April 6, 1998

David S. Guzy
Chief, Rules and Publications Staff
Royalty Management Program
Minerals Management Service
P.O. Box 25165, MS 3021
Denver, Colorado 80225-0165

Re: Supplementary Proposed Rule on Crude Oil Valuation, 63 Fed. Reg. 6113 (Feb. 6, 1998)

Dear Mr. Guzy:

The Independent Petroleum Association of America ("IPAA") and the Domestic Petroleum Council ("DPC") appreciate the opportunity to comment on the most recent rule on crude oil valuation proposed by the Minerals Management Service ("MMS"). On the surface, the proposal would appear to permit many of IPAA's smaller members to value royalties by using their gross proceeds from the sale of oil at the lease. We understand that to have been MMS's intent, and we appreciate the positive movement MMS showed last year in expanding the use of gross proceeds at the lease from MMS's initial, tightly constricted proposal in January 1997. But key features of the proposal continue to put small independent producers at risk that, several years down the road, an MMS auditor will declare that they should have valued royalties using the NYMEX price or some other index price hundreds of miles from their leases. This result, intolerable to small producers, would occur because their transactions were held to violate the new "duty to market," were found to have occurred under a "non-competitive call," or fell within some other exception to the gross proceeds rule. The proposal also offers for the first time -- at the eleventh hour -- new re-definitions of the previously well-understood term "gross proceeds" and "affiliate" which undermine much of the movement we had previously seen toward returning gross proceeds valuation to its pre-existing scope.

These eleventh-hour changes, needless to say, are of equal concern to the large independent members of the DPC and to IPAA's larger members. The revised definition of "affiliate" and the proposal's approach to exchanges have now raised to prominence the burden of "tracing:" the obligation to follow a barrel of oil through a series of arm's-length or non-arm's-length transactions to find its first "true" arm's-length sale, then to trace those proceeds back to the lease. If the transactions all involved similar volumes of oil of similar qualities sold at the same point, the burden might be manageable. Typically, however, the purpose of exchanges is to move smaller "packages" of oil to locations where they can be aggregated into larger packages, increasing value by blending, by increasing volume, and then by being offered to a greater number of potential buyers. Tracing these transactions backward is like unscrambling the scrambled egg. As explained below, a package of 400 barrels of oil from a federal lease can quickly become part of a 644,000 barrel package of oil available for sale in a number of downstream transactions; tracing will require a company to value millions of barrels in an attempt to establish the value of a few barrels back upstream. And with the new and implausibly reduced threshold for defining affiliates, there will be an extraordinary amount of unscrambling to be done. DPC and IPAA therefore continue to have serious objections to the proposal.

Our associations have previously advocated giving a producer who exchanges oil at arm's length -- however many times it needs to -- the <u>option</u> of using revised valuation procedures ("RVPs") or using a netback from the eventual sale of the oil, but do not advocate that they be an absolute requirement for any producer. Having an option leaves it to the producer to consider the trade offs: the cost of structuring its activities to take advantage of the RVPs against the costs of tracing and the cost of additional royalty on value added by exchanges in the midstream market. Where tracing would not be burdensome, a producer might well choose to net back from the downstream sale. The proposal, in contrast, deprives the producer of choice and claims royalties at a point impermissibly far from the lease.

"[T]here is no dispute that ... [federal] royalties [are] to be calculated at values at the wells, not at the pipe line destination...." *Continental Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950). Sound economic analysis teaches that the best evidence of crude oil values at federal wells comes from arm's-length transactions at those or nearby wells. The further the transactions are from the wells, the less reliable they are as indicators of wellhead value of lease production, in part because the forces of supply and demand strike different price balances at different locations.[1] Additionally, as we just explained, as oil moves further from the lease where produced, it ordinarily is aggregated and blended. These

[1] See Affidavit of Marshall Thomas ¶¶ 9, 10, 34, 36, Attachment G to the May 27, 1997, comments of the American Petroleum Institute (hereafter "Thomas"); Excerpts of Testimony of Professor Kalt at 1188, Attachment F to the May 27, 1997, comments of the American Petroleum Institute (hereafter "Kalt Testimony"). In his comments of May 27, 1997, Dr. Joseph Kalt explained that "[t]he actual transactions at the lease reveal market values that commonly vary significantly with supply and demand factors that are specific to individual locations, leases, and transactions." Comments of Joseph P. Kalt at 3 (May 27, 1997) (hereafter "Kalt May comments").

activities, typical in the midstream market, have the economic and practical effect of "changing the product," to use the very apt phrase coined by Bonn Macy, MMS's Special Assistant to the Director, in his February 1998 presentation before the Rocky Mountain Mineral Law Foundation Special Institute. (Attachment 1.) Trying to net backward from downstream transactions is thus only slightly less suspect than trying to net backward from the price of gasoline at the pump.[2]

Consistent with fundamental economic theory, IPAA has previously recommended that MMS adopt RVPs using the best evidence available from the lease market for crude oil. The RVPs provide a consistent, uniform, and simple approach to valuing non-arm's-length sales or exchanges of crude oil, based on each lessee's own arm's-length sales (or its affiliate's purchases) in the same field. The RVPs are the logical complement to the use of a lessee's gross proceeds from sales at the lease as the proper means of valuing arm's-length transactions.

But MMS's latest proposal continues to reject -- almost completely -- the use of lease market information to value transactions not governed by the gross proceeds rule. This rejection poses two overriding questions. Why? And where has it gotten the agency?

The second is easy to answer. Rejecting lease market information, the latest proposal is an index monster with three heads. West of the Rockies, the index is Alaska North Slope crude oil sold in Los Angeles or San Francisco. In the Rockies, the index (which will be applied frequently because of the unnecessarily severe restrictions imposed on the use of IPAA's recommended RVPs) is still NYMEX. East of the Rockies, the index is spot market prices at market centers. And for lessees or their affiliates who sell oil at market centers after transporting it or exchanging it at arm's-length, the rule imposes (as we will demonstrate below) an extremely burdensome obligation to "trace" the value of aggregated barrels of oil back to the leases from which they were produced. In short, in the words of the Ninth Circuit Court of Appeals, the proposal starts valuation "at the pipe line destination" instead of "at the wells" where it belongs.

Why? The real answer to that question is harder to glean from the preamble,

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[2] As Doctor Kalt noted, "[b]ecause transactions at the lease level are not homogeneous, the use of NYMEX or market center prices in the manner proposed by MMS could result in significant under or over payments of royalties on federal crude oil." (Kalt May comments at 5.) Generally, Kalt added, the result is an overpayment because the proposal fails to back out the value added to lease production by midstream marketing activities. (*Id.* at 7.)

and it is a question MMS is obliged to answer persuasively. To avoid arbitrariness, MMS has a special burden of demonstrating that it can no longer rely on information from the lease market. This is so not only because the Interior Department has historically relied on lease market information, but also because that information provides the most appropriate basis for comparison. The preamble, however, fails to make that case. While it continues to attack reliance on posted prices, 63 Fed. Reg. 6113, it does not contest DPC's and IPAA's previous demonstrations that substantial volumes of federal lease crude oil are sold at arm's length at or near the leases from which they are produced. Nor does the preamble deny that arm's-length sales at the lease are appropriate measures of wellhead value. In fact, the proposal ordinarily accepts a lessee's gross proceeds from an arm's-length sale at the well as the most appropriate measure of royalty value. Nor does the preamble deny that IPAA's proposals to focus audits on fields and to use "contemporaneous desk checks" to better target auditing could significantly simplify MMS's auditing burden.[3] In short, MMS is rejecting a system that would create incentives for, and would result in, more federal oil being sold at arm's length at the lease. Yet it has offered no explanation of why that result would be inconsistent with the policies of the federal leasing and royalty collection statutes.

