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April 7, 1998

Via Facsimile: (303) 231-3385
& Overnight Mail

Mr. David S. Guzy, Chief
Rules & Procedures Staff
Royalty Management Program
Minerals Management Service
Building 85, Denver Federal Center
Denver, Colorado 80225

Re: Establishing Oil Value for Royalty Due on Federal Leases
(63 FR 6113, February 6, 1998)

Dear Mr. Guzy:

Marathon appreciates the opportunity to participate in MMS' recent workshops on the proposed rule and to submit the enclosed comments on MMS' recently published supplementary proposed rule for establishing oil value for royalty due on federal leases.

Marathon continues to support and recommend the implementation of a federal royalty-in-kind program as a long-term solution to the complexities and uncertainties that exist in any valuation process.

If you have any questions please contact me.

Sincerely,

Dow L Campbell

Dow L. Campbell

Enclosure

cc: The Office of Information and Regulatory Affairs
Office of Management and Budget
Attention Desk Officer for the Department of the Interior
725 17th Street, N.W.
Washington, D.C. 20503

[90066]

Marathon Oil Company
Comments on MMS Supplementary Proposed Rule
Establishing Oil Value for Royalty Due on Federal Leases
63 FR 6113 - February 6, 1998

INTRODUCTION

In the **Federal Register** of February 6, 1998 (63 FR 6113), the Minerals Management Service ("MMS") proposed further changes to its proposed rule amending the regulations governing the royalty valuation of crude oil produced from federal leases. MMS' original proposal was published in the **Federal Register** on January 24, 1997 (62 FR 3742); a supplementary notice was published in the **Federal Register** on July 3, 1997 (62 FR 36030); and the comment period was reopened by notice published in the **Federal Register** on September 22, 1997 (62 FR 49460). Marathon Oil Company ("Marathon") has committed substantial resources to provide in-depth and substantive comments at each stage of this process and welcomes the opportunity to comment on the latest proposed regulations.

GENERAL OVERALL COMMENTS

"Duty To Market" Issue

Through the inclusion of the term "marketing" in the revised definition of gross proceeds (Section 206.101) and the addition of a duty to market the oil at no cost to the federal government (Section 206.106), MMS continues to attempt to impose a new obligation on federal lessees through regulation rather than legislation. Although MMS contends that federal lessees currently have a duty to market production at no cost to the lessor, there has never been such a duty. Contrary to MMS' previous statements, this is not a clarification of current obligations.

MMS tries to equate the obligation to place production in marketable condition with an obligation to market downstream of the lease; since production must be placed in marketable condition at no cost to the lessor, MMS contends the obligation to market must also be free of cost to the lessor. However, these two obligations are distinct. In the final rulemaking on Gas Transportation, MMS recognizes "that the obligation to place production in marketable condition is legally distinct from the issue of marketing the gas". (62 FR 65756, December 16, 1997) These are indeed separate and distinct principles.

Assuming, arguendo, that this new implied duty exists, it could only mean that the lessee and the lessor share both the benefits and the costs associated with marketing. However, MMS is attempting to obtain all of the benefits without incurring the costs or risks of marketing remote from the lease. Where would this duty end? Would a lessee be forced to find the highest market for its production without regard to the associated costs? This is simply not an obligation which exists in the leases entered into between the lessee and the federal government. Regulations cannot alter the lease agreement as MMS has proposed.

Limited Applicability of Benchmarking Alternative

Marathon has enthusiastically supported the use of benchmarks as a workable method of determining a royalty value for crude oil produced from federal lands which is not sold pursuant to an arm's-length contract. MMS has failed to respond directly to the benchmarks proposed by the Independent Petroleum Association of America ("IPAA") and the Domestic Petroleum Council ("DPC"), and endorsed by Marathon in our earlier comments. Again, Marathon proposes that royalties on crude oil disposed of at non-arm's-length be valued under the following benchmarks:

1) lessee's outright sales of like-quality crude in the field or area (including sales under tendering programs),

2) lessee's, or its affiliate's, arm's-length purchases from producers at the lease in the field or area,

3) outright sales at arm's-length by third parties,

4) prices published by MMS reflecting the prices MMS obtained for its crude oil taken in-kind, and

5) an appropriate netback methodology.

