May 4, 2017

Ms. Amy Holley
Acting Assistant Secretary for Policy, Management and Budget
U.S. Department of Interior
Washington, DC

Re: **Comments on the Office of Natural Resources Revenue's (ONRR) proposed rule *Repeal of Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform*, 82 Fed. Reg. 16323 (April 4, 2017), RIN 1012-AA20**

<u>Submitted via Email and Regulations.gov</u>

Dear Ms. Holley:

The American Petroleum Institute ("API") strongly supports the ONRR proposed rule to repeal the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Rule published on July 1, 2016 ("2017 Valuation Rule") and appreciates this opportunity to comment. The 2017 Valuation Rule significantly altered many important and longstanding valuation policies, creating wide regulatory uncertainty and unconstrained agency "discretion." It placed both offshore and onshore federal oil and gas lessees in an untenable position going forward with respect to their royalty reporting and payment obligations.

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. The industry has paid more than 150 billion dollars in royalty revenues to the federal treasury.

API member companies are committed to continued compliance with royalty regulations consistent with the mineral leasing statutes and support ONRR's original intent "to offer greater simplicity, certainty, clarity, and consistency in product valuation and reporting for mineral leases." We want to work with ONRR to ensure that the agency's regulations achieve these goals.

Unfortunately, the 2017 Valuation Rule did not meet these objectives. The final version of this Rule was essentially unchanged from its proposed rule and contained multiple shortcomings. These shortcomings include:

- A new "default" valuation provision whereby ONRR may unilaterally establish royalty value in the first instance under numerous, broadly defined circumstances. This default provision permits the Agency to "second-guess" lessees' royalty valuation without providing any indication of when ONRR would substitute its judgment for the lessee, how it would wield such discretion, or what factors ONRR would use. The "triggers" for this provision also lack a rational foundation. The default provision undermines the certainty of even a lessee's arm's-length sales prices as value and creates the risk that ONRR may impose a higher royalty value, with corresponding late payment interest, many years after production and initial payment.

- Blanket denial, artificial limitation, and termination of allowances to which lessees are legally entitled, undermining ONRR's longstanding recognition of valuation at or near the lease. For example, with little to no justification, ONRR has arbitrarily capped transportation and processing allowances (respectively, 50% and 66.66% of the value of oil and gas/natural gas liquids) notwithstanding ONRR's prior recognition that some operations incur higher reasonable, actual transportation or processing costs fully justifying higher allowances.
- Arbitrary reversal of longstanding subsea transportation allowances for offshore oil and gas. After two decades of industry reliance, ONRR has reversed its determination – without justification – that subsea movement of oil and gas over long distances in the deepwater Outer Continental Shelf is transportation and therefore an allowable deduction to realize the value of oil and gas at the lease.
- Refusal to recognize for valuation purposes any contract for the sale of oil or gas that is legally enforceable yet may be unwritten or unsigned by all parties; and
- Requirement to pay royalty on unattainable index prices for federal gas. API members conceptually support the option to choose index pricing for unprocessed and processed gas and strongly recommended to ONRR that the option be available to arm's-length sales as they too have the same tracing and unbundling issues as those lessees with non-arm's-length sales. Unfortunately, the index pricing terms implemented in the 2017 Valuation Rule result in an arbitrary premium for the privilege and ignore how oil and gas actually flows and is sold.

The above regulatory changes and others in the 2017 Valuation Rule reverse many longstanding policies on royalty valuation options and allowances, are arbitrary, and create wide business and contract uncertainty for lessees. In many cases, these new requirements are impracticable for lessees to comply with and difficult to implement. For example, the rule requires a payor to identify and split out "transportation factors," which the rule fails to sufficiently define, and then report them as a transportation allowance on a separate line. Having to review all sales contracts to determine if there is a transportation factor or not and then having to split them out is difficult enough, but in many cases it is impossible to fully know whether there is a transportation factor or if it is simply a location or market differential. It is also tedious and difficult for companies to value and report gas sold prior to processing under an arm's length percentage of proceeds or similar contract due to sparse information available from some midstream processors/purchasers.

The many flaws of the Rule are described in more detail within the documents attached and incorporated by reference in this letter:

- A May 8, 2015 comment letter submitted to ONRR jointly by API, the Independent Petroleum Association of America and the National Ocean Industries Association (Attachment A),
- A Petition for Review of Final Agency Action, filed on December 29, 2016, in the United States District Court for the District of Wyoming (Attachment B), and
- A February 17, 2017 letter from Petitioners to ONRR Director Gould requesting postponement of the 2017 Valuation Rule (Attachment C).
- A May 8, 2015 comment letter submitted to ONRR by the Council of Petroleum Accountants Societies (Attachment D).

In light of these many flaws that permeate the rules and cannot be readily fixed, API strongly supports repeal of the 2017 Valuation Rule in its entirety. If the Agency is still interested in amending the existing royalty valuation regulations, then we recommend that it "start fresh" with a new rulemaking. We also strongly encourage the Agency to consider presenting the issue, including all public comments received through the 2017 Valuation Rule process, to the newly re-established Royalty Policy Committee (RPC) Federal Advisory Committee for their counsel as this matter seems to fall squarely within this Committee's scope of work and is an appropriate forum for stakeholder engagement on this issue.

Thank you for your time and attention to our comments on this Proposed Rule. API members remain committed and look forward to working with ONRR on valid, reasonable efforts to improve and strengthen its royalty valuation processes. Please do not hesitate to contact me if you have any questions.

Sincerely,

Emily Hague

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May 8, 2015

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Attn: Regulation Identifier Number (RIN) 1012-AA13

Re: American Petroleum Institute, Independent Petroleum Association of America, and National Ocean Industries Association Comments on Office of Natural Resources Revenue (ONRR) Proposed Rule to Amend Federal Oil & Gas Valuation Regulations, 80 Fed. Reg. 608 (Jan. 6, 2015)

Submitted via: http://www.regulations.gov and U.S. mail

Dear Mr. Southall:

On January 6, 2015, the Office of Natural Resources Revenue ("ONRR") issued a Proposed Rule entitled "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform." This rule would significantly alter regulations applicable to gas valuation for royalty reporting and payment by oil and gas lessees (and other lessees) on federal lands onshore and on the Outer Continental Shelf ("OCS"). It also would materially amend the corresponding regulations governing oil valuation last overhauled in 2000. The American Petroleum Institute ("API"), the Independent Petroleum Association of America ("IPAA"), and the National Ocean Industries Association ("NOIA") (collectively, "we") appreciate the opportunity to submit comments on this Proposed Rule.[1]

API is a national trade association that represents over 625 members involved in all aspects of the oil and natural gas industry, including the exploration and production of both onshore and offshore resources. The U.S. oil and natural gas industry supports 9.8 million U.S. jobs and more than 8 percent of the U.S. economy. The industry has paid more than $150 billion in royalty revenues to the federal treasury.

IPAA is the national association representing the thousands of independent crude oil and natural gas explorer/producers in the United States. It also operates in close cooperation with 44

[1] API, IPAA and NOIA are not commenting on the proposed changes to coal valuation for royalty purposes.

unaffiliated independent national, state and regional associations, which together represent thousands of royalty owners and the companies which provide services and supplies to the domestic industry. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

NOIA, founded in 1972, represents more than 325 companies among all segments of the offshore industry with an interest in the exploration and production of both traditional and renewable energy resources on the nation‘s outer continental shelf (OCS). NOIA's mission is to secure reliable access and a fair regulatory and economic environment for the companies that develop the nation's valuable offshore energy resources in an environmentally responsible manner.

API, IPAA and NOIA appreciate ONRR's focused efforts to improve the regulatory process for federal oil and gas royalty valuation, and we believe certain of ONRR's proposed amendments do further that objective. In particular, we support the expanded option to use index pricing to value federal gas for royalty purposes, akin to the current regulations governing valuation of federal oil for royalty purposes. As explained below, however, key facets of the Proposed Rule are fundamentally flawed, lack a reasoned basis, and would place both offshore and onshore federal lessees in a wholly untenable and uncertain position going forward with respect to their royalty reporting and payment obligations. While we share ONRR's commitment to ensure a fair return to the public on production of oil and gas from federal leases, ONRR's proposal in several respects amounts to unjustified changes to the existing regulatory scheme in an unabashed attempt to benefit the federal coffers beyond the royalties fairly, and legally, due from federal lessees. Additionally, we believe ONRR has significantly understated the cost to industry. For example, ONRR has assigned no cost to its application of the proposed "default provision," or to the moving of arm's-length percentage-of-proceeds ("POP") contracts from the unprocessed to the processed gas regulations – when those and other changes will certainly have negative cost consequences on the regulated community. Many of ONRR's proposals also are legally suspect under the well-established legal principle that ONRR must provide at least as much, if not more, compelling justification to change its regulations than it had in adopting those regulations in the first instance. *Perez v. Mortgage Bankers Ass'n*, 2015 U.S. LEXIS 1740 (Mar. 9, 2015); *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 516 (2009); *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983). ONRR's Proposed Rule, largely based on mere fiat and unbounded discretion, fails to meet this burden. Accordingly, ONRR at a minimum should revise its Proposed Rule consistent with the comments below.

Certain API, IPAA and NOIA concerns pervade multiple aspects of the proposal – such as the entirely uncertain standard created by ONRR's newly claimed "discretion" in any given case to set aside the established regulatory scheme at whim and substitute a blackbox valuation determination by ONRR. Other problems relate to specific provisions. Accordingly, we first present immediately below its overarching and principal comments on the rule. Subsequently, we provide section-by-section comments that, for ease of reference, proceed sequentially through the Proposed Rule's provisions. API, IPAA and NOIA reserve the right to amend or supplement these comments as warranted.

I. API, IPAA and NOIA GENERAL COMMENTS

The Proposed Rule purports to "offer greater simplicity, certainty, clarity, and consistency in product valuation" and decrease compliance costs for all parties. 80 Fed. Reg. at 608. API, IPAA and NOIA fully support these goals. Yet, upon analysis, ONRR's Proposed Rule would in fact remove much of the certainty in royalty valuation that has been a hallmark of the oil and gas valuation regulations since 1988. Instead, ONRR would create new opportunities for the agency to second-guess lessees' valuation processes, arrogate to itself the unilateral ability to set aside its prescribed regulatory processes, and exercise essentially unreviewable discretion to establish the royalty value on a case-by-case basis. Where ONRR does declare new bright-line rules, they are arbitrarily drawn and conflict with prior well-reasoned explanations and settled expectations. Overall, the Proposed Rule does not represent progress.

ONRR's Proposed Rule contrasts sharply with the thoroughly reasoned and supported efforts undertaken by ONRR's predecessor, the Minerals Management Service ("MMS"), in previously overhauling the oil and gas valuation regulations in 1988. MMS there recognized and responded to industry concerns that agency-retained discretion to establish royalty value in the previously existing regulations permitted the agency to "second-guess" lessees' royalty valuation, even for arms'-length contracts reflecting the marketplace, resulting in substantial audit demands for royalty underpayments and associated late-payment interest. Industry sought clear direction on how it must pay royalties so it could report and pay correctly in the first instance. MMS, Industry, States, and Tribes, through the Royalty Management Advisory Committee chartered by the Secretary of the Interior, embarked on a multi-year rulemaking process. That process involved carefully crafted and meaningful compromises on all sides of the table in a collaborative effort to infuse greater certainty into the royalty valuation process, a mutually sought goal. Those dedicated efforts culminated in the 1988 oil and gas valuation regulations. Inexplicably, ONRR is now proposing to reinstate uncertainty and agency discretion in the establishment of royalty valuations, re-creating many of the problems that existed before 1988.

The 1988 rules are not perfect, as ONRR and we would appear to agree. But while certain valuation metrics and references are amenable to updates reflective of the current oil and gas marketplace, the core principles and approach underlying the prior rulemakings remain sound, particularly the reliance on the sanctity of arm's-length contracts. In pursuing any "fixes," ONRR cannot summarily disavow and cast aside prior findings and understandings. Rather, the agency must exercise the same care to ensure its purported improvements rest on substantial evidence, are administratively workable, and respect industry reliance interests. As the U.S. Supreme Court reaffirmed only weeks ago:

> [T]he APA contains a variety of constraints on agency decisionmaking—the arbitrary and capricious standard being among the most notable. As we held in *Fox Television Stations*, and underscore again today, the APA requires an agency to provide more substantial justification when its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance

> interests that must be taken into account. It would be arbitrary and capricious to ignore such matters.

Perez, 2015 U.S. LEXIS at *21-22 (internal citations and quotations omitted). Yet the Proposed Rule and its preamble make little effort to square ONRR's new approach with its well-established existing policies or to explain why the sea changes are warranted. In some instances, the preamble does not even disclose the full nature of the proposed changes to the regulatory text, which could mislead interested stakeholders until it is too late to meaningfully provide input.

The most blatant, and problematic, instances of ONRR's newly injected uncertainty include the "new default provision" proposed at § 1206.144, as well as the various triggers for application of that provision at § 1206.143 and interspersed elsewhere throughout the Proposed Rule. ONRR's preamble concedes ONRR's intent to wipe away the progress achieved in the 1988 rules, second-guess lessees' valuations, and substitute its own values for oil and gas production. 80 Fed. Reg. at 614 ("Like the valuation regulations in effect prior to the 1988 rulemaking that resulted in the current gas valuation regulations..."). Moreover, ONRR would quietly delete 30 C.F.R. §§ 1206.102(c)(2)(ii)(A) and (B), which consist of carefully constructed safeguards against ONRR's second guessing of arm's-length agreements. ONRR does so despite its simultaneous recognition that "gross proceeds from arm's-length contracts are the best indication of market value." 80 Fed. Reg. at 609. ONRR now instead claims "considerable discretion to establish the reasonable value of production using a variety of discretionary factors and any other information the Secretary believes is appropriate." 80 Fed. Reg. at 610.

Whatever the scope of ONRR's discretion might be legally, it does not follow that ONRR can or should dispense with the established rules whenever it wants. ONRR provides no indication of when it will (or will not) substitute its judgment for the lessee, how ONRR would (or would not) wield such "discretion," or what factors ONRR would (or would not) utilize. Rather, lessees are left to guess if and when ONRR will decide to insert itself into regular business transactions and what the results of such intervention would be. That is, lessees must report and then hope for the best – hardly a viable business strategy.

In practical operation, under the Proposed Rule, ONRR may decide it dislikes any given lessee's reported oil or gas valuation for any reason. In that instance, ONRR would not afford the lessee an opportunity to correct any identified errors or utilize a different method, but would simply dictate the new valuation and corresponding royalty due. A mere inadvertent or insubstantial paperwork error could be enough to trigger the "default provision." Unreasonably low arm's-length prices or unreasonably high allowances, with ONRR as the sole arbiter of what is "reasonable," also trigger the default valuation provision. Moreover, ONRR could intercede even without any observed error if ONRR simply is not sure "for any reason" that a lessee "properly" valued oil or gas. In setting the new valuation, ONRR could consider "any information ONRR deems relevant" – including the current gas valuation benchmarks ONRR proposes to rescind for lessees' use, and other metrics or information unavailable to lessees. *Compare* 80 Fed. Reg. at 609 ("ONRR proposes to eliminate current benchmarks" for gas) *with id.* at 614 (Proposed Rule "allows ONRR to consider any criteria we deem relevant, as well as criteria similar to the current gas valuation benchmarks"). The value ONRR establishes would also be effectively unchallengeable given ONRR's likely assertion of confidentiality claims for the underlying information, e.g., sales prices other lessees report to ONRR. The uncertainty that ONRR is creating in the Proposed Rule is particularly problematic in view of ONRR's aggressive new policies on proper initial reporting and payment of royalties and threats of substantial civil penalties for erroneous reporting. (See 79 Fed. Reg. 28,862 (May 20, 2014), and API's prior submitted comments on that separately pending rulemaking.)