Instead, the proposal will create discriminatory royalty consequences for oil from the same well. Consider a well in the Gulf of Mexico jointly and equally owned by a small independent producer, a large independent producer with an affiliate in the midstream market, and a major company with producing and refining operations. The small company's production is sold at the wellhead and valued using its gross proceeds (subject to MMS's later second-guessing), the large company's production must be valued by tracing back from its affiliate's downstream resale, and the major company's production must be valued using the index netback. Identical oil in identical volumes sold the same month will be valued for royalty at three prices under three methods. There is no justification for the disparity.

MMS should not assume that smaller independents are happy. Based on recent public statements, MMS appears to believe that it has addressed all the legitimate concerns of independent producers, claiming that it would never use the duty to market to second-guess the decision of a producer to sell oil at arms'-length at the lease. Most recently, on March 19, 1998, MMS Director Quarterman testified under oath before the House Subcommittee on Energy and Mineral Resources that MMS has no intention of using the duty to market to second-guess a producer's decision to sell oil at arm's length at the wellhead. There is, however, a significant disparity between what the agency says and what

[3] For example, MMS could easily monitor values for onshore California federal leases by targeting the Midway-Sunset field for contemporaneous desk checks. That field produces about 80% of all federal lease crude oil within California.

it has actually proposed on the question of where an arm's-length seller stands under the new duty to market at no cost to the federal government.

The written proposal expressly states that a producer may not use its gross proceeds in an arm's-length sale as royalty value where there is found a "breach of your duty to market the oil for the mutual benefit of yourself and the lessor," proposed § 206.102(c)(2)(ii), a duty which is later "clarified" to be "at no cost to the Federal Government." Proposed § 206.106. Indeed, under the proposal, a lessee currently selling to its affiliate may choose to avoid the snares of the proposal by selling in the future only to non-affiliates. Yet, under the proposal, if the lessee's affiliate is offering the best price at the lease, MMS could fault the lessee for ceasing sales to its affiliate under the new duty to market!

It should now be apparent that the agency's agenda has been all along to move the starting point for royalty valuation as far from the leases as it could. Yet MMS's claims that its proposal promotes "certainty" and "simplicity" are unsupportable. And its new-found conviction that spot prices at market centers are the best measure of value is difficult to understand. The conviction is inconsistent with its own precedent finding that a spot market price was inappropriate to value production under a longer-term contract. *Amoco Production Co.*, MMS-92-0552-OCS p. 6 (June 3, 1996) ("sale to AGC under its spot contract was not comparable to its sale to AGC under its long-term contract with respect to such factors as duration and time of execution"). It is also inconsistent with the agency's purported distrust of exchanges and buy/sell agreements, 63 Fed. Reg. 6113, because the rulemaking record already demonstrates that index prices are often derived from exchange agreements and buy/sell agreements at market centers. (Thomas ¶¶ 45-46, 63-68).

Now it has been disclosed that some of MMS's "consultants" and chief proponents of this proposal have a direct financial stake in federal crude oil valuation in the *qui tam* suit they filed under the federal False Claims Act. *United States of America, ex rel. Johnson v. Exxon Co., U.S.A.*, No. 9:96CV66 (E.D. Tex., unsealed Feb. 19, 1998). At the behest of these consultants and proponents, MMS has spent the last three years on a theoretical valuation odyssey. It is time now for MMS to bring this journey to an end and come home to its sound and long reliance on arm's-length sales at the lease as the basic tool for all valuation.

SUMMARY OF CONCERNS WITH LATEST PROPOSAL

ROYALTY VALUATION PROCEDURES

- The administrative costs of the proposal, for the government and for lessees, are significantly greater than the costs of the royalty valuation procedures recommended by IPAA. MMS has failed to demonstrate, in theory or in fact, that the RVPs are inferior to the costlier index scheme in the proposal.

- IPAA and DPC strongly object to 1) MMS's refusal to allow the use of RVPs east of the Rockies and 2) limiting the use of RVPs in the Rockies to producer-refiners. All other producers are forced to perform the very burdensome, and as later shown nearly impossible, task of tracing. In the associations' view this discriminatory application of RVPs is arbitrary. We reiterate our position that RVPs should be available to all producers.

- The proposal's use of lease market benchmarks only in the Rockies and only for an integrated producer refining its own oil is a major policy contradiction. MMS characterizes the Rockies region as the least competitive marketplace for crude oil in the country, with few producers, few buyers, and few shippers. 63 Fed. Reg. 6115 & 6118. Yet it refuses to use RVPs in areas of greater competition east of the Rockies.

- Several of the restrictions on the Rockies benchmarks are unwarranted and unworkable. Most Rockies producers will be saddled with tracing or the NYMEX scheme of valuation.

GROSS PROCEEDS DEFINITION

- The definition of "gross proceeds" (proposed § 206.101) overstates the Department's authority to establish the "value of production" under federal statute by claiming royalties on payments that are not for production or for the value of production at the well.

- The agency does not have the power to expand the definition of gross proceeds as to leases already in force. Those are governed by the definition in effect when the leases were issued.

- Payments for "marketing" and contract settlement "buydowns" are not royalty bearing. These are not part of the value of production.

- Reimbursements for harboring or terminaling fees are plainly a cost of transportation. *Marathon Oil Co.*, MMS-85-0071-OCS (1986).

- Using "gross proceeds" to compel a producer who repositions production to a market center through a series of arm's-length exchanges to use the eventual sales price with adjustments for location and quality differentials (proposed § 206.102(c)(3)) will, in the great majority of cases, overstate the value of the oil at the well. This "tracing" approach to gross proceeds also improperly allows MMS to impute to federal royalty value added by non-federal oil.

NEW IMPLIED DUTY TO MARKET

- The exception for transactions breaching the alleged duty to market (proposed § 206.102(c)(2)(ii)) is inappropriate. As we will elaborate below, there is no such duty respecting the marketing of crude oil.

- The consequences of adopting this duty-to-market exception, when coupled with proposed duty to market at no cost to the lessor (proposed § 206.106), are potentially staggering for small producers, as two examples will show. First, it is an open invitation for auditors to second-guess the producer's decision to sell oil at the lease instead of moving it downstream. *See Amerac Energy Corp.*, MMS-93-0868-OCS (Apr. 1996) (using duty to market to charge more than the lessee's arm's-length gross proceeds as royalty value), *appeal pending*. Second, because MMS considers aggregation of oil volumes to be part of the duty to market at no cost to the federal government, the duty is especially onerous to small producers operating stripper wells, whose arm's-length sales at the well may be rejected for breaching the alleged duty to aggregate stripper oil into more attractive volumes.

AFFILIATE ISSUES

- Producing companies entering the business of oil trading and repositioning typically create different entities for that task. The reason for doing so is simple: to protect the assets of the producing corporation from the liabilities of the trading corporation. "The law permits the incorporation of businesses for the very purpose of isolating liabilities among separate entities." *Cascade Energy and Metals Corp. v. Banks*, 896 F.2d 1557, 1576 (10th Cir. 1990). American law has developed rules governing those limited circumstances in which a party can disregard the separateness of affiliated corporations. By treating a lessee and its affiliates as essentially one entity for royalty purposes, the proposal runs counter to this entire body of law.

- By treating an affiliated marketing company as if it were the same as the producing company, the proposal discriminates against companies which create affiliates to participate in midstream marketing of crude oil. It does so by imposing a higher royalty value per barrel on an affiliated producer than it imposes on an unaffiliated producer selling an essentially identical barrel. This is a discriminatory policy. In a similar setting, the Interior Board of Land Appeals has already held that discrimination against producers with transportation affiliates is unlawful. *Shell Western E & P Inc.*, 112 IBLA 394 (1990).

- The proposed redefinition of "affiliate" to capture any company in which a producer owns as little as 10 percent is completely unwarranted. The Interior Board of Land Appeals has already counseled MMS that the agency's fears of improper dealings between 50-percent affiliates are greatly exaggerated. *Id.* at 400 n.4. The redefinition is simply another attack on the former policy of accepting arm's-length gross proceeds as the proper value for royalty.

- By improperly inflating royalty values of oil sold to an affiliate, the proposal attempts to assess royalty on the profits earned by a company adding value to oil in the midstream market. IBLA has already reversed MMS for attempting to assess royalty on the profits of non-royalty-bearing transactions. *Petro-Lewis Corp.*, 108 IBLA 20, 39 (1989).