The foundation of this benchmark system is that arm's-length transactions in the field or area are the best indicator of fair market value at the lease and that valuation should be based on comparable sales or purchases.

Although numerous problems exist in the benchmarks proposed by MMS for the Rocky Mountain Area, Marathon welcomes MMS' recognition of the viability of this alternative in the latest proposal. Marathon objects to the proposal in Section 206.103(b)(1) requiring that 33⅓% of a lessee's federal and non-federal production in an area be tendered. While Marathon understands MMS' concern that some of the lessee's equity production be included in the tendering program, MMS' logic in establishing the 33⅓% threshold is seriously flawed and arbitrary. The typical onshore royalty rate is 12½%; there is no need to establish a composite federal and state royalty rate as each lease is either federal, state, or fee. Furthermore, state severance tax rates are totally irrelevant to MMS' royalty regulations. Because the volumes tendered would come from an area comprised of federal and non-federal leases, Marathon believes a tendering requirement of 15% - 20% would be more than sufficient to provide MMS with the comfort level it seeks. These levels are supported by the testimony of Wyoming Governor Jim Geringer on March 19, 1998, before the U.S. House of Representatives Committee on Resources, Subcommittee on Energy and Mineral Resources. In his testimony, Governor Geringer stated:

> The tendering benchmark, at 33⅓ percent of federal and non-federal leases in the area, will be difficult to meet. We thought that a fifteen to twenty percent benchmark would have been more realistic.

The 50% requirement proposed in Section 206.103(b)(2) suffers from the same problems. It is too high. A 15% - 20% minimum figure would be more than sufficient to alleviate MMS' fear of "gaming" by lessees.

In previously submitted comments, Marathon and many others have addressed the numerous problems associated with the use of a NYMEX-based valuation methodology in any producing region. The use of a benchmarking system which includes valuation based on arm's-length tendering programs and/or comparable purchases and sales at or near the lease would avoid the pitfalls and complications arising from a NYMEX-based valuation methodology.

Crude oil is regularly bought and sold at or near the lease throughout the United States. These sales transactions occur in all producing regions, not just in the Rocky Mountain Area. It is arbitrary to apply a benchmark system only in the Rocky Mountain Area. Again, the market dynamics which make benchmarks based on arm's-length sales feasible in the Rocky Mountain Area also make them feasible in all regions.

Marathon continues to support the application of a benchmarking system and is interested in simplifying the valuation process rather than complicating it. A sound benchmarking valuation methodology should be applied to all federal production not sold under arm's length contracts. All federal production should be valued according to its fair market value at or near the lease.

Definition of Affiliate and Tracing of a Lessee's Federal Lease Production

Marathon strongly opposes the definition of 'affiliate' proposed by MMS. Although a bright line test of ownership interest could provide simplicity, a 10% cutoff is unrealistically low. Marathon suggests if a bright line test is established a 50% cutoff is more realistic than the 10% proposed. The logic and reasoning behind changing to a 10% bright line test for defining affiliation is not supported in MMS' proposal. The only reference to it in the preamble is at 63 **Federal Register** 6116 where it states: "Finally, we added four new definitions of terms used in this further supplementary proposed rule. They are *affiliate, prompt month, Rocky Mountain Area, and tendering program.*" Furthermore, the references to limited business arrangements, such as partnerships and joint ventures, should be deleted. It is simply too late in this rulemaking process to add such a fundamental difference to the determination of affiliation.

If MMS disagrees with a realistic 50% bright line test, then in analyzing whether a transaction is truly arm's-length, the determining factor should be the level of control, rather than ownership percentage. At a minimum, MMS should retain the control language in the 1988 regulations which gives lessees the option to refute the presumption of control for interests of 10% to 50%.

