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April 6, 1998

APR 1998
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U.S. Department of the Interior
Minerals Management Service
Royalty Management Program
Rules and Publications Staff, MS 3021
Building 85, Denver Federal Center, Room A-212
Denver, Colorado 80225-0165

Re: *Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Federal Leases*

Dear Mr. Guzy:

Texaco Inc., on behalf of itself and its affiliates, including Texaco Exploration and Production Inc. ("TEPI"), appreciates the opportunity to submit these comments on the Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Federal Leases, published in the Federal Register on February 6, 1998 (63 Fed. Reg. 6112). Texaco has actively participated in the rulemaking process by submitting extensive comments and suggesting alternative valuation methodologies in response to the January, 1997 proposal and the September, 1997 Notice of Reopening of the Public Comment Period. Texaco representatives have also attended all of the public hearings that MMS has held on the rulemaking.

We are, quite frankly, disappointed that MMS seems to have ignored our comments and suggestions. Despite professing a willingness to consider viable alternatives, such as TEPI's tendering program, which reliably measure the value of oil at the lease, MMS has, in the supplementary proposed rule, chosen to abandon the long-standing principle of valuing crude oil at the lease using arm's-length sales prices in the field of production, and to embrace instead a rule that, for most Federal leases, measures the value of oil far downstream from the lease. Not only do most of the original problems identified in Texaco's comments on the January, 1997 proposal remain unresolved, but the supplementary proposed rule creates additional problems and imposes an even greater administrative cost on industry and the government. As a result, the supplementary proposed rule fails to meet two of its stated goals: it does not develop valuation rules that better reflect market value, and it does not add more certainty to valuing oil produced from Federal lands.

There are far better, cheaper, and more reliable measures of market value at the lease than the flawed valuation methodologies contained in the supplementary proposed rule. TEPI's tendering program, for example, has been used successfully to establish market value at the lease. If MMS is unwilling to adopt a tendering program like TEPI's, it should take its royalty oil in kind. The supplementary proposed rule fails to address adequately any of these less burdensome and more reliable alternatives. In contrast to these reliable measures of market value at the lease, the supplementary proposed rule, like the January 1997 proposal, fails to measure market value at the lease, and would effectively (and unlawfully) raise the royalty rate in TEPI's Federal leases. The proposal would simply increase Federal royalty receipts by including in the royalty base the value of integrated lessees' midstream assets and services. MMS has still not provided any rational explanation, much less empirical evidence, for rejecting the value established by arm's-length purchases and sales in the production field. In addition, the supplementary proposed rule is extremely complex and unworkable, and would impose an enormous administrative cost on Federal lessees and on the MMS, with no countervailing benefit. Finally, the supplementary proposed rule, like the January 1997 proposal, is procedurally and substantively flawed.

I. MMS HAS FAILED TO ADEQUATELY CONSIDER LESS BURDENSOME AND MORE RELIABLE ALTERNATIVES, SUCH AS TENDERING AND TAKING ITS ROYALTY IN KIND

The costs and inefficiencies which would be imposed by the supplementary proposed rule are entirely avoidable and unnecessary, because an active market exists for crude oil at the lease that allows a more straightforward, more accurate, more certain, and much less costly approach to valuation than that proposed by MMS. MMS has failed to consider these less burdensome and more reliable alternatives.

A. TEPI's Tendering Program Is A Far Less Burdensome and Much More Reliable Benchmark for Royalty Valuation Than Either the Resale or Index Pricing Alternatives Proposed by MMS

TEPI's tendering program is a far less burdensome and much more reliable benchmark for royalty valuation at the lease than any of the alternatives contained in the supplementary proposed rule. TEPI suggested its tendering program as an alternative to the valuation methodology contained in MMS's initial proposal. MMS appeared to consider an alternative similar to TEPI's program in its September 22, 1997 Notice of Reopening the Public Comment Period. However, despite receiving favorable comments on the tendering alternative, MMS, in the supplementary proposed rule, does not adopt TEPI's tendering program, or even explain why it fails to do so.

Beginning in August 1995, TEPI developed a tendering pilot program to track market value at the lease. Following a successful test in the Offshore Louisiana Gulf, TEPI implemented tendering throughout the United States, including California.[1] A tender is an invitation to third parties for bids on the purchase of crude oil at the lease. TEPI's tendering methodology is based on designating and bidding out tendering packages of representative volumes of crude oil in order to value similarly situated crude oil that is not sold arm's-length. Under TEPI's current tendering program, the first step is to categorize the marketing areas into areas of comparable crude oil quality. Marketing areas are determined on the basis of type of oil (*e.g.*, sweet or sour) and transportation (*e.g.*, truck, barge, or pipeline) and are further categorized based on costs to common transportation points. The marketing areas generally correspond to specific geographic areas.

Currently, the volume of oil tendered ranges from approximately 12.5% to 20% of the volume available from a specified marketing area. Generally, the percentage tendered is at least equivalent to the royalty share of the oil.[2] The tendered volumes do not come proportionally from each lease or from all leases in the marketing area, but instead are packaged so that significant quantities are available at a marketing area to attract competitive bids.

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1 Contrary to the assertion made in the supplementary notice of proposed rulemaking, TEPI has been tendering in California and intends to continue doing so. As well, the Department of Energy successfully used tendering in California until it sold its Elk Hills facility.

2 Although the current TEPI tendering program utilizes tenders of an amount at least as great as the royalty share, TEPI has found that tendering at least 10% of the production is sufficient to accurately establish the market value.

Bids are solicited through letters sent to all credit-worthy buyers known to be active purchasers in a particular area. Most of the bidders are producers, refiners, or marketers. TEPI's affiliates are not allowed to submit bids under the tendering program, because it was felt that affiliate participation might discourage some bidders. The bid invitations specify individual leases, volumes, and transportation methods. Sales are made at the lease. The purchaser is responsible for transportation downstream from the lease. Bids are for a six-month term, which is fairly standard in industry practice. The bids are evaluated when they are received, and the highest bidder is awarded the tender volume. TEPI has a small staff to direct the tendering effort and uses Equilon Enterprises L.L.C. ("Equilon"), a recently-formed joint venture between Texaco Inc. and Shell Oil Company, as its agent for certain administrative purposes of the tender.[3]

Equilon has the opportunity to purchase the remaining untendered production volumes at the high bid price. Equilon routinely exercises this option. On occasion, TEPI has determined that the highest bid is below market price. In such situations, TEPI negotiates with Equilon the market price – a higher price than that bid through the tendering program. On other occasions, Equilon has determined that the highest bid price is overvalued and has declined to purchase the remaining untendered volumes. If this occurs, TEPI offers these volumes to the high bidder. If the high bidder does not purchase all of the remaining volumes at the original high bid price, those volumes remaining are retendered.

TEPI pays royalty on the basis of the proceeds received from production tendered to third parties. For production sold to Equilon, the third party transactions are "normalized" to establish the price of affiliate sales. Normalization is the process by which TEPI utilizes the tendered price to adjust, if necessary, values of oil not sold to third parties within the marketing area. Adjustments are based primarily on location differences and certain quality differences. Adjustments generally are not made for gravity, because the bid request requires the crude to be deemed at specified API. In the normalization process, TEPI uses certain known "market reference points" in adjusting for location. Leases with a common crude oil delivery station generally will have the same price. The process can also result in a higher or lower price for volumes not actually tendered depending on the distance from the lease to the common delivery point. Because these tender packages are designed to aggregate representative volumes

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3 Texaco Trading & Transportation, Inc. ("TTTI"), a wholly-owned subsidiary of Texaco Inc., performed these services before Equilon. Accordingly, our experience with tendering is based on our experience with TTTI.

of comparable crude, there is very little impact on the high bid price from normalization.

TEPI's tendering program is intended to establish the most accurate value possible at the lease, taking into consideration all relevant economic factors. It clearly provides a proper means for valuing production for royalty purposes, since the value assigned to the production reflects the price received in actual arm's-length transactions at the lease in the relevant marketing area. This is particularly important because each marketing area has unique characteristics. By tendering an amount at least as great as the royalty share, TEPI ensures that a volume significantly large enough to determine market price has been used.

As we explained in our November 4, 1997 comments, a tendering program of the type employed by TEPI should be permissive. Although tendering is clearly effective in setting a fair value for crude in the producing field, not every company would be capable of implementing an effective tendering program. Tendering may also be unsuited for certain small leases.

TEPI's tendering program has worked extremely well to achieve market value prices at the lease level. We strongly urge that those companies willing and able to sell a representative share of production be accorded the full recognition that a fair royalty value is established by these arm's-length sales at the lease. TEPI would be willing to consider tendering MMS's royalty volumes at the lease.

TEPI currently has more experience with tendering than any other Federal lessee. With appropriate protection for our proprietary information, we would be pleased to meet with MMS to explain our tendering program in greater detail and to assist in developing guidelines for adaptation of the program for all Federal lessees.

B. The Least Burdensome and Most Reliable Alternative Would be for MMS to Take its Royalty in Kind

If MMS is unwilling to adopt a tendering program like that employed by TEPI, it should take its royalty in kind ("RIK"). Taking Federal royalty oil in kind would allow MMS to obtain fair market value for its oil without the unnecessary administrative complexity and burden that would be imposed by the supplementary proposed rule. Unlike the supplementary proposed rule, the RIK alternative would ensure that MMS obtains the market value of its oil *at the lease,* rather than improperly inflating the MMS royalty share by grabbing the value added by downstream assets and marketing services. Furthermore, the RIK alternative would not impose any burdensome record-keeping requirements on Federal lessees, much less their affiliates. Rather, like the current royalty valuation regulations, taking royalty in kind would retain the lessee's obligation to put Federal oil and gas in marketable condition, but would not impose an obligation on the lessee to market the production at no cost to the Federal government.

The decision-tree charts attached at Tabs 1, 2, and 3 graphically illustrate the enormous difference in complexity between the supplementary proposed rule and these two alternatives.

II. THE SUPPLEMENTARY PROPOSED RULE, LIKE THE JANUARY 1997 PROPOSAL, FAILS TO MEASURE THE MARKET VALUE OF OIL AT THE LEASE FOR MOST FEDERAL LEASE PRODUCTION

Despite acknowledging the basic principle of royalty valuation that "[r]oyalty must be based on the value of production at the lease," the proposed rule does *not* value oil at the lease for most Federal lease production. The most reliable measures of market value at the lease are arm's-length purchases and sales of crude oil in the producing field. *See* Comments of Prof. Joseph P. Kalt, at 6 (May 27, 1997); *see also Shamrock Oil & Gas Corp. v. Coffee*, 140 F.2d 409, 410 (5th Cir.)(holding that to determine "market price" the court must look to "the price that is actually paid by buyers for the same commodity in the same market"), *cert. denied*, 323 U.S. 737 (1994); *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984)(the "best means of determining the market value at the well . . . would be to examine comparable sales"), *cert. denied*, 471 U.S. 1005 (1985); *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996)("Market value is the price a willing seller obtains from a willing buyer"). However, under the supplementary proposed rule, oil disposed of at the lease through outright, arm's-length sales between nonaffiliated parties could not be used to value oil produced at the same lease that is sold to a company affiliate. Only that portion of production sold outright to a nonaffiliated party would be valued that way. All other Federal lease production would be valued using arbitrary "netback" formulae that vary depending upon the location of the lease, the ultimate disposition of the oil, and the terms and conditions of any arm's-length exchange agreements (often after co-mingling). As "proxies" for measurement of market value at the lease, these alternative valuation methods are badly flawed.

Moreover, contrary to the assertion made in MMS' press release of February 5, 1998, for all but a small fraction of Federal lease production, the supplementary proposed rule would consistently provide for royalty payments based on a value *exceeding* the value of production at the lease. (Comments of Prof. Kalt, at 7.) In particular, for oil not disposed of by outright, arm's-length sale at the lease, the supplementary proposed rule improperly inflates the royalty value by imposing a royalty burden on the value of midstream assets and services. (*Id.*, at 7-8.)

Because the proposed alternative valuation methodologies fail to measure the value of production removed or sold from the lease, the supplementary proposed rule exceeds the Secretary's statutory authority and would, if implemented, unlawfully breach essential terms of TEPI's Federal lease contracts. As we explained in our comments filed in response to the January, 1997 proposal, Federal leases require crude oil to be valued at the lease for royalty purposes. TEPI has vested contractual rights in its oil and gas leases. *See e.g., Enron Oil & Gas Oil Co. v. Lujan*, 978 F.2d 212, 214 n.2 (5th Cir. 1992)("Oil and gas leases are 'both conveyances and contracts.' . . . The method by which royalty is to be calculated is a contractual provision"), *cert. denied*, 510 U.S. 813 (1993); *see also Standard Oil Co. v. Hickel*, 317 F. Supp. 1192, 1197 (D. Alaska 1970)("The Government's rights and obligations as lessor of public lands are no different from those of any other lessor"), *aff'd*, 450 F.2d 493 (9th Cir. 1971). Any attempt by MMS to apply the supplementary proposed rule to determine royalty valuation would be a material breach of the lease provisions.

A. Downstream Resale Price Is Not an Appropriate Benchmark to Value Crude Oil in a Producing Field

As we explained in our comments filed in response to the January 1997 proposal, each producing field has unique characteristics. These characteristics range from crude quality to logistical factors. As well, different crude oil fields are subject to widely divergent economic influences depending on such factors as the supply and demand for different types of crude in each region, the production volume of a field, the capabilities of local refiners, the distance from the field to potential buyers, and the transportation alternatives from each field. (*See* Report of Dr. Benjamin Klein, attached to Texaco's comments filed in response to January 1997 proposal, at p. 5.) For example, if crude oil is delivered by truck, road conditions and hauling distances to an intermediate storage point must be considered. If pipeline gathered, factors of physical line conditions and overall capacities at both intermediate and final sales points must be considered.