- Requiring a producer to trace, report, and pay royalties based on an affiliate's resale of crude oil in the midstream market will create exorbitant reporting costs, especially for larger independents whose affiliates aggregate extensive volumes of oil.

OTHER MIDSTREAM MARKETING CONCERNS

- To the extent MMS has a legitimate need to base royalty valuation on index prices at market centers, it has to factor in some way to share in the risks of moving the production to those centers. Private lessors must share in those costs if oil from their leases is marketed initially off the lease. The federal government pays those costs when it sells oil in kind. Yet the proposal continues to deny any federal obligation to share in the costs and risks of the midstream market.

- The proposal attempts to address the fact that wellhead prices and market center prices for identical oil differ because of differences in location and timing of sale. 63 Fed. Reg. 6122. It usually does so by letting the lessee deduct so-called "actual" transportation costs. But transportation costs, especially as limited by MMS, rarely capture the full location differential. (Kalt Testimony at 1179-80.) In effect, MMS is improperly claiming a royalty on the profit a producer can make by taking the risk of transporting the oil. "In fact, implementation of the MMS netback methodology would result in a federal levy on such downstream services and functions under the name of collection of federal royalties on the value of federal crude oil at the lease." (Kalt May comments at 7.)

- Now that MMS has proposed to redefine affiliate to include any company in which a lessee has as little as a 10% interest, problems with MMS's so-called "actual cost" methodology in transportation allowances become especially significant. The pre-tax rate of return allowed under that methodology, the BBB bond rate, is confiscatory. No company would build a pipeline if that rate were its expected rate of return.

SPOT PRICES

- A key problem with the proposal is MMS's belief "that spot prices are the best indicator of value for production...." 63 Fed. Reg. 6120. Spot prices are the best indicator of value of oil sold in spot transactions at the market center where those transactions occur, nothing more. In other words, they are a very good measure of the value of oil at the downstream end of the pipeline (to the extent oil is sold there, for a large percentage of oil is shipped through those centers without sale). But the issue in this rulemaking has to be to find the best indicator of value at the wells because that is what the law requires.

- To work backward from a spot price to determine wellhead prices requires complicated adjustments, making auditing more costly. The adjustments for many independents the adjustments will be MMS-calculated figures based on year-old data. (Thomas ¶¶ 69-74.)

- In nearly all cases, the adjustments will be inadequate to back out the value added by moving the oil from the lease to the market center. (Kalt May comments at 5.) MMS will therefore claim royalties on value added downstream on top of the value at the well. It is for this very reason that courts find a netback "a less desirable method" and "more difficult to apply" than the method using comparable sales in the lease market. *Ashland Oil Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir. 1975).

NON-COMPETITIVE CRUDE OIL CALLS

- The proposal's treatment of "non-competitive crude oil calls" is a significant problem for some small producers, who took assignments from major oil companies who retained a right to take the production at posted prices. These assignments were at arm's length and the price in the calls should be accepted as if the oil were being sold under a long-term arm's-length contract. Even now MMS would accept a posted price as the proper value for royalty if it were the price received under a long-term sales contract. Calls should be treated no differently.

- The proposal's treatment of these calls means that a lessee, at the callor's whim, will be shifting back and forth from month to month between gross proceeds accounting and index-based accounting, a significant burden on smaller producers not considered by the agency in its economic impact and paperwork reduction analyses.

- If a distinction is to be made, MMS should include a grandfather clause excluding calls created before the effective date of the rule. When these calls were negotiated, MMS's policy was that posted prices reflect fair market value. Lessees were hardly on notice that this policy would change.

- At a minimum, the producer should have the opportunity to show that the price received under the call is a fair market price. If he can show that the posted price is consistent with comparable arm's-length sales, then royalty should be paid on that value.

- The best solution, however, would be for MMS to take its royalty on oil subject to "non-competitive" calls in kind for resale. That would give MMS the current market price and spare the producer the burden of paying royalties on revenues it does not receive.

OTHER ISSUES

- Compliance with the proposal will require lessees to obtain information which so-called "affiliated" companies may for legitimate business and legal reasons refuse to give.

- The proposal needs to be clarified to prevent transfers of oil to third parties for value under the terms of joint operating agreements from being treated as non-arm's-length sales.

COMMENTS

1. MMS'S REFUSAL TO PROPOSE RVPS IS UNSUPPORTED.

MMS is correct in concept in proposing the use of lease market benchmarks in the Rockies region. If benchmarks are supportable in the Rockies -- and they are -- they are supportable on a much broader basis in the Rockies and throughout the country.

The preamble to the proposal states that "because we are still in the deliberative process," MMS will not respond to previously submitted comments until it issues the final rule. 63 Fed. Reg. 6114. However, MMS's economic analysis under Executive Order 12866 ("12866 Analysis") makes clear that the agency has rejected the use of RVPs or similar lease market benchmarks. The agency asserts that, "[b]ased on experience under the current regulations," RVPs are "unworkable when applied to production from the entire country.[4] Following benchmarks that rely on access to comparable arm's-length contracts would be costly and difficult to administer compared to the proposed rulemaking." (Attachment 2, p. 8.) In MMS's view, its proposal "will be easier to administer and less costly for industry to comply with." (*Id.*)

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[4] IPAA and DPC strongly disagree with this conclusion. As we have previously stated, RVPs are the most fair and least burdensome means for royalty valuation.

This conclusion is obviously incorrect, as the following comparison will show. The chart entitled "Paperwork Burden" attempts to capture the differences in a readily accessible format. First, under the RVP system no one would need to file the proposed Form MMS-4415; under the proposal, all federal lessees with arm's-length exchange agreements for oil exchanged from an MMS "aggregation point" anywhere in the country to an MMS "market center." Additional burdens imposed by the proposal are identified below by kind of transaction. It must be remembered that on a given lease a lessee may have oil that falls under all of these transaction types, making the burden particularly onerous. Finally, please note that many of the information needs under the RVPs are <u>alternative</u>: the lessee has a choice over which RVP to use. In contrast, the information needs under the proposal are generally <u>additive</u>, and the lessee in response of self-defense will over-accumulate records in anticipation of the many opportunities given auditors to second-guess the lessee's valuation decisions.

PAPERWORK BURDEN

- Under the RVP system no one would need to file the proposed Form MMS-4415.

- Under the proposal, all federal lessees with arm's-length exchange agreements for oil exchanged from an MMS "aggregation point" anywhere in the country to an MMS "market center" must file the proposed Form MMS-4415.

- Additional burdens imposed by the proposal are identified below by kind of transaction. It must be remembered that on a given lease a lessee may have oil that falls under all of these transaction types, making the burden particularly onerous.

- Common to all categories is a basic set of records. These include volume data at the lease measurement point; oil quality data; sales contract for each transaction; invoices; records of sales payments received; if transported prior to first sale, transportation contract or tariff letter, invoices, records of payments made o transporter. The charts below list the additional documents required for each type of transaction.

Oil Sold, First Sale at Arm's Length, No Exchanges	
RVPs	Additional records needed: None.
MMS PROPOSAL	Additional records needed: • information showing exchange differentials between relevant aggregation points and relevant market centers, • MMS-calculated exchange differentials for those points and centers (in case MMS disagrees with your information). Additional records that may be needed: • documents demonstrating that a "call" has been made on your "non-competitive crude oil call;" • if call exercised, documents showing the relevant index pricing averages for the production month.