Marathon also strongly opposes the extent of MMS' proposal to require a lessee to trace the final disposition of its exchanged lease production. This requirement is both unreasonable and unworkable in that it a) may impose an undue administrative burden on the lessee, b) presumes a level of lessee access to records of downstream transactions that may not exist, c) incorrectly assumes that the ultimate disposition of exchanged federal royalty oil is always identifiable, and d) attempts to value federal royalty production based on arm's-length sales which may occur at markets remote from the lease.

MMS attempts to demonstrate the "workability" of its tracing requirement through the use of very simplistic examples of exchange transactions. Unfortunately, these examples are not representative of the majority of exchange transactions occurring in today's crude oil marketplace. To illustrate this point, consider the following example offered by MMS at 63 FR 6117 to demonstrate how a lessee would value lease production subject to more than one exchange:

> "For example, if you enter into two sequential arm's-length exchanges for your Federal oil production and then you or an affiliate sell the reacquired oil at arm's length, you would value your production under paragraph (a)."

Under the proposed rule, the valuation of the lease production in this example situation appears to be fairly straightforward. However, most of the exchange transactions executed in the marketplace are far more complicated than MMS' example. Recently, in conjunction with MMS' National Crude Oil Review, Marathon was asked to trace the final disposition of production from a certain federal lease. The following is a summary of the transactions involved in this <u>actual</u> situation:

1. During the month under review, Marathon produced 800 barrels of West Texas/New Mexico Intermediate crude from a federal lease located in Eddy County, New Mexico. The lease production was aggregated with an additional 106,200 barrels from various sources (i.e., federal, state, and fee leases) and exchanged under an arm's-length agreement for an equal amount of West Texas Sour crude at Midland, Texas.

2. The 107,000 barrels received at Midland, Texas were aggregated with an additional 369,000 barrels from unknown sources. A total of 398,000 barrels were exchanged under two arm's-length agreements for an equal amount of West Texas Intermediate crude at Cushing, Oklahoma. The remaining 78,000 barrels were exchanged under an arm's-length agreement for an equal amount of Light Louisiana Sweet crude at St. James, Louisiana.

3. The 398,000 barrels received at Cushing, Oklahoma were aggregated with an additional 3,231,000 barrels from unknown sources. A total of 2,267,000 barrels were relocated to refineries under 37 arm's-length exchange agreements. The remaining 1,362,000 barrels were sold pursuant to 5 arm's-length sales agreements.

4. The 78,000 barrels received at St. James, Louisiana were aggregated with an additional 2,051,000 barrels from unknown sources. A total of 1,974,000 barrels were transported to Midwestern refineries as feedstock. The remaining 155,000 barrels were sold pursuant to an arm's-length sales agreement.

Under MMS' proposed rule, in order to determine how to value MMS' 100-barrel royalty share of the production from this New Mexico lease, Marathon would be required to trace volumes through 41 exchange agreements and 6 sales agreements which cover a total disposition of over 6,000,000 barrels. Furthermore, Marathon would be expected to repeat this entire process on a monthly basis for each and every federal lease where production is not sold at arm's-length at the lease. What is unknown is how MMS would expect Marathon to determine how many of MMS' barrels to value under Section 206.102 and how many to value under Section 206.103. Also, since the arm's-length sales occurred at two separate market centers, how would MMS expect Marathon to determine the location and quality adjustments required under Section 206.102(c)(3)? It is unrealistic for MMS to claim that this unduly burdensome process would in any way provide certainty to the valuation process. It is also unrealistic for MMS to claim that this process would somehow result in the determination of a true market value at the lease.