Some crudes, such as relatively light, low sulfur crudes, can be processed economically by a large number of different refiners. Others, such as very heavy crudes or crudes with high sulfur levels, are most economically processed by refineries with specialized refining equipment such as cokers, catalytic crackers, and hydrotreating facilities that can upgrade the crude into light products such as gasoline. (*Id.* at p. 6 (referencing California crudes).) Consequently, while some crudes are refined in the same region in which they are produced, others must be shipped long distances to refineries in other parts of the state or in other states. Due to their location or their access to certain pipelines, some crudes can potentially be sold to many buyers. Others have relatively few transportation alternatives and must be moved via a single pipeline or by truck to a relatively small number of potential buyers. Still other crudes are moved to their final destination through a combination of pipelines, tankers, trains, trucks, and other means.

In addition, some crudes, such as heavy California crudes, are much more valuable to refineries that can upgrade the crude into light products such as gasoline using sophisticated refining equipment (*e.g.*, cokers and catalytic crackers). Thus, even within a particular area, crude oil from different fields may have significantly different economic value by operation of such market influences as local refiner demands, operating requirements, and transportation alternatives. All of these factors affect the market value of crude at the lease.

For many of the same reasons that using NYMEX futures pricing is inappropriate for valuing crude oil at the lease, affiliates' downstream sales are also an inappropriate benchmark. As Dr. Klein explained, it is "very difficult to value correctly crude oil in the field based on prices of transactions that occur downstream." (Klein Report, at 15). The oil sold downstream is generally commingled and therefore not the same oil purchased from the lessee; the market in which the oil is sold is very different from the market at the lease; and the affiliates' sales prices include the value of midstream transportation and storage assets and marketing services, as well as the cost of assuming a significant amount of risk. Unless the "net back" methodology properly adjusts for all of these differences, and considers the full value added by all downstream operations, it cannot reliably measure the value of the crude in the field. As discussed below, the proposed "netback" methodology fails to adjust even for quality differences, and fails to subtract the full value added by downstream operations. As a result, the proposed use of resale gross proceeds will consistently overstate the value of the crude in the field. (*Id.*)

1. The Proposed Allowances and Adjustments Fail to Consider the Value Added by Midstream Assets and Services

The proposed allowances and adjustments to affiliates' downstream resale prices fail to consider the value added by downstream assets and services. Such value consists of crude availability services, such as location exchange, transportation, terminaling, storage, and reliability of supply; blending services to suit customer supply; risk management requirements; and marketing services. These combined services both change the composition of the crude oil and increase its value downstream of the production field.

Under the supplementary proposed rule, Equilon, a joint venture between Texaco Inc. and Shell Oil Company, would be an affiliate of Texaco Exploration and Production, Inc., as well as of the various Shell producing entities. Equilon is in the refining and retail marketing business and in the crude oil trading and transportation business.

After Equilon purchases Federal lease crude from TEPI and the Shell producing entities, it adds substantial *non-royalty bearing value* to the crude oil before refining it or reselling it downstream to third parties. Equilon also owns and operates crude oil pipelines in several areas of the United States. Some of these lines are proprietary, and are used by Equilon to capture the location value of crudes and to make crudes available to its customers. Equilon's San Joaquin Valley pipeline network, for example, is one of the most extensive pipelines in that region of California. It includes a major heated pipeline running north from Fellows station in the Midway/Sunset area up to the Avon station in the San Francisco Bay area. This pipeline is generally used by Equilon to make available for purchase in the Bay area a blend of relatively heavy San Joaquin Valley crudes.

Other valuable services performed by Equilon include downstream storage, terminaling, and handling services. In addition, Equilon assumes significant risks, *e.g.*, the risks of spills, line loss, price volatility between the dates of purchase and delivery, exposure to environmental liability, credit risks, changes in customer demand or location differentials, and other marketplace risks in reselling the crude oil. The value arising from these downstream operations would not be reflected in the price of the crude in the field, regardless of whether the lessee sells the crude to an affiliated or unaffiliated party.

The failure to permit a deduction for the fair value of these downstream assets and services would constitute a taking under the Fifth Amendment. There are, according to the United States Supreme Court, three factors relevant to determining whether a taking occurs: "(1) 'the economic impact of the regulation on the claimant'; (2) 'the extent to which the regulation has interfered with distinct investment-backed expectations'; and (3) the 'character of the government action.'" *Connolly v. Pension Benefit Guar. Corp.*, 475 U.S. 211, 224-25 (1986). The supplementary proposed rule would have an adverse impact on TEPI and interfere with its investment-backed expectations concerning production assets, as well as its affiliates' investment-backed expectations concerning pipelines and related downstream assets. The supplementary proposed rule would permanently appropriate Equilon's downstream profits for transportation and other services for the government's own use. This attempt to deny Equilon the value of its services breaches the underlying leases, which never contemplated, for example, that a company such as Equilon would be denied the right to charge reasonable rates for its services. *See, e.g., United States v. Winstar Corp.*, 116 S.Ct. 2432 (1996).

2. The Transportation Allowance Is Illusory for Integrated Lessees, Because Even if it Were Possible to Compute "Actual Costs" of Transportation for Non-Arm's-Length Transportation Arrangements, Such Costs Do Not Reflect Either Full Costs or Full Value

As set forth in earlier comments, the proposed allowance for "actual costs" of transportation fails to consider the full cost, let alone value if a reasonable profit is considered, of midstream transportation assets and services. In addition, the "actual cost" allowance itself would often be illusory, because in many cases it would be virtually impossible to compute. For oil valued on the basis of affiliates' downstream resales, the supplementary proposed rule permits a transportation allowance under either proposed section 206.110, for arm's-length transportation contracts, or section 206.111, for non-arm's-length transportation contracts. Computing "actual costs" under the proposed section 206.111 would be extraordinarily difficult, if not impossible. For example, when Equilon purchases TEPI's Federal lease crude production, it generally commingles the oil with oil purchased from other producers and other TEPI leases. Once the oil is commingled, it cannot be traced either back to its upstream production point or to its downstream sales transactions. In addition, there are multiple delivery points within Equilon's pipeline system, which further complicates any attempt to allocate transportation costs. Based on Texaco's experience, we are concerned that it is impossible to assign an exact transportation cost associated with particular downstream resale contracts to barrels sold to Equilon from a Federal lease or from any other property. Consequently, it is impossible for TEPI to calculate accurately, much less provide documentary support for, its "non-arm's-length" transportation costs netted back to any particular lease production.

3. MMS Lacks Authority to Require Lessees to Market Federal Lease Production at No Cost to the Government at a Location Away from the Lease

In the comments accompanying the supplementary proposed rule, MMS justifies its failure to subtract the value of downstream assets and services (which MMS characterizes as the "costs of marketing production") from the royalty base by asserting that "[t]he lease requires the lessee to market production at no cost to the lessor." (63 Fed. Reg. 6120.) MMS further contends that the "Interior Board of Land Appeals has consistently upheld MMS on this position," and that MMS is not, therefore, proposing to alter "its long-standing policy." *Id.* MMS is wrong on all three points.

None of TEPI's Federal oil and gas leases contains any requirement that the lessee market lease production at a downstream market center at no cost to the lessor. Indeed, TEPI's Federal leases are silent with regard to any duty to market.

While the IBLA has held that Federal lessees have a duty to market lease production, it has consistently limited that duty to the first available market, because that is the only market relevant to determining the value of the lease production. For example, in *Walter Oil & Gas Corp.*, the IBLA made clear that "the value of the gas for royalty purposes is what a buyer is willing to pay for it." 111 IBLA 260, 264 (1989). Similarly, in *Xeno, Inc.*, the IBLA noted that its decision in *Beartooth Oil & Gas Co.* had been reversed in part because "the Board erred in applying the marketable condition rule without considering the conditions under which gas will be accepted by a purchaser under *a sale contract typical for the field or area.*" 134 IBLA 172, 182 n.14 (1995)(emphasis added). Because there is an active crude oil market at the lease, it is the amount purchasers at the lease are willing to pay which determines the value of the crude. Federal court cases are in accord. *See Enron Oil & Gas Co. v. Lujan*, 978 F.2d 212, 215 n.3 (5th Cir. 1992)("the value of a unit of gas is equivalent to what a customer will pay"); *Diamond Shamrock Expl. Co. v. Hodel*, 853 F.2d 1159, 1165 (5th Cir. 1988)("It is obvious from a complete reading of all the relevant statutes, regulations, and lease provisions, that royalties are not due on 'value' or even 'market value' in the abstract, but only on the value of production saved, removed or sold *from the leased property*")(emphasis added); *see also Martin v. Glass*, 571 F. Supp. 1406, 1415 n.2 (N.D. Tex. 1983)("The lessee's obligation to market is to market at the well").

The cases have also consistently held that the lessor must bear the costs of transporting and marketing lease production away from the lease. *See Xeno, Inc.*, 134 IBLA at 180 ("When gas is valued at a point downstream from the wellhead where the value of production is ordinarily determined, allowances are generally required for the value added to the gas after production"); *Viersen & Cochran*, 134 IBLA 155, 164 (1995)("the Department has long permitted an allowance for certain costs which have been deemed not to be directly related either to the costs of production or to the fulfillment of the lessee's contractual obligation to market production *from the lease*")(emphasis added).

Accordingly, because there is an active market at the lease, Federal lessees have no duty to market lease production in a downstream market away from the lease and certainly no duty to market free of cost to the lessor. It follows, therefore, that if MMS chooses to use a downstream resale price to value Federal lease production, it must subtract from that price the full value of downstream assets and services. The supplementary proposed rule, on the other hand, seeks to dramatically expand the lessee's duty to market, to require the lessee to market Federal royalty oil for the benefit of, and without cost to, the United States. The Secretary lacks statutory authority to unilaterally impose such an obligation.

4. The Supplementary Proposed Rule Improperly Discriminates Against Integrated Lessees by Attempting to Impose a More Expansive Duty to Market on Integrated Lessees than on Non-Integrated Lessees

The supplementary proposed rule would also unlawfully discriminate between integrated companies (*i.e.*, production companies that are affiliated with transportation companies) and nonintegrated companies, and is arbitrary and capricious. If a nonintegrated company were to sell its Federal lease production to Equilon, the lessee would pay royalties on the gross proceeds received from the sale less appropriate transportation costs. Yet, if TEPI were to sell its Federal lease production to Equilon for the same price, TEPI would, under the supplementary proposed rule (and the rule's overly broad definition of "affiliate"), pay royalties on the gross proceeds subsequently received by Equilon less the "actual cost" of transportation (which, under the supplementary proposed rule, could not be based on Federal Energy Regulatory Commission ("FERC") approved tariffs). By attempting to impose a more expansive duty to market on integrated lessees, MMS is essentially seeking to appropriate and use (without just compensation) the integrated lessees' midstream infrastructure and deprive the integrated companies of the full, fair value of their midstream assets and services. It is also fundamentally unfair to limit an integrated company to "actual costs" of transportation while a nonintegrated company using a third party to transport its crude oil is permitted to deduct the full charge for transportation. *See, e.g., Cotton Petroleum Corp. v. United States Department of the Interior, Bureau of Indian Affairs*, 870 F.2d 1515, 1527 (10th Cir. 1989). In similar circumstances, courts have rejected as arbitrary and capricious such disparate treatment by the Secretary. *See e.g., Independent Petroleum Ass'n of Am. v. Babbitt*, 92 F.3d 1248, 1258, 1260 (D.C. Cir. 1996) ("An agency must treat similar cases in a similar manner unless it can provide a legitimate reason for failing to do so. . . . The treatment of cases A and B, where the two cases are functionally indistinguishable, must be consistent. That is the very meaning of the arbitrary and capricious standard."). There is no statutory basis for making royalty valuation turn on the status of the lessee as opposed to the lease market value of the crude oil, and no legitimate regulatory or policy goal is served by the distinction.

B. ANS is Not an Appropriate Benchmark to Value California Crude Oil Production

As demonstrated by our comments filed in response to the January, 1997 proposal, and by the accompanying reports of Samuel A. Van Vactor and Dr. Benjamin Klein, Alaska North Slope ("ANS") prices are not an appropriate benchmark for valuation of California crude oil. For example, ANS crude oil is not reasonably comparable to the vast majority of California crude oils. The State of California has one of the most diverse indigenous crude supplies of any region in the world. (Klein Report, at 4.) California crudes range from heavy (*e.g.*, 13 degrees API) crude oils, sometimes with high levels of sulfur and other impurities, to light crudes (*e.g.*, 40 degrees API) with relatively few impurities. (*Id* .) Dr. Klein states that "different crude oil fields in California are also subject to widely divergent economic influences depending on such factors as the quality of the crude, the supply and demand for different types of crude and the capabilities of local refiners in each region, the distance from the field to potential buyers, and the transportation alternatives available from each field." (*Id.* at 5.)

By contrast, ANS is a waterborne crude oil available in tanker quantities having much different quality characteristics compared to most California crudes. (*See* Report of Samuel Van Vactor, attached to Texaco's comments filed in response to the January, 1997 proposal, at 10.) Since 1993, for example, ANS spot prices have averaged 82¢ per barrel higher than spot prices for Line 63, a blended stream of California crudes delivered to Los Angeles with similar API gravity and sulfur content to ANS. These arm's-length price differences reflect economic and quality differences between ANS and California pipeline-delivered crudes that would not be captured by the MMS proposed methodology. (*Id.* at 6-9.) Dr. Klein's report shows that the spread between arm's-length prices of ANS and California crudes changes frequently. (Klein Report, at 9-11.) Dr. Klein also shows that "[i]n addition to the large changes in relative prices between ANS and California crudes there are also large changes in relative prices of different California crudes." (*Id.*) Dr. Klein demonstrates that "[t]hese price changes reflect changes in the forces of supply and demand for different types of crude and crudes in different locations." (*Id.*)

In addition, the spot market transactions for ANS crude oil sold in California and reported by Platts are relatively thin. Only three sellers of ANS exist on the West Coast, and probably less than a dozen buyers are active. In contrast to the spot market, most sales of ANS are term transactions. For competitive reasons, many transactions involve contract terms that are private and confidential, whereby both the seller and buyer agree not to report prices to the reporting services. Consequently, the validity of reporting services' price assessments for ANS are often suspect.