The Proposed Rule also would reverse course on other important and longstanding policies, valuation options, and allowances upon which industry has come to heavily rely in expending the huge investments necessary for developing oil and gas resources on federal leases onshore and on the OCS. This is best illustrated by several newly announced "blanket" rules that remove current flexibility and accommodations without any explained rationale for the change (except to increase ONRR's revenue streams). A prime example is ONRR's sudden reversal on treatment of all subsea movement of bulk production as "gathering" rather than "transportation," ignoring any relevant facts such as the long distances traveled and the relative paucity of deepwater surface facilities. Companies that undertook the risk and expense and paid higher bonuses to develop deepwater oil and gas resources for the last 16 years did so in reliance on ONRR's existing, well-reasoned deepwater policy explaining that much of the subsea movement of oil and gas from subsea manifolds to distant platforms (some 50 or more miles away) constituted a deductible transportation cost and was not "gathering" as defined by the regulations. ONRR acknowledges that this change will cost tens of millions of dollars annually as companies would have no flexibility to conform their operations to the new rule. ONRR offers no new circumstances or factual or engineering support for this change.

Separately, ONRR would arbitrarily cap transportation and processing allowances (respectively, 50% and 66.66% of the value of oil and gas/natural gas liquids) notwithstanding ONRR's recognition that some operations incur higher reasonable, actual transportation or processing costs fully justifying higher allowances. Further, ONRR would terminate existing agreements providing for such higher allowance exceptions. ONRR's sole proffered reason to upset well-settled and reasonable investment-backed expectations is administrative convenience.

As ONRR continues to admit, the value for royalty purposes of production from federal oil and gas leases must be established at or near the lease. 80 Fed. Reg. at 609 ("the Department reaffirms that the value, for royalty purposes, of crude oil and natural gas produced from Federal leases… is determined at or near the lease"). This foundational principle derives from the terms of the mineral leasing statutes and the leases. But ONRR fails to explain how the above and other limitations categorically denying lessees the ability to deduct reasonable, actual, and necessary transportation and processing costs preserve that key principle.[2] These new rules

[2] ONRR perhaps said it best in its preamble to its recently finalized Indian oil valuation rule:

> In essence, transportation allowance accounts for the costs that a lessee must incur to move its production to a market and, therefore, captures the value at the lease. The lessor shares in this expense because the lessor reaps the benefit of selling its lease production at a market rather than at the wellhead . . . . [F]or decades ONRR's regulations have allowed a lessee to deduct its

upsetting established and well-founded expectations not only are unfair, but also risk raising breach of contract and other legal claims. As specified in the existing regulations, lease terms and written agreements prevail over existing regulations. 30 C.F.R. § 1206.100(d). ONRR's Proposed Rule contains the same reservation, and cannot instantly alter the relationship of existing contractual parties to extract additional financial consideration after the fact.

On that note, ONRR's authority to implement royalty valuation changes is more limited where, as here, the existing valuation rules constitute a core economic component of oil and gas leases. Such lease agreements between lessees and the government are valid existing contracts to the same extent that they would be between private parties. *See, e.g., Mobil Oil Exploration & Producing Southeast, Inc. v. United States,* 530 U.S. 604, 607 (2000). While the BLM, BSEE, and BOEM may have the right to alter certain operational requirements onshore or offshore, ONRR does not have the same latitude to change economic terms to extract more royalty from lessees after the leases have been issued.

As discussed below, individual provisions in the Proposed Rule fully justify our overarching concerns regarding industry uncertainty, standardless ONRR discretion, second-guessing of arm's-length contracts and other lessee valuations, and denial of lessees' ability to deduct all appropriate costs to reflect value at the lease. Other specific problematic provisions we explain below include, but are not limited to, the following:

- Freedom to select the index option if <u>lessees</u> sell their gas downstream of the lease (whether the sale is arms-length or non-arms-length)
- Inflated proposed index values (both in the requirement to use the "highest" monthly bid week price, and the requirement to use the highest index among multiple index pricing points to which the lessee's gas could flow, even if the lessee's gas does not, and even could not due to pipeline constraints, physically flow to those other index pricing points)
- Vague limitations on transportation allowances for costs lessees did not "incur"
- An ineffective process to obtain valuation guidance from ONRR
- Reliance on outdated cost information (2007-2011) to justify proposed regulatory standards, which also fails to reflect the significant effect of the new price environment
- Unwarranted reduction of the 1.3 multiplier applicable to the S&P BBB bond rate in determining transportation and processing costs
- Unnecessary elimination of the use of a FERC/State approved tariff in lieu of the complicated process of calculating actual transportation costs
- Disallowance of transportation factors

> transportation costs to calculate the value of their Indian oil production when it sells that oil at a location remote from the lease. . . . ONRR has consistently allowed transportation costs because transporting oil to market off of the lease increases the value of the oil.

In addition, we fully support the detailed comments submitted by the Council of Petroleum Accountants Societies ("COPAS"). COPAS is the leading accounting organization for the oil and gas industry and, like our members, provides invaluable viewpoints about the workability of ONRR's valuation regulations based on longtime experience working directly with them. As explained by COPAS, ONRR should take this opportunity to consider and resolve various issues with its proposed (and existing) federal oil and gas valuation rules, including but not limited to the following:

- Allowing sufficient time for industry to make any necessary accounting system changes
- Express assurance of no retroactivity in the Proposed Rule
- If ONNR believes royalties need to be reported and paid on field fuel/disallowed plant fuel volumes, then the regulations need to address them as added costs/royalties to industry
- For NGL index values, whether ONRR intends the average highest price or the average average price, and the need for inclusion of a transportation allowance from the lease to the plant
- ONRR's proposal to codify that deductions for boosting are never allowed, resulting in some lessees having to place the gas into marketable condition twice. Due to cryogenic plant processes, gas is often compressed and/or produced to mainline pressure base (for offshore production often it leaves the platform well above mainline pipeline specs). Thus, when ONRR adds "and cost of boosting residue gas" is disallowed, it will result in requiring lessees that use cryogenic plants to pay for the compression twice. It will also result in inconsistent handling between processed and unprocessed gas and the different plants
- Formal notice, communication, and appeal procedures for any "default" provision, to enable lessees to respond, dispute, or provide additional information
- Unavailability of necessary data for ONRR's reporting for keepwhole contracts
- Unnecessary retention of "Accounting for Comparison" given the new requirement for affiliated sales to use the first arms-length sale

While some of these issues identified herein may be sufficiently addressed by altering the proposed or existing regulatory language, others require ONRR to reassess its overall approach and underlying assumptions. ONRR should also consider re-proposing an amended rule for further public comment to ensure that the identified deficiencies and ambiguities have in fact been resolved to the satisfaction of both the agency and the regulated community.

II. <u>API, IPAA and NOIA SECTION-BY-SECTION COMMENTS</u>

The below comments track the organization of the Proposed Rule. While most of the changes pertain to gas valuation regulations, many of the proposed modifications are intended to conform those regulations to the structure of the existing and proposed oil valuation regulations. Where ONRR proposes to also change oil regulations, the corresponding oil and gas provisions in the Proposed Rule are listed together and largely subject to the same comments. Unless otherwise noted, ONRR should make the same recommended changes to both its oil and its gas proposed regulations.

A. <u>§ 1206.20 Definitions</u>

API, IPAA and NOIA support ONRR's consolidation of definitions for oil and gas into one place in the regulations. That said, certain proposed definitions are problematic or unclear.

1. *Gathering* [*See also* §§ 1206.152(a)(2)(ii) (gas), 1206.110(a)(2)(ii)(oil)] For oil and gas produced from OCS leases, ONRR would categorically declare "any" movement of production from the wellhead to a platform as gathering. As evidenced by ONRR's own economic analysis accompanying the Proposed Rule, this change would have the most significant economic impact. 80 Fed. Reg. at 633, 637. It would reverse guidance that has stood for over 15 years. *See id.* at 623-24. And the proposed change is substantively wrong – moving offshore oil or gas over many miles is transportation, not gathering.

This is not the first time that the agency has contemplated this issue. In July 1998, during its rulemaking process resulting in the 2000 valuation rules for oil, MMS specifically "requested comments on the definition of 'gathering' as related to deepwater leases involving subsea production without a platform but with long-distance movement of bulk production." 63 Fed. Reg. 38355, 38356-57 (July 16, 1998) (further supplementary proposed rule); 65 Fed. Reg. 14022, 14046 (March 15, 2000) (final rule). The submitted comments, including those from API and IPAA, explained at length why such costs are more appropriately deemed allowable transportation costs. The comments explained that the historical concept of gathering from onshore or shallow water development, wherein field processes take place on or near the lease, failed to translate to the deepwater OCS. This is because physical and economic barriers necessarily preclude platform facilities from being constructed on each and every deepwater lease. Indeed, the Department elsewhere has stated its interest in minimizing the number of platforms and facilities for the efficient exploration, development, and production of oil and gas resources. *See* 30 C.F.R. §§ 250.1301(c), 250.106(e). In these areas, a subsea manifold or other collection point can effectively serve the function of the first surface facility. Subsea pipelines also entail greater costs and risks borne solely by the lessee, including those for fabrication, installation, operation, and maintenance. To deny transportation allowances for subsea pipelines necessary only to bring production across greater distances to shared platforms would arbitrarily discriminate based on the technology utilized.[3]

In response to these comments, MMS ultimately determined it was <u>not</u> necessary to redefine gathering to include subsea transportation. Rather, nearly a year after soliciting comments and a year before issuing its final rule, MMS issued guidance resolving the issue by confirming that most movement of oil or gas long distances in the deepwater OCS is transportation. *See* 80 Fed. Reg. at 623-24 (acknowledging the 1999 guidance). Another year later, MMS' final rule for oil referenced this guidance and did not revise the regulatory definition of gathering to include such movement. Over the last two decades, companies have proceeded to significantly expand their activities into deeper water, expending many millions of dollars on lease bonus bids, exploration,

[3] The sparse comments received in 1998 opposing transportation deductions lacked any legal or technical rationale, instead merely opining that lessees should be penalized for receiving certain deepwater royalty relief volumes enacted by Congress.

and development. In planning and constructing these facilities, including joint platforms with tie-backs to distant leases, these lessees have reasonably relied on the agency's allowance of transportation costs for subsea movement.

ONRR now purports to "rescind" this precedent and adopt the opposite position, but its cited authority and reasoning do not support its conclusion. ONRR claims that "almost all of the movement the Deep Water Policy allows as a transportation allowance is, in actuality, non-deductible 'gathering,'" relying on *Kerr-McGee Corp.*, 147 IBLA 277 (1999). That statement is patently wrong and the cited case does not support ONRR's assertion. *Kerr-McGee* was decided <u>before</u> MMS issued the 1999 guidance, and thus MMS was aware of it in crafting its now-longstanding policy. Moreover, the IBLA there merely denied retroactive transportation allowances for production from "adjacent leases." *Id*. at 263 ("We agree that, even though production is moved across lease boundaries, because it is treated and sold <u>on adjacent leases</u> the costs of moving it there are properly regarded as gathering, not transportation….We conclude that MMS correctly determined that Kerr-McGee was not entitled to reimbursements for the costs of gathering and accumulating the gas <u>under the circumstances of this case</u>.") (emphasis added). This principle of close proximity or adjacency remains key. Indeed, in *Kerr-McGee*, the agency itself took the position that transportation involved moving production "remote from the lease or field." *Id.* at 282. In a subsequent case citing *Kerr-McGee*, the IBLA further clarified that "we in general have no objection" to the proposition that "'gathering' refers only to well head and in-field movement of production." 147 IBLA 386, 396 (1998) (disallowing transportation cost deductions only because the Section 6 leases pre-dating the Outer Continental Shelf Lands Act stated that "no gathering <u>or other charges</u> are made chargeable to the lessor" in calculating royalty) (emphasis added).

ONRR also asserts that "[i]t is well established that the movement of oil and gas that ONRR determines is 'gathering' is not allowable as a transportation allowance." But that is not entirely true either, if ONRR means to circularly imply that anything ONRR says is gathering is irrefutably not transportation. ONRR cites *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961), but that case has nothing to do with gathering, transportation, or offshore leases. Indeed, the court went to lengths to make clear that the Secretary was not claiming royalty for long-range movement of oil and gas, unlike ONRR would now do via its Proposed Rule. *Id.* at 387 ("Let us here insert a cautionary parenthesis. <u>No transportation costs are involved in this case.</u> The Secretary is <u>not</u> here claiming that costs incurred in moving gas from the field in the neighborhood of the wells to a <u>distant</u> selling point are includable in the royalty base. This gas was conditioned by the seller and delivered to the purchaser in the field within a <u>short distance</u> of the wells.") (emphasis added). Moreover, the agency's denial of transportation costs has not withstood scrutiny in other cases. *See, e.g., Shell Offshore, Inc.*, 142 IBLA 71 (1997); *Exxon Corp.*, 118 IBLA 221 (1991); *Indep. Pet. Ass'n v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002).

Moreover, it appears that ONRR has understated the cost estimate of the impact to industry from this reversal. ONRR estimates a $17.4 to $23.6 million total annual loss to all of industry. But it is likely much higher. Companies have a number of projects in process that would be affected. The construction cost for a subsea system is running as much as $10 million to $15 million per mile, and they may cover many miles between lease areas. These systems are more than a piece of pipe on the bottom of the gulf. The operational controls and safety systems associated with a subsea transportation system increase the construction, operation, and maintenance costs drastically. At the same time, standalone deepwater platforms dedicated to a single lease's production are increasingly difficult to justify given the price volatility for oil and gas and changing regulatory environment. Even conservative assumptions regarding future activity levels and economic conditions would yield an annual royalty share of costs of approximately $1.5 to $2.0 million per project. At that rate, ONRR's estimated costs would account for only 8 to 10 subsea system projects across the entire industry, whether now or in the future. ONRR's estimate does not reflect reality within the industry, and instead hides the true extent of its novel proposed change.

For these reasons, ONRR has no justification to reverse its current policy and create a blanket rule disallowing subsea transportation costs. We are not suggesting that everything subsea-related must be transportation, but categorically determining that no subsea movement to the first platform can ever qualify for a transportation allowance is plainly arbitrary and capricious given the substance and history of this issue. ONRR should continue to recognize that traditional principles of gathering are wholly inapplicable to the unique deepwater environment. Expensive subsea movement across many miles to a surface location is a necessity in some instances, and the valuation of deepwater oil and gas should appropriately reflect that reality. At a minimum, lessees must have the flexibility to defend such transportation deductions in a given case. ONRR's failure to accommodate these concerns would create legal issues and perverse incentives, such as potentially promoting more deepwater structures at significant wasted cost and accompanying risk. Accordingly, ONRR should remove the additions to the definition of "gathering," as well as the duplicative proposed provisions at §§ 1206.152(a)(2)(ii) (gas) and 1206.110(a)(2)(ii) (oil).