MMS uses another simplistic example to illustrate how to value production initially transferred to an affiliate or other party at less than arm's-length and subsequently sold by that party at arm's-length. At 63 FR 6117, MMS offers an example of a working interest cooperative which purchases all of the production from a lease and resells the acquired volume at arm's-length. However, MMS avoids the "affiliate" issue by stating in its example that none of the working interest owners owned at least 10% of the cooperative venture. For a more complicated version of this particular situation, assume that ten working interest owners each own ten percent of a cooperative venture. Next, assume that the ten owners transfer their production to the cooperative venture, which resells the combined volume to "X Marketing Company", the marketing subsidiary of "X Producer", one of the ten percent working interest owners in the cooperative venture. Finally, assume that "X Marketing Company" exchanges the oil for an equal amount of West Texas Intermediate crude at Cushing, Oklahoma, where it is sold by "X Marketing Company" at arm's-length. Under the proposed definition of "affiliate", MMS might view these working interest owners as "affiliates" due to their levels of ownership in the cooperative venture. Thus, in order to determine the royalty value of MMS' share of production, the nine working interest owners, other than "X Producer", might be required by Section 206.102 of the proposed rule to trace the downstream transactions of "X Marketing Company", a company over which they have absolutely no legal control. Does MMS truly believe that these nine working interest owners would have access to the downstream transactions of their "affiliate" (i.e., "X Producer") necessary for them to comply with the tracing requirement?

There may be inherent antitrust violation problems in this proposal. Unless lessees, and their 'affiliates' as defined by MMS, are granted complete statutory immunity from possible antitrust violations stemming from the compliance with affiliate valuation requirements, this requirement to trace affiliate transactions must be rejected. When a lessee and its affiliate contractually require that any purchases or sales between the two be negotiated at arm's-length and the two entities directly compete in the crude oil market, the lessee would have no right to access its affiliate's records. For MMS to require such access would require the two entities to breach their mutual contract and potentially violate antitrust laws. Even if such access does not result in an antitrust violation, the exchange of information necessary for compliance with MMS' valuation proposal poses serious confidentiality and proprietary problems.

Marathon strongly urges MMS to reconsider its proposal to require the lessee to trace the final disposition of its, or its affiliate's, exchanged lease production. Marathon also urges MMS to consider the following modifications to its current proposal for valuing exchanged lease production:

1. The requirement to trace the final disposition of exchanged lease production would only apply to exchange agreements which meet all of the following criteria:
   a) the agreement was executed between the lessee, or its wholly-owned subsidiary, and any other party,
   b) the agreement identifies the leases from which production is being disposed of under the exchange agreement, and
   c) any subsequent sales and/or exchanges involve only the further disposition of the aggregated volume covered by the initial exchange.

2. In all other situations involving exchanged lease production valuation would be based upon the benchmarking system.

3. MMS needs to adopt a two-pronged definition of the term "affiliate". For the purposes of determining whether a transaction is arm's-length or non-arm's-length, "affiliate" should be defined based upon the level of "control". However, "control" should not be construed by MMS to also mean "access to company records"; the former does not necessarily imply the latter. Therefore, to ensure that a lessee has access to downstream transactions required to trace the final disposition of exchanged lease production, the term "affiliate" for tracing purposes should be narrowly defined as a lessee's wholly-owned subsidiary. It should not, however, apply to any legal entity created by a limited business arrangement, such as a joint venture or partnership.

As a whole, these modifications seek to address the major problems inherent with MMS' proposed tracing requirement which, as currently written, is an unreasonable and unworkable proposal.

Lack of Certainty

MMS' latest proposal fails dramatically when viewed in light of MMS' goal to add more certainty to the process of federal royalty valuation. The proposed regulations are full of pitfalls which leave a federal lessee without certainty, despite a diligent attempt to fairly and accurately report and pay federal royalty.

There is little flexibility built into these regulations. What happens when circumstances change in mid-year or even mid-month? For example, under the tendering program if a lessee fails to meet the 33⅓% requirement in one month, it would be forced to recalculate its entire royalty for that area using a different valuation formula. Or, if a lessee later discovers that one of its bidders also had a tendering program, this would require royalties to be paid on a different valuation methodology.

