WESTERN ENERGY
ALLIANCE
Formerly IPAMS

July 26, 2011

Submitted via Federal eRulemaking Portal and certified mail

Hyla Hurst
MS61013C
Office of Natural Resources Revenue
U.S. Department of the Interior
P.O. Box 25165
Denver, Colorado 80225

RE: Western Energy Alliance comments on Advance Notice of Proposed Rulemaking on Federal Oil and Gas Valuation (Docket Number ONRR-2011-0005, RIN 1012-AA01)

Dear Ms. Hurst:

Western Energy Alliance (formerly IPAMS) represents over 400 companies engaged in all aspects of environmentally responsible exploration and production of natural gas and oil across the West. We submit the following comments to the Office of Natural Resources Revenue's (ONRR) advance notice of proposed rulemaking on federal oil and gas valuation.

The Alliance appreciates the opportunity to comment on the agency's attempt to provide greater simplicity, certainty, clarity, and consistency in the valuation of federal oil and gas for royalty payment purposes. Members of the Alliance are concerned, however, that certain concepts, such as mandatory index zone pricing, will result in royalty values that exceed the market value of production at the lease. We look forward to further discussion of these issues at the upcoming workshops.

SPECIFIC COMMENTS

<u>Index Pricing</u>

Question: The ONRR is seeking comment on the existing use of index pricing to determine the value of production for oil royalty purposes and whether the use of index pricing should be expanded or altered. Additionally, the ONRR is considering the use of index pricing in valuing Federal gas for royalty purposes.

The Alliance does not oppose the expanded use of index pricing, so long as industry can enjoy administrative simplicity of an index approach. If ONRR moves forward with expanded use of index pricing, then it should be an option for industry to utilize for valuation in all circumstances, including arms-length, non arms-length, oil and gas.

Two important sideboards must be honored, however, in the use of index pricing. First, royalty may only be assessed on the reasonable market value of production at the lease. *United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 & 254 (S.D. Cal.

1947), *aff'd sub nom.*, *Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950) ("royalties are payable on the gas as it is produced at the well"); *Mobil Producing Texas & New Mexico, Inc.* 115 IBLA 164, 1717 (1990) ("normally gas is sold and valued for royalty purposes at the wellhead"); *see also California Co. v. Udall*, 296 F.2d 384, 387 (D.C. Cir. 1961) ("value" under Mineral Leasing Act means "fair market value"). The Alliance does not oppose ONRR's interest in attempting to make changes in the rules "revenue neutral," but the changes cannot be a vehicle for raising the royalty on production above its value at the lease.

Second, ONRR cannot unilaterally increase lessees' royalty obligations through post-lease rulemaking. As lessor, the United States acts in a dual capacity and may only alter lease provisions relating to conservation; proprietary obligations such as royalties are frozen as of the time of the lease. Warren M. Christopher, *The Outer Continental Shelf Lands Act: Key to a New Frontier*, 6 Stan. L. Rev. 23, 43-44 (1953).[1] *See also Mobil Oil Exploration & Producing Southeast, Inc., v. United States*, 530 U.S. 604, 607 (2000) ("When the United States enters into contract relations, its rights and duties therein are governed generally by the law applicable to contracts between private individuals.") (internal citation and quotation marks omitted).

It is therefore improper to propose, and the Alliance opposes the inclusion of, any safety net calculations as currently required for Indian Gas Valuation. The government should also ensure that the use of index pricing is optional for lessees, allowing companies to utilize gross proceeds as the valuation method or to opt out of gross proceeds to utilize index pricing for oil or gas. Optionality allows companies to incorporate index pricing if they have the capacity to do so and also

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> In its proprietary capacity, the Government is like any other lessor, bargaining hard for the best lease terms, but recognizing their binding effect as a contract once they are agreed upon …. The net result of this dual capacity is that federal leases are subject to some regulations (those of a proprietary nature, such as revisions regarding annual rental payments) <u>which are frozen as of the time of the lease</u>, while other regulations (those relating to conservation, such as rate of production) are subject to continuing amendment.

Warren M. Christopher, *The Outer Continental Shelf Lands Act: Key to a New Frontier*, 6 Stan. L. Rev. 23, 43-44 (1953) (emphasis added). The federal oil and gas lease form states that

> Rights granted are subject to applicable laws, the terms, conditions and attached stipulations of this lease, the Secretary of the Interior's regulations and formal orders <u>in effect as of lease issuance</u>, and to regulations and formal orders hereafter promulgated <u>when not inconsistent with lease rights granted or specific provisions of this lease</u>.