2. ***Misconduct*** The proposed regulations would define "misconduct" as any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior, "regardless of the mental state of the lessee or any individual employed by or associated with the lessee" (emphasis added). This definition is overbroad. Any common understanding of "misconduct" involves an element of intentional wrongdoing. Indeed, that was the agency's own understanding reflected in its approach to the analogous concept of breach of duty to market. 65 Fed. Reg. 14022, 14046 ("This provision is simply meant to protect royalty value if, for example, a lessee were to inappropriately enter into a substantially below-market-value transaction for the purpose of reducing royalty.") (emphasis added). Under ONRR's new definition, however, even a good faith error is "misconduct," as is a minor paperwork error amounting to no practical harm. Also, under the proposed definition errors made by employees and contractors would be imputed to the lessee, notwithstanding limits governed by the law of agency. Additionally, the proposed definitional phrase "any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior" could bring in almost anything, even laws or obligations ONRR does not enforce. Closer inspection and revision of this definition is critical given the broad use of the term "misconduct" throughout the proposed rules, including the provisions under which, if ONRR determines that misconduct occurred, ONRR may apply its so-called "default provision" and unilaterally establish the royalty value (see, e.g., proposed §§ 1206.104, 1206.143).

B. <u>§ 1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-length contract?</u>

As noted, our comments regarding ONRR's proposed changes to oil valuation are expressed alongside the corresponding provisions for gas valuation below. We comment separately here on unique aspects of this proposed oil-specific provision.

Subsection (c)(1) allows the lessee to opt to use index pricing when it disposes of production through a downstream arm's-length exchange agreement; the option is not limited to transfers from the lessee to an affiliate that then sells or exchanges at arm's-length. ONRR should afford a similar option for federal gas lessees to avoid the burden of chasing gross proceeds to distant markets and to obviate the unnecessary step of creating an affiliate simply for the purpose of affording the lessee the regulatory option of choosing index pricing – see comments below on § 1206.141.

Subsection (c)(1) additionally provides, with regard to the election to use arm's-length oil sales contracts, that if the lessee fails to make the election between gross proceeds or index value, the election cannot be made retroactively and ONRR will determine value. However, the rule does not specify how that election is to be made, providing a light trigger for ONRR valuation under the "default" provision.

Moreover, under subsection (c)(1)(i), if ONRR determines that location or quality differentials are not "reasonable," ONRR may determine royalty value under the "default" provision. The rule provides no criteria for the reasonableness determination. The rule also states in subsection (a) that "[t]his value [gross proceeds] does not apply . . . if ONRR decides to value your oil under § 1206.105." Read literally, this means that ONRR cannot use gross proceeds when it chooses to determine value for oil even if there is an arm's-length disposition involved in the transaction. We object to this standardless ONRR discretion in both subsections for the same reasons explained elsewhere in connection with similar changes for federal gas valuation.

API, IPAA and NOIA also recommend deletion or replacement of the ambiguous and overbroad phrase "or another person" as used in conjunction with the defined term "affiliate" in subsection (a)(2), for the same reasons that we suggest that change in proposed § 1206.141(b)(2) for federal gas.

C. <u>§ 1206.141 How do I calculate royalty value for unprocessed gas I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?</u>

API, IPAA and NOIA generally support the Proposed Rule's efforts to harmonize federal oil and gas valuation, and to afford greater flexibility for federal lessees to elect to use index pricing to value unprocessed gas. That said, certain aspects of this section require clarification or revision in any final rule.

Several proposed terms would create enormous uncertainty by allowing ONRR to exercise unilateral valuation authority with no reviewable standard. Section 1206.141 specifies how to value unprocessed gas. Subsection (a)(2) defines unprocessed gas as gas that "ONRR does not value under § 1206.144," i.e., the "default provision." Read literally, if ONRR were to invoke that proposed § 1206.144 "default" valuation provision, then ONRR could exempt that gas from the coverage of its proposed § 1206.141 and avoid using those same valuation standards, despite the fact that the gas is sold unprocessed just like unprocessed gas lessees must value under § 1206.141.

Further, under subsection (b), the applicable arm's-length value would not apply "if ONRR decides to value your gas under § 1206.144." Like the analogous proposed text in § 1206.101(a) for oil, this language provides an open-ended path to the default provision irrespective of the nature of the gas transaction or the lessee's conduct. Subsection (b)(2) should also be revised to remove "or another person" from the phrase "your affiliate or another person under a non-arm's length contract." To clarify and simplify its proposal, ONRR should replace "or other person" with any other particular arrangements ONRR deems non-arm's-length. Besides "affiliates," the only such arrangement mentioned in the preamble is a "cooperative venture that purchases all of the working interest owners' production and resells the combined volumes to a purchaser at arm's-length." 80 Fed. Reg. at 617. Alternately, ONRR may modify the definition of "affiliate" or "arm's-length contract." These changes would align with the stand-alone use of "affiliate" in the title of § 1206.141 and elsewhere in the Proposed Rule to describe valuation in non-arm's-length situations.

Further creating uncertainty by reserving unbounded discretion to the agency, under subsection (c)(1)(vi), ONRR may exclude an index pricing point "if ONRR determines that the index pricing point does not accurately reflect the values [sic][4] of production." Once again, the Proposed Rule provides no standards for when and how such a decision would be made and justified. As regulated entities, lessees "are entitled to know the rules by which the game will be played." *United States v. AMC Entm't Inc.*, 549 F.3d 760, 768 (9th Cir. 2008) (internal citation omitted); *see also Gen. Elec. Co. v. USEPA*, 53 F.3d 1324, 1333-34 (D.C. Cir. 1995). Here, the exceptions easily could swallow the rule by driving more and more valuations to the "default" provisions for gas (§ 1206.144) as well as for oil (§ 1206.105). Indeed, it is unclear what utility ONRR's regulatory revisions could provide if ONRR reserves the right to entirely ignore them and prescribe whatever alternate value ONRR sees fit in a given case.

Under subsection (b), value for arm's-length unprocessed gas sales is established as the gross proceeds accruing to the lessee <u>or</u> an affiliate under the first arm's-length contract, less applicable allowances. Chasing gross proceeds through multiple exchanges/transfers before the first arm-length sale is complicated and requires a lessee to establish royalty value based on a downstream sales price less applicable transportation allowances or location/quality differentials. This presents particular issues for gas converted to LNG where the first arm's-length sale may be in a distant foreign market. The lessee would only be permitted to deduct "costs" in liquefying and shipping LNG – there is no marketing deduction, so the ONRR gets all the benefit of price lift with no risk. Also, the regulations are deficient in that they address transportation and processing allowances, but there are no existing or proposed regulations addressing allowances for liquefaction plant costs and other costs unique to LNG or CNG.

[4] We assume that, as in the preamble, ONRR intends the term "value" rather than "values."

ONRR would give the lessee the option of not chasing its affiliate's gross proceeds and using an index-based valuation method prescribed by ONRR in subsection (c). That option, however, is conditioned upon there first being a non-arm's length transfer to an affiliate and subsequently an arm's-length sale. Under this section, if the lessee sells directly to the purchaser under an arm's-length contract there is no option to use an index value. Instead, the lessee must chase the gross proceeds through potentially multiple transactions, or if it sells arm's-length after transporting gas in an affiliated pipeline which requires a complex transportation allowance calculation. But if the lessee transfers to an affiliate non-arm's-length, and the affiliate resells at arm's-length, then the option to use index is available. ONRR fails to provide any justification for this disparate treatment. There is no principled reason to make a lessee chase gross proceeds when an affiliate is not so limited, particularly since the lessee can get around the limitation through the formality of creating an affiliate transfer. ONRR should not adopt rules that require a lessee to take that unnecessary step to make use of the index valuation option. Removing this condition also would harmonize this section with the corresponding oil rules at § 1206.101(d)(1), under which the lessee has the option to use index if the lessee enters into one or more arm's-length exchange agreements.

ONRR also should harmonize and resolve ambiguities between subsections (b) and (c). Subsection (b) states that the arm's length value does not apply if a lessee "may exercise the option provided in paragraph (c)" (an index-based methodology). Read literally, this provision means a lessee must use index if it is available – there is no option to chase gross proceeds. That outcome does not appear to be ONRR's intent. At the same time, it is unclear why subsection (c) refers to an election ("If you do not sell under an arm's-length contract, you may elect to value your gas under this paragraph (c)"). The Proposed Rule provides lessees with no alternative to index pricing for dispositions other than under an arm's-length contract. In addition, this subsection allows the lessee to opt to use index in lieu of gross proceeds whereas subsection (b)(1) does not allow that option – ONRR needs to harmonize those sections. And, as noted above, both sections provide an unrestricted avenue towards ONRR's "default" provisions. ONRR should clarify these provisions accordingly.

Section 1206.141 additionally would impose other new restrictions that do not reflect, and would likely overstate, actual market value of gas production and should be deleted in any final rule.

- Under subsection (c)(1)(i), if a lessee can only transport gas to one index pricing point, value is the highest reported monthly bidweek price for that index pricing point for the production month. The preamble provides no justification for requiring the "highest" price. The range of prices reported during bidweek can vary for any number of reasons, including but not limited to access to transportation, access to premium markets, available capacity, location of supply, etc. The highest reported price at any given time could be $.50 or more above the average. There also could be a brief market anomaly during the month boosting the price for a couple days, making the "highest" price unobtainable by most lessees. We are also not aware of "highest" bidweek price requirements in oil and gas sales contracts. It is unreasonable and patently unfair for ONRR to require that royalty be paid on a value most lessees cannot ever hope to obtain for their fields. These are not Indian leases that carry a duty for ONRR to "maximize" return. *See* 25 C.F.R. § 211.1 (intended to ensure Indian tribal oil and gas development "maximizes [Indian mineral owners'] best economic interests"); *Kerr-McGee Corp. v. Navajo Tribe,* 471 U. S. 195, 200 (1985) ("basic purpose" of Indian Mineral Leasing Act is for Interior Secretary to "maximize tribal revenue from reservation lands"); 80 Fed. Reg. 24794, 24795 (May 1, 2015) (ONRR final rule for Indian oil valuation) ("the purposes of the [Indian oil] rule is to maximize revenues for the Indian lessor"). The lessee's duty to market production for the mutual benefit of the lessor and the lessee has never been construed to require the lessee to obtain the highest possible price for the production or to pay a royalty on that theoretically obtainable price. Consistently, the existing federal gas regulations expressly state that receipt of a price less than other measures of market price is insufficient to establish breach of the duty to market absent evidence of unreasonable or bad faith actions. 30 C.F.R. § 1206.102(c)(2)(ii)(B). At a minimum, an average of the bidweek prices for the index pricing point would be more appropriate than the "highest" bidweek price provision.

- Under subsection (c)(1)(ii), if a lessee physically has the capability to transport gas to more than one index pricing point, but does not actually transport gas to the other index pricing point, it must use the highest reported monthly bidweek price for <u>any</u> of those index points "whether or not there are constraints [e.g. lack of physical access] for that production month." This effectively is requiring that a lessee pay royalty on the highest theoretically obtainable price, even though that price is not, in fact, obtainable. ONRR cites no authority or justification for this proposed standard. The physical ability to transport gas to more than one index pricing point does not automatically guarantee access to any one pricing point, or the ability to receive the highest reported monthly bidweek price available for any of those pricing points. Presumably, all pricing points would be void of gas with the exception of the highest pricing point if all gas could readily access that point and if that point could take unlimited amounts of gas at the highest price. That is obviously fiction. Factors such as the ability of any single market to take certain volumes of supply, the ability to access firm transportation on a particular pipeline, the ability to meet gas specifications of a particular pipeline, and the ability to access premium markets can all factor into the ability of any given field to receive the highest price amongst competing, interconnected pipelines to which the field may have physical access. To burden a given field with a de facto higher royalty rate due to its inability to access the highest pricing point would be discriminatory. The required index should be based upon *how the lessee's gas actually flowed.*

- As a proxy for location differential, subsection (c)(1)(iv) provides that a lessee must reduce the index value by 5 percent for the GOM OCS and 10 percent elsewhere, but not by less than 10 cents per mmbtu or more than 30 cents. These 10 cent and 30 cent limitations are the same factors used in the existing Indian gas valuation regulations (see 30 C.F.R. § 1206.172(d)(1)(iii)) adopted 16 years ago – but again, ONRR has a duty to maximize value for Indian leases, not for federal leases. The preamble purports to rely on data from 2007-2011 for the percentages selected (with no further detail provided), but this data is already four to eight years out of date and not a reasonable standard, particularly in light of the falling commodity prices in recent months. Moreover, there is a significant risk to codifying proposed adjustment standards in the first instance. It typically takes two or more years for ONRR to change a rule; meanwhile, if the market changes dramatically in the future both ONRR and industry are stuck with these percentages even if they no longer reflect the market. For processed gas, § 1206.142(d)(4) provides that ONRR may change these values by publication on its website.

But there is no parallel provision under § 1206.141. In any event, such a unilateral publication provision in either section may present an issue under the Administrative Procedure Act ("APA") if ONRR fails to adopt these changes through a rulemaking with notice and opportunity for public comment. Thus, ONRR should reexamine its proposed adjustments to index value both as to their amount and whether they should be included in final rule at all. Additionally, ONRR has failed to provide any justification for these proposed fixed adjustments. The Proposed Rule also fails to explain whether the percentage adjustment must be rounded up or down to the nearest whole cent.

Finally, under paragraph (d), ONRR claims the ability to determine the royalty value if there is no <u>written</u> arm's-length sales contract or no sale at all, or if there is no index pricing point. ONRR provides no explanation as to why an unwritten, but legally binding, arm's-length contract should not be adequate to establish the royalty value, particularly if the sales price is equivalent to other sales in the field or area or the lessee's sales under comparable written arm's-length contracts. The proposed regulations need to allow for valid unwritten arm's-length contracts and should not require those situations to be valued at index or under the "default provision." This would be consistent with the Proposed Rule's definitions of "arm's-length contract" and "contract" in proposed § 1206.10, neither of which require a writing (or signature).

D. <u>§ 1206.142 How do I calculate royalty value for processed gas I or my affiliate sell(s) under an arm's length or non-arm's-length contract?</u>

For residue gas, this section reflects many of the same issues described in § 1206.141 for valuing unprocessed gas (e.g., triggering of "default" provision, selection of index pricing points), given that the proposed valuation methods are essentially the same for unprocessed gas and residue gas. These same problems also apply to NGL valuation under this section, except that NGL valuation is subject to commercial price bulletins instead of index prices.

ONRR's proposed valuation process for residue gas and NGLs also creates an APA issue for failure to comply with rulemaking requirements, and will result in less certainty for lessees. For residue gas, subsection (d)(4) provides that "ONRR will post changes to any of the rates in this paragraph (d) on its website." These "rates" include the 5%/10% and 10 cent/30 cent adjustments to index for location. Likewise for NGLs, under subsection (d)(2)(ii), if a lessee uses commercial price bulletins ONRR will post adjustments for location differentials on its website, periodically, using the method described in the preamble. According to ONRR, "[t]his process would give ONRR the flexibility to quickly recalculate and provide revised reductions to lessees in response to market changes." This process is legally insufficient. ONRR cannot reserve unilateral authority to simply and instantly change these important standards. It skirts applicable notice and comment protections, and also creates enormous potential for reporting errors based on a potentially moving target on ONRR's website. ONRR holds all of the control, but lessees bear all of the associated risk.

