Ms. April Lockler, Director (Acting)
Office of Natural Resources Revenue
Building 85, Entrance N-1
Denver Federal Center
West 6th Avenue and Kipling St.
Denver, CO 80225

RE: Comments on the Federal Oil, Gas, and Coal Amendments Proposed Rule (RIN 1012-AA39)

Submitted via: https://www.regulations.gov

The Independent Petroleum Association of America ("IPAA") is a national upstream trade association that provides a unified voice for independent oil and natural gas producers and service companies across the United States. Independent producers operate 95 percent of the nation's oil and natural gas wells and are responsible for 85 percent of U.S. oil production and 90 percent of natural gas production onshore.

Western Energy Alliance (the "Alliance") is the leader and champion for independent oil and natural gas companies in the western United States. Working with a vibrant membership base for over 50 years, the Alliance stands as a credible leader, advocate, and champion of industry. Alliance members engage in all aspects of environmentally responsible exploration and development of oil and natural gas. Our expert staff, active member committees, and committed board members form a collaborative and welcoming community of professionals dedicated to abundant, affordable energy and a high quality of life for all.

Together, IPAA and the Alliance (the "Associations") represent many members who are responsible for the filing of the Federal production and royalty reports to the Office of Natural Resources Revenue ("ONRR").

The following tenets underly the Associations' comments that follow:

1. The Associations support Secretary Burgum's efforts to repeal regulations that are burdensome and unneeded. The Associations support the Secretary's efforts to make regulations clearer, more consistent, and more certain in their application.

2. The Associations agree that free markets are the best way to create jobs, provide energy, and increase the nation's wealth. To further those goals, the Associations continue to believe that the Department's decision in 1988 to use the gross proceeds from arm's-length contracts as the best indication of market value is still the correct approach to follow in royalty valuation.

3. The Associations welcome this rulemaking as an opportunity to correct ill-considered trends in recent years in ONRR's valuation and enforcement practices. More specifically, ONRR has altered its interpretation of the rules in recent years through ad hoc decisions that lead to costly, long drawn out disputes. In so doing, it has failed to take into account general principles of accounting. ONRR has often demanded royalties retroactively based on policies which it has never announced in the Federal Register, a practice prohibited by the Administrative Procedure Act. 5 U.S.C. § 552(a)(1) *See Morton v. Ruiz*, 415 U.S. 199 (1974) (barring the Interior Department from denying benefits based on an interpretation not published in the Federal Register). Finally, ONRR is still as slow in auditing and collections as it was when a frustrated Congress passed the Federal Oil and Gas Royalty Simplification and Fairness Act ("RSFA") in 1996. RSFA was enacted in response to royalty appeals languishing for 12 years after the date of production. Cases are pending today that demand money for oil or gas produced over 20 years ago. The Associations' comments will propose solutions to some of those practices.

4. The Associations strongly support the changes in the definition of gathering and urge that the standard proposed for the Outer Continental Shelf ("OCS") also be applied to non-OCS leases.

5. The Associations appreciate the Administration addressing the marketable condition rule. However, the proposal does not consider much of what lessees face in the market. We propose alternatives.

6. The Associations welcome the extension of the index-pricing option to arm's-length sales. We propose several improvements.

7. The Associations have concerns about the Department's position when lessees are forced to sell residue gas at negative prices to avoid shutting in oil production and production of natural gas liquids ("NGLs"). We propose an alternative approach.

8. The Associations support the key features of the fresh look at depreciation of costs under the rules governing non-arm's-length transportation and processing. We offer several modifications to enhance the proposal.

9. In keeping with the concerns identified in paragraph 3 above, the Associations urge the Department to revise key provisions governing how ONRR conducts audits, how it should properly and timely close audit; and how its appeals process addresses its continued delays.

10. The Associations support the removal of the so-called "Default Provision" from the 2016 royalty rule, along with the definition of misconduct and related provisions.

11. Finally, The Associations ask for greater clarity in the Preliminary Regulatory Impact Analysis (RIN 1012-AA39 (2026). Specifically, the RIA says it "used royalty data for 2020-2024 and analyzed how the proposed rule would have changed royalties during this period," but provides no data or explanation of how its conclusions are reached.

12. When issuing a final rule, the Associations ask that the Department consider not only an "effective date" for the rule, but also a "compliance date" by which lessees must come

into compliance. Depending on the changes adopted, the compliance date ought to be 90 days to 180 days after the effective date.