Spot market assessments of ANS crude oil landed in California have no justification whatsoever as a mechanism for valuing California crude oil. Not only is ANS a crude grade with limited liquidity on the spot market, its physical characteristics are substantially different from most California crude oils. Even relatively higher gravity offshore California crude oils are not only significantly higher in sulfur content and lower in gravity than ANS, but have much higher metals and nitrogen content that reduce their market value.

The administrative record contains no evidence that the ANS net-back methodology proposed by MMS would ever reflect supply and demand conditions in any California producing field, let alone accurately reflect the quality differences between ANS and California lease production. If anything, the supplementary proposed rule is worse than the initial proposal, because it not only continues to use ANS prices for California, but arbitrarily limits quality adjustments to crude oil that happens to be transported through a pipeline with a quality bank. Whether crude oil is transported by pipeline, truck, or barge, a quality adjustment is necessary if the lease oil is not the same quality oil as the oil on which the index pricing is based. (*See* Supplemental Report of Dr. Benjamin Klein, April 6, 1998, p. 4, attached at Tab 4.)

C. The NYMEX Futures Market is Not an Appropriate Benchmark to Value Crude Oil in Rocky Mountain Area Producing Fields

In applying index pricing to the Rocky Mountain Area, MMS proposes to use benchmarks based on arm's-length transactions at the lease. Inexplicably, however, the supplementary proposed rule imposes wholly arbitrary restrictions on the use of these benchmarks, so that most Federal lease production would nevertheless be valued using NYMEX index pricing. As explained in our comments and the accompanying report of Dr. Philip K. Verleger, Jr. (an economist and former Director, Office of Domestic Energy Policy, U.S. Department of the Treasury) filed in response to the January, 1997 proposal, New York Mercantile Exchange ("NYMEX") prices are a flawed and unreliable indicator of all types of crude oil prices at the time and place of production, and use of NYMEX-based prices would lead to substantial valuation errors. Ironically, the supplementary proposed rule retains the proposed NYMEX index pricing for the one area of the country where MMS admits it would be most difficult (and least appropriate) to apply.

1. The Supplementary Proposed Rule Unreasonably Restricts Use of More Reliable Benchmarks of Market Value at the Lease

Tendering is a far more reliable, easier to verify, and far less costly, means of valuing oil at the lease than either the resale or index pricing methods proposed in the supplementary proposed rule. However, the supplementary proposed rule permits the use of tendering to value non-arm's-length transactions only in the Rocky Mountain Area, because the isolated nature of the Area from the major oil market centers makes it more difficult to apply index pricing. Because tendering is a more accurate benchmark, it should be used *instead* of index pricing, not just when index pricing is deemed too difficult to apply. The supplementary proposed rule also imposes wholly arbitrary limitations on tendering that would make it impossible for most Federal lessees to use in valuing their Federal lease production.

TEPI has more experience with tendering than any other company in the industry. Based on two and one half years worth of data -- for tendering across the United States -- we have found that with properly designated tendering packages, approximately 10% of the lease production is sufficient to ensure market prices are received. Indeed, we found virtually no difference in bid prices when we tendered 20% or more of the lease production than when we tendered 10%. Accordingly, it is unnecessary to require lessees to tender 33% of their production to establish market price. Dr. Joseph Kalt drew similar conclusions in his review of Conoco's tendering program:

> Offering for bid 10 percent of Conoco's volume in any producing area is, in general, more than adequate for market forces to reveal fair market value of their crude. There is no need for the percentage to bear any relation to Conoco's royalty or working interest obligations in the area. The design of the program provides the opportunity for market forces as expressed in arm's-length bids to operate, and if you're using a competitive bid program at the lease, that is the fair market value at the lease, not some distant trade center.

(Transcript of MMS Public Hearing, at 79 (Feb. 18, 1998)(as related by Conoco representative, John Hayey).)

The second limitation, requiring three bids from purchasers that do not have a tendering program, is equally unfounded, and will, in most cases, be impossible to meet. In the Rocky Mountain Area, for example, we typically receive one to four bids on Wyoming Asphaltic Sour and we typically receive two to eight bids on Wyoming, Colorado, and Montana Sweet crude oils; whereas in other areas of the country we may receive as many as sixteen bids. We generally do not know whether those who submit bids have their own tendering programs. No basis exists to suggest that a sale to a single unaffiliated bidder does not reflect an arm's-length price. MMS lacks authority to impose the third limitation, because it cannot require Federal lessees to tender non-Federal production (notably, however, TEPI's tendering program includes private royalty production).

MMS explains that these restrictions are necessary to prevent "cross-bidding" and "gaming" of the system. There is absolutely no evidence of any such conspiratorial conduct among sellers and buyers. In addition, an allegation of such conduct makes no sense. MMS's theory that such gaming is possible ignores the fact that third party competitors are free to bid, and would routinely outbid purchasers who intentionally submitted below-market bids. As a result of these arbitrary and unwarranted restrictions, MMS is effectively precluding lessees from using one of the most straightforward and reliable measures of value at the lease.

2. NYMEX Futures-Based Pricing is Particularly Inappropriate for the Rocky Mountain Area

The third benchmark, which MMS acknowledges will probably apply most often for integrated lessees (because of the arbitrary restrictions on use of the first two benchmarks), is NYMEX futures-based pricing. The use of NYMEX-based pricing was overwhelmingly criticized by the public comments received in response to the initial proposed rule. Moreover, MMS concedes that NYMEX-based pricing is particularly difficult to apply in the Rocky Mountain Area, because of "distances between Rocky Mountain Area locations and Cushing, Oklahoma, and the additional difficulties in deriving location/quality differentials." (63 Fed. Reg. at 6119.) MMS's proposal to use NYMEX-based pricing in the one area of the country where MMS openly acknowledges it is most difficult to apply is inexplicable, and will lead to grossly erroneous royalty valuations.

D. Spot Prices are Not an Appropriate Benchmark to Value Crude Oil in a Producing Field

Ironically, after rejecting spot prices in the January 1997 proposal, MMS now contends that spot prices are an appropriate benchmark to value Federal lease production, because unidentified "studies indicated that when the NYMEX futures price, properly adjusted for location and quality differences, is compared to spot prices, it nearly duplicates those spot prices." (63 Fed. Reg. at 6116.) As pointed out in our comments regarding the January 1997 proposal, NYMEX is a flawed and unreliable indicator of all types of crude oil prices at the time and place of production and would lead to substantial valuation errors. Hence, the fact that spot prices may be comparable to "properly adjusted" NYMEX futures prices is no basis for assuming that spot prices are any more appropriate than NYMEX futures prices for valuing crude oil *in the producing field.* (Klein Supp'l Report, at 3.)

The use of spot prices is problematic for at least three reasons: the number of transactions often is too small to provide any statistical certainty, there is no uniform method for calculating spot market averages, and the accuracy of any report depends heavily on the skills of the individual journalist covering the market on a given day. (*See* Affidavit of Marshal Thomas, ¶¶ 59-62 (submitted in support of comments filed by American Petroleum Institute in response to January, 1997 proposal).) As we explained in our November 4, 1997 comments, published crude oil spot prices, such as Platts assessments East of the Rockies, cover only the following grades: WTI at Cushing, Oklahoma and Midland, Texas; West Texas Sour at Midland; Light Louisiana Sweet at St. James, Louisiana; Eugene Island Sour at St. James; Louisiana Heavy at Empire, Louisiana; and Wyoming Sweet at Guernsey, Wyoming. Price spreads among those grades and places fluctuate widely. There are dozens of other grades of crude oil produced East of the Rockies for which there are no published spot prices. Many of these crude oil grades have substantially different physical and market characteristics from the Platts spot price assessments, and cannot equitably be equated to those spot price values. Crude oil spot markets are less mature than, for example, natural gas spot markets, and a much smaller percentage of crude production is traded in spot markets as compared to natural gas.

Platts does not report volumes for its published spot price assessments, and doubt exists about certain of the reported grades. For example, presently, arm's-length spot market transactions at Guernsey of Wyoming Sweet Crude oil more often than not differ significantly from Platts reported spot prices.

Platts also does not divulge its method of obtaining market assessments other than to state they are for one-hour time windows in the afternoon using telephone polling of selected people in the "industry." Of course, such people might be selective in the data they provide. Therefore, contrary to MMS's assertion that publications reporting spot prices are "independent" of MMS and industry, assessment values are subject to distortion and, perhaps, manipulation. In addition, since transactions occur between parties over a 24-hour period, the one-hour window of time used by Platts may not be a reasonable indicator if a crude grade is thinly traded and market prices are changing.

Spot price contracts are also not representative of transactions at the lease. In California and elsewhere, the majority of crude oil volumes are sold through term sales rather than one-time spot sales. (Klein Report, at 6.) Because offers for spot sales opportunities are relatively inconsistent, and the cost of maintaining inventories is high, refiners over time have opted to secure as much of their crude supplies as possible using term contracts. (*Id.*, at 6-7.) Thus, market demand for spot purchases is thin, and rationally so. The consequences of using spot prices to value lease production can be serious overvaluation depending on market conditions. For example, economic and market conditions that force refiners out of the term supply arrangements and shape spot market transactions are typically distortive, unforeseen events, which have uneven and short-lived effects on crude markets. These events, such as the Persian Gulf War uncertainty, major refinery fires, and similar occurrences, can result in significant short-term price differentials. (*Id.*)

Consistent with Dr. Klein's analysis, in 1987, the MMS Associate Director for Royalty Management rejected a proposal to use spot prices as an alternative valuation methodology for crude oil sold in non-arm's-length sales, because the proposed use of spot prices would "be either contrary to existing law, lease terms, and regulations, or too impractical and nonspecific to administer." Letter from Associate Director for Royalty Management to Director, MMS, "Review of Analysis Titled 'Crude Oil Royalty Valuation Monitoring System,' by Bob Berman, Policy, Budget, and Administration" (Feb. 12, 1987). The Associate Director noted that while MMS could change its regulations, the proposed use of spot prices would still be precluded by existing statutes and Federal lease terms. Federal lease terms generally require that royalty be paid based on a percentage of the "amount or value of production removed or sold from the leased lands." Because spot prices are not based on the value of production *from the leased lands*, their use is precluded by the plain terms of the lease. Moreover, the Associate Director explained, spot prices are in any event an inappropriate benchmark for valuing crude oil at the lease:

> Application of spot prices in valuing non-arm's-length disposals of lease production would not be specific. Spot prices are available only for a limited number of 'benchmark' domestic crudes delivered at specific points, *e.g.*, West Texas Intermediate at Cushing, Oklahoma. It is not clear how spot prices would be adjusted for differences in quality or necessary transportation between that of the 'benchmark' crude and that of the crude to be valued. . . . The price differences in crude oil nationwide depend upon a host of factors not limited solely to gravity and transportation adjustments. Factors important to the establishment of value of a particular crude include the need for and availability of crude oil supply, the cost of transportation to the refinery, the chemical composition and refining characteristics of the crude oil, the cost to refine the particular crude, the mix of refined products derivable from the crude and their values, prices currently paid or offered for the same or

> comparable crudes, and other economic criteria. . . . '[B]enchmark' spot prices . . . cannot relate these factors specifically to each producing area.

Id., at 2.

Neither the underlying statutes, contract lease terms, nor basic economic principles have changed since the Associate Director's 1987 letter. Nor is there any evidence of record to suggest that spot prices represent anything other than the market margin. Given this record, it would be an abuse of discretion to use spot prices to value crude oil disposed of through non-arm's-length sales.

E. The Allowances and Adjustments to Index Pricing Set Forth in the Supplementary Proposed Rule Do Not Correct the Rule's Deficiencies

1. The Proposed Allowances and Adjustments Fail to Consider the Value Added by Midstream Assets and Services

Depending on the circumstances, the supplementary proposed rule permits "actual" transportation costs from the lease to an aggregation point, market center, or alternate disposal point such as a refinery. As noted above, these "actual" costs fail to consider the value added by midstream assets (including transportation assets), services, and assumptions of risk. In addition to adjustments for physical transportation costs, the costs of blending, terminaling and storage operations, as well as location and availability advantages, various risks, insurance, overhead, and line fill must be taken into account. (Klein Report, at 15.) The costs of these services are reflected in downstream sales, not in the price of crude oil in the field. (*Id.* at 6.) In addition, a substantial level of economic and environmental risk is involved in moving crude oil downstream. For example, Equilon assumes risks of line loss, price volatility between the time of production in the field and delivery downstream, exposure to risks of spills and other environmental liability, volatility in customer demand, and many other market-based risks. The proposed allowances and adjustments fail to consider this added value, and therefore artificially and improperly inflate the royalty value.

2. The Proposed Allowances and Adjustments Fail to Consider the Quality Differences Between Federal Lease Production and the Oil for Which Spot Price Assessments Have Been Made

The proposed allowances and adjustments also fail to consider the quality differences between Federal lease production and the oil for which spot price assessments have been made. Quality adjustments for gravity alone are wholly inadequate, particularly in the case of valuing California crudes, which have very broad quality differences. MMS's Payor Handbook identifies some of the factors relevant to determining whether crudes are of "like-quality": API gravity, sulfur content, paraffin (wax) content, heavy metals components, and pour point. *See* Payor Handbook, July 1993, § 2.5.5., p. 2-20.

The supplementary proposed rule fails to account, for example, for differences in sulfur content, metals content or the fact that ANS is more predictable in quality than most blended streams of California crudes delivered to downstream markets. In addition to quality differences, the supplementary proposed rule fails to adjust for numerous other economic factors creating price differences between Federal lease production and ANS and other spot price crudes. As noted, for example, ANS generally is delivered in higher volumes, which is more valuable to refiners than the lower volume production from any particular California field. All of these quality factors affect the value of the crude at the lease and must be taken into account in order to properly use index pricing to measure royalty value.