As with § 1206.141(b) and (c) for unprocessed gas, proposed § 1206.141(c) and (d) create unnecessary ambiguity. It is unclear what exactly the referenced "option" is, given that subsection (d) provides only that if the lessee does <u>not</u> sell under an arm's-length contract, then the lessee may elect the option of using index pricing and commercial price bulletins for residue gas and NGLs, respectively. But absent an arm's-length contract, commercial price bulletins are the <u>only</u> available valuation method under the Proposed Rule. The preceding subsection (c) only adds to the confusion.

E. <u>§§ 1206.143 (gas), 1206.104 (oil) How will ONRR determine if my royalty payments are correct?</u>

These sections are among the most, if not the most, problematic aspects of the Proposed Rule. We do not dispute ONRR's underlying authority to monitor, review, or audit reported royalty. The fundamental problem arises from the manner in which ONRR proposes to implement that authority, and the resulting major uncertainty for both oil and gas valuation. ONRR is reneging on its commitments to the regulated community to preserve the sanctity of arm's-length contracts and to administer a transparent, fair, and predictable regulatory system for royalty valuation.

The opening provision, subsection (a)(1), provides that "if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of value or decide your royalty value under § 1206.144." Under existing rules, and any concept of reasonableness, ONRR would employ the first option – that is, notify the lessee of a perceived error, following which the lessee would correct the error in accordance with the applicable method prescribed in the rules. *See, e.g.*, 30 § C.F.R. 1206.102. Now, in lieu of directing the lessee simply to fix the error and report correctly, ONRR would open the door to a totally different royalty valuation determined unilaterally by ONRR under § 1206.144, using the full breadth of its discretion. And as § 1206.143 and the other triggers in Proposed Rule (e.g., §§ 1206.141 and 1206.142 above) are currently written, the trigger for such re-valuation by ONRR can be <u>anything</u>, even a minor error. <u>This system is clearly arbitrary and unreasonable.</u>

Under subsection (b) of § 1206.143, if ONRR determines that the lessee's contract does not reflect all the consideration from the purchaser, rather than just increasing the gross proceeds for the additional consideration ONRR may again unilaterally determine the value. That is, every marketable condition/unbundling dispute that potentially could arise gives ONRR free rein to value the lessee's production. Moreover, as this subsection is written, an ONRR takeover would not even require the misconduct or other preconditions in subsection (c) – ONRR could merely determine it does not like the royalty paid. ONRR is again creating more uncertainty and risk of audit determinations for underpayments and interest years after the production month.

Subsection (c) provides that ONRR may decide the lessee's value under § 1206.144 if it determines that gross proceeds do not reflect "reasonable consideration" for any of three reasons: "misconduct," "breach of the duty to market," or "ONRR cannot determine" if the prior valuation was proper. As noted above, ONRR would alter the current oil regulation at 30 C.F.R. § 1206.102, under which the consequence of any "misconduct" or "breach" is that the lessee must instead re-report under the methods for oil sold not at arms'-length. The three conditions themselves are troubling both individually and collectively:

(i) While the first "misconduct" trigger at proposed subsection (c)(1) basically mirrors the existing oil regulation at 30 C.F.R. § 1206.102(c)(2)(i), its practical impact is far greater under the Proposed Rule given that ONRR would now expressly define "misconduct" in proposed § 1206.20 as a very low standard. As discussed above, at a minimum, ONRR should make it clear that ONRR will not allege misconduct absent some intent by the lessee to lower its royalty payments to the government beyond what is reasonable.

(ii) The existing oil regulation also already speaks to "breach of duty to market." 30 C.F.R. § 1206.102(c)(2)(ii). ONRR would supplement that trigger (for both oil and gas) at proposed subsection (c)(2) by adding the phrase "unreasonably low" price, and defining "unreasonably low" as "10 percent less than the lowest reasonable measures of market price. . . ." This standard is circular, somehow using the lowest reasonable measure of market price to establish the basis for an unreasonably low price. Also, ONRR apparently is reserving to itself the authority to decide the lowest reasonable price, but provides no standards for that determination. ONRR also provides no justifiable basis for the proposed 10 percent threshold; the preamble provides no explanation for that number. This issue is particularly problematic in a falling market where a producer may be compelled to sell at a low price or not at all. And once again, the consequence of falling below the threshold is not just moving the lessee's value up to the 10 percent floor. Once ONRR determines that the lessee's price is, for example, 10.2 percent below what ONRR deems reasonable, then ONRR can proceed to disregard the floor altogether and unilaterally establish the value for royalty purposes using index prices, prices reported to ONRR for like quality gas (which the ONRR likely won't reveal to the lessee because of confidentiality concerns) or anything else ONRR deems relevant.

(iii) ONRR is reserving the right under subsection (c)(3) to set the royalty value if it cannot determine if the lessee properly valued its gas or gas plant products "for any reason," "including but not limited to" failure to provide documents under proposed 30 C.F.R. Part 1212. In other words, ONRR does not even need to find an error before invoking its default provision – ONRR could merely suspect something is amiss or desire a different valuation. This is effectively providing authority for ONRR to determine value without providing any standards for such a determination. This provision obliterates any concept of certainty in the regulations.

Moreover, under subsection (g), all contracts and all amendments or revisions thereto would have to be in writing and signed by all parties to be acceptable. If the contract is not written or signed, ONRR may determine the value. But under the regulations proposed in §§ 1206.141 and 1206.142, if the lessee does not sell under an arm's-length contract it must use an index if it is applicable. ONRR fails to explain why the same valuation process should not apply to the circumstance of an unwritten contract. ONRR also fails to adequately explain why an unwritten contract that is enforceable by law is not sufficient to establish the royalty value, particularly if it is equivalent to the lessee's sales under its written contracts or to other contracts in the field or area. Moreover, the further requirement for signature is neither found in other provisions of the Proposed Rule, nor reflective of business realities. For example, some agreements have monthly addendums that are not executed by both parties, but are binding unless objected to as defined. Many other contracts or amendments have the signature of one only party. Other agreements may exist electronically or by email confirmation. Some written contracts even specifically provide for oral or telephonic transactions, or agreements verified in writing by one party. ONRR's proposed requirements for written and signed contracts again are inconsistent with the realities of industry procedures and the Proposed Rule's own recognition of other forms of contract in its proposed definitions in § 1206.10.

Fundamentally, ONRR's newly announced freedom in these sections (and elsewhere in the Proposed Rule) to invoke the § 1206.144 "default" provision and reset oil and gas values in a potentially limitless number of cases is entirely at odds with longstanding and well-understood principles governing oil and gas royalty valuation. In particular, a key principle upon which the 1988 regulations were founded is the sanctity of arm's-length contracts. Over many years, the agency has repeatedly assured the regulated community that it will not second-guess sales, transportation, or other agreements reached in good faith by unaffiliated parties. MMS did so in the prior 1988 rulemaking for federal gas valuation. *See* 53 Fed. Reg. 1230 (Jan. 15, 1988). This was also true in the most recent 2000 amendments for oil – which ONRR now seeks to align with gas valuation – wherein MMS included express preamble language calming industry fears that the agency would rewrite contracts to extract more royalty for itself. *See, e.g.*, 64 Fed. Reg. 73820 (Dec. 30, 1999) ("It is longstanding MMS policy to rely on arm's length prices as the best measure of value and we have no intention of changing this."); 65 Fed. Reg. 14022, 14051 (March 15, 2000) ("MMS continues to reiterate that it will not 'second guess' a company's decision on how it disposes of production. We have emphasized this at several points, both in the text of the rule and in the preambles to this rule and previous proposals….MMS has rarely, if ever, 'second guessed' the value received in an arm's-length sale of oil"); *id.* at 14046 ("lessees have nothing to fear if they are acting in good faith"). To erase any doubt, MMS specifically added regulatory text to this effect at current 30 C.F.R. §§ 1206.102(c)(2)(ii)(A) and (B), which provide as follows:

> (A) ONRR will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.
>
> (B) The fact that the price received by the seller under an arm's length contract is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless ONRR finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil from the lease.

Notably, ONRR's Proposed Rule does not even mention these provisions. What is more, ONRR is quietly proposing to <u>write them out of the regulations</u>. The only conclusion that can be gleaned is that ONRR no longer intends to respect these limitations on its discretion as to valuations determined under arm's length contracts. Thus, when the preamble states that "[t]his Department reaffirms…that gross proceeds from arm's-length contracts are the best indication of market value," that appears to be little more than lip service compared to the actual regulations ONRR proposes to create.

F. **§§ 1206.144 (gas), 1206.105 (oil) How will ONRR determine the value of my gas/oil for royalty purposes?**

These effectively identical "default" provisions are the common destination for any oil and gas lessee that ONRR determines has not valued acceptably under the regulations. ONRR declares that it may determine the royalty value "by considering any information we deem relevant." This is entirely standardless, unfairly handicapping any opportunity to challenge an ONRR valuation. Any "default" should be index pricing, which is deemed good enough elsewhere in the rule.

ONRR enumerates certain factors, but they are of little value since they are neither exhaustive nor binding. The factors ONRR may consider "include, but are not limited to" the listed factors, following which subsection (f) allows consideration of "[a]ny information ONRR deems relevant regarding the particular lease operation or the saleability of the gas." The listed factors also contradict what ONRR permits lessees to consider. For example, ONRR may look to the value of like-quality gas, residue gas, or gas plant products in the same or nearby fields or plants, but is not permitting lessees the option to use these standards as part of their valuation processes in the first instance. ONRR also states that it may use information available or reported to ONRR, but fails to take into account that in most cases this information will be deemed proprietary or confidential, making the lessee's access to that information for confirmation of accuracy or a challenge almost impossible. This is especially concerning given the significant flaws industry has identified in ONRR's unbundling calculations used to determine the Unbundling Cost Allocations ("UCA"s) posted on ONRR's website.

This new overreaching approach by ONRR is fundamentally unworkable, and no reasoned basis exists for it. As ONRR recognizes in its preamble, "even with the changes outlined in this rule, royalty valuations will continue to be complex, and the markets for oil, gas, and coal will continue to evolve." 80 Fed. Reg. at 609. Given that inherent complexity, there is no assurance or check that ONRR's valuation determination would be any more fair, objective, or reliable than the lessee's reported data. This is particularly true since ONRR views itself as exempt from the same valuation rules binding on a lessee. ONRR cites *Independent Petroleum Ass'n of America. v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002), as support for its role and discretion in determining value, when in fact that case overturned the agency's exercise of discretion in denying certain transportation allowances (i.e., unused firm demand charges for oil and gas pipelines). Like the agency's rationale there, the Proposed Rule offers little more than "raw ipse dixit" for promulgating its "default" provision and for how ONRR intends to use it. *Id.* at 1042. When a lessee is engaged in good faith efforts to value its oil and gas for royalty purposes, and particularly under negotiated arm's length contracts, it should not be penalized and forced to accept a different, potentially arbitrary value by ONRR. ONRR should refrain from setting aside a lessee's valuation absent evidence of actual errors or wrongdoing; lessees need guidance from ONRR, not for ONRR to assume their roles. And when errors are discovered, the lessee should be required to do no more than correct those errors to conform to the standards in the regulations.

G. §§ 1206.146 (gas) What are my responsibilities to place production into marketable condition and to market production?

This proposed provision essentially eliminates the separate marketable condition requirements for processed (§§ 1206.152(g)(i)) and unprocessed (§§ 1206.153(h)(i)) gas, and replaces them with a consolidated marketable condition requirement. To ensure the lessee is not charged twice for placing a lease product into marketable condition, the following needs to be added to item (a) under this section: "The lessee is only required to place the applicable gas, residue gas, and gas plant products into marketable condition once."

H. §§ 1206.148 (gas), § 1206.108 (oil) How do I request a valuation determination or guidance?

This provision should be strengthened to facilitate more reliable guidance for more lessees. As ONRR recognizes, complex issues will persist even under the Proposed Rule. When lessees elect to proactively approach ONRR with questions, it is in all parties' interests for ONRR to respond fully and fairly, thereby avoiding valuation disputes after royalties are reported and paid.

Under ONRR's proposal, not only must a lessee's request for a valuation determination provide all relevant facts, but it must include "your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents)." In essence, this requires a legal brief, which is complex and expensive. As to precedents, because the Interior Board of Land Appeals ("IBLA") issues many determinations via Orders which are unpublished and not researchable, only ONRR is privy to all those precedents. Moreover, it is ONRR's own responsibility to ensure that it administers its regulations in a consistent matter. *See, e.g., Westar Energy, Inc. v. Federal Energy Regulatory Commission*, 473 F.3d 1239, 1241 (D.C. Cir. 2007) ("A fundamental norm of administrative procedure requires an agency to treat like cases alike."); *Colorado Interstate Gas Co. v. Federal Energy Regulatory Commission*, 850 F.2d 769, 774 (D.C. Cir. 1988) ("dissimilar treatment of evidently identical cases...seems the quintessence of arbitrariness and caprice").

ONRR affords itself three response options in the Proposed Rule: (1) it may have the Assistant Secretary for Policy, Management and Budget ("ASPMB") issue a determination; (2) it may decide that ONRR will issue guidance; or (3) it may provide no response to the valuation request. Each of these options has drawbacks that limit its utility. A non-response is not helpful, and arguably an abdication of ONRR's responsibilities. If ONRR determines a lessee erred in valuing its oil and gas, and that error could have easily been prevented by a response from ONRR to the lessee's prior request, ONRR should not prosecute the lessee for that error beyond requiring the correction.

ONRR guidance is only marginally helpful. It is not binding on ONRR, States, or the lessee. It also is not appealable, so the lessee's only recourse is to value as it believes proper and then if ONRR issues an audit order the lessee could appeal that action. This places the lessee at risk of civil penalty demands for improper reporting, and of ONRR undertaking the valuation under § 1206.144 for the lessees' alleged failure to follow the regulations (as informally interpreted by

ONRR through the guidance). The rules should also expressly provide that, if a lessee does not follow the guidance, that lessee is not subject to civil penalties for that decision.

Finally, the Assistant Secretary is unlikely to become involved in a valuation determination except for an issue of wide-ranging applicability. If the ASPMB does decide to issue a valuation determination, the decision by the ASPMB is binding on ONRR and the lessee. ASPMB decisions are final for the Department and not subject to appeal to the IBLA. The lessee's only recourse would be to seek judicial review.

ONRR should revise §§ 1206.258 and 1206.458 to provide for two options: determinations by the ASPMB (which are always available) and valuation determinations by ONRR amounting to more than mere guidance, which then could be administratively appealed if the lessee believes the determination is in error. This revision would foster active engagement and accountability. As currently written, the Proposed Rule's provision would likely produce little utility.

I. § 1206.151 How do I perform accounting for comparison?

We believe this section is no longer necessary given the nature of the proposed regulations. Please see the comments submitted by COPAS on this issue.

J. §§ 1206.152 (gas), 1206.110 (oil) What general transportation allowance requirements apply to me?

Subsection (a) would include a new provision that "[y]ou may not deduct transportation costs you incur to move a particular volume of production to reduce royalties you owe on production for which you did not incur those costs." As COPAS' comments also point out, ONRR should provide a fuller explanation and examples of what "incur" means in the context of a transportation system physically handling oil or gas. Depending on what ONRR intends, this could be a major and problematic change. It also could be very complicated to implement with respect to separating out what ONRR calls different "volumes" within a regularly operating system. For example, precluding a lessee from looking at upstream costs from its gas access point may create an accounting nightmare given that gas may enter a pipeline at various points along the line. It is also unclear whether, by emphasizing the physical movement aspect of transportation, ONRR proposes to disallow costs necessary for permitting and operating the infrastructure, such as air monitoring demanded by state and local authorities.