Offer to Lease and Lease for Oil and Gas, Form 3100-11 (October 2008) (quotation from lease preamble) (emphasis added). ONRR cannot impose, by later regulation, royalty valuation requirements more onerous to the lessee than those in place when its lease was issued.

allows companies to determine which valuation method actually provides the greatest simplicity. As such, optionality is ultimately a selection between the uses of two different revenue neutral methodologies. Furthermore, index pricing should be defined in a way to minimize any potential revisions to royalty payments and prior period adjustments. And the use of index pricing should apply to all resources produced in natural gas production including all liquids, not just NGLs.

Question: We seek input on how well index prices currently represent the value for oil and gas produced in different regions or areas of the country, such as states on the Gulf of Mexico coast (including Texas, Louisiana, Mississippi, and Alabama, as well as onshore areas within those states), the Midwest (including Oklahoma and North Dakota), the Southwest (including New Mexico and the Permian and San Juan Basin areas), the Rocky Mountain area (including Wyoming, Montana, and Colorado and Utah outside the San Juan Basin), the West Coast states (primarily California), and Alaska. Please identify what index publications you believe apply to what parts of these areas and the relative advantages and disadvantages, and strengths and weaknesses, of using each of the identified published index prices.

At least in some instances, index zone prices do not reflect the market value of production. For example, *Cudd Operating Corp.*, MMS-06-0066-IND (June 19, 2009), involved an order directing the lessee to pay royalties on the Oklahoma Index Zone 1 price for gas sold between January 2004 and June 2006. Cudd's lease was subject to the Indian gas regulations which require royalties on the index value for leases that are (1) located within an index zone and (2) provide for dual accounting or value determined by the Secretary. *See* 30 C.F.R. § 206.172(a)(1). Cudd argued that it could not sell its gas at the index price which was higher than market value. The Bureau of Indian Affairs Director concluded, however, that even if prices received by other producers were shown to be less than the index value, the regulations require royalties on the index zone price. *See also Huntingon Energy, L.L.C.*, MMS-03-1015-IND (May 20, 2005) (order directing lessee to pay Oklahoma Zone 1 Index price upheld even though sales proceeds were less than index value; decision does not identify the time period at issue). Another company reports that the mandatory use of index zone pricing to value Indian gas and liquids has not been revenue neutral. The actual prices received by the company were in all cases lower than the index zone price resulting in a loss of revenue to the company.

These cases illustrate that an index-based or zone-based price methodology may be inconsistent with existing lease requirements and may not fairly reflect the value of oil or gas at the lease. As noted above, royalty can only be assessed on the reasonable market value of production at the lease. Alliance members report that they frequently receive less for the sale of gas than the reported index price.

For the majority of the country there are adequate indices for both oil and gas, "adequate" in the sense that enough transactions occur there to make the index price potentially reliable. However, there are more complete indices for gas than there are for oil. Should the government move forward with the use of index pricing, then it should have a system in place to ensure that adequate indices are available and deemed feasible for use the use by industry. The government and industry should collaborate on defined indices to ensure that indices are applicable, available for use, and can be validated.

ONRR must also have a system in place to actively review defined indices so that adjustments are made to maintain the adequacy and applicability of the indices and so that additional indices can be added. The Alliance recommends that indices be reviewed at least annually for relevance and accuracy. For example, if ONRR uses five separate prices to compile the index price for producers in southeast Wyoming, one of the prices could become less relevant over time and should, therefore, carry less weight in ONNR's index calculation. The index pricing system must be kept current to keep it valid.

Furthermore, if there are problems that arise, then there has to be a mechanism in place for individual companies to work through the problems with the ONRR to ensure adequate resolution and accuracy in the indices. For those that choose indexing, ONRR should consider a process within which lessees can submit a recommended list of indices that are appropriate for the dispositions.

Question: We also seek input on whether value should be based on first-of-month prices, daily spot prices, or some mixture of the two when considering the use of index prices.

For natural gas, first of month pricing makes the most sense because it is available and provides greater simplification. Furthermore, any indices should include actual location and quality adjustments associated with the pipeline quality banks (use the actual quality bank).

Question: In addition, we seek input on how to best value this gas for royalty purposes in situations where gas from Federal leases is produced in areas not covered by index pricing, or where limited reported spot market activity exists.

The Alliance does not see this as being a major prevailing issue. However, in the event such a situation arises, the lessee could utilize gross proceeds or work with ONRR to develop or determine applicable index in those situations.

Question: Does the concentration of Federal production in some areas of the country create any potential problems with relying on index prices in those areas, now or in the future?