3. The Proposed Allowances and Adjustments for Lease Production Transported Directly to the Lessee's Refinery are Particularly Arbitrary and Irrational

Proposed Section 206.113(b) is particularly irrational. If lease production is transported directly to an alternate disposal point, such as a refinery, the royalty valuation is measured using NYMEX or spot prices at the market center nearest to the lease, less the "actual" cost of transporting the crude to the refinery and adjusted for any pipeline quality bank adjustment. This valuation methodology does not even pretend to be a net back; it is just a way of using NYMEX or spot prices from a market center in which the oil is never sold. The erroneous valuation that will result from this proposal will probably be most pronounced in the Rocky Mountain Area. Consider, for example, Wyoming Asphalt that is transported, by truck, to an asphalt plant five miles from the lease. The lessee would pay royalty based on NYMEX prices for West Texas

Intermediate at Cushing, Oklahoma, less the actual cost of transportation from the lease to the asphalt plant. This type of comparison fails to address the fundamental crude oil type differential, that is Wyoming Asphaltic Sour versus West Texas Intermediate Sweet. According to the supplementary proposed rule, the burden would be on the lessee to justify a different market value *at the refinery*, and, if a lessee pursued this option, it would forfeit any transportation allowance or quality adjustment it might otherwise be entitled to. MMS fails to explain how market value at either Cushing or a refinery could possibly be an appropriate measure of royalty valuation at the lease. This problem could be avoided entirely by starting with market value at the lease, rather than starting with NYMEX and spot prices and trying to force fit them into situations where it makes no sense.

III. THERE IS NO RATIONAL BASIS TO REJECT ARM'S-LENGTH SALES IN THE PRODUCING FIELD

Arm's-length purchases and sales in the producing field are all but eliminated as a measure of value by the supplementary proposed rule, in spite of the fact that these transactions are the best, most direct measure of market value at the lease. First, the proposed rule excludes from the definition of "arm's-length" many bona fide arm's-length transactions at the lease. Second, the rule eschews entirely any reliance on *comparable* arm's-length transactions at or near the lease when other lease production is not sold arm's-length.

The supplementary proposed rule's overbroad definition of affiliate, which includes common ownership of as little as 10%, combined with the new definition of arm's-length, which requires that the parties both be nonaffiliated and have opposing economic interests, excludes an unduly large segment of bona fide arm's-length transactions. The exclusion of arm's-length exchange agreements is similarly unjustified and overbroad. MMS has the ability, under section 206.102(c)(2), to police misconduct. Hence, it is unnecessary and unjustifiable to exclude bona fide arm's-length exchange transactions based on suspicions of potential misconduct. MMS's view of exchange agreements is also overly simplistic, because MMS appears to assume, erroneously, that arm's-length exchange agreements will always be in perfect balance. In other places in the supplementary proposed rule, MMS similarly demonstrates its lack of knowledge of exchange agreements. For example, in describing the application of the gross proceeds rule to multiple arm's-length exchanges, the preamble states that "MMS believes that as long as the integrity of the differentials and adjustments is maintained, there is no reason not to look to the ultimate arm's-length sale proceeds." (63 Fed. Reg. at 2117.) Because oil is generally commingled after purchase at the lease and may then be exchanged numerous times, it is virtually impossible to track or calculate the differentials and adjustments.

Even arm's-length sales at the lease are subject to subsequent MMS challenges under the supplementary proposed rule. Under the supplementary proposed rule, even if a lessee were to sell every royalty barrel at the lease to a nonaffiliated third party, MMS reserves the right to subsequently determine that the lessee failed to obtain a "reasonable value" for its lease production. It is possible, given MMS's expansive view of the lessee's purported duty to market for the benefit of, and at no cost to, the United States, that MMS may determine that the price received in these arm's-length sales at the lease are "unreasonable" because the lessee failed to sell the oil to an affiliate and have the affiliate market the oil for MMS at no cost at a downstream market center.

MMS is required to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n of the United States v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983). The Supreme Court has called this an "axiom" of administrative law. *Bowen v. American Hosp. Ass'n*, 476 U.S. 610, 626 (1986). Notwithstanding this essential requirement of agency rulemaking, MMS cites no market theory or evidentiary basis for rejecting arm's-length transactions in the producing field.

IV. THE SUPPLEMENTARY PROPOSED RULE IS NEEDLESSLY COMPLEX AND UNWORKABLE

Far from streamlining or adding certainty to the valuation of Federal lease production, the supplementary proposed rule is needlessly complex and unworkable, as graphically illustrated by the decision-tree diagram attached at Tab 1. Under the supplementary proposed rule, valuation of Federal crude oil would be more complex by several orders of magnitude than it currently is under the 1988 regulations. The comparison between the supplementary proposed rule and other, more reliable alternatives, such TEPI's tendering program or taking Federal royalty oil in kind, is even more dramatic. *See* Tabs 2 and 3. Administration of the proposed valuation regulation would also require many, many more MMS auditors. The supplementary proposed rule is thus completely inimical to the Administration's goal of streamlining government.

A. Compliance With the Supplementary Proposed Rule May Be Impossible, Because it is Generally Not Possible to Track the Ultimate Disposition of Federal Lease Production or Crude Oil Received in Exchange for Federal Lease Production

Lessees would be required under the supplementary proposed rule to determine the "ultimate" disposition of each barrel of lease production, and to apply the exceptions to the arm's-length gross proceeds rule on a contract-by-contract basis. If oil sold to an affiliate is thereafter sold under multiple arm's-length contracts, the royalty value of the oil under proposed section 206.102(b) would be the volume-weighted average of the values established under section 206.102 for each contract. Lessees would also be required to determine the ultimate disposition of oil received in exchange for Federal lease production. As the preamble explains: "For example, you may have multiple arm's-length and non-arm's-length exchange agreements involving your Federal oil production. Depending on its ultimate disposition under each exchange agreement, you might value some of the production under § 206.102 and some under § 206.103." (63 Fed. Reg. at 6117.)

By definition, oil at an aggregation point is aggregated (*i.e.*, commingled), and from that point forward it is not possible to provide accurate and verifiable information on what happens to particular lease production. In other words, once crude oil is commingled there is simply no way to distinguish between Federal and non-Federal oil, or between Federal oil from different leases. Therefore, it is generally not possible to actually trace the ultimate disposition of Federal lease production, or of oil received in exchange for Federal lease production. Rather, some allocation methodology would be required, which, of course, reduces certainty. The supplementary proposed rule fails to offer any guidance on what allocation methodologies (*e.g.*, first in first out, last in first out, first in last out, etc.) would be acceptable to MMS. Allocation also presents problems in determining the quality of Federal lease production. For example, if 50° API crude is blended with 40° crude, there is no accurate way to ascertain how much of the resale price is attributable to which barrels.

The following description of a typical disposition of TEPI's Federal lease production from the Gulf of Mexico may help illustrate how hopelessly complex royalty valuation would be under the supplementary proposed the rule: Assume that TEPI sells a barrel of Federal lease production to Equilon at a lease in the Gulf of Mexico. The barrel is immediately commingled with oil that Equilon purchases from non-affiliated third parties from the same lease. The commingled oil is then transported off the lease through a partially-owned pipeline to shore at Caillou Island. Along the way, the oil is mixed with other oil purchased by Equilon from other TEPI leases, from Shell leases, and from third parties. Once at Caillou Island, the oil is run through a wholly-owned Equilon pipeline to St. James. Once at St. James, the oil goes into a storage tank with oil that Equilon has purchased from other areas, including oil that it has purchased from TEPI, Shell, and third parties. Equilon then sells some of the oil from St. James to two of Shell's refineries. Some is sold to third party refineries, both within the State of Louisiana and outside the State, and is transported there on various pipelines, some of which are partially or wholly-owned by Equilon, and some of which are not owned by Equilon. The circumstances of the sales vary; some are at St. James and some are at the refinery inlet valve. Some of Equilon's oil from St. James is sold to third parties, either at St. James or after being transported somewhere else, sometimes by pipeline and sometimes by truck, either of which may be wholly, partially, or not owned by Equilon. Some of the oil is exchanged by Equilon to various other market centers. The exchanged volumes are, of course, indistinguishable at the market centers from the other volumes that Equilon owns at those market centers. There are also exchanges between points that are not market centers, both before St. James and after St. James. The oil that Equilon receives in exchange is sold to third parties, sold to affiliated and non-affiliated refineries, and possibly exchanged. Finally, an Equilon-affiliated refinery may, because of a shut down or due to economic reasons, resell oil that it purchases from Equilon.

To correctly pay royalty on a barrel of oil under the supplementary proposed rule, TEPI would need to ascertain the final disposition of every barrel that Equilon bought, sold, or exchanged during the production month, as well as the methods of transport and the "actual cost" (as defined by the supplementary proposed rule) of that transportation. Generally, there is no business reason for Equilon to know from which individual leases its purchased oil comes or to where it goes; it cares only that it has sufficient supply to meet its contracts and that it is a successful business enterprise in the activities it performs and risks it incurs. Likewise, Equilon's transportation books, as well as those of the operators on other transportation systems used by Equilon, are not designed to provide the information needed to comply with the supplementary proposed rule. Rather, they likely use different depreciation schedules and credit direct and indirect expenses differently from the MMS guidelines. However, for TEPI to correctly pay its royalty, it would need to allocate to each barrel of oil on a volume-weighted basis each of the various transactions and transportation methods utilized by Equilon. The matrix that would be required to compute the necessary allocations is mind-boggling. And, every time adjustments are made, it would be necessary to recalculate the entire matrix. This clearly does not add more certainty to valuing oil produced from Federal lands.

B. The Supplementary Proposed Rule Presumes Access to Downstream Information that Most Lessees Do Not Have

The proposal also presumes a degree of access to downstream information that most lessees do not currently have, and may be unable to acquire. Assume for example, that Federal lease production is sold to one or more "affiliates" who are not under the control of the lessee. These partially-owned affiliates may not have the information available and may be unwilling to give the lessee competitive information. Because the affiliates are not under the control of the lessee, the lessee has no means of compelling them to provide the records needed to determine the volume-weighted averages necessary to compute the Federal royalty. Regardless of the degree of ownership, affiliated entities often have separate record-keeping, accounting, and administrative systems that do not readily communicate with each other. Affiliates' computer and record-keeping systems are generally not integrated, and the employees from the different affiliates often have little knowledge of or access to the operational characteristics of systems maintained by other affiliates.

For example, compliance with the supplementary proposed rule would be problematic when the leaseholder has an equity interest in an interstate pipeline. The Interstate Commerce Act prohibits pipeline owners from "knowingly disclosing to another person, except the shipper or consignee . . . information about the nature, kind, quantity, destination, consignee, or routing of property tendered or delivered to that carrier . . . ." 49 U.S.C. § 16103(a).

C. The Supplementary Proposed Rule Would Create Multiple, Wholly Unpredictable "Values" for the Same Quality Crude Produced at the Same Time from the Same Well

Arm's-length purchases and sales of crude oil in the field may realize a range of prices that represent market value at the lease. However, under the supplementary proposed rule, the same quality crude produced at the same time from the same well could be valued differently depending upon whether it is sold or exchanged, and whether it is ultimately refined by an affiliate or disposed of by arm's-length sale. As the City of Long Beach noted in its comments on the January 1997 proposal: "The market value of a crude at the lease does not change depending on its valuation. There is only one market value of a given crude at a given lease, and thus all Federal crudes should be evaluated the same way, irrespective of where it is shipped." (City of Long Beach Comments, at p. 25.) The fact that the supplementary proposed rule creates a vast array of unpredictable values for the very same lease production confirms that the valuation methodology is badly flawed. MMS's rejection of more reliable methodologies is therefore arbitrary and capricious and contrary to law.

V. THE SUPPLEMENTARY PROPOSED RULE WOULD IMPOSE AN ENORMOUS ADMINISTRATIVE BURDEN ON FEDERAL LESSEES WITH NO COUNTERVAILING BENEFIT

Even if compliance with the supplementary proposed rule were possible, the proposal would nonetheless impose an enormous administrative burden on Federal lessees with no countervailing benefit. The added cost of compliance that would be imposed on Federal lessees and their affiliates would not be recoverable under the supplementary proposed rule, and, in many cases, would be borne by companies like Equilon that are not parties to any lease or contract with MMS.

A. The Cost of Compliance Would Increase Dramatically Under the Supplementary Proposed Rule

Virtually every aspect of the supplementary proposed rule would dramatically increase the cost of compliance. The supplementary proposed rule would result in increased cost to trace lease production to the first, downstream "arm's-length" sale. Computer systems would need to be changed to capture sales and exchange data, calculate prices, and perform recalculations whenever any component of the price changes. The supplementary proposed rule would also result in increased cost to collect information necessary to pay royalties on index and spot sale prices. Computer systems would be necessary to develop prices and retain information on an historical basis in order to make prior period adjustments. Existing computerized revenue systems would likely require modification to accommodate the different geographic pricing methodologies. The proposed changes in allowable transportation deductions would also result in reduced deductions and increased costs, and the proposed, overly broad definition of "affiliate" would result in the use of "actual" transportation costs in situations where a transportation deduction is now based on arm's-length transportation costs.

In addition, the supplementary proposed rule would result in a dramatically increased audit burden on both MMS and industry. Tracing affiliate resale proceeds, calculating allowable allowances and adjustments, and determining the appropriate index prices would make future audits significantly more complicated. Industry would be faced with increased record-keeping requirements in order to document all of the components of the weighted average price calculations for affiliate sales. In some cases, this could result in maintaining duplicate sets of records -- one for the marketing affiliate(s), and one for the producing affiliate.