As noted above regarding the proposed re-definition of "gathering," proposed subsection (a)(2)(ii) would categorically label the movement of oil and gas produced on the OCS from the wellhead to the first platform as gathering and not transportation. Again, this eviscerates guidance that has been in place since 1999 and substitutes a misguided and extremely burdensome additional royalty requirement.

Subsection (d) prohibits any transportation allowance if index methods are applied to value unprocessed gas, residue gas, or gas plant products. This would be acceptable so long as ONRR includes a proper factor for the cost to get the NGLs from the lease to the plant. That is, a lessee should be permitted to deduct the costs that would otherwise be deductible in moving production from the well to the point of valuation, even if valuation at that point is by index price. As identified above, however, ONRR's proposed fixed limitations on location and quality adjustments are misguided and risk impermissibly inflating royalty demands beyond the value of production at or near the lease.

Subsection (e)(1) sets a new unwavering rule that a transportation allowance may not exceed 50 percent of the value of the oil, gas, or gas plant products. The existing federal oil and gas regulations have the same limitation, but existing §§ 1206.109(c)(2) and 1206.156(c)(3) authorize ONRR to approve a request to exceed the limit if the lessee demonstrates the costs are "reasonable, actual and necessary." The existing oil regulation at § 1206.110(g)(2) also imposes the 50 percent limitation absent approval when transportation factors are specified in an arm's-length contract. An inflexible limit is arbitrary, and illegally mandates overpayment of royalty.

ONRR and IBLA have stated on numerous occasions that royalty is due on the value of the production "at the lease." In the preamble of its Proposed Rule, ONRR purports to do the same: "By proposing these amendments the Department reaffirms that the value, for royalty purposes, of crude oil and natural gas produced from Federal leases . . . is determined at or near the lease . . . . Thus, like the current regulations, in this proposed rule, ONRR may begin with a "downstream" price or value and determine value at the lease by allowing deductions for the cost of transporting production to downstream sales points or markets, or by allowing appropriate adjustments for location or quality." 80 Fed. Reg. at 609. But its proposed regulatory text denying any actually incurred transportation cost plainly violates that principle. It also may violate the Mineral Leasing Act and Outer Continental Shelf Lands Act, and lease terms, which limit the royalty owed to the "value of production" – unilaterally limiting allowances to less than reasonable, actual costs artificially increases value and royalties owed and violates that standard. This limitation could be a more significant issue now that there is a possibility that LNG or crude oil may be exported in large volumes in the future. Further, if the gas market were to drop significantly like oil, but transportation costs remain the same, this limitation could become an issue for gas as well.

Subsection (e)(2) reflects a further problem, as ONRR would terminate any existing approvals that exceed the 50 percent limit. This is impermissibly retroactive. For existing leases, the dismissal of existing agreements and the categorical preclusion of any allowances above 50 percent both may present potential takings/breach of contract issues. Given that ONRR acknowledges that the "vast majority" of transportation situations do not involve an exception, administrative burden is no justification. ONRR's concession also implicitly recognizes that <u>some</u> lessees (even if a minority) <u>do</u> bear higher transportation costs and thus warrant corresponding allowances. Additionally, if ONRR wants to reduce the administrative burden, it simply needs to approve the exception for two to three year periods, versus requiring that it be re-approved each year.

Notably, on May 1, 2015 – well after issuance of its Proposed Rule for federal oil and gas valuation – ONRR proposed but ultimately rejected similar blanket limitations for Indian oil. 80 Fed. Reg. at 24801 ("The final rule retains a lessee's ability to request approval to exceed the 50-percent limitation on transportation allowances."). The agency there recognized that upon receipt of a request for a greater transportation allowance, the agency's existing "controls satisfy its trust responsibility to the Indian lessor." Similarly, ONRR has provided no rationale or evidence that it is unable to review, decide, or renew a requested transportation allowance greater than 50 percent where warranted. To reach a different conclusion for federal oil and gas lessees would be plainly arbitrary.

In subsection (g), ONRR would borrow the same provisions from the basic valuation regulations that reserve unconstrained authority for ONRR to re-determine the transportation allowance under the "default" provisions. (See discussion of §§ 1206.104 and 1206.143 above.) Once again, ONRR could invoke §§ 1206.104 1206.105 or 1206.144 if there is "misconduct" between the contracting parties, the lessee has "breached" its duty to the lessor by claiming an "unreasonably high" transportation allowance, or ONRR simply "cannot determine" whether a claimed transportation allowance was "properly calculated." In turn, "unreasonably high" is defined as "10-percent higher than the highest reasonable measures of transportation cost" including allowances reported to ONRR or applicable tariffs. As is the case with basic valuation, this standard is circular, basing "unreasonable" on what is "reasonable." ONRR provides no standards for picking the highest "reasonable" cost, and no basis for 10 percent. It is particularly curious that ONRR believes that the same 10 percent standard should apply to both valuation and transportation, but it provides no explanation for such a parallel standard. Furthermore, under subsection (g)(3), like with basic valuation, ONRR could determine the transportation allowance if it is unable to determine if the lessee properly calculated its allowance, including failure to provide documents. ONRR acknowledges in the preamble that this would give the agency the ability to set the transportation allowance "when arm's-length transportation service providers charge bundled fees" – a common occurrence. Finally, since transportation deductions are a component of overall valuation, it is unclear whether ONRR's triggering of its default provision for transportation would open up the lessee's entire valuation to ONRR re-determination even if unrelated to transportation. As is the case with basic valuation, these provisions undermine the certainty that is critical to industry.

Finally, under proposed subsection 1206.110(g) and 1206.152(h), a lessee does not need ONNR approval before reporting a transportation allowance. API, IPAA and NOIA support this positive and useful change. ONRR also should delete its proposed § 1206.111(a)(3), which is redundant and thus unnecessary in view of the earlier proposed provision.

K. §§ 1206.153 (gas), 1206.111 (oil) How do I determine a transportation allowance if I have an arm's-length transportation contract?

Subsection (a) reaffirms that if the lessee or its affiliate has an arm's-length transportation contract, the allowance is the "reasonable, actual costs" incurred. This subsection includes exceptions cross-referencing the above-described problematic provisions of §§ 1206.110 and 1206.152 regarding the 50 percent limit and the ONRR authority to establish the transportation allowance.[5] Subsections (b) and (c) include a detailed list of allowable and non-allowable

[5] Rather than precluding individual requests for transportation allowances in excess of 50 percent, ONRR should lessen the administrative burden associated with requesting and

transportation costs, respectively (with different items for oil and for gas in the respectively proposed regulation). For gas, subsection (c)(8) specifically disallows "[a]ny cost you or your affiliate incur(s) for services you are required to provide at no cost to the lessor, including but not limited to, costs to place your gas, residue gas, or gas plant products into marketable condition disallowed under § 1206.146 and costs of boosting residue gas disallowed under 30 CFR § 1202.151." This is a new provision and effectively requires unbundling of arm's-length transportation agreements. There currently is no IBLA or federal court decision confirming ONRR's position that unbundling is required for arm's-length transportation contracts under the existing regulations. A compelling argument exists under the current rules that, if the lessee incurs transportation costs under an arm's-length contract, then all costs should be allowed, unless there is an express provision in the contract requiring the transporter to perform a marketable condition function. In 1988, MMS was well aware of how transportation services are provided, and nowhere in the preambles to the multiple proposed and final regulations is there any suggestion of a duty to unbundle an arm's-length transportation contract. Nor does ONRR explain the administrability of this new requirement from the perspective of the lessee or the agency.

As stated previously, because the proposed rule eliminates the separate marketable condition rules for both unprocessed and processed gas, and replaces them with a consolidated marketable condition rule (Section 1206.146), the additional disallowance of boosting residue gas in this section and in 30 CFR 1202.151(b) is either redundant or results in the lessee having to incorrectly pay for some marketable condition costs twice for processed gas. Eliminating the proposed language on boosting will ensure consistency in product valuation for all natural gas, whether processed, unprocessed, conventional or coalbed methane, and all plants (cryogenic, lean oil absorption, refrigeration, and CO2 removal). It will also ensure the proper treatment involving leases that produce at a pressure above the marketable condition requirement or for offshore leases where the gas leaves the production platform at or above the marketable condition pressure, by requiring the gas be placed into marketable condition only once. Lastly, it should be noted that boosting residue gas is part of plant costs and it is not associated with a transportation system or transportation allowance.

ONRR also proposes to disallow further use of transportation factors for federal oil and gas. *See* §§ 1206.110(g), 157(a)(5)). Instead, all transportation factors would now have to be reported as a transportation allowance on the Form ONRR-2014. ONRR should discard this proposal, just as it recently discarded its similar proposal to eliminate transportation factors for Indian oil. 80 Fed. Reg. at 24800. At a minimum, ONRR must better explain on what grounds requiring this unbundling of arm's-length transportation contracts and sales contracts is legally required, how it can be efficiently accomplished, and how the current use of transportation factors supposedly frustrates administrative functions. Indeed, ONRR needs to somehow square its proposal with the fact that it was the agency which created and endorsed the current regulatory treatment of transportation factors. 52 Fed. Reg. 30776, 30800 (Aug. 17, 1987) ("The MMS has determined that the regulations should be revised to provide that transportation factors which reduce arm's-

maintaining approval for such exceptions where the costs conditions warrant, perhaps by increasing the 12-month effective period to 24 or 36 months without re-filing.

length sales contract or posted prices are to be considered as reductions in value rather than transportation allowances."). Additionally, ONRR needs to fully define what a transportation factor is (e.g., post plant NGL transportation or fractionation; location or quality differential), recognize that some of these items may not be identifiable separately, and realize the significant accounting and reporting burden this will create to calculate transportation allowances from the bevy of contracts in which a transportation factor may be embedded somewhere. Furthermore, any items that would now have to be reported as a transportation allowance must be specifically identified as an allowable transportation deduction under proposed §§ 1206.111(b) and 1206.153(b). Just as ONRR determined to retain transportation factors for Indian oil, in part to "have consistency with the Indian gas valuation rule," here ONRR likewise should retain transportation factors to ensure consistency of federal and Indian oil and gas. 80 Fed. Reg. at 24800.

If a lessee has no written contract, then ONRR would determine the transportation allowance under §§ 1206.105 or 1206.144. This poses the same concerns described above for §§ 1206.104(g) and 1206.143(g), particularly where a valid unwritten, arm's-length agreement exists. Open access transportation agreements are one such example. The proposed regulations need to be revised to recognize and accept these legally binding situations. It is also unreasonable for ONRR to require that the lessee must first propose a methodology using the burdensome procedures, and uncertain outcome, in §§ 1206.108 and 1206.148 for requesting a valuation determination.

L. §§ 1206.154 (gas), 1206.112 (oil) How do I determine a transportation allowance if I do not have an arm's-length transportation contract?[6]

Conceptually these sections appear to mirror existing regulations. Yet, ONRR is proposing to eliminate existing § 1206.157(b)(5) that allows the lessee to apply for an exception from the requirement to compute actual costs if there is a FERC/state-approved tariff applicable to the pipeline and third parties are actually paying the tariff to transport product. Additionally, ONRR would reduce the rate of return used to calculate the return on investment from 1.3 to 1.0 times the S&P BBB bond rate. These changes lack justification in the Proposed Rule, and we second COPAS' comments opposing each of them. They also contradict the agency's articulated statements and positions regarding use of tariffs and the 1.3 times BBB bond rate.[7]

We also disagree with ONRR's proposal to eliminate actual or theoretical line loss as a transportation cost. This is a real cost, and the Proposed Rule concedes it would cost industry an estimated $4.5 million annually. Inclusion of line loss in the 1988 rules was well-justified; ONRR fails to explain how that reasoning has changed to warrant this significant new imposition

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[6] The gas provision is actually titled "How do I determine a transportation allowance if I have a non-arm's-length transportation contract?" To avoid any ambiguity, the titles of these two regulations for oil and gas should be the same.

[7] *See* 52 Fed. Reg. at 30801; 70 Fed. Reg. 11869, 11871 (Mar. 10, 2005); 69 Fed. Reg. 24959, 24964-65 (May 5, 2004).

on lessees, or how deletion of the line loss deduction is consistent with the concept of valuation at or near the lease where all actual transportation costs must be allowed.

M. § 1206. 159 What general processing allowances requirements apply to me?

Under subsection (a)(2), ONRR clarifies that a lessee does not need ONRR approval to report a processing allowance. This is a positive change, much like the similar provision for transportation.

API, IPAA and NOIA do not support other proposed revisions which parallel objectionable changes to the transportation allowance regulations. Subsection (c)(1) expressly disallows any processing allowance against the value of residue gas, even processing necessary for unusual gas streams. Subsection (c)(2) expressly disallows any processing allowance exceeding 66 2/3 percent of the value of each gas plant product. ONRR also is eliminating the "extraordinary processing cost allowance" provision from the existing regulations, and in subsections (c)(3) and (c)(4) is terminating any existing approvals. This could have significant impacts for those lessees that actually bear higher processing costs and need such relief. The categorical limit and rescission of existing agreements also raise potential breach of contract/takings issues as investments have been made with the understanding that the additional processing costs would be deductible. ONRR's rationale that these higher allowances have been invoked only a few times defeats any argument about agency burden. Meanwhile, for those who need it, there is good reason to keep the provision. Nor has ONRR fairly estimated the costs of this change to industry. For example, ONRR assigns a zero cost to this change as applied to POP contracts, contrary to ONRR's prior recognition that a higher allowance than 66 2/3 percent may be warranted. Consistent with the points above regarding transportation and ONRR's recently finalized Indian oil valuation rule, ONRR should reject an arbitrary limitation on processing allowances, and instead review and grant such requests where warranted.

N. § 1206.160 How do I determine a processing allowance, if I have an arm's-length processing contract?

This section presents many of the same issues as for the parallel provisions regarding transportation allowances, and we object to these proposed changes for the same reasons. Under proposed subsection (a)(3)(ii), ONRR could determine the lessee's processing allowance under § 1206.144 if ONRR determines the claimed allowance is "unreasonably high" – again defined as 10 percent higher than the highest reasonable measures of processing costs – based on processing allowances reported to ONRR. Processing plants are unique – some are older and less efficient making comparisons problematic. Also, ONRR will not reveal processing plant costs it obtains from other lessees, making any challenge to an ONRR-determined allowance difficult. Finally, under subsection (g), if a lessee has no written arm's-length processing contract, ONRR would determine the allowance.

O. Other Concerns

API, IPAA and NOIA are concerned how the Proposed Rule will impact the nature and operation of audit authority ONRR has delegated to the States pursuant to 30 U.S.C. § 1735. It is unclear how States will be able to carry out audit functions under the vague new standards proposed by ONRR. For example, ONRR's proposal to reserve authority to determine the "reasonableness" of sales contracts, transportation agreements, and processing agreements may result in inconsistent applications of those principles by the various States. Moreover, it is unclear how ONRR intends to exercise the "default" provisions in conjunction with State delegated audits and enforcement actions. This topic is addressed nowhere in the Proposed Rule.