The Alliance does not foresee this as a problem.

Question: Finally, we request comment on whether ONRR should use published index prices to value Federal oil and gas sold under non-arm's-length contracts as well as arm's-length contracts.

Index valuation should be an option for producers in place of the current gross proceeds methodology for all transactions, whether at arm's-length or not.

Transportation Allowances

Question: The ONRR is examining possible alternatives to the requirement to track actual costs for determining transportation and to address the bundling issue. Please consider the following:

If ONRR were to adopt index-based valuation, the point at which the index prices are compiled and published may or may not be the point of actual sale for particular gas, and the costs of transportation to the actual point of sale may not be relevant. However, the index pricing point would be remote from the lease or unit in virtually all circumstances, and value at the index pricing point may not reflect value at or near the lease or unit. If ONRR employed index prices to value Federal oil and gas for royalty purposes, what methods should be considered that would adjust for location differences between the lease or unit and the index pricing and publication point?

In order to most accurately reflect value in an optional index-based valuation, there needs to be a location differential with an escalation factor and a separate component for fuel. The government must also provide a mechanism for review such that differentials and escalation factors are periodically revised to maintain validity. Provisions for extraordinary transportation allowances also need to continue - 30 CFR 206.156(c)(3).

Question: In the interest of simplifying the determination and verification of location adjustments, should ONRR consider prescribing either a fixed differential amount per unit volume (thousand cubic feet (Mcf) or million British thermal units (MMBtu)) or a fixed percentage to be deducted from the index value to account for location differences?

In an optional index-based valuation, a fixed amount per MMBtu for the infrastructure costs or transportation fee plus a fixed percentage for the fuel component should be used.

Question: Should ONRR apply a fixed differential amount per unit volume to all production in a particular area or that is transported through a particular pipeline?

In an optional index-based valuation, a location differential/fuel component adjustment needs to be calculated for each index point, including offshore. The government should include different rates for coalbed methane development and for conventional gas development, and the rates must be kept on MMBtu basis to maintain simplicity and effectiveness with existing systems.

Question: Would a flat percentage of the index value (perhaps with a cap) be preferable, either on a regional or nationwide basis?

Rather than deducting a percentage of the index value as a transportation allowance, costs on a system-by-system basis, if it wishes to provide an optional index based method of valuation. For natural gas transportation systems and processing plants in New Mexico, ONRR annually publishes the percent of actual bundled fees that may be deducted from royalty values. *See* Dear Reporter Letter, Guidance on Valuing Gas for Royalty Purposes – Transportation Systems and Processing Plants – Onshore Federal Leases (Oct. 6, 2010); www.onrr.gov/unbundling/. The quality of production varies widely depending on geographic location. For example, gas produced from one area may require more processing than gas from another. Calculating deductions on a system-by system basis is therefore more likely to result in more accurate values for services provided. ONRR should do the same for all pipelines and transportation/processing systems both on and offshore.

A flat percentage would likely keep the index-based option from being widely used and is not preferred. Using a flat percentage would introduce substantial complexities due to the variabilities, distances, differences in offshore development, differences in coalbed methane development, etc. It would more accurately reflect actual transportation costs to use a fixed cost with an escalation factor and a separate component for fuel.

Should ONNR adopt a flat percentage, there should not be a cap. In most cases, as prices rise and stay elevated, costs associated with transporting gas can rise dramatically. A cap on allowances would be costly to producers during times of rising or sustained higher pricing. If ONRR decides upon a flat percentage with a cap, however, then it should also include a floor.

Please note, however, that Alliance members have found ONRR's approach to unbundling to be especially troublesome, as explained in greater detail at the end of these comments.

<u>Processed Gas and Processing Allowances</u>

Question: The ONRR is considering accounting for the value of liquid hydrocarbons contained in the gas stream by applying an adjustment or ''bump'' to the index price, applicable to residue gas when gas is processed, in lieu of valuing residue gas and extracted liquid products separately, calculating the actual processing costs, and deducting those costs from the value of the extracted liquids (the procedure required under 30 CFR 1206.153(a) and 1206.158 through 1206.159). This adjustment could be based on, or could incorporate, a number of components, including the following:

Gas quality (either Btu content or gallons per Mcf (GPM)).

An adjustment or bump should not apply to keep-whole contracts where there no is "plus" or "uplift". GPM would more accurately capture the cost of the gas but it would be administratively burdensome and difficult to carry it out. GPM is not always available in a timely manner, depending on the processing arrangements. Additionally, revisions to the plant statements would most certainly result in revisions to the GPM, creating a need to revise royalty reporting and payments. The Alliance thus supports the use of a bump, except for in situations where the gas is processed under keep-whole contracts.

