot price for quality based on premiums or penalties determined by pipeline quality bank specifications at intermediate commingling points or at the market center if those points are downstream of the royalty measurement point approved by MMS or BLM, as applicable. Make this adjustment only if and to the extent that such adjustments were not already included in the location and quality differentials determined from your arm's-length exchange agreements.

(2) If the quality of your oil as adjusted is still different from the quality of the representative crude oil at the market center after making the quality adjustments described in paragraphs (a), (b) and (c)(1) of this section, you may make further gravity adjustments using posted price gravity tables. If quality bank adjustments do not incorporate or provide for adjustments for sulfur content, you may make sulfur adjustments, based on the quality of the representative crude oil at the market center, of 5.0 cents per one-tenth percent difference in sulfur content, unless MMS approves a higher adjustment.

(d) The examples in this paragraph illustrate how to apply the requirement of this section.

(1) *Example.* Assume that a Federal lessee produces crude oil from a lease near Artesia, New Mexico. Further, assume that the lessee transports the oil to Roswell, New Mexico, and then exchanges the oil to Midland, Texas. Assume the lessee refines the oil received in exchange at Midland. Assume that the NYMEX price is $30.00/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is −$.10/bbl; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of −$.08/bbl; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is $.40/bbl. In this example, the royalty value of the oil is $30.00−$.10−$.08—$.40 = $29.42/bbl.

(2) *Example.* Assume the same facts as in the example in paragraph (1), except that the lessee transports and exchanges to Midland 40 percent of the production from the lease near Artesia, and transports the remaining 60 percent directly to its own refinery in Ohio. In this example, the 40 percent of the production would be valued at $29.42/bbl, as explained in the previous example. In this example, the other 60 percent also would be valued at $29.42/bbl.

(3) *Example.* Assume that a Federal lessee produces crude oil from a lease near Bakersfield, California. Further, assume that the lessee transports the oil to Hynes Station, and then exchanges the oil to Cushing which it further exchanges with oil it refines. Assume that the ANS spot price is $20.00/bbl, and that the lessee's actual cost of transporting the oil from Bakersfield to Hynes Station is $.28/bbl. The lessee must request approval from MMS for a location and quality adjustment between Hynes Station and Long Beach. For example, the lessee likely would propose using the tariff on Line 63 from Hynes Station to Long Beach as the adjustment between those points. Assume that adjustment to be $.72, including the sulfur and gravity bank adjustments, and that MMS approves the lessee's request. In this example, the preliminary (because the location and quality adjustment is subject to MMS review) royalty value of the oil is $20.00−$.72−$.28 = $19.00/bbl. The fact that oil was exchanged to Cushing does not change use of ANS spot prices for royalty valuation.

§ 206.118 [Removed]

■ 9. Section 206.118 is removed.

■ 10. Paragraph (c) of § 206.119 is revised to read as follows:

§ 206.119 How are royalty quantity and quality determined?

* * * * *

(c) Any actual loss that you may incur before the royalty settlement metering or measurement point is not subject to royalty if BLM or MMS, as appropriate, determines that the loss is unavoidable.

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§ 206.121 [Removed]

■ 11. Section 206.121 is removed.

[FR Doc. 04–10083 Filed 5–4–04; 8:45 am]

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DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Parts 62, 66, 67, and 72

[USCG–2001–10714]

RIN 1625–AA34

Update of Rules on Aids to Navigation Affecting Buoys, Sound Signals, International Rules at Sea, Communications Procedures, and Large Navigational Buoys

AGENCY: Coast Guard, DHS.

ACTION: Final rule.

SUMMARY: The Coast Guard is revising its aids to navigation and maritime information regulations by updating technical information concerning buoys, sound signals, international rules at sea, communications procedures, and large navigational buoys, and by rewriting some regulations to make them clearer and gender-neutral. These changes will update existing rules to reflect current practices and make them easier to understand.

DATES: This final rule is effective June 4, 2004.

ADDRESSES: Comments and material received from the public, as well as documents mentioned in this preamble as being available in the docket, are part of docket USCG–2001–10714 and are available for inspection or copying at the Docket Management Facility, U.S. Department of Transportation, room PL–401, 400 Seventh Street SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. You may also find this docket on the Internet at *http://dms.dot.gov.*

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call Mr. Dan Andrusiak, Project Manager, Office of Short-Range Aids to Navigation (G–OPN), Coast Guard, telephone 202–267–0327 (e-mail: *dandrusiak@comdt.uscg.mil*). If you have questions on viewing the docket, call Andrea M. Jenkins, Program Manager, Docket Operations, telephone 202–366–0271.

SUPPLEMENTARY INFORMATION:

Regulatory History

On May 14, 2003, we published a notice of proposed rulemaking (NPRM) entitled ''Update of Rules on Aids to Navigation Affecting Buoys, Sound Signals, International Rules at Sea, Communications Procedures, and Large Navigational Buoys'' in the **Federal Register** (68 FR 25855). We also published a correction of a web address on May 22, 2003 (68 FR 28052). We are adopting that proposed rule as final with the exception of changes described in the *Discussion of Comments and Changes* and *Changes not related to comments* sections below.

We received two letters commenting on the proposed rule. No public hearing was requested and none was held.

Background and Purpose

The Coast Guard's Office of Short-Range Aids to Navigation frequently reviews the rules on Aids to Navigation. During our most recent review, we found that many rules do not reflect current technologies and practices. For example, what we formerly called ''fog signals,'' we now call ''sound signals.'' Also, we want to inform users that