B. Completion of the Form MMS-2014 Would Become Extraordinarily Burdensome and Costly

The current Form MMS-2014 generally assumes that there will be one type of disposition and valuation methodology for any one lease. The form does not report the information that would be required for Federal lessees to compute royalty value under the supplementary proposed rule. Accurate royalty valuation under the supplementary proposed rule would require tracking every transaction, and all of the transportation costs, for every barrel of Federal lease production from the lease through ultimate disposition. Computation of transportation costs would also be far more burdensome under the supplementary proposed rule, because it requires tracing Federal lease production to its "ultimate" disposition. By contrast, the current regulations require computation of transportation costs only to the first collection or onshore point.

The supplementary proposed rule would therefore require changes to the MMS-2014 to capture the information needed to compute the royalty valuation. Reporting systems that currently create MMS-2014s for electronic filing would have to be reprogrammed. The supplementary proposed rule would also require changes in payor codes and AID number relationships to accommodate geographical pricing.

Because Federal lease production may have many different royalty valuations under the supplementary proposed rule, TEPI would have to establish a multitude of different divisions of interest for almost every barrel. Because TEPI's computer system allows only two prices for each pipeline division property ("PLDP") number, it would be necessary to establish many more PLDP numbers to separately account for different portions of the lease production. As well, the supplementary proposed rule would, because of its complexity, virtually destroy the single payor concept. If every Federal lessee paid his own royalty, as would be likely under the supplementary proposed rule, the number of payors would dramatically increase. There are currently about 2,600 payors; that number would probably increase to about 25,000 if the supplementary proposed rule is implemented.

As pointed out in the Barents Group analysis submitted in response to MMS's request for extension of its existing collection authority for the Form MMS-2014, MMS has ignored completely the substantial increase in time and record-keeping that would be required to complete the Form MMS-2014 if the supplementary proposed rule is implemented. Lessees do not currently know or retain the information that would be required to compute royalty valuation required under the supplementary proposed rule, and, as described above, could encounter serious legal problems in providing information to and receiving information from "affiliates" who are separate legal entities.

If, for example, crude oil is transferred in two non-arm's-length transactions before being disposed of through an arm's-length sale, to complete MMS-2014, the lessee would first have to obtain the sales price from the party that sold the oil at arm's-length. Assuming that the lessee was able to obtain the sales price from the ultimate seller (and this is something that is uncertain), it must then trace through each transaction from arm's-length sale to the first non-arm's-length transfer keeping track of any appropriate location and quality differentials and "actual" transportation costs. These transportation adjustments must be reported separately on the MMS-2014. Because the crude may have been commingled with other production from either Federal or non-Federal leases, some allocation method would be required. If some of the lease production is ultimately refined rather than sold arm's-length, completion of the MMS-2014 becomes even more complicated and time-consuming. Indeed, it is possible that production from one geographic region, such as the Rocky Mountain Area, could be commingled with production from another geographic region, which could multiply exponentially the number of lines that must be reported on the MMS-2014.

C. The Proposed Form MMS-4415 Would Be Costly and Largely Useless to TEPI

As MMS recognizes, the proposed Form MMS-4415 burden will be borne by companies like TEPI that would not generally have any use for the data reported. Companies reporting actual location and quality differentials on the Form MMS-4415 would use their actual differentials to adjust spot prices when valuing crude oil using an index methodology. The published differentials, computed from companies who would be required to file the MMS-4415, would be used by companies without their own, actual differentials. As a result, MMS is proposing to impose a burden on one segment of the industry to regulate a different segment.

The proposed Form MMS 4415 would require additional manpower and computer support to complete, and the form requires information that is not currently known or retained by producing entities that pay royalties. The cost of implementing the proposed Form MMS-4415 would be significant, and there are no provisions for recouping this cost or receiving any credit for it. In short, the cost of the proposed Form MMS-4415 would far outweigh any negligible benefit it might have. The proposed Form MMS-4415 should therefore be eliminated.

D. Establishing "Customized" Valuation Methodologies Unnecessarily Complicates Royalty Valuation, Reduces Certainty, and Increases Costs

The supplementary proposed rule would require integrated lessees with nationwide operations to establish at least four different valuation methodologies, the application of which would depend on the location of the lease, the ultimate disposition of the lease production, and a contract-by-contract analysis of arm's-length exchanges. Separate computer systems may be necessary to maintain and calculate different prices for the three different geographical areas. Developing these computer systems would require large start up costs, and there would also be continuing added costs to maintain three different computer systems. The costs of establishing and maintaining such a system would be enormous, and, industry-wide, may even exceed the amount of increased royalties that MMS expects to receive from the supplementary proposed rule.

E. The Added Cost and Complexity of the Proposed Valuation Methodologies Would Discourage Marketplace Efficiencies

If the supplementary proposed rule is implemented, TEPI -- and probably many others -- would move to consider ceasing to pay Federal royalties on behalf of third parties, because of the difficulty of determining royalty value under the proposed rule.

The supplementary proposed rule would similarly discourage other marketplace efficiencies. For example, designees may cease selling Federal oil for the various interest owners. Because of the expansive new definitions in proposed section 206.101, even arm's-length sales from joint operating agreement owners to a designee's affiliate would be valued at the designee's affiliate's downstream resale price. Hence, joint operating agreement owners would be reluctant to sell to their designee's affiliates. If the interest owners sell their own oil, it would be even more difficult for designees to properly report royalty values, because the supplementary proposed rule would require tracking each interest owner's oil to its ultimate disposition.

VI. THE SUPPLEMENTARY PROPOSED RULE, LIKE THE JANUARY 1997 PROPOSAL, IS PROCEDURALLY AND SUBSTANTIVELY FLAWED

A. The Proposed Valuation Methodologies Exceed the Secretary's Statutory Authority

The proposed rule exceeds the statutory authority of the Secretary, because it does not measure the "value of production removed or sold from the lease." Regulations can have the force and effect of law only if they are promulgated pursuant to a statutory grant of authority. *See Chrysler Corp. v. Brown*, 441 U.S. 281, 308 (1979); *accord, Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988) ("It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress."). The statutory basis for the collection of royalties is contained in the Minerals Leasing Act of 1920 and the Outer Continental Shelf (OCS) Lands Act. The Minerals Leasing Act gives the Secretary authority to lease public lands, and requires that any such "lease shall be conditioned upon the payment of a royalty at a rate of not less than 12.5 percent in *amount or value of the production removed or sold from the lease.*" 30 U.S.C. § 226(b)(1)(A) (1994) (emphasis added). Similarly, the OCS Lands Act requires that royalties be obtained based on the "amount or value of the production saved, removed, or sold." 43 U.S.C. § 1337(a)(1)(A) (1994). The plain language of both Acts requires that royalties be based on the value of the production *at the lease*. This statutory interpretation is well settled. *See, e.g., United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. Cal. 1947) ("royalties are payable on the gas as it is produced at the well"), *aff'd. sub nom. Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164, 171 (1990) ("[n]ormally gas is sold and valued for royalty purposes at the wellhead"); *Shell Oil Co.*, 52 IBLA 15, 20 (1981) (transportation allowance to the nearest open market only needed "where no market exists at the wellhead" for crude oil). A course of dealing over many years reflects an intent of both the government and its lessees that production is to be valued at the lease.

MMS has for over seventy-five years consistently interpreted these statutes to require the valuation of lease production at the lease. In a closely analogous case, a Federal court rejected the Secretary's attempt to change a royalty valuation rule that had been subject to long-standing interpretation. *Marathon Oil Co. v. Andrus*, 452 F. Supp. 548 (D. Wyo. 1978). In that case, the court noted that for over fifty years, both the Secretary and lessees understood that oil and gas used in lease production or unavoidably lost were not subject to royalty, and the court therefore concluded that it was arbitrary and capricious for the Secretary to change this settled valuation rule. As the court in *Marathon* explained:

> This Court cannot lose sight of the general rule that, when the executive department charged with the execution of a statute gives a construction to it and acts upon that construction for many years, the Court looks with disfavor upon a change whereby parties who have contracted in good faith under the old construction may be injured by a different interpretation.
>
> * * *
>
> A review of the legislative history of the Mineral Leasing Act, together with its many enactments and re-enactments, each leaving intact the wording that a royalty is to be paid on "value of the production removed or sold from the lease," plus the interpretation placed thereon by the Secretary of the Interior for a long period of time holding that royalties are not to be collected on oil and gas that was unavoidably lost or used in lease operations, are entitled to great weight.

452 F. Supp. at 551, 552-53; *accord Amoco Prod. Co. v. Andrus*, 527 F. Supp. 790, 792 (E.D. La. 1981)(reaching same result under the OCS Lands Act). The courts in *Marathon* and *Amoco* also carefully examined the legislative history of the Minerals Leasing Act and OCS Lands Act, and, in both cases, concluded Congress intended to ratify the Secretary's long-standing interpretation by not altering the statutes in subsequent re-enactments. *Amoco Prod. Co.*, 527 F. Supp. at 794 ("[t]he law is clear that Congressional re-enactment of a statutory provision which has been consistently interpreted by an administrative agency signifies congressional approval and adoption of that interpretation."); *Marathon Oil Co.*, 452 F. Supp. at 551 (noting that Congress amended the Mineral Leasing Act seventeen times since its original enactment and seven times since the August 8, 1946 amendment which added the language "removed or sold from the lease," but consistently left unchanged the royalty valuation requirement, thus evincing its approval of the Secretary's long-standing interpretation).

The supplementary proposed rule does not measure the value of production removed or sold from the lease. On the contrary, the proposed rule (1) uses unrelated values away from the lease for crude oil production in the field, (2) fails to account for the full increase in value to crude oil after its removal from the field, and (3) produces widely varying, unpredictable and artificial "values" within each field depending upon the ultimate disposition of each barrel.

B. The Proposed Record-Keeping and Audit Provisions Exceed the Secretary's Statutory Authority

The supplementary proposed rule purports to require Federal lessees and their affiliates to track Federal lease production through multiple non-arm's-length transactions until the oil is ultimately refined by an affiliate or sold at arm's-length to a nonaffiliated party. Proposed section 206.102 also looks beyond arm's-length exchange agreements to require a Federal lessee to track the disposition of oil received in exchange for Federal lease production through one or more arm's-length exchange agreements. Both aspects of the supplementary proposed rule exceed the Secretary's statutory authority. Section 103(a) of the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 ("FOGRMA") provides, in pertinent part, that:

> A lessee, operator, or other person directly involved in developing, producing, transporting, purchasing, or selling oil or gas subject to this Act through the point of first sale or point of royalty computation, whichever is later, shall establish and maintain any records, make any reports, and provide any information that the Secretary may, by rule, reasonably require for the purposes of implementing this Act or determining compliance with rules or orders under this Act.

30 U.S.C. §1713(a). In construing this provision, the Interior Board of Land Appeals (IBLA), as affirmed by the United States District Court for the District of Delaware, and the United States Court of Appeals for the Tenth Circuit have held that MMS can require the production of records from those directly involved in the *first* purchase of Federal oil or gas. *See Santa Fe Energy Products Co. v. McCutcheon*, 90 F.3d 409, 414 (10th Cir. 1996)(concluding that, because lessee's affiliate was a "person directly involved in . . . purchasing . . . oil or gas subject to this chapter through the point of first sale or royalty computation," MMS could require the affiliate to establish and maintain records and make reports); *Shell Oil Co. v. Department of the Interior*, 945 F. Supp. 792, 800 n.7 (D. Del. 1996)("FOGRMA is . . . limited to persons 'directly involved' in transactions of oil or gas from Federal leases"). No case has ever held that MMS can require those who are not directly involved in the first sale of Federal lease production to establish and maintain records or make reports. Nor is there any authority for MMS to require anyone -- lessees or first purchasers -- to establish and maintain records and make reports relating to disposition of non-lease oil *received in exchange* for Federal lease production.

FOGRMA does not limit the term "first sale," as the supplementary proposed rule does, to the first arm's-length, outright sale between nonaffiliated parties. TEPI's transactions with Equilon involve *sales* of crude oil, not transfers. Title transfers from TEPI to Equilon, and Equilon pays valuable consideration for the crude oil. Similarly, Equilon's buy/sell transactions with third parties are *sales*. Indeed, MMS's own Oil and Gas Payor Handbook recognizes that exchange agreements and buy/sell transactions are sales. Volume III, Product Valuation, Section 3.3, Oil Exchange Agreements, explains that: "The exchange agreement represents two distinct sales under the contract and the value of lease production is determined at the first point of sale (the first exchange point)."

While MMS may have the authority to impose record-keeping regulations on both parties to the first sale of Federal lease production, it lacks authority to impose any record-keeping obligation beyond the first sale, or on anyone not directly involved in the first sale. It follows, therefore, that MMS cannot require lessees to track Federal lease production to its "ultimate disposition." Nor can MMS require lessees, much less their affiliates, to track oil received in exchange for Federal lease production.

C. The Irrebutable Presumption of Control Contained in the Supplementary Proposed Rule's Definition of "Affiliate" is Arbitrary and Capricious

The supplementary proposed rule's new definition of "affiliate" is arbitrary, capricious and contrary to law because it creates an irrebuttable presumption that a lessee who "owns, is owned by or is under common ownership with another person to the extent of 10 percent or more" is an "affiliate" of that other person for purposes of applying the valuation regulations. 63 Fed. Reg. at 6126. The proposal then bases the lessee's choice of valuation point and methodology on the status of its selling partner as an "affiliate," as defined by these ownership criteria. If a party is deemed to have made a sale to an affiliate, it must engage in a far more complicated valuation process. By contrast, the current definition of affiliate creates a *rebuttable* presumption of control for situations involving ownership between 10 percent and 50 percent, and provides that two parties are affiliated if one person controls, is controlled by or is under common control with, another person. 30 C.F.R. ß 206.101(1997); Revision of Oil Product Valuation Regulations and Related Topics, Final Rule, 53 Fed. Reg. 1184, 1193 (Jan. 15, 1988) ("lessees can rebut presumptions of control between 10 and 50 percent").