The differential between the gas price and the oil or natural gas liquids (NGL) price similar to a ''frac spread'' or a ''processing margin.''

This may be a way to adjust for processing cost, but this method could present significant complexities and the differentials would have to be published in a very timely and ongoing manner. This differential truly changes over time and the adjustment would have to continuously take into account this variability. Revenue neutrality must be maintained if this type of differential is used to adjust for processing costs.

Certain plant operation factors, such as shrinkage, producer processing costs, and plant operations costs.

In order to maintain revenue neutrality, the adjustment should take these factors into account, because the consideration of these factors would result in closer approximation the actual royalty value. This type of an adjustment must take into account both the processing fees and plant fuel charges. The government must also maintain provisions for extraordinary processing allowances in the event this adjustment is used.

Question: We also seek input regarding whether such an approach could eliminate the burden of accounting for allowable costs to process gas and reduce or eliminate the potential for disputes over unbundling of gas plant charges, without reduction in royalty value. The ONRR could calculate this adjustment on a monthly basis and make it available on our website expressed in the form of a price per unit volume (MMBtu or Mcf).

If done timely, accurately and effectively then this adjustment has the potential to reduce burden. The ultimate goal should be the elimination of burden, and the monthly postings on the website musts be done timely so that lessees can utilize the approach and actually gain the potential benefits of reduced burden. Under this approach MMBtu content is preferable. Posting the rate on the website on a monthly basis should help reduce disputes, but this raises several questions that must be addressed in order to avoid further complications down the line. What if something is posted incorrectly? Will the agency make retroactive revision? How far back could these revisions be made? These types of corrections could significantly add to the burden and should be considered in developing such an approach. Furthermore, any potential approach should address all gas liquid products, including condensate and others that do not fall under the NGL category.

Question: ONRR could maintain current reporting requirements for processed gas and NGLs but establish a fixed processing allowance. This fixed allowance could be either on a nationwide basis for all Federal gas or on a narrower basis, such as offshore and onshore leases; offshore regions and onshore basins; or gas-plant-specific.

A narrower basis is preferred; the narrower the basis the more revenue neutral the allowance will be. At a minimum, the allowance should be on an offshore region and onshore basin basis, AND on a plant type basis. The type of plant, e.g., cryogenic, lean oil, adsorption, absorption, and the plant efficiency should also be considered.

As with transportation allowances, the Alliance opposes the use of a percentage of index price for processing allowances. See response to whether ONRR should adopt fixed percentages of index value for transportation deductions.

GENERAL COMMENTS

Revenue Neutrality

The Alliance agrees with ONRR's assessment that compliance costs are extremely high and that arm's length transactions are the best indicator of value. However, the government currently scrutinizes lessee's contracts and disallows most costs associated with getting the gas to market. The existing royalty regulations result in significant costs to industry through disallowed compression, transportation and processing costs.

Providing efficient royalty valuation methodology is important and early certainty that payments are correct is a good measure of efficiency. If ONRR waits 18 or 20 months before identifying incorrect payments, it results in substantial time and costs to fix. If federal royalty is inadvertently reported and paid incorrectly for those 20 months, they must be corrected by amended reporting. The amended reporting burden can go up significantly when the complexity of reporting for a communitization or participating agreement is involved.

The Alliance believes a fixed amount per MMBtu on a regional basis would be the most accurate and efficient way to apply and account for transportation and processing allowances. Allowances based on percentage of price would be harder to adjust and less accurate than a flat per MMBtu assessment. To be as accurate as possible, indices should be regionally based or perhaps county based in states with larger counties.

Industry believes a properly implemented index price (revenue neutral and allowing for actual costs to process and transport hydrocarbons) would result in appreciably lower administrative costs.

Arbitrary Disallowance of Compression Costs

ONRR's recent practice has been to scale back dramatically on costs of compression as allowable deductions from downstream sales proceeds. The latest development in ONRR's practice has been to disallow compression costs within processing plants even when compression is essential to the process of removing liquefiable hydrocarbons from a gas stream. For example, to safely transport condensate from hydrocarbon-rich gas streams, it is often necessary to "stabilize" the condensate by increasing the proportion of heavier hydrocarbons such as pentanes and hexane plus to reduce the vapor pressure within the condensate. Stabilizer towers are used to perform this task. In the tower, pressure is reduced. Heavier hydrocarbons drop out. Lighter hydrocarbon molecules rise to the top of the tower as vapor. Compressors are then necessary to inject the tower vapors into the gas stream. The drop in pressure and increase in pressure are part of the process of removing marketable hydrocarbons. ONRR has rejected allowances for processing related compression in audits in western states. The regulations need to be clarified to stop that practice.