The Associations enclose a series of issue papers with comments on the following topics:

Enclosure 1: Gathering

Enclosure 2: Marketable Condition/Unbundling

Enclosure 3: Index Pricing

Enclosure 4: Negative Price Gas Sales

Enclosure 5: Depreciation

Enclosure 6: Audit Closure and Audits

Enclosure 7: ONRR Appeals Process

Enclosure 8: Default Valuation/Misconduct Issue

Closing Comments

The Associations support the effort of the Department to better define and update portions of the regulations to reflect current practices while streamlining regulations and clarifying regulatory requirements with the goal of reducing administrative burden to the agency and industry.

Once again, the Associations appreciate the opportunity to comment on the Request for Information. If you have any questions regarding our comments, please contact Dan Naatz at (202) 857-4722, and Melissa Simpson at (303) 623-0987.

Sincerely,

Dan Naatz
Executive Vice President and Chief Policy Officer
Independent Petroleum Association of America

Melissa Simpson
President
Western Energy Alliance

Enclosures

ENCLOSURES

Enclosure 1: Gathering

Enclosure 2: Marketable Condition/Unbundling

Enclosure 3: Index Pricing

Enclosure 4: Negative Price Gas Sales

Enclosure 5: Depreciation

Enclosure 6: Audit Closure and Audits

Enclosure 7: ONRR Appeals Process

Enclosure 8: Default Valuation/Misconduct Issue

GATHERING

A. Background

In the first royalty value regulations in the 1920s, before the term "gathering" was coined, the only cost clearly not deductible after production left the wellhead was the initial separator. The concern was that to make oil marketable the lessee needed to remove the oil from a state of "emulsion," often accomplished at the separator. If unusual treatment was needed to address the problem, the Department allowed the lessee to deduct the cost of the treatment "before royalty is computed."[1]

Later in the 1950s began the Department's march toward expanding the list of post-production equipment on lease that could not be deducted. The bellwether of this initial effort was *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961). That case held that if custody of produced gas passed to the buyer in the same field in which that gas was produced, and if the contract subtracted from the sales price a charge to compress the gas to enter the buyer's pipeline, then that charge could not be deducted from federal royalty. The theory was that the lessee had the duty to compress the gas to a pressure needed to enter the sales line. The case was the judicial original of what became the marketable condition rule. But the court imposed a limit. Once the gas left the field, the movement was transportation, not gathering: "Let us here insert a cautionary parenthesis. No transportation costs are involved in this case. … This gas was conditioned by the seller and delivered to the purchaser in the field within a short distance of the wells." *Id.* at 387.

The first effort to establish comprehensive regulations on royalty value was completed in 1988. "Gathering," defined for the first time then and changed only once since, means "the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off of the lease unit, or communitized area that BLM or BSEE approves for onshore and offshore leases respectively[.]" *See, e.g.*, 30 C.F.R. § 1206.20 (defining "Gathering"). In a change to what has become called the "2016 Rule" to the royalty rules,[2] the Department added to the end of that definition

[1] Operating Regulations to Govern the Production of Oil and Gas, 47 Dec. Pub. Lands 552, 554 (1920); Operating Regulations to Govern the Production of Oil and Gas, 52 Dec. Pub. Lands 1, 6 (1926).

[2] The preamble is correct to acknowledge where the proposed rule departs from prior positions, particularly those made in the 2016 Rule. It is also worth observing that the period when these prior positions were in force was briefer than the label

"including any movement of bulk production from the wellhead to a platform offshore." *Id.* That change was in response to, and based on a misreading of, the 1999 Deepwater Policy paper.[3]

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suggests. Through a series of administrative and judicial actions, the effectiveness of the 2016 Rule was in doubt until November 2021. On July 1, 2026, the Department published the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Final Rule, 81 Fed. Reg. 43338 (July 1, 2016). The Rule was set to take effect on January 1, 2017. In February 2017, the Department published a Dear Reporter Letter stating that it was postponing the effective date of the 2017 Rule until the litigation over the rule was resolved. In April 2017, the Department published a proposed full repeal of the 2017 Rule. 82 Fed. Reg. 16323 (April 4, 2017). On August 30, 2017, a magistrate judge decided *Becerra v. United States Dep't of Interior*, 276 F. Supp. 3d 953 (N.D. Cal. 2017), finding the Department's postponement of 2017 Rule after it was already in effect violated the APA. On September 6, 2017, a rule repealing the 2016 Rule went into effect. On March 29, 2019, a court reinstated the 2015 Rule. *See Becerra v. Dept. of the Interior*, 381 F. Supp. 3d 1153 (N.D. Cal. 2019). On October 1, 2020, the Department published a proposed new rule. 85 Fed. Reg. 62054 (Oct. 1, 2020). On January 15, 2021, the Department published the final rule. 86 Fed. Reg. 4612 (Jan. 15, 2021). After further rulemaking, the 2020 rule was repealed, effective November 1, 2021.