Statutes creating permanent irrebuttable presumptions have long been disfavored under the Due Process Clause, and such presumptions contained in economic regulations must have a rational basis. *See Vlandis v. Kline*, 412 U.S. 441, 446 (1973) (collecting cases); *Cleveland Board of Educ. v. LaFleur*, 414 U.S. 632, 650 (1974); *Usery v. Turner Elkhorn Mining Co.*, 428 U.S. 1, 23 (1976); *Sakol v. Commissioner*, 574 F.2d 694, 698 (2d Cir. 1978). Furthermore, an administrative agency's regulations must withstand greater scrutiny than that imposed on Congress when it regulates in the economic arena. *Bowen v. American Hosp. Ass'n*, 476 U.S. 610, 626 (1986). With regard to agency regulations, "[t]he mere fact that there is 'some rational basis within the knowledge and experience of the [regulators],' under which they 'might have concluded' that the regulation was necessary to discharge their statutorily authorized mission, *will not suffice* to validate agency decisionmaking." *Bowen*, 476 U.S. at 626 (citations omitted, emphasis added). MMS has an affirmative obligation to explain the rationale and basis for its decision; the proposed rule clearly does not satisfy its obligation. *Id.*

An irrebuttable presumption of affiliation based on greater than ten percent common ownership bears no rational relation to MMS's goal in valuing transactions between affiliates differently from transactions between arm's-length trading partners. *See Sakol*, 574 F.2d at 698. MMS has previously expressed its belief that "when parties to a contract . . . no longer have opposing economic interests, the reliability of that contract as an accurate indicator of value becomes suspect." 53 Fed. Reg. at 1193. The current regulatory framework is based on the presumption that parties meeting the "control" criteria do not have opposing economic interests. However, under the current regulation, lessees are permitted to rebut the presumption of control. Situations commonly arise in which two parties meet the 10 percent criteria, but are not sufficiently under common control or controlled by each other that they lack opposing economic interests. By eliminating the opportunity for rebuttal, the supplementary proposed rule denies a lessee the ability to demonstrate to MMS that although its corporate relationship with its affiliate meets the 10 percent criteria, the relationship lacks the element of common control that renders a contract price suspect for royalty valuation purposes. The irrebuttable presumption therefore lacks any rational relationship to the goal of defining the term "affiliate" and basing product value determinations on that definition, and consequently is arbitrary, capricious and contrary to law.

D. MMS Has Grossly Underestimated the Cost that Would be Imposed on Industry and MMS by the Supplementary Proposed Rule

MMS estimates that the economic impact of the supplementary proposed rule will be about $66 million. The estimate is based solely on the annual increase in royalty payments that MMS expects under the supplementary proposed rule. The MMS estimate overlooks entirely the enormous cost that would be imposed on industry (and MMS) by the supplementary proposed rule. The supplementary proposed rule would impose a myriad of new administrative functions on industry, including the pipelines that have not previously been burdened with MMS's record-keeping requirements.

Without considering this cost, it is impossible for MMS to properly perform the cost-benefit analysis required by the Regulatory Flexibility Act, 5 U.S.C. §§ 601 *et seq.*, and Executive Order 12988. *See* Barents Group LLC, "Analysis of MMS' 'Economic Analysis of Proposed Federal Oil Valuation Rule Under Executive Order 12866" (Apr. 7, 1998)(concluding that MMS has not fulfilled the requirements of Executive Order 12866). MMS's failure to consider the administrative cost that would be imposed by the supplementary proposed rule also calls into question the accuracy and veracity of MMS's certification, under the Unfunded Mandates Reform Act of 1995, 2 U.S.C. §§ 1502 *et seq.*, that the rule will not impose a cost of $100 million or more in any given year on local, tribal, or State governments, or the private sector. MMS should not publish an interim or final rule without having first evaluated the substantial costs that would result.

E. MMS is Still Relying on Apparently Biased "Experts" with No Evidentiary Support

MMS continues to rely on apparently biased "experts" with no evidentiary support. Despite repeated requests, including Freedom of Information Act requests, MMS has steadfastly refused to identify the work of consultants on whom it is relying in this rulemaking. Virtually no evidence has been included in the public record backing up the consultants' opinions. As best we can tell, MMS is relying on the opinions of consultants working for plaintiffs' lawyers that have been and remain involved in litigation against TEPI and other producers and buyers.

The consultants' opinions apparently relied upon by MMS have been consistently discredited in litigation against TEPI and others. For example, a New Mexico state court heard the testimony of an individual identified as an MMS consultant in support of plaintiffs' motion to certify a class of royalty owners, which the court rejected. *Engwall v. Amerada Hess,* No. CV-95-322 (N.M. 5th Jud. Dist. Mar. 26, 1997).

Notably, in the *Engwall* case, the consultant testified that he had recommended to MMS that only as a *last resort* should market values of crude oil in the producing fields be calculated using a net-back formula based on NYMEX prices. (Tr. at 347-48, attached at Tab 5 to Texaco's May 28, 1997 comments.) He also testified that he had recommended to MMS that if oil companies sell crude oil either "outright in an arm's-length final sale with no other consideration," or if the companies enter into a "buy-sell transaction" where "oil was exchanged for oil at another location," then such transactions should be used for royalty valuation purposes. (*Id.*) The consultant testified that his recommendation to MMS was that "[i]f we didn't have *any* of those actual transactions . . . then we can *use a comparable analysis* to look at other *nearby* *locations* whereby we look at buy-sell transactions that were employed by the defendants or by other companies of similar sophistication." (*Id.* at 348 (emphasis added).) According to the consultant, his recommendation to MMS was that only if *none* of these arm's-length transactions exist, then as a last resort, should a net-back methodology be attempted:

> Then the final method is, if there are none of those, if there are *no [outright sales or] buy-sell transactions available*, then *the last* would be a methodology, a net-back type methodology to be administered by the Minerals Management Service.

(*Id.* (emphasis added).)

VII. CONCLUSION

Texaco urges MMS to withdraw the "Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Federal Leases" because it does not provide for value at the lease and it unfairly and unlawfully attempts to boost government revenues by effectively raising the royalty rate for Federal crude oil production. Like the initial proposal, the supplementary proposed rule is based on fundamentally false assumptions about crude oil markets and blatantly discriminates against integrated firms. The supplementary proposed rule is also extremely complex and unworkable, and would impose a tremendous administrative cost on both the oil industry and MMS. Texaco urges MMS to consider adopting a tendering program, like that utilized by TEPI, to establish oil value for royalty due on Federal leases. TEPI's tendering program is far more reliable, and much less costly, than any of the valuation methodologies contained in the supplementary proposed rule. If MMS declines to adopt a tendering program, then Texaco urges MMS to take its royalty in kind. We stand ready to assist MMS in any effort to clarify or improve methods to ascertain values of crude oil at the lease. However, as a matter of sound economic policy, fairness, practicality, and law, such methods must continue to use arm's-length sales prices at the lease.

Sincerely,

James C. Pruitt

James C. Pruitt

Attachments:
1. Decision-Tree Diagram, MMS Supplementary Notice of Proposed Rulemaking
2. Decision-Tree Diagram, TEPI's Tender Methodology

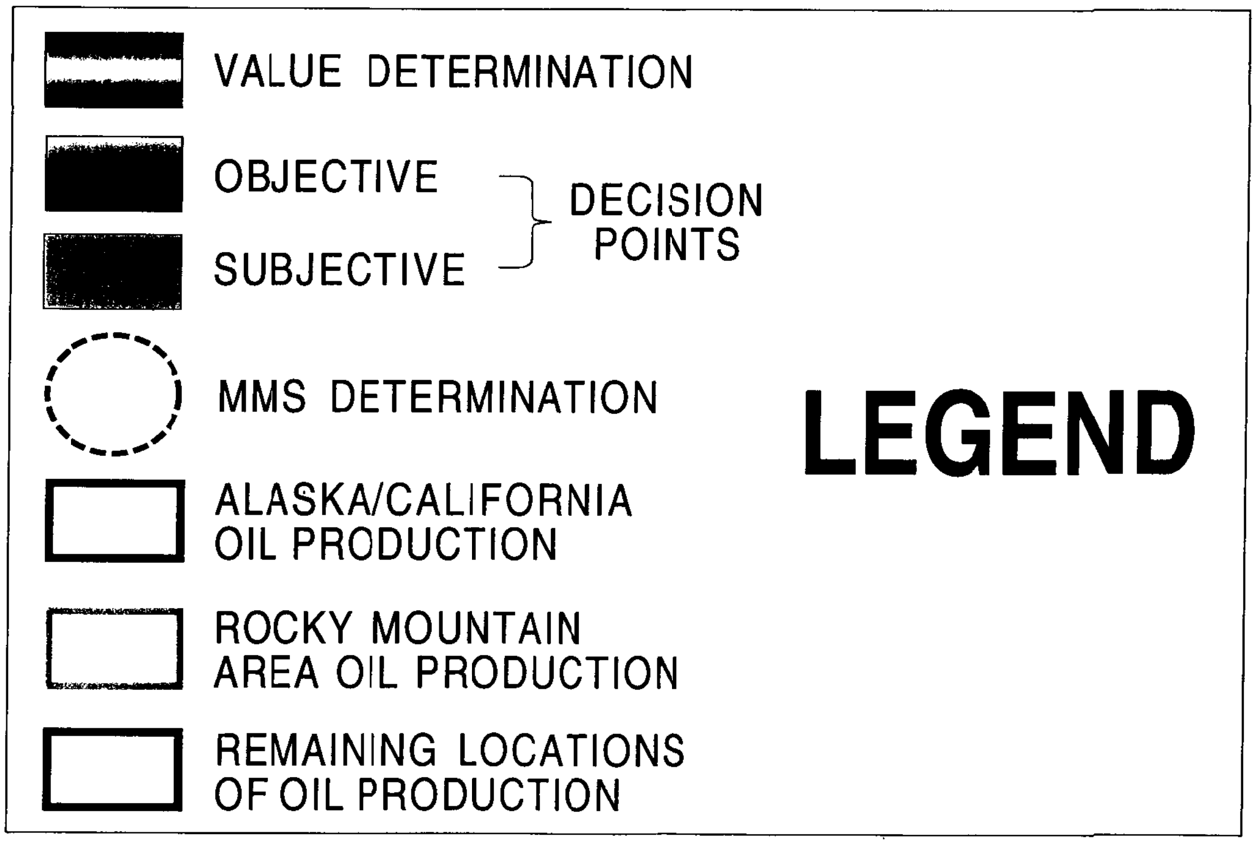
3. Decision-Tree Diagram, Royalty-In-Kind Alternative
4. Supplemental Report of Dr. Benjamin Klein, April 6, 1998

Attachment 1

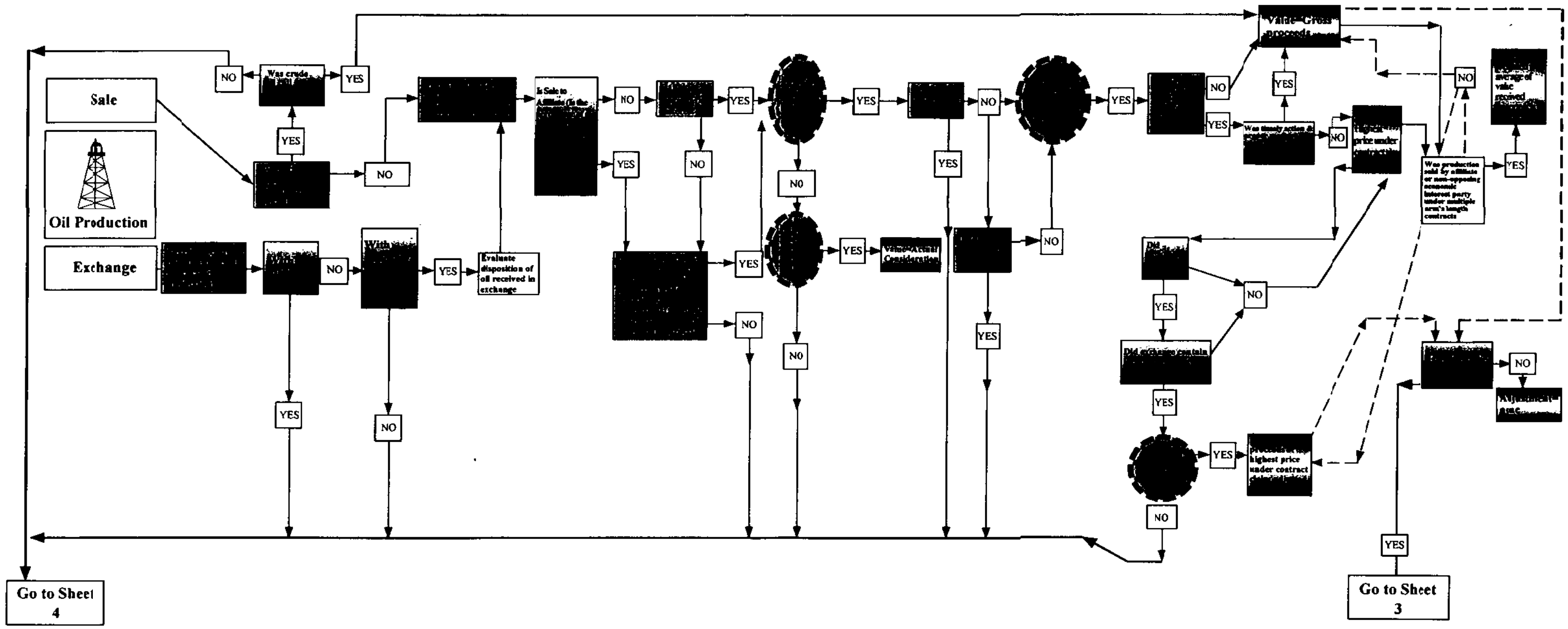
MMS Supplementary Notice of Proposed Rulemaking