Although Marathon addresses many of the areas where there is no certainty in the section-by-section comments offered below, two examples of this lack of certainty are: 1) Section 206.100(b) states that this subpart does *not* apply if the regulations are inconsistent with an express provision of an oil and gas lease. Since most of the federal leases contain gross proceeds language, will MMS still require some sort of separate and distinct gross proceeds analysis for production valued under Section 206.103? 2) In Section 206.107 the best that MMS offers to a lessee requesting valuation guidance is a <u>non-binding</u> determination. What amount of certainty is contained in a non-binding determination?

Certainty is very important to Marathon. At the time royalty payments are made Marathon needs to know that the value it assigned to its federal production is accurate and defensible. These regulations fail to provide that level of certainty.

SPECIFIC SECTION-BY-SECTION COMMENTS

The following are Marathon's section-by-section comments on the proposed oil rule:

Section 206.101 - Definitions

Affiliate - Marathon strongly disagrees with the changes to the definition of affiliate at this late stage of the rulemaking process, and recommends MMS adopt a two-pronged approach as discussed previously in these comments.

Gross proceeds - Marathon has several concerns with MMS' proposed definition of gross proceeds. First, as explained above, Marathon adamantly disagrees with MMS' inclusion of the duty to market language in the definition of gross proceeds via the insertion of the term 'marketing'. Second, the definition implies that the gross proceeds of both the lessee and its affiliates are included. The problem with tracing affiliate sales was also discussed previously in these comments. And third, example (5) addresses take or pay payments. This issue is currently under litigation, and Marathon believes the reference to such payments be deleted pending final resolution of the matter.

Rocky Mountain Area - Marathon has two comments regarding the Rocky Mountain Area. First, the use of the word "area" in this term may create confusion as "area" is a defined term. Does MMS propose to treat all six states as one area? Marathon firmly believes there are many "areas" within the "Rocky Mountain Area." For this reason, it is recommended MMS use the term "Rocky Mountain Region" rather than "Rocky Mountain Area."

MMS requested comments on whether New Mexico should be included in the Rocky Mountain Area. Marathon believes it is logical and feasible to include Northwest New Mexico (the San Juan Basin) in the definition.

Tendering program - What is an "other geographical/physical unit"? MMS should either clarify this phrase or delete it.

Section 206.102 - How do I calculate royalty value for oil that I or my affiliate sell under an arm's-length contract?

(a)(2) - This paragraph would require lessees to pay royalty based on the gross proceeds from the sale of the oil by either the lessee or its affiliate. As discussed previously, tracing oil to its ultimate disposition is both burdensome and unworkable. Marathon urges MMS to adopt the two-pronged definition of "affiliate" discussed earlier in these comments.

(a)(3) - This paragraph would require lessees which sell or transfer oil to a non-affiliate under a non-arm's-length contract to pay royalty based on the gross proceeds received by the other party. This is totally unworkable. Lessees do not have access to the records of non-affiliates and would not have any way to determine how the non-affiliate disposed of the oil or what price it received.

(c)(2)(ii) - Although this particular section of the proposed rule reads the same as in the 1988 regulations, Section 206.106 of the proposed rule adds the phrase "at no cost to the Federal Government." Marathon strongly disagrees with MMS' assertion that lessees have the duty to market production away from the lease at no cost to the government.

(c)(3) - The last sentence of this paragraph states, "But if MMS determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, MMS may require you to value the oil under Section 206.103." This is yet another example of the uncertainty of this proposal. Contracts between non-affiliated parties are, quite simply, negotiated. The contract agreed to by the parties is based on each party's assessment of the circumstances and reflects terms acceptable to both parties. Barring any evidence of fraud or collusion, MMS should not second guess the terms of any arm's-length contract. The location and/or quality differentials in an arm's-length contract must be recognized by MMS as the actual location and/or quality differentials, and used by lessees in paying federal royalties.

Section 206.103 - How do I value oil that I cannot value under Section 206.102?