We also have serious questions regarding ONRR's basis and justification for its projected cost impacts of its Proposed Rule. Contrary to its 2011 Advance Notice of Proposed Rulemaking which purported to pursue revenue neutral changes, ONRR's Proposed Rule now projects over $*80 million each year* in additional royalty burdens, nearly all of which ONRR assigns to the oil and gas industry. 80 Fed. Reg. at 633. And even that number appears to be too low and based on faulty or unstated assumptions. For example, ONRR escapes assigning *any* cost impact of its "default provision" by deeming it "speculative." *Id.* at 640. But that change would undoubtedly operate to increase the royalty due; otherwise, ONRR would have no reason to second-guess and revise lessees' own valuations. Nor does ONRR articulate whether it will properly account for the present environment of falling oil and gas prices in reviewing lessees' application of the Proposed Rule's royalty valuation methods or in conducting its own block box valuation under its default provision. Despite its publication in early 2015, the Proposed Rule curiously cites only old, bad data from the last decade.

Additionally, ONRR's Proposed Rule appears to be penalizing new technologies and industry's attempts to maximize royalties for the federal government. For example, as described above, discontinuing longtime allowances for offshore deepwater subsea transportation would for no reason punish and stymie increasing frontier resource development. As another example, the rules would effectively disallow boosting, which affects modern cryogenic plants and would result in improperly duplicate treatment of boosting as a marketable condition cost.[8] Disallowing recompression at a plant is inconsistent with the intent of the marketable condition rule. ONRR should be coordinating its efforts with other Interior agencies to ensure the continued promotion of increasingly efficient, safe, and effective means to develop federal oil and gas, which in turn will necessarily yield higher royalties.

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[8] Consider the following hypothetical illustrating the problems with proposed § 1206.153(c)(8). Gas is compressed offshore to more than 1500 psig and delivered for transportation onshore, then moves more than 100 miles before reaching the processing plant. Additional compression on the pipeline is needed before reaching the plant. Under the marketable condition rule, this is considered an allowable deduction as recompression since the redelivery pressure is only 500 to 700 psig. Once onshore, the gas is delivered for processing to extract the NGLs at a cryogenic plant. The pressure drop for processing requires recompression to achieve tailgate pipeline pressure of 500 to 700 psig, but under the Proposed Rule this would firmly not be a disallowed cost since it would be classified as boosting residue gas. To require the lessee to place the gas, residue gas, or gas plant products into marketable condition at no costs to the lessor more than once is excessive.

Conversely, reducing allowances increases the expense borne by the lessee and therefore reduces the economic life of the project, thus leaving resources in the ground that may never be recovered once the existing infrastructure is removed due to lack of viability. The Secretary is statutorily tasked to provide for the prevention of waste and conservation of the natural resources, and to develop such rules and regulations as may be necessary to accomplish those ends. Capping the adjustment associated with actual costs of transporting and processing, and expecting lessees to place volumes in a marketable condition more than once at their own expense – not to mention the administrative burden and regulatory uncertainty associated with several facets of this Proposed Rule – could result in ONRR reducing the economic life of onshore or offshore oil and gas projects, thus creating waste of the country's natural resources.

Because of the numerous, significant, and pervasive issues presented in these comments, ONRR should issue a supplemental proposed rule before adopting any changes in a final rule. The oil and gas valuation issues are too significant for the regulated community to not have an additional opportunity to review and comment upon their ultimate resolution proposed by ONRR.

Thank you for your time and attention to our comments on ONRR's Proposed Rule. API, IPAA and NOIA remain committed and look forward to working with ONRR on valid, reasonable efforts to improve and strengthen its royalty valuation processes. In particular, we invite a dialogue with ONRR regarding the nature of the oil and gas markets, which should provide further guidance to ONRR as it proceeds with any federal oil and gas valuation rulemaking. Please do not hesitate to contact Emily Hague (202-682-8260, hague@api.org), Dan Naatz (202-857-4722, dnaatz@ipaa.org), or Nicolette Nye (202-465-8463, nnye@noia.org) if you have any questions.

Sincerely,

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UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF WYOMING

AMERICAN PETROLEUM INSTITUTE, Petitioner, v. UNITED STATES DEPARTMENT OF THE INTERIOR; SALLY JEWELL, in her official capacity as Secretary of the U.S. Department of the Interior; OFFICE OF NATURAL RESOURCES REVENUE; and GREGORY GOULD, in his official capacity as Director of the Office of Natural Resources Revenue, Respondents.	)	Case No. 16CV316-F

PETITION FOR REVIEW OF FINAL AGENCY ACTION

Pursuant to the Administrative Procedure Act (APA), 5 U.S.C. §§ 701-706 and Local Rule 83.6, Petitioner American Petroleum Institute (API) submits this Petition challenging the U.S. Department of the Interior's Office of Natural Resources Revenue's (ONRR) recent final rule on valuation for royalty purposes of federal oil and gas production, as well as federal and Indian coal production. *See* Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, 81 Fed. Reg. 43,338 (July 1, 2016) (the Final Rule). ONRR purports to promote "greater simplicity, certainty, clarity, and consistency in product valuation," but its Final Rule is anything but simple, certain, clear, or consistent. With no reasoned basis, the Final Rule upends a longstanding valuation system and replaces it with widespread uncertainty and unconstrained agency "discretion," thereby placing both offshore and onshore federal oil and gas lessees in an untenable position going forward with respect to their royalty reporting and payment obligations. Its net effect is an attempt to inflate royalty demands beyond what is fairly, and legally, due from federal lessees based on the value of the oil or gas production at or near the lease. The Final Rule is arbitrary and capricious and exceeds ONRR's authority under applicable statutes and lease terms, and must be set aside. 5 U.S.C. § 706.

Parties. API is a national trade association that represents over 625 members involved in all aspects of the oil and natural gas industry, including the exploration and production of both onshore and offshore resources. The U.S. oil and natural gas industry supports 9.8 million U.S. jobs and more than 8 percent of the U.S. economy. The industry has paid more than $150 billion in royalty revenues to the federal treasury. Several of API's members operate leases on federal and Indian lands with royalty obligations in Wyoming, other states, and on the Outer Continental Shelf (OCS). API, on behalf of its members, submitted detailed comments on ONRR's proposed rule that became the Final Rule—comments which ONRR largely ignored in making almost no changes between its proposed and Final Rule. *See* 80 Fed. Reg. 608 (Jan. 6, 2015).

Respondent Department of the Interior is a federal agency of the United States within the scope of 5 U.S.C. § 701(b)(1) (APA) and 28 U.S.C. § 1391 (venue). Respondent Office of

Natural Resources Revenue is a federal agency within the U.S. Department of the Interior with responsibility for implementing the federal and Indian royalty program. Respondents Jewell and Gould are respondents in their official capacities and officers of the United States, which has waived its sovereign immunity under the APA, 5 U.S.C. § 702.

Legal Background. The Mineral Leasing Act and the Outer Continental Shelf Lands Act, and lease terms, limit the royalty owed to a specified percentage of the "value of the production removed or sold" from an onshore lease, or "saved, removed, or sold" from an offshore lease, in each case determined at or near the lease. *See* 30 U.S.C. § 226(b); 43 U.S.C. § 1334(a)(1). Since 1988, the oil and gas industry has operated under a comprehensive regulatory regime for valuing oil and gas production from federal leases. Those regulations were the product of a multi-year, collaborative effort specifically intended to resolve uncertainty and standardless agency discretion that had plagued valuation for royalty purposes prior to 1988. Many companies, large and small, relied on those regulations and implementing agency guidance and agreements over many years in investing the enormous resources necessary to undertake commercially risky and expensive leasing, exploration, and development of federal oil and gas resources.

Several foundational legal principles emerged from the underlying statutes, lease terms, and ONRR's and its predecessor agency's years of administering royalties from federal onshore and offshore oil and gas leases. For example, ONRR may not second-guess fairly-reached arm's-length prices, and should not substitute wholesale its own values for lessees' valuations. Moreover, value for royalty purposes must be established at or near the lease. Relatedly, ONRR must permit lessees to deduct reasonable, actual, and necessary transportation and processing costs to reflect value at the lease. One prime example is ONRR's longtime treatment of movement of bulk production from subsea manifolds to platforms many miles away as deductible transportation costs. Other examples include existing agreements approving higher allowances where warranted by individual operations.

Summary of Final Rule Defects. It is well-established that an agency cannot summarily disavow and cast aside prior regulations. Rather, ONRR must provide a compelling justification to change its regulations. The Final Rule easily fails this requirement. Discarding longstanding regulations for valuation of federal oil and gas for royalty purposes, and with no proffered evidence or meaningful justification, the Final Rule instead creates widespread uncertainty and in many cases makes compliance impossible, placing lessees at risk for enforcement actions and substantial penalties.

Through its so-called "default" provision, and numerous triggers throughout the Final Rule, ONRR defeats the very purpose and need of having regulations for lessee valuation in the first instance. Indeed, the Final Rule gives ONRR almost limitless power to retroactively increase the amount of royalty due, with corresponding late payment interest, even if the lessee fully complied with ONRR's valuation regulations in initially paying its royalties. The Final Rule provides no indication of when ONRR will (or will not) substitute its judgment for the lessee, how ONRR would (or would not) wield such "discretion," or what factors ONRR would (or would not) utilize. ONRR introduces an unreasonably broad "misconduct" trigger for ONRR's application of the default provision, and even this term does not limit ONRR; for example, ONRR can invoke the default provision if "for any reason" ONRR cannot determine that a lessee properly paid royalty. Further, ONRR claims it can demand additional royalty if the lessee's arm's-length sales price is 10% lower than the "lowest reasonable price," or if arm's-length transportation or processing allowances are 10% higher than the "highest reasonable measures" of such costs—facially circular and arbitrary standards. In sum, valuation devolves into a guessing game for lessees, at their sole risk of determining a royalty value that ONRR may later deem "wrong."

Moreover, ONRR's disagreement with a lessee on valuation would produce far more drastic consequences under the new regulations than the lessee's opportunity to fix reporting or payment errors that had been available under the longstanding regulations. Under the Final Rule, years after a sales contract is executed, oil and gas is produced, and royalty is paid, ONRR can arbitrarily demand additional royalty, and substantial late payment interest. ONRR can substitute whatever it believes the value of particular oil and gas should be, with no transparent rationale or accountability to lessees or reviewing bodies. For example, if ONRR believes a lessee's oil or gas price is more than 10% below what ONRR deems "reasonable," ONRR in its unilateral revaluation can proceed to disregard the 10% floor altogether. Moreover, in doing these unilateral calculations, ONRR ironically would utilize benchmarks and metrics that ONRR is not permitting lessees to use, and its calculations likely would not be replicable by lessees due to ONRR's reliance on confidential information of other lessees. This reservation of unilateral valuation authority divorced from any predictable, objective criteria observable by lessees is neither fair nor consistent with the statutory authority Congress has delegated to the agency or the lease contract that the lessee entered into.

ONRR's newly announced freedom to reset oil and gas values especially contravenes the agency's longstanding recognition of the reliability of arm's-length contracts. While the Final Rule's preamble "reaffirms" that "gross proceeds from arm's-length contracts are the best indication of market value," in reality the Final Rule silently deletes longstanding provisions in the existing regulations specifically protecting against ONRR's substituting its judgment for an arm's-length sales price. Moreover, the Final Rule disregards any contract that is not in writing and signed by all of the parties, an artificial distinction that fails to reflect the realities of modern business transactions and black letter law. Indeed, the Final Rule at the same time defines "contract" and "arm's-length contract" as any written or oral agreement that is enforceable by law, and not requiring a writing or signature. Nevertheless, now ONRR may unilaterally determine the royalty value under the default provision despite a valid unwritten arm's-length contract or addendum thereto.

The Final Rule impermissibly seeks to extract additional financial consideration also through blanket denials of allowances to which lessees are legally entitled. ONRR's preamble to its Final Rule states that "for purposes of determining royalty, the value of crude oil produced from Federal leases is determined at or near the lease," and incorporates the same statement for federal gas. But this is mere lip service. The Final Rule imposes a number of new, arbitrary limits on transportation and processing allowances, including but not limited to the circular 10% above what is "reasonable" threshold noted above; hard caps on allowances as a percentage of the total value of oil, gas, or natural gas liquids; vague constraints on transportation allowances for costs lessees purportedly did not "incur"; and elimination of any ability to net transportation factors in reporting royalty value for oil and gas production. These artificial limitations are significant since substantial volumes of gas are now being liquefied and transported long distances. ONRR also is terminating all existing agreements that provide for higher allowance exceptions, notwithstanding ONRR's prior recognition that some operations justifiably incur such higher costs as allowable deductions.

ONRR's sudden reversal on offshore subsea transportation serves as the most blatant example of the Final Rule's arbitrary denial of transportation costs. The Final Rule now defines non-deductible "gathering" to categorically include all movement of offshore oil or gas over many miles. This rescinds over 15 years of guidance and extensive analysis of this issue, whereby ONRR determined that most movement of oil or gas over long distances (e.g., to some platforms 50 or more miles away) in the deepwater OCS is transportation, and thus deductible as a transportation allowance to realize the value of oil and gas at the lease. After two decades of industry reliance, ONRR without justification purports to reach the opposite conclusion. The Final Rule's contradiction of years of consistent precedent ignores the realities of OCS development, upsets settled investment-backed expectations, and vastly understates the associated cost to industry.

Similarly, though it allows more lessees to use index pricing to value gas production from federal leases, the Final Rule demands an arbitrary premium for that privilege and ignores how oil and gas actually flowed and was sold. For example, a lessee inexorably must use the "highest" reported monthly bidweek price at the market center. In addition, a lessee must use the highest index among multiple index pricing points to which the lessee's gas hypothetically could flow, even if the gas does not or could not physically flow to those other index pricing points due to pipeline constraints or other factors.

The Final Rule contains several other legally problematic facets. For example, the Final Rule affords no way for lessees to obtain meaningful oil or gas valuation assistance from ONRR. Further, it relies on outdated cost information, and fails to reflect the significant effect of the new price environment.

Lack of statutory authority. The Final Rule exceeds ONRR's statutory authority because, under the applicable statutes and binding corresponding lease terms, the government's royalty must be based on "value of the production" of oil or gas from federal leases. The Final Rule concedes these principles, but then proceeds to violate them by asserting unilateral authority to cast aside lessees' valuations, particularly those based on arm's-length contract prices, at whim and based on vague and unworkable standards; by imposing inflexible blanket rules denying lessees' ability to deduct all appropriate transportation and processing costs; and by requiring an inflated premium to utilize index pricing.

The Final Rule is Arbitrary and Capricious. ONRR does not articulate any reasoned basis for why wholesale changes are needed to the existing royalty valuation system which is already subject to robust audits by regulatory authorities. The Final Rule is arbitrary and capricious for numerous reasons, including: (i) lessees face uncertainty on whether their royalty payments are correct, or whether ONRR will interject its own black box valuation under its default provision; (ii) ONRR prohibits certain lessees from valuing gas based on a published or adjusted index price proximate to the lease, and in other instances requires use of index prices that are unattainable for that gas; (iii) ONRR arbitrarily limits transportation and processing costs for oil and gas lessees; and (iv) while ONRR claims the Final Rule provides "greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees," the Final Rule yields precisely the opposite outcome.