**Establishing Oil Value for Royalty Due on Federal Leases,
and on Sale of Royalty Oil**

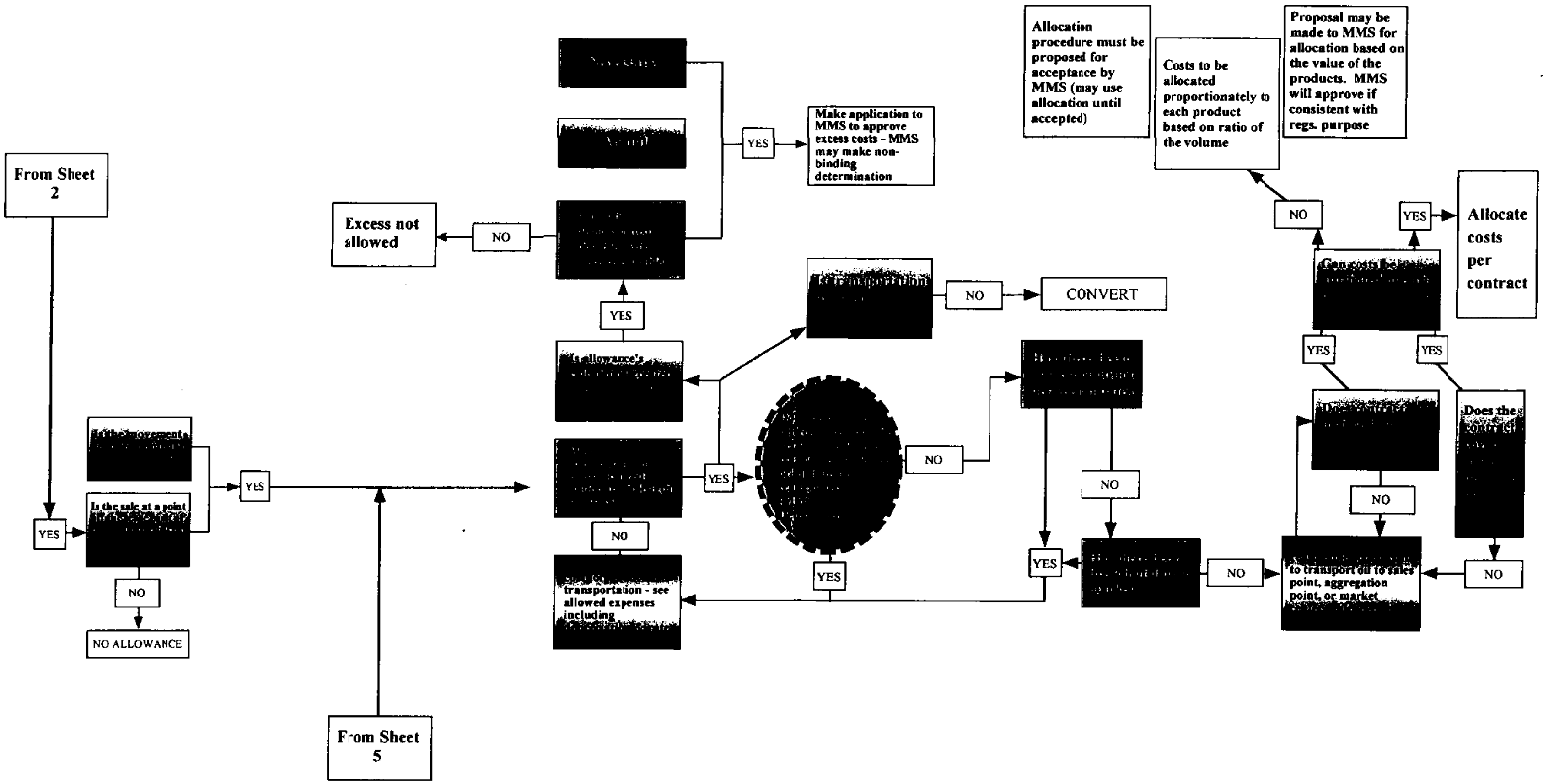
63 FED. REG. 6113
FEBRUARY 6, 1998



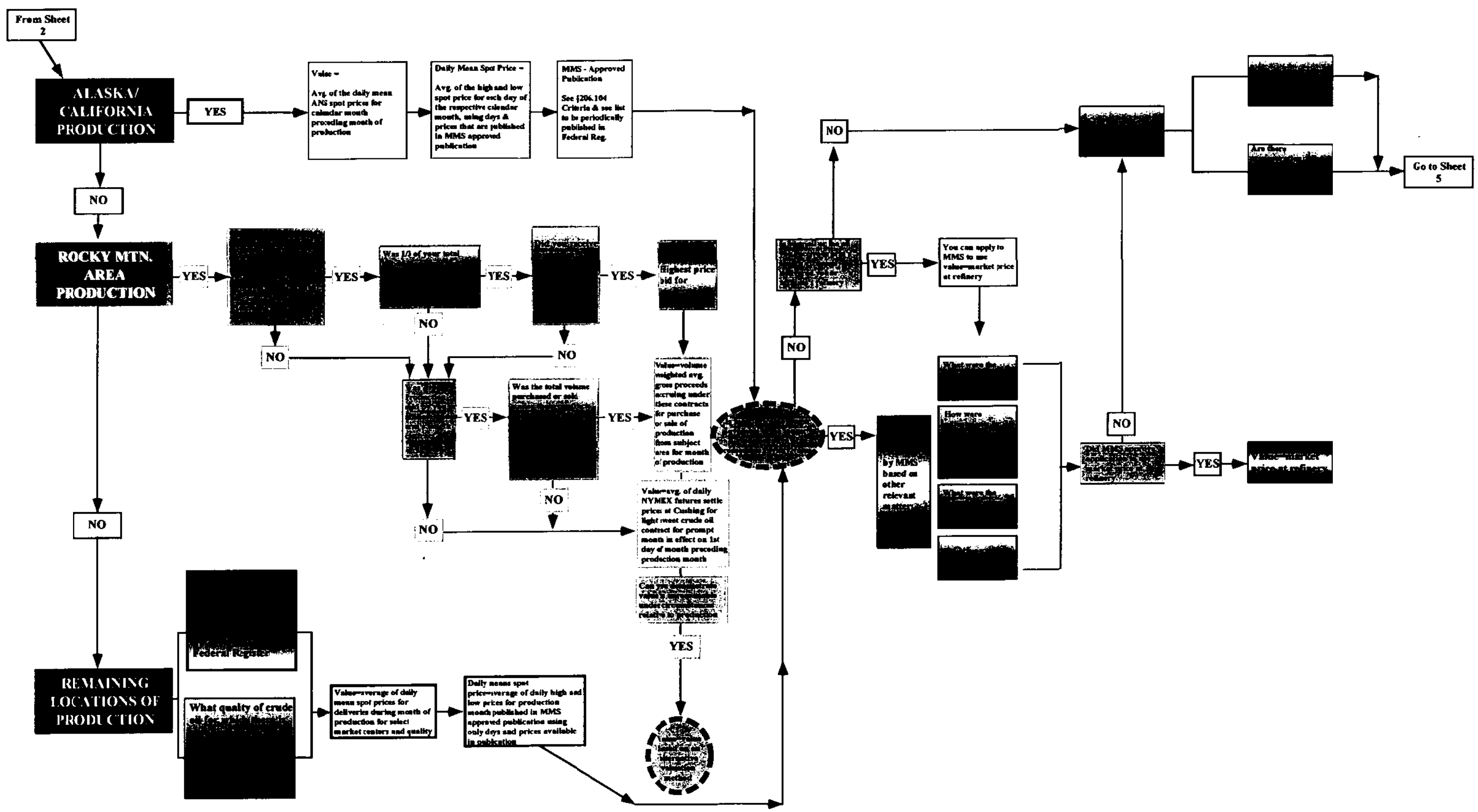
MMS PROPOSED METHOD FOR ARM'S LENGTH CONTRACTS - "GROSS PROCEEDS"* DETERMINED AS FOLLOWS:

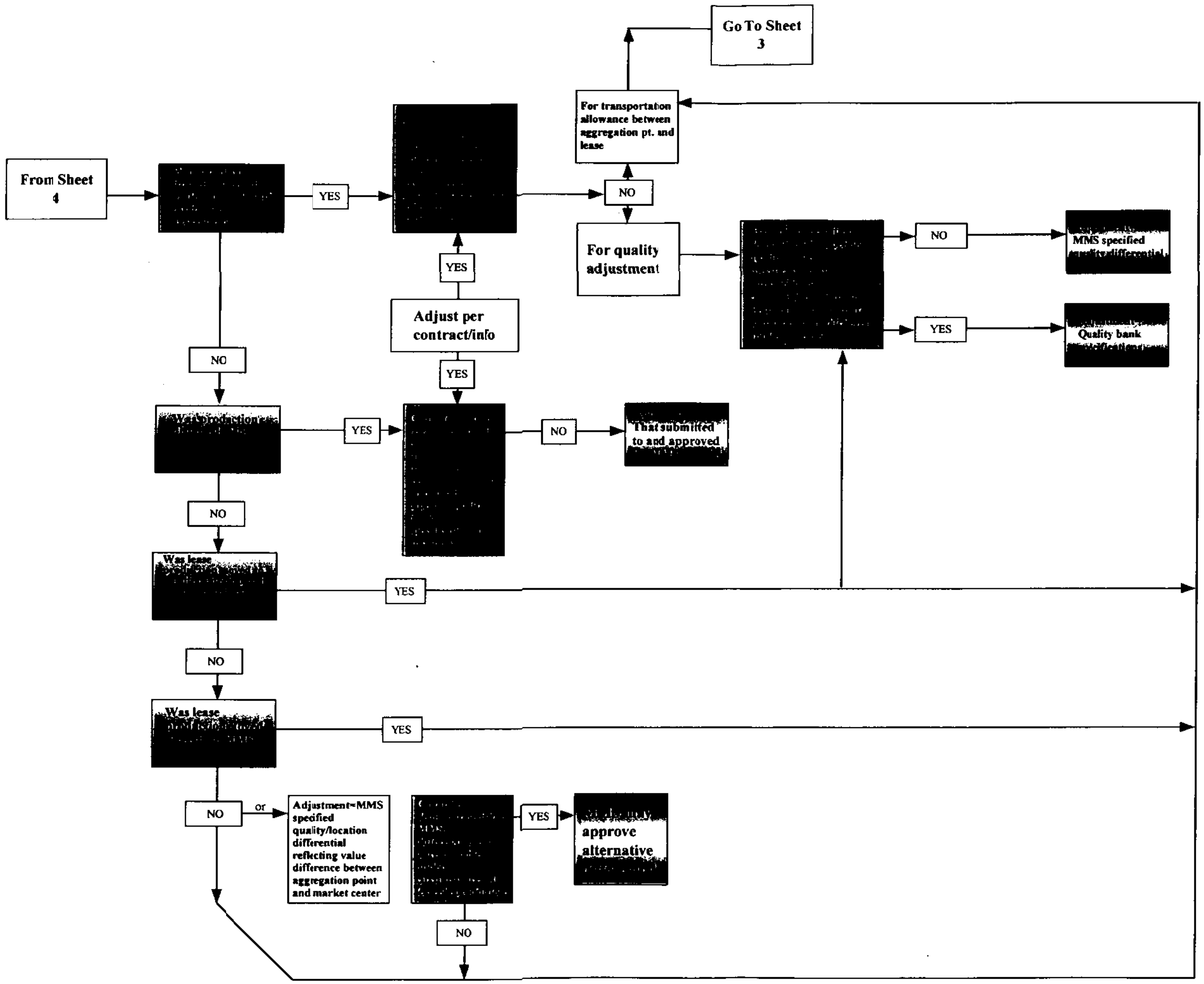


*Assumes lessor is able to trace lease production to its "ultimate disposition," which may not be possible


From Sheet 2
YES
NO
NO ALLOWANCE
YES
From Sheet 5
Excess not allowed
NO
YES
Make application to MMS to approve excess costs - MMS may make non-binding determination
YES
NO
CONVERT
YES
NO
NO
YES
YES
NO
Allocation procedure must be proposed for acceptance by MMS (may use allocation until accepted)
Costs to be allocated proportionately to each product based on ratio of the volume
Proposal may be made to MMS for allocation based on the value of the products. MMS will approve if consistent with regs. purpose
NO
YES
Allocate costs per contract
YES
YES
NO
NO
NO