(a) - Marathon has no additional comments to make regarding the valuation of oil produced in California and Alaska. However, Marathon is disappointed MMS has not addressed the comments made by Marathon and others in response to the proposed rule published in January 1997.

(b) - Marathon is pleased MMS has recognized the use of and need for a benchmark system based on comparable prices in the field or area. However, it is arbitrary for MMS to assume that arm's-length transactions are the best indication of production value in Wyoming but not the best indication of production value in Louisiana. MMS should acknowledge that such a system is workable in all producing regions, not just in the Rocky Mountain Area.

(b)(1) - Marathon has several comments regarding the tendering program proposed by MMS. First, MMS should not be entitled to the highest bid price if not all the oil was sold at that price. For example, if a lessee tendered 1,000 barrels and received bids of $17.75 for up to 250 barrels, $17.50 for up to 350 barrels, and $17.35 for the entire volume, MMS should not receive $17.75 for all of its royalty barrels. Rather, the price received by MMS should be the weighted average of the prices actually received for the 1,000 barrels, which represents the fair market value.

Second, in addition to the objections stated earlier in these comments regarding the 33⅓% requirement, the proposed regulations are unclear as to how this percentage is to be determined. What volumes would comprise the ratio's numerator and denominator? How often would a lessee be required to calculate this ratio? These issues must be clarified in order to provide a lessee any certainty when calculating and paying its royalties.

Third, how will MMS determine the "area"? Marathon is concerned that MMS can manipulate whether tendering programs qualify for valuation purposes by the method it uses to determine the "area".

Fourth, what "additional criteria" will MMS provide in the Payor Handbook? Marathon is concerned MMS will construct criteria that is so restrictive that no company will be able to develop a tendering program acceptable to MMS. Acceptable parameters should be defined now.

(b)(2) - Marathon believes that the use of a lessee's arm's-length sales and purchases in the field or area results in a fair and reasonable determination of the value of production for royalty purposes. However, adjustments to gross proceeds should be allowed for quality differences. Also, if a lessee sells its production at a point distant from the actual lease, an adjustment should be allowed for all costs incurred by the lessee from the lease to the point of sale.

As with the tendering program, Marathon is concerned with how MMS will determine areas under this benchmark.

(b)(3) - As explained in the comments filed by many companies and industry associations last year, there are significant problems with using a NYMEX-based netback methodology. MMS has not addressed these concerns, which include the shortcomings of NYMEX itself and the unrealistic location/quality differentials needed to "netback" to the lease.

Marathon refers MMS to its comments filed on May 27, 1997 regarding the many problems associated with the use of a NYMEX-based netback methodology in general and in the Rocky Mountain Area. Regarding the rule currently proposed, Marathon is concerned that MMS failed to correct the timing problem. MMS proposes to use a NYMEX price that was established one month prior to the actual production month rather than the price established during the production month. Any such pricing calculation should be on a calendar month basis. For example, January 1998 royalties should be valued at the average of the prompt month NYMEX settlement prices established each business day during the production month of January.

(c) - The goal of any fair and equitable valuation rule should be to determine value at both the time of production and place of production. Therefore, value must be determined at the lease. MMS proposes to impose a theoretical value at the lease by attempting to establish a mechanical link between lease value and spot index prices at a market center. The lease market is not a spot market. Lease production is subject to administrative burdens such as tax payments, royalty payments, ownership record keeping and transportation reporting that simply do not exist at a market center. Additionally, lease production volumes can fluctuate rather significantly due to operational matters, and the purchaser, gatherer and/or transporter incurs price exposure associated with contractual obligations that involve the disposition of individual lease production. Environmental and safety issues also have an impact on lease market values. As you can see, there are many factors that affect lease market value. Transportation and quality adjustments alone do not adequately reflect the differences between term market prices at the lease and spot market prices at a market center.

There are numerous problems with the adjustments MMS proposes to make to the spot prices. These are discussed in the comments to Sections 206.112 and 206.113.