Jurisdiction and Venue. This Court has jurisdiction under 28 U.S.C. § 1331. Venue is proper under 28 U.S.C. 1391(e) because Defendants are either agencies of the United States or officers or employees of the United States or agencies thereof acting in their official capacities or under color of legal authority; several of Petitioner's members have federal oil and gas leases and substantial operations in Wyoming; and the Final Rule will directly and adversely affect their oil and gas operations involving their federal leases in Wyoming.

Dated this 29th day of December, 2016.

Respectfully submitted,

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February 17, 2017

VIA EMAIL AND FEDEX

Gregory Gould, Director
Office of Natural Resources Revenue
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Sixth Ave. and Kipling St.
Denver, CO 80225

Re: Request to Postpone Implementation of ONRR Oil, Gas, and Coal Valuation Rule

Dear Director Gould:

Pursuant to 5 U.S.C. § 705, the National Mining Association, the Wyoming Mining Association, and the American Petroleum Institute, each on behalf of their respective members, and Cloud Peak Energy Inc., Black Hills Corporation, Tri-State Generation and Transmission Association, Inc., Basin Electric Power Cooperative, and Western Fuels-Wyoming, Inc. (collectively, "Petitioners") respectfully request that the U.S. Department of the Interior, Office of Natural Resources Revenue ("ONRR"), postpone implementation of the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Final Rule, 81 Fed. Reg. 43,338 (July 1, 2016) (the "Final Rule"). The Petitioners have sought judicial review of the Final Rule through multiple Petitions filed in the United States District Court for the District of Wyoming.[1] The Final Rule is first effective as to royalty reporting due February 28, 2017 for oil, gas, and coal production in January 2017. For the reasons set forth below and in the Petitioners' court filings and submitted comments on ONRR's proposed rule, which mirrors the Final Rule, postponement of the Final Rule's implementation is necessary in the interests of justice.

Petitioners initiated the challenge to the Final Rule because it adopts new royalty reporting and payment requirements that are impracticable, and in some cases impossible, for Petitioners and many other federal and Indian lessees to comply with by the February 28, 2017 royalty reporting due date. A federal or Indian lessee's failure to properly report and pay its royalties exposes the lessee to potential knowing or willful civil penalties. In contrast, by its own analysis in the Final Rule, ONRR's delayed implementation of the Final Rule would have no significant revenue impact to the lessors, and in the interim would continue regulations that have functioned adequately for more than 25 years.

Under the Administrative Procedure Act ("APA"), "[w]hen an agency finds that justice so requires, it may postpone the effective date of an action taken by it, pending judicial review." This provision gives federal agencies broad discretion to postpone the effect of agency action

[1] *Cloud Peak Energy Inc., et al. v. USDOI*, Case No. 16-cv-315 (filed Dec. 29, 2016); *American Petroleum Institute v. USDOI*, Case No. 16-cv-316 (filed Dec. 29, 2016); *Tri-State Generation and Transmission Ass'n, Inc., et al. v. USDOI*, Case No. 16-cv-319 (filed Dec. 29, 2016).

while litigation is ongoing. This temporary postponement under 5 U.S.C. § 705 to preserve the status quo will afford ONRR sufficient time and opportunity to determine how to proceed regarding the Final Rule. At the same time, it would avoid the expenditure of further resources of the Petitioners and ONRR on implementing a rule under which compliance is infeasible or impossible, and which may be declared invalid by the Court or modified by ONRR.

The Final Rule features a number of fundamental problems that gave rise to the regulated community's detailed rulemaking comments and currently pending litigation. The three Petitions filed against the Final Rule, as well as the detailed sets of comments submitted on the nearly identical proposed rule (available on the rulemaking docket at regulations.gov), are incorporated by reference in this letter. As more fully explained therein, the Final Rule in its current form is unlikely to survive judicial review because it exceeds ONRR's authority under applicable statutes, including the Mineral Leasing Act of 1920, the Federal Coal Leasing Amendments Act of 1976, and the Outer Continental Shelf Lands Act, and applicable lease terms, and is arbitrary and capricious under the APA. Some Final Rule provisions demand the impossible from lessees; others manufacture arbitrary and unconstrained "discretion" by ONRR. The problematic provisions in the Final Rule include, but are not limited to:

- A new "default" valuation provision whereby ONRR may unilaterally establish royalty value in the first instance under numerous, broadly defined circumstances, undermining the certainty of even a lessee's arm's-length sales prices as value, and creating the risk that ONRR may impose a higher royalty value many years after production and initial payment;

- Mandatory valuation of coal production via an inherently unreliable "netback" method that courts and the Department have historically used only as a "last resort" if no other methodology, such as comparable sales, is available to establish a reasonable value at or near the mine;

- Inadequately defined transportation allowances particularly for coal sold for ultimate delivery at distant locations;

- Requirement that coal cooperatives and vertically integrated lessees use a novel and untested method to value coal based on the sales price of electricity generated by the coal, an entirely different commodity, and apply generation and transmission allowances summarily imported from geothermal resource valuation with no analysis of their applicability to coal-fired electric generation. This ignores the value added by all activities converting coal to electricity between the mine and the end use customer's switch, the multiple resale tiers prior to end use, the variety of retail prices paid by end use customers, and the fact that the fuel component of a retail electricity price includes non-coal energy sources from the royalty payors' complete portfolios of natural gas, hydro, wind and solar, effectively making the Final Rule's required valuation impossible to calculate;

- For all coal not sold by the lessee at arm's length, failure to provide any index or other option to use reliable alternative valuation methods established near the lease like those available for oil and gas valuation;

- Blanket denial, artificial limitation, and termination of allowances to which lessees are legally entitled, undermining ONRR's longstanding recognition of valuation at or near the lease;

- Unsupported singling out of coal cooperatives for special treatment, including royalty valuation calculations that are impossible to perform, and disregard of well-established legal principles governing "affiliated" entities;

- Sudden reversal of longstanding subsea transportation allowances for offshore oil and gas;

- Refusal to recognize for valuation purposes any contract for the sale of oil, gas, or coal that is legally enforceable yet may be unwritten or unsigned by all parties; and

- Requirement to pay royalty on unattainable index prices for federal gas.

The Final Rule proffered no evidence or compelling justification for promulgating the wholesale changes to ONRR's well-established royalty valuation regulations. Rather, ONRR ignored the many comments pointing out the multiple shortcomings in the rule ONRR proposed and then finalized the rule essentially unchanged. Moreover, ONRR failed to sufficiently analyze and disclose the overall negative economic impacts of its Final Rule.

Federal and Indian coal lessees and federal oil and gas lessees face significant hardship and uncertainty in the face of their upcoming first reporting deadline under the Final Rule. As noted above and previously, many lessees simply cannot conform to the terms of the Final Rule, which requires calculations that are infeasible to perform and information that is impossible to obtain. Industry efforts to obtain adequate guidance from ONRR thus far have been unsuccessful, as the agency has provided no substantive responses to several inquiries over multiple months. Exacerbating the harms to lessees is their exposure to enforcement actions, including significant knowing or willful civil penalties, if they are unable to report and pay their royalties in accordance with the Final Rule's stated requirements. The Final Rule also allows ONRR to impermissibly recoup more financial consideration from federal and Indian lessees than ONRR is entitled to receive. Yet, if the Final Rule challenge is successful, ONRR has no authority to compensate lessees for their substantial costs of compliance (including their creation

and implementation of new accounting systems) or with interest on any royalty overpayments. This reality defeats ONRR's purported goal in the Final Rule to provide "greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees."

Postponement of the Final Rule's implementation pending judicial review, consequently with no risk of retroactive application, would avoid the above harms, and also serve the public interest. The regulated community stands to suffer the most harm absent a postponement, while postponement and continued application of regulations that have been in effect for over 25 years would not harm ONRR or any member of the public. Postponement also serves the public interest by obviating costly and time-consuming individual enforcement and corresponding appeals simultaneous with the present litigation against the Final Rule. Finally, the public interest is served by proper application of regulations consistent with ONRR's statutory authority, in contrast to the present Final Rule.

Sincerely,

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cc: K. Jack Haugrud, Acting Secretary of the Interior
Matt Wheeler, Office of the Solicitor, U.S. Department of the Interior
Rebecca Jaffe, U.S. Department of Justice
Nick Vasallo, Office of the U.S. Attorney, Wyoming

copas
Council of Petroleum Accountants Societies
Turning Energy Into Synergy

May 8, 2015

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Regulatory Specialist
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Comments on Proposed Rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report (1012-AA13)

COPAS is a professional organization comprised of the oil and gas industry's most knowledgeable and influential accounting professionals. COPAS has operated as a non-profit entity for 50 years and has over 4,000 members with 24 societies in the United States and Canada. COPAS was established in 1961 by representatives from various independent local societies throughout the U.S. and Western Canada. These societies recognized the need for standardized procedures and guidelines as the oil and gas industry expanded across the country so that common issues and problems could be addressed in a central forum. The societies have developed standardized documents in areas such as joint interest accounting, auditing, production volume and revenue accounting, and financial reporting and tax matters so that companies operating in all parts of the U.S. and Canada can effectively and efficiently use the same standards and guidelines. Additionally, many of our members are responsible for the filing of the Federal royalty reports to the ONRR.

COPAS appreciates the opportunity to comment on the proposed rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report. With that said, we would like to provide comments for the following areas:

COPAS agrees with ONRR that gross proceeds from arm's-length contracts are the best indication of market value, and we support ONRR's efforts to collect every dollar due, as long as the reporting requirements can be cost justified. We also commend ONRR for proposing the "Index Option" which could simplify and provide certainty in the reporting of Federal royalties, although we believe ONRR's proposal has significant changes that need to be made to be viable to our members. Conversely, COPAS does not support duplicative and burdensome reporting requirements, requirements that are difficult if not impossible to comply with, or valuation changes that do not allow gross proceeds from arms-length contracts or that result in ONRR collecting more royalties than what is actually due. Lastly, COPAS has not, and never will support retroactive valuation or reporting changes.

COPAS also has concerns that the cost to industry is greater than what was identified in the proposed rule. No additional cost was identified for situations where ONRR would invoke the "Default Provision", and no cost was identified for the proposed move of arms-length percentage of proceeds "POP" contracts from the current unprocessed gas regulations to the proposed processed gas regulations. If an estimated cost would have been included for these items, the total estimated cost to industry could exceed $100 million.

Default Provision (Oil – 1206.104 & 1206.105; Gas – 1206.143 &1206.144)

COPAS believes the proposed rule provides too much discretion resulting in additional uncertainty, with some proposed situations being inappropriate for the ONRR to invoke the "Default Provision". COPAS recommends the proposed rule be amended or clarified in the following areas:

- ONRR needs to identify who has the authority to invoke the "Default Provision." Is it Audit & Compliance Management, the Asset Valuation Team, the Office of Enforcement, Delegated states, and/or anyone else? How will ONRR ensure consistency when and how the "Default Provision is applied?"
- Anytime ONRR invokes the "Default Provision", the remitter needs to be notified of the reason/justification as to why it is being invoked, so the remitter could provide additional information or justification as to why it should not be. Additionally, the notice should be sent to the individual/s identified on the ONRR Form 4444 that handles Audit & Compliance correspondence. In ONRR's notice it should also include the lessee's rights to appeal.
- The "Default Provision" should not be invoked for simple or inadvertent reporting errors. Similar to today, the errors should be given to the lessee to correct.
- 1206.104(c)(2) & 1206.143(c)(2) - ONRR should not be able to invoke the "Default Provision" because the value is 10% below the lowest reasonable measure of value in arms-length situations. Current regulations require the value to be reasonable, so adding a discretionary "10% below the lowest reasonable measure" requirement is unnecessary.
- 1206.110(f)(2) & 1206.152(g)(2) - Similarly, ONRR should not be able to invoke the "Default Provision" because the transportation or processing allowance is 10% above the highest reasonable measure of transportation or processing. Current regulations require deductions to be reasonable actual costs, so it is unnecessary to add the discretionary "10% above the highest reasonable measure of transportation or processing" requirements. Additionally, ONRR provides no justification for the change to not allow all reasonable actual transportation or processing costs, resulting in ONRR collecting more royalties than what is due.

Transportation Deductions (1206.20; Oil – 1206.110, 1206.111, 1206.112; Gas 1206.152; 1206.153; 1206.154)

COPAS believes the proposed oil & gas valuation rule eliminates several transportation deductions without appropriate justification:

- The transportation allowance for OCS leases for the movement to first platform (1206.20 Definition of Gathering, Oil 1206.110(a)(2)(ii) and Gas 1206.152(a)(2)(ii)) should be added back because the MMS had previously determined after a significant amount of research and comments, that the current regulations allowed these transportation allowances. In discussions with industry prior to the May 20, 1999 guidance letter on "Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters" it was recognized that utilization of subsea completions tied to host platforms was key in the ability to develop leases in water depths greater than 200 meters. It also noted this allowed smaller fields to be developed economically that would not have been if the construction of a platform was required. It was also recognized that the products would be transported/severed off the lease in a commingled stream and then separated on the host platform. ONRR recognized the transportation as an allowed deduction for royalty bearing products. ONRR stated that they felt the current regulations allowed for the transportation allowance and requested industry agree to the use of a guidance letter for industry and ONRR to use instead of going through the process of revising regulations to clarify the application of the subsea producer owned transportation allowance. In all discussions ONRR recognized the cost of this transportation as being an allowed deduction that is supported by the regulations. COPAS strongly disagrees with changing the regulations to disallow these valid transportation costs that ONRR has publically recognized as an allowed transportation deduction. If there are specific situations where a lessee is inappropriately applying the guidance provided by the MMS's Associate Director on May 20, 1999, then those situations should be specifically excluded.

- The ability to request approval to exceed the 50% limit on transportation allowances needs to be added back (Oil 1206.110(d)(1) &(2) and Gas 1206.152(e)(1)&(2)) – There are operational/environmental/current pricing circumstances that result in the regulations appropriately allowing exceptions to exceed the 50% transportation cap. As required by the current regulations, all exceptions have to be requested and the transportation costs must be actual, reasonable and necessary. ONRR has the ability to not approve any request that does not meet these standards. Additionally, ONRR's comments that "the current 50-percent limit on transportation-related costs is adequate in the vast majority of transportation situations" proves there are a small number of transportation situations for which the current 50-percent limit is NOT adequate and having to process the requests for exception cannot be an administrative burden. ONRR cites administrative cost as a reason to do this, but provides no documentation or data that justifies the disallowance of actual, reasonable and necessary transportation costs. If ONRR wants to reduce the administrative costs for processing these requests for exception, they should consider approving the exception for periods of 2-3 years versus requiring they be approved every year.
- As stated in previous comments, COPAS does not support the elimination of netting a "transportation factor" (covered in the section by section analysis for Oil 1206.111 & Gas 1206.153). We support MMS/ONRR's position that was identified in the 1988 Final Oil & Gas Valuation Regulations which stated: "The MMS has determined that the regulations should be revised to provide that transportation factors which reduce arm's-length sales contract or posted prices are to be considered as reductions in value rather than transportation allowances."
- COPAS would also like to point out that "transportation factor" is not defined in the proposed rule, and it is unclear what is or is not a 'transportation factor." If ONRR pursues not allowing the netting of the transportation factor, it needs to be clearly defined (egg. NGL transportation and/or fractionation, location and/or quality differential on oil and/or gas). This may result in unbundling issues where a single factor includes multiple items, some of which may not be considered a transportation factor. It should also be noted that eliminating the netting of a "transportation factor" will result in a major accounting and system effort to split out the identified transportation factors.
- If the "transportation factors" are now to be included in the transportation allowance, then the regulations need to be expanded to include the "transportation factors" as an allowable transportation cost. Additionally, the final regulations need to acknowledge that some

factors are not actually <u>incurred</u> by the lessee, as they are simply netted by the purchaser from their payment.