[3] On May 20, 1999, the Associate Director for Royalty Management, after approval by the MMS Quality Council, published a memorandum ("1999 Deepwater Memo") instructing the audit managers and the chief of the Royalty Valuation Division ("RVD"). The 1999 Deepwater Memo assessed whether MMS should specify conditions under which subsea movement of production upstream of the first platform should be considered transportation. Consistent with the regulatory definition of "gathering," the 1999 Deepwater Memo determined that "[m]ovement prior to a central accumulation point is considered gathering" and that the "central accumulation point may be a *single well*, a subsea *manifold*, the *last well* in a group of wells connected in series, or a *platform* extending above the surface of the water." (Emphasis added). This approach was consistent with the Department's historical case-by-case analysis to determine when gathering ends. There were no bright-line central accumulation points as the test for gathering under the 1999 Deepwater Memo. In the 2016 Rule, the Department modified the definition of gathering alleging the 1999 Memo had incorrectly considered a subsea manifold located on the OCS in deep water always to be the "central accumulation point" regardless of whether it was actually a central accumulation or treatment point as ONRR's regulations require. This claim was patently untrue. It is important that when the preamble acknowledges what former positions the new rule changes, it supports the

In recent years, ONRR has tried to enforce an interpretation of "gathering" to mean that gathering does not end until it has reached what royalty regulations have called the "point of royalty settlement." The interpretation would apply no matter how far the production had flowed from the well to reach that point. This interpretation has been hotly contested. The proposed rule tries to resolve the contest.

B. **ONRR Proposal**

Gathering means:

1. For production from non-OCS leases, the movement of ~~lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off of the lease, unit, or communitized area that BLM or BSEE approves for onshore and offshore leases, respectively, including any movement of bulk~~ production from the ~~wellhead~~ well to the BLM-approved FMP for royalty measurement.

2. For production from OCS leases, the movement of production from the well to one of the following locations, whichever is nearest to the well:

(i) the first point at which the production from two or more wells accumulates;

(ii) the point at which the production of a ~~platform offshore.~~ well is first separated into discrete constituents; or

(iii) the boundaries of the lease.

C. **Overview**

ONRR's proposed rule seeks to amend the regulations to more clearly distinguish between gathering and transportation. ONRR acknowledges that royalty payors have frequently disputed and litigated the meaning and application of "central accumulation or treatment point" and "integral part[s] of the transportation system," in part because these terms are not defined in the regulations and have been subject to differing interpretations. Over the last few decades, this regulatory uncertainty has shifted a substantial portion of the interpretive burden for deductible transportation costs to audits, administrative appeals, and litigation. Applying the precedent

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change by indicating the 2016 deviation from prior policy was itself unreasoned and unexplained because it mischaracterized the 1999 Deepwater Memo. The new proposal restores the interpretation to the historical approach.

developed through those proceedings to the unique circumstances of individual lessees can be challenging for both ONRR and royalty payors. The Associations therefore support ONRR's effort to provide clearer, more administrable standards for gathering and deductible transportation costs that align with past precedents and the lease terms. We believe, however, that a few targeted refinements would help the proposed rule achieve those objectives while preserving the ability to recognize legitimate transportation costs that ONRR and administrative or judicial decisions have previously treated as allowable.

The Department explains that this rulemaking is consistent with the Administration's policy of unleashing America's energy potential as set forth in Executive Order ("E.O.") 14154 and Secretarial Order 3418, and that the downstream impact of the proposed changes could create financial incentives for industry that support increased production of resources from Federal lands and waters. ONRR further expects the rule to qualify as an E.O. 14192 deregulatory action. The Associations strongly support these objectives. We believe the proposed rule can advance them, while also preserving the intended benefits, if a few provisions are refined to avoid inadvertently increasing costs or creating uncertainty for investments in production and infrastructure, both offshore and onshore. The recommendations below are intended to support ONRR's effort by helping ensure that the final rule provides clarity without creating unnecessary disincentives for efficient development and shared infrastructure.

D. <u>Particular Comments</u>

i. Onshore

For onshore production, ONRR proposes that gathering end at the BLM designated facility measurement point ("FMP"). The proposal claims this "change does not impact the current interpretation of gathering for onshore leases" and "maintains the same effective definition for gathering as onshore Indian leases[.]" 91 Fed. Reg. at 39758.