Arbitrary Methodology for Unbundling Gathering and Processing Fees

Question: [C]ertain provisions of the current Federal oil and gas regulations have presented challenges that led to disputes between lessees and ONRR auditors, particularly in situations involving non-arms'-length sales and non-arms'-length transportation and gas processing allowances. For some Federal oil & gas production, changes in the oil and gas transportation industry have made it difficult for lessees to obtain the information they need to comply with ONRR regulations that require the use of actual costs in determining transportation allowances. Additionally, pipeline operators often bundle transportation and processing charges, including charges that the regulations do not allow lessees to deduct in calculating royalty value, such as marketing costs and costs of placing gas into marketable condition.

Currently production from numerous federal wells in New Mexico is processed through plants that maintain keep-whole contracts with the operators. A keep-whole agreement requires that the gas plant processor deliver the same number of Btu's of residue gas as was delivered in raw gas at the plant inlet, while the processor retains the liquids. It is common for gas processing plants to charge a bundled fee which includes all services performed by the plant such as compression, gathering, transportation, and processing. ONRR has in the last four years attempted to "unbundle" these fees to separate them into deductible and nondeductible costs on the theory that some costs are incurred to place the production into marketable condition. "Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 206.151.

All processed gas must be valued under 30-CFR §§ 1206.153(a), 1206.158, & 1206.159. One of ONRR's proposed options is to value the gas quality through Btu content, which the Alliance does not oppose. If the point of royalty settlement is the inlet meter to the plant, under a typical keep-whole contract the processor "shall be entitled to the Plant Products Processed from Shipper's Gas and shall be responsible for replacing the Shrink attributable to Processing Shipper's Gas." As such, royalties would be valued at the point of royalty settlement based on the delivered MMBtu's. Current ONRR regulations require that value be determined after processing to ensure full marketable value is realized for both residue and NGL's. A typical processing contract states that the "Shipper dedicates to Processor for Gathering, Processing, Dehydrating and Treating all of Shipper's present and future right, title and interest in the gas produced from upstream of the receipt point." This phrase implies an operator has no right to the delivered gas beyond the inlet of the plant and no control over how the gas is processed.

A keep-whole contract requires the operator to value NGLs utilizing the theoretical composition of the gas to determine the liquids content. An index price is then applied to each potential product. A processor is unable to provide any supporting documentation on the specific products removed from any individual gas stream. Furthermore, there is no proof of what would eventually be sold or otherwise disposed. Revenue neutrality cannot be maintained using undocumented sales. Due to subscription copyright issues, the ONRR will not provide NGL index pricing for the sole purpose of reporting to the ONRR. This is an additional cost burden (approximately $15,000 annually) on operators that are not in the business of selling NGL's and do not have the pricing readily available.

Once a total theoretical value is generated for processed gas, the unbundling process can begin. The plant should provide detail as to the fees that are included in their bundled rate. The fee needs to broken out, usually as a percentage of the total fee, and applied individually to the value of the gas. As noted above, for a number of individual gas plants and gathering systems in New Mexico, ONRR provides deductible percentages of costs. In one company's experience with a particular plant, the bundled fee contains charges for processing, transportation, gathering, and compression. However, only processing and transportation are allowed to be deducted from the gross proceeds of residue gas or NGL's, and only 17.61% and 4% respectively, of the total fees from that specific plant can be deducted. That ONRR disallows so much of the fee is an indicator that ONRR is following an incorrect approach to determining what the marketable condition rule requires.

A flat rate or index would alleviate the cumbersome accounting required in breaking out the fees, taking the allowed percentages and then deducting from the appropriate products. It should also be noted that posted unbundling rates are not current beyond 2007.

Ultimately, operators are faced with a combination of a keep-whole contract as well as the unbundling of fees charged by the processor. The result to an operator is additional accounting time to analyze and value the wellhead gas to processed residue and NGL's, as well as the additional cost of purchasing the NGL index pricing subscription.

CONCLUSION

We appreciate the opportunity to comment on ONRR's advance notice of proposed rulemaking on federal oil and gas valuation and request that you give our responses to the questions posed in the FR and other comments serious consideration. If you have questions, please contact me at (303) 623-0987 or skimball@westernenergyalliance.org.

Sincerely,

Spencer Kimball
Manager of Government Affairs