- In the Proposed Rule under the transportation allowance Section 1206.153(c)(8) - *Other non-allowable costs,* it now requires the lessee to place the gas, residue gas or gas plant products into marketable condition at no costs to the lessor as identified under Section 1206.146 (marketable condition rule) <u>and</u> it disallows the costs of boosting residue gas as identified in 30 CFR 1202.151(b). With ONRR proposing to eliminate the separate marketable condition rules for both unprocessed and processed gas, and replace them with a consolidated marketable condition rule (Section 1206.146), the additional disallowance of boosting residue gas (both in the proposed rule and in 30 CFR 1202.151(b)) is either redundant or may result in the lessee having to incorrectly pay for some marketable condition costs twice for processed gas. The booster compression exclusion was first included in the regulations prior to the advent of modern cryogenic technology. Thus, to add the boosting residue gas language to the requirement to place products into marketable condition is unnecessary and not correct. Eliminating the proposed language on boosting will ensure consistency in product valuation for all natural gas, whether processed, unprocessed, conventional or coalbed methane, and all plants (cryogenic, lean oil absorption, refrigeration, and CO2 removal). It will also ensure the proper treatment involving leases that produce at a pressure above the marketable condition requirement or for offshore leases where the gas leaves the production platform at or above the marketable condition pressure, by requiring the gas be placed into marketable condition only once. Lastly, it should be noted that boosting residue gas is part of plant costs and it is not associated with a transportation system or transportation allowance.

<u>NAL Transportation (Oil 1206.112; Gas 1206.152; 1206.154)</u>

- Gas – Eliminates option to use FERC/State approved rate (1206.154). Because the lessee must file the necessary information to obtain FERC or State approval of their transportation rate, as previously identified by the MMS when the option was added to the current regulations, it would be duplicative and an unnecessary burden to also have to file similar information with the MMS. The MMS further stated "The underlying concept that the current provision is meant to embody is that if a regulatory agency has either adjudicated a particular tariff for a transportation system (to resolve an objection to the tariff as filed) or has analyzed the tariff (if there is no objection filed) and found it to be a just and reasonable rate, the lessee should be able to use it as the basis for its transportation allowance as long as the tariff rate is still consistent with actual market conditions." It should be noted that many of these situations involve affiliated pipelines where obtaining the information to do these calculations would be problematic and burdensome due to the governmental restrictions placed on pipeline companies in sharing information with shippers. For these reasons we believe this option needs to be retained.
- The deduction for line fill for oil was previously justified and added to the oil valuation as a cost of transportation several years ago by the MMS and now it is being eliminated. In the Final Federal Oil Valuation rule in 2004, ONRR identified line fill to include "The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill" as an allowable deduction. Furthermore, they stated "MMS does not modify its long-standing policy of not allowing as a deduction from gross proceeds the costs of placing production in marketable condition or costs of marketing production, including indirect or internal costs, or any other costs that are not necessary for the lessee to incur in order to move its oil. MMS believes that the

costs it lists as transportation costs in the final rule are consistent with the reasoning that it has always followed in determining whether costs are for transportation or for something else." Since it was specifically identified in 2004 by the MMS/ONRR as not being marketing related and being an actual cost of transportation, we disagree with it being eliminated in the proposed rule - (1206.111(c)(9)).

- Eliminates the multiplier of 1.3 times the S&P BBB Bond rate, now allowing only a 1.0 multiplier (Oil 1206.112(i)(3); Gas - 1206.154 (i)(3)). A lot of analysis was done justifying the 1.3 multiplier when it was added to the regulations. When the multiplier was added for oil in 2004 the MMS stated: "MMS, through its Offshore Minerals Management, Economics Division, has studied several years' worth of data for both non-integrated oil transportation companies and larger oil producers, both integrated and independent, that MMS believes are more likely to invest in oil pipelines. After a thorough review of the MMS and API studies, and consideration of the comments submitted by States and industry, we believe that the allowance for the rate of return on capital should be adjusted to 1.3 times the Standard & Poor's BBB bond rate. This number is the mid-point of the range suggested by the MMS study, which concluded that the range of rates of return appropriate for oil pipelines would be in the range of 1.1 to 1.5 times the Standard & Poor's BBB bond rate." In 2005 when the multiplier was added to gas transportation, the MMS said: The MMS believes that the study conducted by its Economics Division, Offshore Minerals Management, used the most relevant data for a reasonable period and, therefore, is the best source to decide on the appropriate rate of return. If ONRR believes the 1.3 multiplier as identified by their study is no longer justified, they should have a similar review done to support their proposed change.
- 1206.152(a) disallows claiming transportation costs for transportation when the production did not incur those costs. Further clarification and examples are needed on what is meant by the term "incurred". Similar to how ONRR calculates their unbundling UCAs, costs of transportation/processing systems are totaled and then divided by the throughput, but not all gas goes through every piece of equipment on the transportation system or plant.

<u>Processing Deductions (1206.159; 1206.160; 1206.161)</u>

- The proposed rule eliminates the ability to request approval to exceed the 66.67% processing cap (1206.159(c)(2)&(3). As has been documented in the past, there are extenuating circumstances where there are unique production profiles with little or no liquids to offset all the processing costs or other operational/environmental/current pricing circumstances (eg. keepwhole contracts) that result in exceeding the 66.67% processing cap. The lessee on a case-by-case basis, must submit a request to exceed the 66.67%, and the costs must be actual, reasonable <u>and necessary</u>. ONRR also comments that "the current 66 2/3 percent limit on processing-related costs is adequate in the vast majority of situations" which proves there are a small number of processing situations for which the current 66 2/3 percent limit is NOT adequate and having to process the requests for exception cannot be an administrative burden. ONRR provides no documentation or data that justifies the disallowance of these actual, reasonable, and necessary processing costs. If ONRR wants to reduce the administrative costs for processing these requests for exception, they should consider approving the exception for periods of 2-3 years versus requiring they be approved every year.
- The proposed rule also eliminates the ability to request an extraordinary processing allowance (1206.159(c)(4). As supported by the two fields that have received an extraordinary allowance, there are fields that have unique gas composition, complex plant designs and extremely high unit costs that justify them being extraordinary. ONRR's

explanation that the plants are old is not sufficient justification for them to revoke their existing agreements to allow an extraordinary processing allowance, and ONRR provided no justification for no longer allowing a lessee to request an extraordinary processing allowance.

<u>Gas Index Pricing Option (1206.141(c) and 1206.142(d))</u>

COPAS supports the option to choose index pricing for unprocessed and processed gas, and strongly recommends the option be available to arms-length sales (this was recommended by the 1995/96 Federal Gas Valuation Negotiated Rulemaking Committee) as they too, have the same tracing and unbundling issues as those lessees with non-arms-length sales. Unfortunately, the proposed terms identifying the index price that you must use, results in a value so far above what is reasonable, that it is doubtful many lessees will choose the index option.

- Pay on the <u>highest</u> reported monthly bid week price 1206.141(c)(1)(ii) & 1206.142(d)(1)(ii) is not reasonable or justified, as this price is often \$.05-\$.20/mmbtu more than the average, and can be \$.50-\$1.00/mmbtu above the average for a month or two each year.
- If gas "can" flow to multiple index points, you must use the highest index even if your gas did not flow due to pipeline constraint 1206.141(c)(1)(iii) & 1206.142(d)(1)(iii). There are reasons other than pipeline constraint – the lessee may not have a processing contract for that plant; or the transportation rate for that index price may be greater, which results in a lessee not transporting on a specific pipeline. The index price should be based upon which way the lessee's gas flowed.
- The above requirements result in a higher price than the Indian Gas Valuation price that contains a major portion pricing provision.

<u>Index Pricing Option for Gas (Transportation Deduction)(1206.141(c)(iv) and 1206.142(d)(iv))</u>

The proposed transportation deductions and the floor and cap are outdated and do not reflect the current market.

- The 10% of the gas index for all other areas was derived from the Indian Gas Valuation Rule based upon transportation deductions associated with periods prior to 2000 and is not reflective of the transportation rates we are seeing today.
- The 5% of the gas index for OCS GOM needs to be higher and not lower than onshore, as offshore transportation does not have the unbundling issues associated with onshore. Additionally, the OCS GOM has the IBLA 97-120 approved TLP transportation and the subsea transportation allowances, and much higher capital costs making it more expensive than onshore.
- The proposed floor and ceiling for transportation deductions (can never be below \$0.10 per mmbtu nor above \$0.30/mmbtu) is also based upon the 15 year old Indian Gas Valuation rule and is not reflective of current transportation costs. Both the floor and ceiling needs to be raised to be more reflective of the current market.

<u>Index Pricing Option for NGLs (1206.142(d)(2))</u>

COPAS supports the option to choose index pricing NGLs, and strongly recommends the option be available to arms-length sales as they too, have the same tracing and unbundling issues as those lessees with non-arms-length sales. Unfortunately, the proposed terms identifying the index price that you must use is unclear, and the allowed deductions appear to be not reflective of the current market and do not cover all the transportation costs incurred by the lessee. If the proposed terms are not more in line with the current market, it is doubtful many companies will choose the index option.

- If NGLs are sold with an ONRR-approved commercial price bulletin, you can opt to value NGLs using bulletin's monthly average price (1206.142(d)(2)(i)). The regulations need to specific whether "the monthly average price for that bulletin" means to use the monthly average "average" price or the monthly average "high" price. The index option is more likely to be chosen if it is the monthly average "average" price.
- The proposed rule stipulates that you <u>must reduce this price</u> by the amount ONRR posts on their website for (1206.142(d)(2)(ii);
    - Theoretical processing allowance (Onshore - \$0.15/gal; GOM - \$0.10/gal); and
    - T&F charge (NM - \$0.07/gal; Other Onshore - \$0.12/gal; GOM - \$0.05/gal). Appears low.
- The proposed standard processing deduction is based on the minimum monthly rate over the past 5 years. This is too long of a time period for which the minimum monthly rate should be chosen. To be more market sensitive, the chosen rate should be over the most recent year or two. There is concern with using ONRR 2014 information as some companies are not deducting anything or have already started unbundling, therefore, choosing the minimum monthly rate may not be appropriate.
- The proposed rule says the reductions would be updated periodically, but ONRR needs to update them annually, and they should be prospective only.
- The standard deduction for T & F charges only represents costs after the processing plant and does not include a theoretical transportation allowance to get the NGLs to the plant. The proposed rule allows a theoretical transportation allowance for field transportation for unprocessed and processed gas, but does not provide a similar standard deduction for NGLs. A standard deduction for the transportation of the ngls from the lease to the plant needs to be provided in the final rule.
- The standard T&F charges in the proposed rule appear to be too low and out of sync with the current rates for transportation and fractionation.

<u>Field Fuel Reporting (1206.142(b)(1)&(2)&(3); 1206.142(d); 1206.150(b)(1))</u>

If a company chooses to pay on index, the proposed rule instructs them to apply the index prices to residue and NGL volumes only. If ONRR also expects royalties to be paid on the field fuel/lost or unaccounted for volumes and disallowed plant fuel, then the regulations need to be updated to reflect this requirement with examples. If the final rule does require royalties to be paid and reported for the field fuel and disallowed plant fuel by companies that choose the index option, it will increase the cost to those companies making the index option less likely to be chosen.

<u>No Written Contract (1206.111(d); 1206.141(d); 1206.143(g); 1206.153(d); 1206.160(c)</u>

The proposed regulations need to be revised to recognize unwritten, unsigned, arms-length, legally binding contracts for sales, transportation and/or processing, and they should be acceptable in establishing value. Not having a written or signed contract should not be the sole determining factor in requiring the oil or gas be valued at index or through the "Default Provision."

<u>Miscellaneous Comments</u>

The proposed rule retains accounting for comparison 1206.151. COPAS recommends this requirement be eliminated as it is no longer necessary because companies will now be required to report the first arms-length sale or index, and it requires too much effort and manpower for very little additional money.

The proposed rule also retains keepwhole accounting/reporting as processed gas (1206.142), and COPAS recommends it be eliminated. Although the proposed rule gives an example on how the keepwhole accounting is to be calculated, the plant statement usually does not contain sufficient information (plant efficiencies and NGL values) to perform all the calculations. This requirement needs to be removed or simplified, or the index option to value as unprocessed gas needs to do away with the keepwhole reporting requirement.

Both the "Location Differential" and "Spot price" definitions need to be expanded to cover all relevant products. Also, 1206.116(d) which is on the reporting requirements for non-arms-length contracts for oil, references 1206.112(j) which does not exist in the proposed regulations. ONRR also needs to add a section under the oil valuation regulations similar to proposed gas regulation 1206.147 - When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Opportunities to Further Streamline Valuation Process – ONRR Requests Comments on:

1. The potential for creating standardized ''schedules'' for transportation and processing allowances to reduce the need to rely on case-by-case operator reporting and agency review of actual costs.

COPAS is interested in meeting with ONRR to discuss the possibility of ONRR creating standardized tables that could be used to identify the disallowable component costs for compression, dehydration, CO2 removal, and/or H2S removal. Thus, if your lease required dehydration and compression that would be disallowed under the regulations, the lessee could simply add back the standard components to their transportation or processing deduction. Because of the complexities involved, we would be interested in meeting and discussing how the calculations/schedules would work, the need for them to be updated periodically, and for them to be optional to allow lessees to use actual costs. These schedules would eliminate the need for unbundling and prior period adjustments.

2. Opportunities to more fundamentally reassess how non-arm's length transactions are treated for the purposes of determining royalties owed.

COPAS recommends ONRR allow a company to use the previous year's actual costs/rates for the current year provided they are within a threshold, and not have to do prior period adjustments in the following year when the actual information is available. An additional option would be to take the below threshold adjustment for which no adjustment was made, and to roll it forward into the deduction for the following year.

We also recommend the lessee be allowed the option to deduct the standardized processing or transportation deductions ONRR is going to post for the index pricing option. Thus, they could still use their product price, but they could deduct the standardized processing or transportation charge.

Similar to item 1, due to the complexity of the issues involved, COPAS would like to meet with ONRR to discuss these recommendations to streamline the handling of non-arms-length transactions for determining royalties owed.

Closing Comments

COPAS chose not to comment on all the proposed changes and focused on those areas that need to be clarified or result in costly reporting requirements, unjustified changes that result in ONRR collecting more than "every dollar due," and changes that result in making the COPAS supported index option too costly to be chosen by many companies. COPAS also wants to emphasize that due to the magnitude of the valuation, accounting, and ONRR 2014 reporting changes, at least 12 months will be needed from when the final rule and any 2014 report reporting changes are published to make all the accounting and system changes.

Once again, COPAS appreciates the opportunity to comment on the proposed rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report. COPAS also welcomes and encourages additional opportunities for Industry participation in drafting these valuation rules. We believe that Industry can provide valuable insight to ONRR on how the proposed valuation rules will impact royalty reporting and payments. If you have any questions regarding our comments, please contact me at (832) 337-2592.

Sincerely,

Pam Williams

Pam Williams
COPAS Revenue Committee Chairperson