Oil Sold, Exchange Prior to First Arm's-Length Sale	
RVPs	Additional records needed: • copies of the first exchange agreement and, at the lessee's option, **either** • 1) information about its other arm's-length purchases or sales in the same field to apply the RVPs, **or** • 2) the remaining exchange agreements in the given exchange sequence to permit an adjustment for value back to the lease.
MMS PROPOSAL	Additional records needed: • copies of the first exchange agreement and, all additional exchange agreements in the transaction, • information needed to address the problem of tracing the oil downstream (see page 21 below), • index price information from the relevant market center (because MMS may disagree that your arm's-length exchanges had reasonable differentials or because the exchanges were not at arm's length), • information showing your other exchange differentials between the relevant aggregation point and the market center, **and** • MMS's calculated differentials.
Oil Sold, First Sale Not at Arm's Length	
RVPs	One of the following: • 1) information about its other arm's-length purchases or sales in the same field to apply the RVPs **or** • 2) if lessee elects not to sell or buy enough in the field at arm's length, then a) index price information from the relevant market center **or** b) the affiliate's resale price; and information needed to support a deduction of the value added by midstream activities. • **Or**, as an alternative to 2), the lessee could use MMS-published data on prices it receives at the wellhead from the given field when selling royalty-in-kind.
MMS PROPOSAL	Additional records needed: • affiliate's resale prices, **and** • information about NYMEX or relevant market center price, • buy/sell contracts, • all exchange agreements involved in the transaction, • information for benchmarks if in the Rockies region.

As one can see, from the lessee's perspective, MMS's proposal has a far greater hunger for data than the RVPs, a hunger sated only at the lessee's expense. The proposal, in short, relies on more costly data requirements with less intrinsic reliability than the RVPs. This alone is enough to make the agency's adoption of the proposal arbitrary. But the proposal cannot be saved by viewing the problem solely from the agency's point of view, because other comparisons of data needs show that MMS's proposal probably isn't simpler for the agency either.

For example, for the proposal to work in California, MMS must monitor exchanges from at least 24 "aggregation points" spread around the southern half of the State. Under the RVP's, in contrast, MMS could cover over 80% of the oil royalties from onshore California leases simply by targeting one field, the Midway Sunset. (Attachment 2, p. 19: "Midway-Sunset production is roughly 80 percent of all Federal onshore California production, and another 10 percent of the Federal onshore California production comes from the same general area and is similar quality crude."). Similarly, MMS's proposal would need to monitor exchanges from 26 aggregation points in Wyoming, when it could cover the majority of oil sold and valued under the RVPs by targeting fields in just six counties: Campbell, Converse, Hot Springs, Park, Sweetwater, and Uinta. (Royalty Management Program, Mineral Revenues by State and County: Fiscal Year 1997 at 96-99.) The proposal will require monitoring of exchanges from 26 aggregation points in Texas, but under the RVPs, MMS could cover the oil of interest to that state by targeting a few offshore fields.

As we have noted in prior comments, with some additional rulemaking, MMS could define several uncontroversial "areas" for the purpose of applying the RVPs. In other instances, it would continue to be appropriate to focus on individual fields. *Cf. Anderson-Prichard Oil Corp.*, GS-12-O&G (1946) (rejecting agency's attempt to base value on highest price paid for like-quality production in the "area" of Eddy and Lea Counties, using instead the major portion price in the given field, Langlie field). This effort could significantly ease the recordkeeping and auditing burden for both lessees and MMS.

Furthermore, for the more limited purpose of applying the "contemporaneous desk check" strategy which IPAA previously proposed, MMS could quite rationally treat each of the producing basins in Wyoming as a single "area." Thus, for example, the 200 or so fields in the Powder River Basin could constitute an area. Treating Wyoming basins as areas would vastly simplify the use of the contemporaneous desk check strategy and could significantly aid state and federal auditors in targeting fields for further review. Audits in New Mexico could be similarly focused because that state's federal oil production comes almost entirely from fields in two counties: Eddy and Lea. (Royalty Management Program, Mineral Revenues by State and County: Fiscal Year 1997 at 61-64.)

Given the agency's claim that its proposal is simpler and more certain, one would expect that assessment to be reflected in the agency's budget requests. Despite MMS's assertion that its proposed rule is simpler and less costly to administer, there is no evidence to suggest that MMS's budget is shrinking. To the contrary, MMS's projected budget is higher or even at best. A budget increase is readily understandable when one compares the complexity of the agency's proposal with the simpler RVP system advocated by our associations. The attached "decision tree" charts compare the various decision points lessees and MMS must pass through in applying the two systems. (Attachments 3 and 4.) An extensive textual discussion is unnecessary here. The pictures tell the story.

Particularly in the valuation of produced oil, American law favors the use of comparable transactions in the field and uses netback methodologies reluctantly. Until now, this has been the Department's approach as well. Until the Department can make the case for reversing this well-settled preference, it is obliged to continue valuing non-arm's-length sales by reference to similar arm's-length sales.

2. THE PROPOSED DUTY TO MARKET AT NO COST TO THE LESSOR IS CONTRARY TO LAW.

MMS continues to insist that federal lessees have a duty to market for the mutual benefit of lessee and lessor at no cost to the lessor. 63 Fed. Reg. 6120. Recently, the Interior Board of Land Appeals appeared to add support for this proposition.

> It is established that the creation and development of markets for production is the very essence of the lessee's implied obligation to prudently market production from the lease at the highest price obtainable for the mutual benefit of lessee and lessor; traditionally, Federal lessees have borne 100 percent of the costs of developing a market for gas. *ARCO Oil & Gas Co.*, 112 IBLA 8, 11 (1989); *Walter Oil & Gas Corp.*, 111 IBLA 260, 265 (1989). It is the lessee's duty to perform that service at no cost to the lessor.

Taylor Energy Co., 143 IBLA 80, 81 (1998). Regrettably, the Board was wrong.[5]

[5] DPC and IPAA have separately attached an extensive analysis of the problems with the proposal's treatment of affiliates. (Attachment 5.) Many of the themes of that analysis are equally relevant here and are incorporated by reference.

Both logic and tradition hold that the federal royalty share is to be determined by reference to the value of production at the well. The Department's early litigation over the value of crude oil in the Kettleman Hills field established precisely that point. *United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. Cal. 1947) ("lessees are obligated to return to the government the specified percentage of the reasonable market value at Kettleman Hills of the oil produced;" "'value' means value at the wells at Kettleman Hills"), *aff'd sub nom. Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950). The logic behind this point of demarcation inheres in the nature of the lease itself.

> The government leases oil producing lands in order to, among other things, reap the benefits, through royalty payments, without having to shoulder the associated risks of exploration, production, and development.

Diamond Shamrock Explor. Co. v. Hodel, 853 F.2d 1159, 1167 (5th Cir. 1988). Because the government does not shoulder those risks, the government does not, for example, share in any unrecouped take-or-pay payments, even though those payments are received for gas sold <u>at the lease</u> and are received under the terms of the sales contract. *Id.* From this it follows necessarily that the government, not sharing in risks downstream from the lease, cannot claim a share of the value added by those activities free of cost.

The Board's statement that the essence of the implied duty is the creation and development of markets at no cost to the lessor is squarely at odds with prior positions of the Department. For example, in the 1926 regulations as amended on September 14, 1929, the U.S. Geological Survey was directed to allow lessees to deduct from the royalty value the cost of heating needed to remove emulsion from produced oil in order to place it in marketable condition.

> The lessee shall operate his wells in such manner as to eliminate, so far as possible, the formation of emulsion, or so-called B. S. If the formation of emulsion, or B. S., can not be avoided and the oil can not be recovered from the emulsion by usual methods of treatment, the lessee shall treat the oil to put it into a marketable condition if it can be recovered at a profit. The supervisor is empowered to authorize a deduction, before royalty is computed, on account of the cost of putting the oil into marketable condition by such unusual methods....

1926 Operating Regulations § 2(m) (Attachment 6.) Similarly, the Department was required to deduct the full cost, including cost of capital, needed to gather natural gas in the Kettleman Hills field.

> If the lessees had had no gathering system of their own they would have been compelled to have that service performed by someone else. In such event the contract for that service would necessarily have included as elements of cost to the lessees not only the labor and other costs for operating the lines and depreciation on the capital investment therein, but as well a reasonable return on the capital investment in the facilities so used. When, instead of paying for the service to be done by someone else, the lessees performed that service for themselves and for the government, <u>they were entitled to have the government royalty gas bear its proportionate share of these costs which daily accrued against them</u>.