(d) - How would MMS determine that an index price no longer represents "reasonable" royalty value? What does MMS mean by "other relevant matters"? Would changes to the royalty base be made on a prospective or retroactive basis? This paragraph is contrary to MMS' desire to add certainty to the royalty process as MMS is given an "out" to change the rule as it sees fit.

This paragraph must be deleted from the proposed rule, since MMS cannot create for itself a right to change the valuation methodologies set forth in this or any other rule at its sole discretion. Lessees must be given the opportunity to comment on any proposed changes to the valuation methodology.

Section 206.105 - What records must I keep to support my calculations of value under this subpart?

MMS has proposed an overwhelming record keeping requirement under this section, which could theoretically include all records from the lease to the refinery gate. Lessees would be required to keep records of affiliated pipeline companies and marketing affiliates. Compliance with this requirement is difficult when wholly-owned affiliates are involved. However, it is nearly impossible for lessees to require entities affiliated through limited business arrangements, such as partnerships or joint ventures, to comply.

Section 206.106 - What are my responsibilities to place production into marketable condition and to market production?

As stated previously in these and other comments, Marathon objects to MMS' assertion that lessees have an obligation to market oil "for the mutual benefit of the lessee and the lessor at no cost to the Federal Government." Marathon generally endorses the comments made by API and IPAA regarding this issue.

Section 206.107 - What valuation guidance can MMS give me?

In order to achieve certainty, valuation determinations issued by MMS should be binding on MMS, at least for the specific situation in question. However, if the determinations are non-binding, lessees following the determinations should not be subject to interest or penalties if MMS determines additional royalties are due upon audit.

Section 206.111 - How do I determine a transportation allowance under a non-arm's-length transportation arrangement?

(a) - MMS has also failed to respond directly to Marathon's and industry's earlier comments on the disallowance of the use of FERC tariffs in the determination of a lessee's non-arm's-length transportation deductions. Marathon believes that market rates or commercial rates (including FERC tariffs), not "actual costs", should be taken into consideration when transportation allowances are determined. A lessee should not be required to perform transportation services for MMS at cost just because a lessee owns an equity interest in a pipeline. The lessee should be able to deduct a transportation allowance reflecting market rates on regulated and unregulated pipelines whether or not it owns an interest in the pipeline.

Section 206.112 - What adjustments and transportation allowances could apply when I value oil using index pricing?

(b)(2) - Marathon, other companies and industry associations offered many comments last year regarding Form MMS-4415. Most of these comments have not been addressed by MMS. It is still unclear how MMS would use the information reported on the forms to calculate the differentials. How would industry be assured the differentials were reasonable? Would the forms be subject to audit? Would lessees be required to revise royalty payments if MMS were to determine the differentials it published were incorrect? If so, where is the certainty?

Form MMS-4415 would impose a substantial administrative burden on lessees. First, lessees who have exchange agreements with location/quality differentials would be required to complete the form even though they would not be using the results. As discussed in previous comments, completing Form MMS-4415, even in its revised form, would be no easy task. Second, if MMS were to revise its published differentials, lessees which relied on them would be required to revise royalty payments. This would be an administrative burden for both the lessee and MMS.

Section 206.113 - Which adjustments and transportation allowances may I use when I value oil using index pricing?

(b) - MMS uses a refinery as an example of an alternate disposal point. Who determines what constitutes an alternate disposal point? What are other examples of cases in which MMS foresees the use of alternate disposal points?

If a lessee transports oil from a lease through a market center directly to its refinery, would the transportation costs all the way to the refinery be deductible as a transportation allowance, or would the allowance be limited to the transportation from the lease to the market center?

Section 206.114 - What if I believe MMS-published location/quality differential is unreasonable in my circumstances?

In order to achieve certainty, if MMS approves an alternative location/quality differential, MMS' decision must be binding.

Section 206.115 - How will MMS identify market centers and aggregation points?