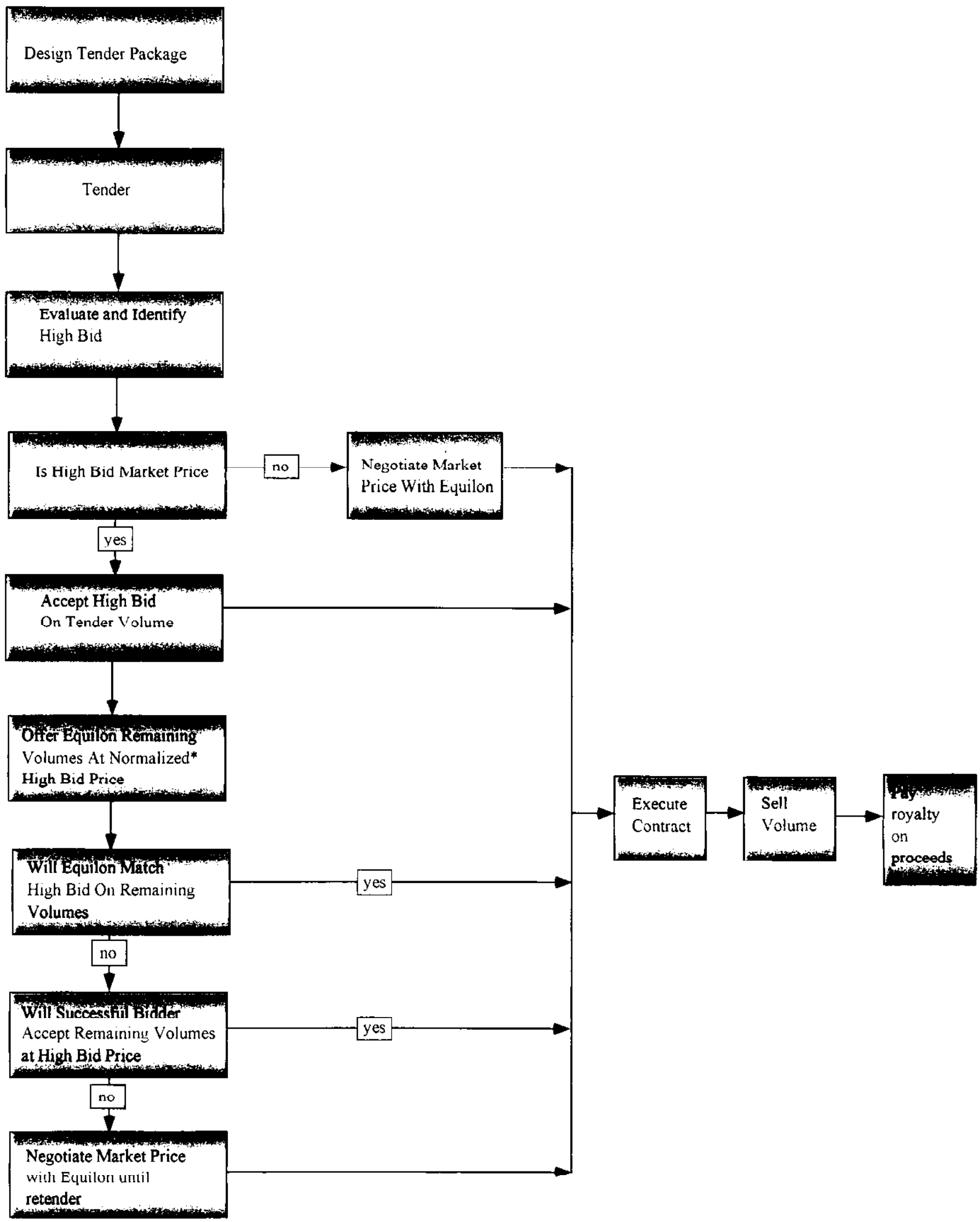
MMS PROPOSED METHOD FOR NON-ARM'S LENGTH CONTRACTS - DETERMINED AS FOLLOWS:




From Sheet 4
YES
NO
For transportation allowance between aggregation pt. and lease
Go To Sheet 3
For quality adjustment
Adjust per contract/info
YES
YES
NO
NO
YES
MMS specified
YES
Quality bank
YES
NO
That submitted to and approved
NO
Was lease
YES
NO
Was lease
YES
NO
or
Adjustment=MMS specified quality/location differential reflecting value difference between aggregation point and market center
YES
approve alternative
NO

Attachment 2

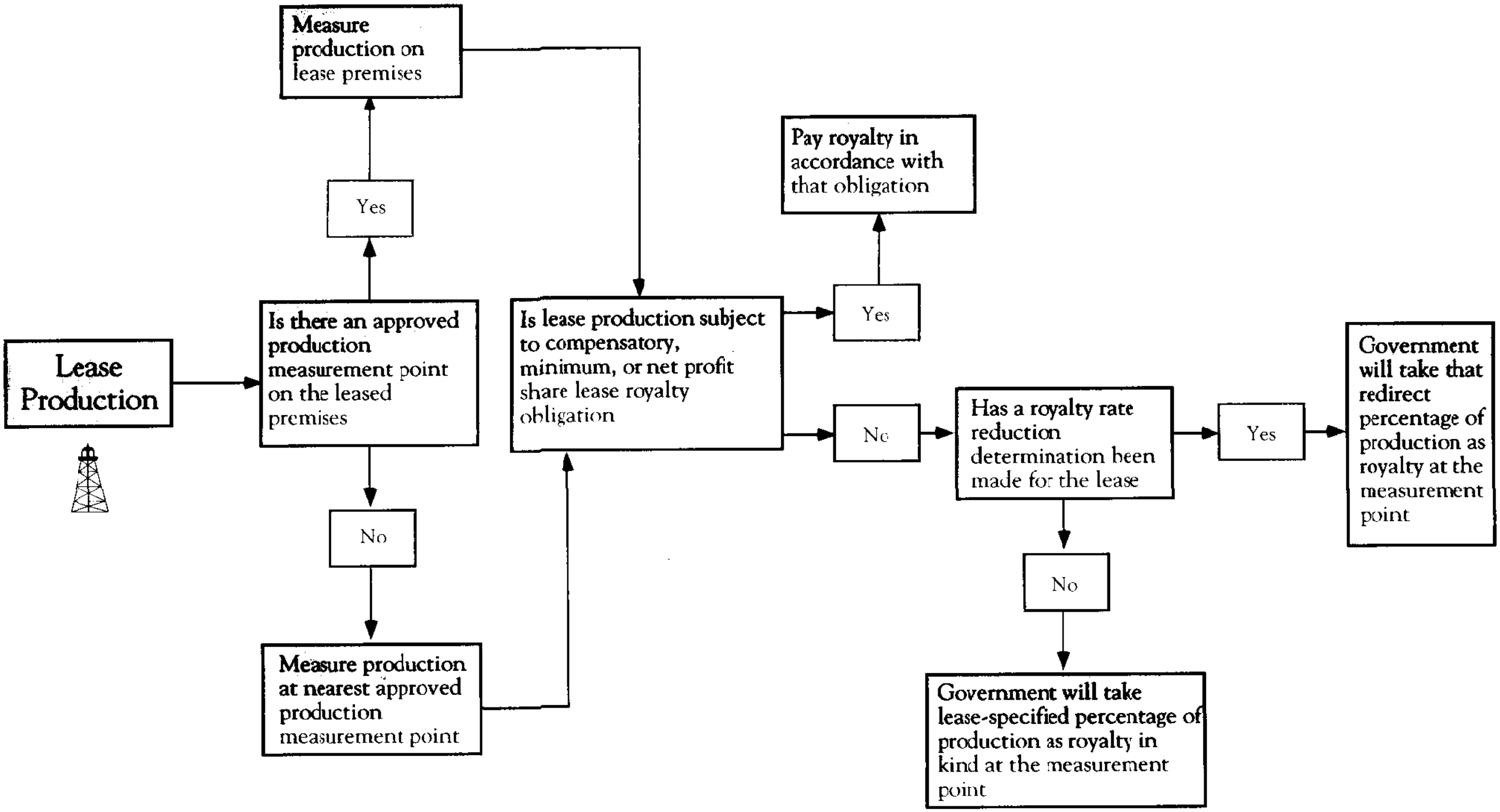
TEPI'S TENDER METHODOLOGY



* Normalization = Process of adjusting, if necessary, the high bid price for nearby production with different transportation characteristics.

Attachment 3

RIK ALTERNATIVE



Attachment 4

Comments of Professor Benjamin Klein on the Supplementary Proposed MMS Crude Oil Royalty Regulations

I. Overview of primary conclusions

1. I, Benjamin Klein, am a Professor of Economics at the University of California, Los Angeles (UCLA), a position I have held since 1978. In addition, I am President of Economic Analysis Corporation, which provides economic consulting services to law firms, corporations and government agencies. I previously filed extensive comments on the NOPR in May of 1997. I believe that all of the points I made in those comments continue to be applicable to the Supplementary NOPR ("SNOPR"). My comments here are confined to a relatively small number of specific issues that arise in the SNOPR.

2. My primary conclusions are essentially the same as those expressed in my previous comments and can be summarized as follows:

a. The SNOPR continues to advocate a highly complex and burdensome royalty system which is certain to produce substantial valuation errors in an attempt to "fix" a problem that has not been established to exist.

b. The SNOPR seeks to replace the great diversity of actual crude oil qualities and market conditions at the lease with a small number of downstream spot prices and an arbitrary and inaccurate system of transportation, location and quality differentials and allowances.

c. The SNOPR inappropriately continues to attribute values of downstream services and assets to the crude oil at the lease. Hence, it overstates crude values at the lease and discriminates against vertically integrated producers.

II. The SNOPR's proposal that lessees must attempt to track federal lease crude (or crude received on exchange for federal lease crude) to its ultimate disposition ignores complicating features of actual crude oil transactions and will result in substantial valuation errors.

3. The SNOPR proposes that crude oil producers must attempt to track federal lease barrels from the lease to their ultimate disposition. However, the circumstances of actual crude oil transactions makes such tracing extremely difficult. For example, consider a case where TEPI produces 13-degree Kern River crude from a federal lease in the San Joaquin Valley. It then sells the crude to its transportation affiliate Equilon at the lease. Equilon then commingles the federal lease crude with a variety of other crude oils it either purchases or receives on exchange in its proprietary pipelines. It may sell some portion of this commingled stream in arms length or non-arms length transactions in the San Joaquin Valley area, or it may exchange some of this crude for other crudes in other locations. In addition to tracking any arms-length sales, the SNOPR also requires TEPI to track each of the crudes received in these exchanges to its ultimate disposition. Equilon then transports the remainder of the commingled crude oil stream to Midway Sunset where it is combined with still other crudes or blended in large blending tanks with different crude oils along with natural gas liquids and other light hydrocarbons in order to meet the pipeline specifications for Line 63. The resulting crude is then transported to Los Angeles where it could be sold in arms length sales, refined in Texaco's LA refinery, or exchanged for still other crudes.

4. The valuation of TEPI's original federal lease production in these circumstances would obviously be very complicated and would impose large data collection and computational burdens on producers. The proposed method will also result in significant valuation errors. Even for the portion of the crude that is sold outright in arms length sales, since the sales involve commingled and/or blended streams, the sales proceeds must somehow be allocated among the different crude oils and/or natural gas liquids. This calculation could be further complicated by the fact that each of the crudes in the commingled or blended stream may have incurred different transportation, handling, storage, blending and other costs before reaching the final point of sale.

5. The appropriate allocation of gross proceeds of each sale back to TEPI's original federal lease crude could obviously be very different for sales of commingled SJV crudes in the San Joaquin Valley vs. sales of Line 63 crude oil in LA vs. any subsequent sales of crudes received on exchange. Further, any non-arms length dispositions, such as sales to Texaco's Bakersfield or

LA refineries would have to be valued on index pricing or some other basis. (As discussed in Section IV below, the valuation procedure for crudes delivered directly to a producer affiliated refinery is particularly arbitrary and prone to error.)

6. The complexity and record keeping burden in this system is potentially enormous. In addition, in many cases the transportation affiliate will not be a wholly owned subsidiary of the producer and, hence, will have no incentive to provide information on its subsequent crude oil transactions.

III. The SNOPR's proposal to use spot prices to value federal lease crude continues to be flawed.

7. The fact that published spot prices can be shown to track NYMEX prices closely does not imply that such spot prices can be used to accurately value crude oil at the lease. As discussed in my previous comments on the NOPR, the proposal to use published spot prices to value federal lease crude at the lease will result in substantial valuation errors.

8. For example, TEPI produces crude oil from 21 federal leases in California. As discussed in section III of my comments on the NOPR, the quality, location and economic characteristics of these crudes varies widely, both across fields and over time. Nevertheless, the SNOPR proposes to value all of these crudes based on a single spot price (ANS) and a complicated and likely inaccurate system of transportation, location and quality differentials. As I discussed at length in sections III-V of my comments on the NOPR, the result is likely to be significant errors in valuation and will not accurately approximate the prices that federal lease crude would sell for in arms length sales at the lease.

9. In addition to the errors caused by the likely use of arbitrary and inaccurate differentials to adjust the small number of published spot prices, the "actual cost" methodology used by the SNOPR in many situations to net these adjusted spot prices back to the lease frequently ignores or understates the values of downstream assets and services and, hence, overstates the value of crude at the lease. In economic terms, this inclusion of downstream value into the assumed value of the crude at the lease is economically equivalent to raising the lease rate. It also discriminates against

vertically integrated lessees, and hence, reduces the incentive to make efficient downstream investments. (see my comments on the NOPR, section VIII.)

IV. The valuation errors in the proposed methodology are likely to be particularly large for crude that is transported directly to the lessees' refinery.

10. The potential problems inherent in trying to value crude oil at the lease by "netting back" a small number of downstream spot prices are even more severe in the proposed methodology for valuing crude oil that is transported directly to the lessee's refinery. The SNOPR proposes to value such crude using NYMEX or the spot price for the market center nearest to the lease, less the "actual" cost of transporting the crude from the lease to the refinery. In effect, the methodology assumes that the refinery is located at the market center when, in fact, it may be far away and the cost of transporting the crude to that market center could be substantial. There is no economic reason whatever to believe that this methodology would produce crude values approximating the price the crude would sell for in an arms length transaction at the lease.

11. In addition, the proposed methodology only permits a quality adjustment if the oil passes through a pipeline quality bank or if an arms length exchange agreement used to transport the oil to the refinery contains a separately identifiable quality adjustment. This obviously makes no sense. All crude oils that differ in quality from the index crude obviously require a quality adjustment regardless of whether they happen to be transported through a pipeline with a quality bank or not.

12. The non-sensical values resulting from this methodology can be illustrated with an example. *TEPI*'s Wyoming asphalt, with an average API gravity of 22.6 - 23 degrees, typically sold for about $12.90 per barrel during the period from September 1994 through February 1995. The price of WTI at Cushing (with an average API of 40 degrees) was about $17.83 per barrel during the same period. Since the cost of transportation was about $1.50 per barrel, the royalty value of TEPI's crude would be calculated as $17.83 - $1.50 = $16.33 per barrel or $3.43 per barrel greater than the actual price of $12.90 per barrel.