United States v. General Petroleum Corp., 73 F. Supp. at 257 (emphasis added). Because the Department was compelled under the leases and regulations to grant deductions for these actions taken on the lease or in the field, it cannot be true that the lessees have implied duties to take actions downstream of the lease and field for the government's benefit at no cost to the lessor.

And indeed the case law is clear on this point. Even the case the Department cites with the greatest frequency and fondness, involving the use of the price for liquefied natural gas landed in Tokyo and netted back to the lease in Alaska, recognizes the need to deduct marketing costs when a netback must be used. Referring to the lease clause and the then-existing rule on royalty valuation, 30 C.F.R. § 206.103 (1984), the court explained the operation of the federal royalty obligation when royalties are paid in value.

> I agree that the first sentence of the regulation directs the Associate Director to look to sales price[s] in the field. However, the regulation does not end there. In the second sentence it requires that the royalty basis be not less than the gross proceeds accruing to the lessee. Thus this regulation combines characteristics of a "wellhead value" royalty clause with characteristics of a "proceeds" type royalty clause. By its own language, the provision aims to ensure that the gross proceeds accruing to the lessee is the absolute minimum value

> for computation of royalties. In describing a "proceeds" type royalty clause, Professor Hemingway states: "Royalty payable upon the 'proceeds' of the sale of gas will be computed on the basis of aggregate gross receipts from all products less the costs of marketing and transportation."

Marathon Oil Co. v. United States, 604 F. Supp. 1375, 1384 (D. Alaska 1985) (emphasis added), *aff'd* 807 F.2d 759 (9th Cir. 1986) (adopting district court's "well-reasoned opinion"), *cert. denied* 480 U.S. 940 (1987).

If the creation and development of markets for federal lease production at no cost to the lessor is the essence of a duty to market, then it is difficult to understand why the Department has traditionally granted transportation allowances, processing allowances, and the like. A market is a place of buying and selling. A necessary step in developing a market is transporting the production to the place of marketing; otherwise, no market can develop. And if a producer has a duty to create a market at no cost, then why can it deduct the costs of processing a stream of wet gas to extract liquid products to be sold separately from the remaining dry gas? If the producer can create a market by extracting the propane liquid, would it not be his obligation under this implied duty to extract it at no cost to the lessor?[6] There simply is no principled way to distinguish these activities from any other downstream marketing activity if there is indeed an implied duty to create and develop markets.

But if MMS cannot accept this proposition on the basis of logic or tradition, it must accept it on the basis of authority. When the United States issues oil and gas leases, it acts in a dual capacity. In its governmental capacity, the United States retains its right to exercise police powers over the leased lands in matters such as conservation. However,

> [i]n its proprietary capacity, the Government is like any other lessor, bargaining hard for the best lease terms, but recognizing their binding effect as a contract once they are agreed upon....The net result of this dual capacity is that federal leases are subject to some regulations (those of a proprietary nature, such as provisions regarding annual rental payments) which are

[6] The only response the Department can logically offer here is that lessees should be grateful for the grant of any allowances at all. This is precisely the tack the Department took in arguing against allowing the full cost of the Kettleman Hills gathering system, arguing that the government had "been more than generous" in allowing any deductions at all. *United States v. General Petroleum Corp.*, 73 F. Supp. at 257. As previously noted, the court rejected that view.

> frozen as of the time of the lease, while other regulations (those relating to conservation, such as rate of production) are subject to continuing amendment.

Warren M. Christopher, *The Outer Continental Shelf Lands Act: Key to a New Frontier,* 6 STAN. L. REV. 23, 43-44 (1953) (emphasis added).

The law is clear that when the United States enters the marketplace as a commercial lessor, "the government's role is taken to be no different from that of any private lessor or proprietor...." *United States v. General Petroleum Corp.*, 73 F. Supp. at 234.

> Regardless of the type of lease Congress might authorize, a lease executed in accordance with what it *has* authorized becomes a private, contractual matter and is to be interpreted according to the general rules of law respecting contracts between individuals. And regardless of what Congress has authorized, unless the authorized provision is mandatory, it may not be "read in" if the Secretary omitted to include it.

Id. (emphasis by underlining added). In other words, a duty to market at no cost to the lessor cannot be read into the lease "for the simple reason that no such right ... is stated in the lease."[7] *Continental Oil Co. v. United States*, 184 F.2d at 810.

IPAA and DPC have already commented at length on the history of the Department's rules on the question of marketing. To that we now add a compendium of federal lease forms, summarized on the chart appearing as Attachment 7, showing that no federal lease form and no federal regulation has ever stated that the lessee has a duty to market oil at no cost to the lessor.[8] In short, the duty doesn't exist.

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[7] The requirement that the Department must point to express language in the lease is simply an aspect of the broader principle that any contract drafted by the United States, such as a lease, "should be construed most strongly against the drafter...." *United States v. Seckinger*, 397 U.S. 203, 210 (1970).

[8] There appears to be confusion within the Board of Land Appeals on the existence of an implied duty. Contrary to *Taylor Energy*'s assertion of an implied duty, *Viersen & Cochran*, 134 IBLA 155 (1995), argues that the obligation to market is not implied, but express. *Id.* at 164 n.8. *Viersen & Cochran* is based on the conditional express duty to market natural gas present in the Department's rules from 1942 to 1987. (See IPAA May 1997 comments at 27; DPC May 1997 comments at 15.) *Viersen* indicates that even IBLA recognizes that a duty to market must be express to exist at all. As our associations have previously noted, the conditional express duty

3. <u>TRACING ULTIMATE ARM'S-LENGTH SALES BACK TO THE LEASE WILL BE A NIGHTMARE</u>.

For lessees who are affiliated with mid-stream marketing companies that do not own refineries, the proposal constitutes nothing less than a levy on the mid-stream marketing enterprise taken as a whole. The dispositions of hundreds of thousands of barrels of production, or in many instances millions of barrels of production, would have to be tracked and analyzed in order to establish the value of production from a *single* lease for a *single* production month. Further, the month-to-month, and in some instances, day-to-day, downstream marketing arrangements of mid-stream marketers are in constant flux, changing in response to market forces, thereby rendering virtually impossible any systematic means of conducting the required analyses.

In essence, virtually every transaction downstream of the affiliated lessee's federal production adds value to the product. The proposal thus does not result in a determination of either the value of the royalty share of production at the lease, or the royalty share of the value of total lease production, as is required under relevant statutes. Rather, the proposal constitutes a levy on a volumetrically determined pro rata share of the proceeds of the lessee's affiliate, taken in the aggregate, for all of the affiliate's downstream transactions, subject only to an adjustment for transportation, and without regard to the comparability of any of the production sold by the mid-stream marketer. This is arbitrary, capricious, an abuse of discretion and contrary to law.

An example of a recent and typical onshore transaction reveals the enormous burdens imposed by the proposal, burdens which, even if met, do not establish a reliable determination of the value of production at the lease. Cases of this sort are the rule rather than the exception.

In April, 1997, a member company sold slightly less than 400 barrels of condensate produced from a federal lease to an affiliated company active in the mid-stream market. Neither the mid-stream marketer nor any other affiliated company owns a refinery. The marketer either resells the oil it purchases, or exchanges its purchased oil for other production which it resells to other marketers or to companies that refine the product.

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respecting natural gas did not express any obligation to market <u>without cost to the lessor</u>.

The lease production in question was transported by truck to a storage facility where the original 400 barrels were stored along with approximately 68,000 barrels of production produced from approximately 60 other leases, including both federal and non-federal land, purchased by the lessee's affiliate from both the lessee and others. These purchases occurred throughout the month of April 1997. Monthly average prices by lease ranged from a low of approximately $17.42 a barrel to a high of $19.66 per barrel. Gravities ranged form 38.1 degrees to 71.2 degrees. Monthly volumes by lease varied considerably due to the varying productive capacities of the leases in question. (Some leases reflected sales almost every other day while for others, only one or two purchases were made for the entire month.)