What does MMS mean by "periodically"? Will a review of market centers and aggregation points be conducted on a regular basis, such as annually? Does MMS plan to retroactively change market centers or aggregation points? In order to provide certainty to lessees, Marathon believes any changes must only be made prospectively.

Section 206.118 - What information must I provide to support index pricing adjustments, and how is that information used?

The first two sentences of this section conflict with each other. The first sentence states information must be provided for all federal leases. The second sentence indicates information is needed only for differentials between market centers and aggregations points. Based on the discussions at the public hearing in Houston, it seems MMS is only interested in information regarding differentials in arm's-length exchange agreements between market centers and aggregation points. This issue needs to be clarified. Marathon suggests MMS use the language included in the instructions for Form MMS-4415: "differential information for oil exchanged under arm's length exchange agreements between paired aggregation points and associated market centers."

The proposed rule states lessees would have two months after the effective date of this reporting requirement to submit the initial forms. Two months is insufficient time to gather the needed information and complete the forms. In most companies, employees from multiple disciplines would need to gather and review the exchange agreements and complete the forms. This task becomes even more complex if lessees are required to obtain exchange agreements from affiliates, or if the affiliates (many of whom may not be lessees and have no knowledge of MMS' reporting requirements) are involved in the exchanges and filing of Form MMS-4415.

Form MMS-4415 - Federal Oil Location Differential Report & Step-by-Step Instructions

The implementation of Form MMS-4415 would create numerous problems, including but not limited to:

1. It would potentially impose reporting responsibilities on entities which have never reported to MMS before. For example, marketing affiliates which currently have no reporting requirement would be responsible for filing this form.

2. There is a potential confidentiality problem. For example, in certain circumstances there could be only one applicable arm's-length exchange. If MMS were to then report the terms of this transaction, the parties' confidentiality would be breached.

3. The use of this form would result in the comparison of transactions that had a transportation allowance with those that had a transportation factor. These two methods do not result in comparable values.

4. The form should be designed with flexibility in mind. The form is structurally limited to the crude oil market as it exists today.

5. There is a timing problem with the reporting requirements. A company cannot feasibly report October transactions by October 31. September 1 is probably the latest date to meet the October 31 deadline. As a result, data from September 1997 would affect the allowance permitted on production as late as December 1999. This illustrates a dramatic lack of market responsiveness.

6. The reporting requirements are complicated by the common practice of commingling federal and non-federal production into a common production stream. It would be difficult to extract and only report data on the federal volumes.

There remain many unanswered questions on the use of this form in addition to the administrative burden associated with its filing. How will any handwritten comments on the form be incorporated into MMS' analysis? If a sulfur differential is not referenced in the contract, how should it be determined? Without a box on the form, how will MMS know whether or not a quality bank was used? MMS must address these questions regarding Form MMS-4415 prior to requiring its use.

CONCLUSION

MMS' proposed rule provides anything but certainty to the royalty valuation process. Marathon continues to believe that the adoption of a standard benchmark system applicable in all producing regions is the best method to determine a royalty value for crude oil which is not sold at arm's-length. This is consistent with valuing the production as near to the lease as possible. Any netback methodology should remain an exception to the rule, and should be used only when a contemporaneous value at the lease cannot be determined through another benchmark. In light of MMS' recently imposed duty to market obligation, the difficulties associated with tracing barrels through downstream transactions, the problems inherent with an index-based netback methodology, and MMS' proposed elimination of the FERC oil tariff based transportation allowances, Marathon views a comprehensive and mandatory royalty-in-kind program as the most viable alternative to resolving the issue of valuing federal royalty oil.

Royalty-in-kind offers the best long-term solution to satisfying the federal lessee's royalty obligations while confirming the federal government will receive fair market value for its royalty share of oil production. Proper design and implementation of a program is critical to its success. The program must reflect the concerns and the input of all stakeholders including the federal government, the states, and producers. Marathon is committed to work with MMS, Congress, and the states to develop and implement a workable royalty-in-kind program. A royalty-in-kind program can be a win/win solution for all parties involved.

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