No sales of production were made by the marketer from the storage facility. Rather, all but about 200 barrels of the 68,000 barrels were transported by pipeline to a pipeline interconnect where the 68,000 barrels (including presumably the 400 barrels to be valued) were further "blended" with an additional 200,000 barrels acquired by the marketer through a variety of transactions. The 200 barrels not transported by pipeline were trucked to a downstream point where they too were "blended" with approximately 119,000 barrels acquired by the marketer from other sources.

Again, at this point no sales by the marketer occurred. Nevertheless, in order to determine the value of the 400 barrels of production at issue, the lessee and its affiliate are at this stage now required to attempt to follow the subsequent disposition of some 387,000 barrels of production, moving in separate packages of 268,000 and 119,000 barrels. But the story does not end here. The 268,000 barrels were transported further downstream by pipeline where they were aggregated with additional production acquired through numerous transactions by the marketer for a total of 525,000 barrels, *not* including the additional 119,000 barrels that must also be tracked in order to value the 200 barrels not transported by pipeline from the first storage facility. In the end, the aggregated volumes to be traced in order to value the 400 barrels at issue total 644,000 barrels.

Though the proposal does not detail how tracing must be accomplished in a situation like this, one assumes that the agency would expect the 400 barrels at issue to be somehow deemed evenly dispersed throughout the 644,000 "downstream" barrels. Under the proposal, the affiliated marketer's ultimate arm's-length proceeds for the disposition of 1,610 barrels of production would be used in valuing *each barrel* of the 400 barrels in question. (644,000 divided by 400 = 1,610.) The 644,000 barrels required to be traced in order to establish royalty value were acquired throughout the production month, from a variety of geographically disparate sources, some federal, some not, under changing market conditions, in a variety of wellhead markets, with the various barrels being of various qualities, under contracts of varying duration and covering a range of volumes and subject to a multiplicity of transportation arrangements, part or all of which will change to some extent during the next production month. These 644,000 barrels were subsequently disposed of in an equally complex number of transactions occurring at a variety of downstream points.

Under the RVPs, the value of the production in question would be based on values established under arm's-length contracts for purchases of significant quantities of like-quality oil in the field or area. Yet under the proposal, the affiliate's proceeds for the disposition of hundreds of thousands of barrels of production are somehow attributed to the lessee in determining the "value" of 400 barrels of production at the lease without regard to the comparability of the contracts under which the affiliate's volumes were resold.

4. <u>THE REDEFINITION OF "AFFILIATE" IS ARBITRARY</u>.

Under the current crude oil value rule, a company owning more than 50% of another company is irrebuttably deemed to control that company, and the two are considered affiliated. A company owning 10% through 50% of another company is rebuttably deemed to control that company. 30 C.F.R. § 206.101 (definition of "arm's-length contract"). The proposal would drop the rebuttable presumption of control, making ownership of 10% or more enough to establish that the one company controls the other. 63 Fed. Reg. 6126. This change would have three primary effects. More wellhead sales would be considered non-arm's-length. More resales of crude oil would be subjected to burden of tracing. More transportation would be subject to MMS's so-called "actual cost" methodology.

This change is without foundation in logic. The rationale for any provisions addressing degrees of affiliation is to assure that the parties to the contract "have opposing economic interests regarding that contract." *Id.* The lessor wants to assure that its lessee has sufficient incentive to maximize the wellhead sales price of the oil and to minimize the costs of transportation. That way the lessor can be confident that the lessee is not shifting part of the wellhead value of the oil away from the sales price and "hiding" it in transportation or resale profits. Indeed, the whole point of using RVPs is to have an objective measure of wellhead value so that the lessor and lessee may fairly determine that the lessor is receiving no less and no more than the fair value of the oil at the wellhead.

Even the current rule's irrebuttable presumption is arbitrary in most cases. For example, consider a lessee in sole ownership of a federal lease with a 12½% royalty rate. The lessee takes bids for the purchase of its oil at the lease. The highest bidder is a company in which the lessee owns a 75% interest. The question is whether the lessee is financially motivated to sell the oil at less than market value in order to 1) lower its royalty payment and 2) make up any lost profit from the lease sale in its profits from the affiliate's resale. Clearly not on these facts. For every extra dollar it makes in the wellhead sale, the lessee must pay 12½ cents to MMS; but for every dollar less it makes in the wellhead sale, it loses 25 cents to its partner when the affiliate resells the oil. So the lessee, even selling to an affiliate in which it owns 75%, is financially motivated to sell at the wellhead for as much as it can get. And the law imposes liabilities on majority interest owners whose dealings with an affiliate result in a price less than that obtained in a similar arm's-length transaction. (See Attachment 5 at 17-18.)

This example applies equally to transportation affiliates. The Interior Board of Land Appeals has already analyzed MMS's malaise over these affiliates in precisely the same way.

> While the Board has, indeed, recognized that economic incentives exist which might impel producers to shift profits to wholly owned subsidiaries as a means of decreasing royalty obligations, <u>the economic viability of such a strategy declines where, as here, outside interests in the subsidiary are substantial</u>. Thus, while a parent corporation might well desire to have profits transferred from one corporation to another in an attempt to lessen royalty payments of 12.5 percent on the value of production, <u>the incentive to do so when the parent corporation owns only 50 percent of the second corporation evaporates</u>, since such a procedure results in the net loss of 37.5 percent.

Shell Western E&P Inc., 112 IBLA at 400 n.4 (1990) (citation omitted, emphasis added).

Yet MMS has continued to reject transactions between companies with any degree of affiliation, even when the Director admitted that the facts showed that the lessee would lose money by shifting value to the affiliate. *See Mobil Exploration and Producing U.S. Inc.*, MMS-93-0997-O&G pp. 25 & 27 (1996). Under the Director's logic in that decision, any degree of affiliation between the parties was enough to taint the transaction. The proposal is apparently designed to make this abhorrence of affiliation the new policy by rule.

Though illogical, the current irrebuttable presumption has been workable because lessees whose transactions were deemed not at arm's length could rely on lease market benchmarks to value those transactions for royalty purposes. But the proposed rule significantly "ups the stakes" for transactions between affiliates;[9] and by irrebuttably presuming even more transactions not to be at arm's length, the proposal becomes especially objectionable. At a minimum, MMS is wrong to change the status quo in the manner proposed.

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[9] The proposal also shows little awareness of the difficulty of obtaining information from affiliated companies. Consider, for example, a larger independent which creates an affiliate -- 40% owned by holders of publicly-traded shares of stock -- to participate in the midstream market, which affiliate in turn is a 20% owner of a crude oil pipeline. The independent has no effective control over the pipeline and is no more entitled to information needed to perform MMS's so-called "actual cost" methodology than any other member of the public. Indeed, it is not uncommon for a business venture comprised of several companies to disqualify any member from participating in negotiations between the venture and that member's affiliate. The proposal's 10% irrebuttable presumption would treat any contracts of such a venture as non-arm's-length even with no proof of control.

5. THE RESTRICTIONS ON THE ROCKIES BENCHMARKS ARE UNWARRANTED.

As previously explained, the agency's reasons for not applying a national system of RVPs or benchmarks are unsupported. Denied the use of benchmarks, independents will be required to trace barrels through a series of exchange agreements, as that phrase is broadly defined. And while they trace, independents in the West Cameron and West Delta areas of the Gulf of Mexico will wonder why companies with refining affiliates are permitted the use of benchmarks in the Rockies. They will further wonder why the producer-refiners are given the opportunity to seek an exception to compliance with the rules, proposed § 206.103(e), while non-refiners are not. But the non-refiners will not wonder alone. Even the Rockies producer-refiners will have difficulty understanding why they can seek an exception for barrels they refine but not for barrels they sell without refining.

Although no sound reasoning supports reliance on lease market benchmarks in the Rockies when they are rejected in the Gulf of Mexico, DPC and IPAA obviously believe that producers in the Rockies should be permitted to rely on benchmarks. It is most objectionable that independent producers are not permitted to use the Rockies benchmarks unless their oil is sold under a non-competitive call or is sold in breach of the purported duty to market. Equally unsupported, we believe, are the restrictions placed on the use of the benchmarks there.

With regard to the benchmark of establishing value by "tendering" volumes of oil, the restrictions are fundamentally at odds with MMS's rationale for even permitting lease market benchmarks in the Rockies at all. The agency has characterized the crude oil market in that region as one with limited competition, a conclusion with which IPAA and DPC disagree. According to MMS, "production in the Rocky Mountain Area is controlled by relatively few companies and the number of buyers is more limited than [elsewhere]. As a result, there is less spot market activity and trading in this area due to the control over production and refining."[10] 63 Fed. Reg. 6118. Yet, despite this finding, the proposal would require a tendering lessee to receive at least three bids, none of which can be from a lessee-refiner running its own tendering program. So even if the agency's observations about the competitiveness of the crude oil market in the Rockies were correct, the proposed rule is illogical. In other words, in a market with relatively few buyers, the proposal eliminates a

[10] MMS's reference to the Rocky Mountain "Area" creates ambiguity and anxiety as well. "Area" is a term defined in proposed section 206.101. Is the defined term "area" to include an area as big as the proposed Rocky Mountain Area? What size for an "area" does proposed section 206.103(b)(1) refer to when it speaks of "production from leases in the area the tendering program covers...?"

number of companies most interested in buying oil. While the restriction is grounded in a concern about "the possibility of cross-bidding between companies at below-market prices," 63 Fed. Reg. 6119, that concern is more realistically addressed by the use of less-restricted benchmarks and the possibility of audit and sanctions.

While we agree with MMS's conclusion that spot trading is thin in the Rockies, the reason is different than that portrayed in the preamble. Refining demand in the region is approximately 450,000 barrels per day. Produced supply in the region is about 360,000 barrels per day. Most oil is sold in the Rockies to end users under arms'-length term contracts. It is the strength of the lease market, not the weakness of the spot market, that provides the compelling policy argument for the use of lease market benchmarks in the Rockies.

Other restrictions warrant comment. First, the use of the highest of three bids is not reasonable unless all the bids happen to be for the full tendered volume. A lessee may tender 2,000 barrels, for example, and receive numerous offers at $13 per barrel; but one small refiner facing an emergency might pay $16 per barrel for 250 barrels. The $16 price can hardly be imputed to the rest of the tendered oil. Second, it would be more realistic to require only two bids instead of three. Third, requiring the tender to include one-third of all of a lessee's production (even non-federal) is particularly onerous as a practical matter. In most cases the lessee allowed to use this benchmark has a refining affiliate.[11] By the lessee's tendering, the lessee's affiliate is disqualified from bidding on oil tendered by others; yet it is being excluded from buying at least one-third of its affiliated lessee's own production. The rationale for this restriction is, to be frank, pulled out of thin air. "MMS chose the 33 1/3 percent figure because it exceeds the typical combined Federal royalty rate and effective composite State tax and royalty rates for onshore oil leases by roughly 10 percent." *Id.* State royalty rates are, however, irrelevant to the federal lessor, and we fail to see on what basis MMS purports to protect a state's severance tax system, let alone by doing so with a 10% margin. The purchaser is not going to know, or if he knows is not going to care, whether the volume tendered for sale is 33% or greater of the seller's production. The purchaser is going to offer the lowest reasonable price it feels it can get away with -- constrained by the fear that a competitor may outbid it -- for the number of barrels it needs. If a minimum is needed at all, 15% is more than adequate in the Rockies region for a tendering program to provide

[11] For example, lessees without refining affiliates who breach the duty to market will also use this benchmark.

a reasonable picture of how local forces of supply and demand are setting the price at the lease or in the field.[12]

Similarly, no basis is given for limiting the use of a volume-weighted average price to situations in which at least 50% of sales are at arm's length. The agency offers no supportable reason for setting a different threshold for this benchmark. In any event, like the State of Wyoming, IPAA and DPC believe that both percentages are too high. In testimony before Congress, Wyoming Governor Jim Geringer expressed his concern that

> the proposed method of valuation based on NYMEX pricing does not sufficiently relate to the realities of the regionalized Wyoming marketplace. MMS might be able to justify the NYMEX approach since regional differences tend to come out neutral overall for the federal share. Not so for regional markets including Wyoming. MMS did attempt to incorporate our comments in the proposed rule to recognize a Rocky Mountain Region market. We don't care for NYMEX pricing as it is a futures market. The Wyoming proposal would create at least two other benchmarks for any non-arms'-length transaction before resorting to NYMEX. The tendering benchmark 33 1/3 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 second benchmark would be established by comparable sales in arms'-length transactions. Again, here, the benchmark is too high to be of much use. The rule will require that 50% of sales be arm's-length in order to be used as benchmarks. The state believes that 20 to 25% would have been a sufficient statistical percentage to establish the value of oil in a particular area. We are not confident that a single valuation approach can be devised which could apply to regional markets.

Royalty Enhancement Act of 1998, H.R. 3334: Hearings Before the Subcomm. of Energy & Mineral Resources of House Comm. on Resources, 105th Cong. (March 19, 1998) (Testimony of Wyoming Governor Jim Geringer).

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[12] Although market conditions can vary around the country, a single set of valuation principles along the lines proposed by our associations have the flexibility to address those variations.

In sum, MMS's proposals on the use of RVPs in the Rockies region are so restrictive that, as a practical matter, NYMEX will be the predominant method of valuation in the Rockies, even for producer-refiners.

6. THE TREATMENT OF "NON-COMPETITIVE" CALLS IS UNWARRANTED.

Under the proposal, a lessee whose oil must be sold under the exercise of a "non-competitive crude oil call" must value that production as if it were a non-arm's-length sale. Proposed § 206.102(c)(4). That means that the lessee, if in the Rockies region, might be able to base the value on the volume weighted average of its other arm's-length sales, proposed § 206.103(b)(2), but would otherwise have to use the NYMEX-based scheme to value its production. Proposed § 206.103(b)(3). Elsewhere the lessee would have to use the market center index price with adjustments supplied by MMS from its analysis of information supplied on proposed form MMS-4415. Proposed § 206.103(a) & (c).

We continue not to understand the agency's undue preoccupation with this issue. Information from our membership indicates that very little oil is actually taken under "non-competitive" calls and that the gain in royalty payments is probably outweighed by the costs incurred by a small producer to change its royalty accounting method every time a callor exercises its right. Under this provision, a producer can move in and out of the index-based pricing scheme, paying some months on gross proceeds, other months on index, all based on the purchasing whims of the callor.

But there is also a fundamental point of fairness here. The price set in these calls is no different than the price set in any other long-term sales contract. Even now, if a lessee was selling at arm's length under an old, long-term contract that referenced a posted price as the sales price, the proposal would accept the posted price as value. There is no justification for treating oil sold under an arm's-length call any differently. Additionally, producers entered into these calls in good faith at a time in which the Department had frequently expressed its confidence that posted prices fairly reflected the value of production. Now that they are locked into the price set in the call, the proposal has the retroactive effect of declaring these transactions not to have been at arm's length. At a minimum, therefore, MMS should grandfather non-competitive calls entered into before the effective date of the rule, and apply the index scheme only to oil delivered under non-competitive calls entered into after the effective date. MMS officials indicated at the October 14, 1997, Houston hearing that grandfathering might be acceptable. The agency should have placed this option on the table in this proposal.

Two other options, while less appropriate, are still preferable to the proposal. One is to give the lessee an opportunity to demonstrate that it obtained a fair market price when the call was exercised. The lessee could point to the price received under a similar arm's-length sale in the field or area. It could also show that it had received bids from third parties comparable to the price received from the callor. The other is for MMS to review its database for the field or area to verify that the price received was within the range of prices received by others at arm's length. If the lessee's call price fell short, the lessee would pay the difference.

7. THE PROBLEM OF "SALES."

Some clarification or correction is needed concerning the proposed definition of "sale" and how transfers of production under joint operating agreements are handled under the proposal. Under the terms of a typical joint operating agreement (this one for a unit), "[i]f any Party fails to take in kind or separately dispose of its proportionate share of the oil produced from the Unit Area, Unit Operator shall have the right ... to purchase such oil or sell it to others at any time . . . ." (Attachment 8, § 6.5A.)

It is unclear whether the proposal treats the operator's taking of the non-operator's oil as a sale. If it is a sale, then the non-operator may base its royalties on the gross proceeds it receives from the operator or the person to whom the operator sells the oil, even if that person is the operator's affiliate. Proposed § 206.102(a)(1). If it is not a sale, and if the operator sells the oil to an affiliate, then one of two options would appear to apply. Under proposed § 206.102(a)(3), the transfer might be treated as a "transfer to another person under a non-arm's-length contract...." If so, the non-operator would be required to "trace" the proceeds from the operator's affiliate's resale back to the lease, a task the non-operator could not perform because of lack of access to the affiliate's records. Alternatively, the transfer might be treated under proposed § 206.103 as one concerning "oil you may not value under § 206.102." If so, the non-operator must use index-pricing for valuation.

We raise this concern because it is the view of some MMS audit officials that, because joint operating agreements are not sales contracts, the only relevant contracts for royalty valuation would be the contracts between the operator and its affiliate and the affiliate's resale contract. Obviously, the proposal requires clarification to prevent the absurdity that a non-operator could have the operator sell the oil on its behalf to the operator's affiliate, yet the resulting transfer of title for value would be treated as other than an arm's-length sale.

8. MMS'S "ACTUAL COST" METHODOLOGY DOES NOT FAIRLY REFLECT LOCATION DIFFERENTIALS AND PRODUCES A CONFISCATORY RATE OF RETURN ON INVESTED CAPITAL.

The proposal is correct in recognizing that one barrel of crude oil can vary in value from another not only because of differences in quality and differences in the timing and terms of sale, but also because of differences in location. 63 Fed. Reg. 6122. Two barrels of crude of identical quality, sold at the same time on the same terms, are almost certain to have a different price if one is sold at a platform 150 miles offshore in the Gulf of Mexico and the other at St. James, Louisiana.

Even the proposal appears to recognize that the difference in values which result from differences in location is not identical to the cost of transporting oil from the one location to the other. *Id.* Nor has the Department historically maintained that transportation costs equal location differences. On the contrary, the Department's transportation allowance in the past has only been authorized from the point of production to the first available market for the oil. *Xeno, Inc.*, 134 IBLA 172, 180 (1995). In other words, where there is no market at the well, there is no location differential (based on different forces of supply and demand at the two locations) to be calculated, and the only available measure of the value added by moving the oil is the transportation cost.

But this proposal generally abandons market information at the wellhead in valuing oil under proposed section 206.103 and will rely heavily on MMS's so-called "actual-cost methodology" under proposed section 206.111 as a proxy for measuring location differentials. This sea-change in valuation theory accentuates the shortcomings of that methodology, some of which we have identified in earlier comments. Here we will address a particularly acute problem: the inadequacy of the rate of return permitted.

Under proposed section 206.111, a lessee shipping oil not at arm's length could deduct an allowance based on the transporting affiliate's operating expenses, maintenance expenses, overhead, and "either (1) Depreciation and a return on undepreciated capital investment ..., or (2) A cost equal to the initial capital investment in the transportation system multiplied by a rate of return...."[13] Proposed § 206.111(b). "The rate of return is the industrial rate for Standard and Poor's BBB rating."[14] Proposed § 206.111(c)(5). This rate of return has generally been around 7.75% recently, calculated <u>before</u> income taxes are assessed. After tax, the effective rate is less than 5%. No one would build a new oil pipeline if its expected rate of return were less than 5% after tax.

This low rate of return violates the agency's constitutional obligation to permit a fair rate of return. *Bluefield Water Works & Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692 (1923) ("A public utility is entitled to such rates as will permit it to earn a return ... equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by the same risks and uncertainties"). The Department and the courts have previously recognized the Department's *Bluefield* obligation to provide an adequate rate of return in the context of transportation allowances and other "netback" computations. *See, e.g., General Petroleum Corp.*, 73 F. Supp. at 257; *Petro-Lewis Corp.*, 96 Int. Dec. 127, 137 (1989) (MMS must allow "a reasonable rate of return").

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[13] The references in proposed section 206.111(b) to paragraphs (b)(4)(i) and (ii) presumably are meant to refer to paragraphs (c)(4)(i) and (ii).

[14] The BBB rate of return is for company bonds and thus is for debt. MMS assumes the rate of return should be the same for invested capital, or assumes that pipelines can be built financed entirely by debt. Neither assumption is realistic.

In contrast to MMS's rate, the Federal Energy Regulatory Commission has been authorizing rates of return under its cost-of-service methodology for oil pipelines of around 12%, after tax, on the cost of capital. Basically, by limiting the rate of return so severely, MMS is not only failing to capture location differentials, it is also effectively imposing a royalty on the profits of the transportation system. Transportation profits are plainly beyond the Department's reach under statute to obtain the fair "value of production."

To the extent MMS takes the position that it is not substantively reproposing its actual-cost methodology, the associations hereby petition the Secretary of the Interior, under 43 C.F.R. § 14.2, to amend the rule proposed as section 206.111(c)(5). At a minimum, MMS needs to incorporate procedures similar to FERC's for oil pipelines to assure a more appropriate rate of return. Even more appropriately, MMS needs to strike the provision excluding income taxes from allowable costs and then using a rate of return equal to twice the BBB bond rating.

9. RESPONSES TO PARTICULAR QUESTIONS.

MMS sought comment on four topics.

a. Definition of Rocky Mountain Area. 63 Fed. Reg. 6116 & 6118 asked for comment on the scope of the Rocky Mountain region, in particular whether northwest New Mexico should be treated as part of the region. DPC and IPAA believe that Nevada should be added to the region, and northwest New Mexico should be treated like the Rockies because of its isolation from other markets. But whether it is included in the Rockies or designated its own region is a matter of indifference to us.

b. Comments on "overall location/quality/transportation adjustments proposed." 63 Fed. Reg. 6121 sought comments on the revised adjustments. The chief problem we see is with an oil pipeline with crude oil of mixed quality but no quality bank. An illustration of this problem is moving oil from leases in North Dakota on the Butte pipeline. The pipeline operates without a quality bank. Sweet crude entering the pipeline is commingled with crude of lesser quality and results in a lower gravity, more sour mix. The easiest solution to address the problem is to use RVPs to value the crude before it is mixed in the pipeline.

c. Question on scarcity of non-competitive calls and availability of actual differentials. 63 Fed. Reg. 6123 inquired whether so little oil is sold under non-competitive calls that MMS might abandon the requirement of Form MMS-4415 altogether. We would support the abandonment of Form MMS-4415 for any reason, and therefore would agree with the course suggested by the question. The volume of oil being sold under calls at truly non-competitive pricing is small, too small for MMS to demand that a producer be prepared to switch his royalty accounting systems back and forth from month to month. And if MMS let callees pay on their gross proceeds or another non-index basis and if it abandoned the unauthorized duty to market at no cost, then independents selling at the wellhead would never need recourse to differentials generated by the MMS-4415. That wasteful program of form filing could be jettisoned in full.

d. Whether paperwork burden is reasonable. 63 Fed. Reg. 6124 inquired about paperwork burdens. By ignoring the costs and burdens of tracing from downstream sales or resales back to the lease (see point 3 above), MMS has failed to consider the significant accounting, economic, labor, computer and other burdens that will be imposed.

<u>Conclusion</u>

As is often the case, the simpler way is the better way. Royalty-in-kind remains the simplest approach on the table; but in any event RVPs are simpler, cheaper, more accurate, and theoretically sounder than the proposal.

Diemer True, Chairman
Land and Royalty Committee,
IPAA

J. Larry Nichols
Chairman, DPC

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