However, during the negotiated royalty rulemaking in the Clinton Administration, the Department considered adopting the same bright-line rule that gathering continues until the FMP. In the 1990s, the Department entered in a negotiated rulemaking on natural gas valuation. The Department initially proposed to change the definition of gathering from the (still current) one tied to the central accumulation point to a "bright-line" rule under which gathering would end "where the production stream undergoes initial separation into identifiable oil, gas, or free water."[4] States objected and proposed a different bright line: "using the FMP [facility measurement point, used as the RMP] as the dividing line between gathering and transportation."[5] In response, the Department proposed five options for further comment, three of which would have adopted the FMP as the bright-line test for the end of gathering.[6] After further consideration, the Department adopted no bright line and withdrew the proposed rule.[7]

It is likely adopting this bright-line rule now would impact the current interpretation of gathering in many circumstances. First, there is no reason to define gathering differently for onshore and OCS leases. Facility measurement points are meters. The meters do not treat or accumulate production. Obviously, meters are the only point at which to calculate the volume of production for royalty calculation, but generally any required treatment or accumulation has already occurred. Gathering has ended already, and transportation has already begun. (This is not to say that the cost of the meter itself is a transportation cost, because the measurement has been treated as part of the lessee's duty to market the production.) Sometimes, it is true, the FMP is located so close to a central accumulation point that ONRR's designation of transportation beginning at the FMP is of no practical import. *See, e.g.*, Department of the Interior, *Valuation Determination for Coalbed Methane Production from the Kitty, Spotted Horse, and Rough Draw Fields, Powder River Basin, Wyoming* at 33 (pipelines located downstream of the central delivery points (CDPs) were transportation, but certain compressors and certain dehydrators downstream of the CDPs were for marketable condition). But it would be incorrect to assume that this arrangement of equipment predominates.

Second, RMP locations for a given lease can change over time. For an illustration, the Associations refer to a presentation on BLM's regulations for facility measurement point: Richard Estabrook, Washington Office, BLM, "*BLM Update of Gas/Oil Measurement,*" before the Petroleum Accountants Society of Oklahoma (Feb. 9, 2017) (Attachment 1). In this example, in the first five years of a new discovery, hypothetical lease NM-25211 has three wells. The FMP is placed within the lease, represented by the red square on Attachment 1 at 2. Later, the lessee establishes production to the north on lease NM-25533 and to the east on a fee lease. The lessee and BLM determine that the prudent place to locate the FMP is on the fee

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[4] 60 Fed. Reg. 56007, 56019 (Nov. 6, 1995).
[5] 61 Fed. Reg. 25421, 25423 (May 21, 1996).
[6] *Id.* at 25423–25.
[7] 62 Fed. Reg. 19536, 19536 (Apr. 22, 1997).

lease, again represented by the red square on Attachment 1 at 3. Under the proposed rule, pipe and perhaps other equipment that were for transportation are, by the stroke of a BLM keyboard, converted into non-deductible gathering expenses because the RMP has been moved off-lease. The function of the equipment has not changed; so re-assigning this cost to the lessee because the FMP's relocation has made the pipe "gathering" is pure whimsey.

Third, ONRR justifies the definition of gathering for non-OCS leases by claiming BLM rarely approves off-lease measurement and that the proposed definition would not change the current interpretation of onshore gathering. As we expressed above, we are concerned that the proposed definition would shift the point at which gathering ends further downstream relative to the current framework for certain lessees. There are many instances in which onshore lessees transport production (both pre- and post-separation) miles off-lease to another well pad or central facility before royalty measurement. Under the current regulations, movement occurring after production is initially treated on a well pad would constitute transportation, even if royalty measurement occurs farther downstream. Under the proposed definition, that downstream movement could instead be treated as nondeductible gathering whenever royalty measurement is located at a centralized facility.

The proposed definition's reliance on BLM approval of FMPs for onshore leases creates some substantial challenges. BLM had not historically approved FMP locations on the lease, limiting its approval to off-lease measurement and commingling. *See* 43 C.F.R. § 3173.12(a)(1) (requiring FMP to be located on the lease unless prior approval is obtained for off-lease locations). While on-lease FMPs require approval, the focus is on the measurement equipment, not the location. Final rules promulgated by BLM in 2016 regarding oil and gas site security and measurement began requiring operators to apply for approval of FMPs. Yet, in a 2024 Proposed Notice to Lessees, BLM acknowledged that, even eight years later, it had been unable to process many of these applications. This raises a practical implementation question: what will determine the onshore gathering endpoint on a lease where an FMP has not yet been approved? We encourage ONRR to consider an approach that provides a clear rule in those circumstances and does not make the applicability of the ONRR definition dependent on an approval process administered by another bureau.

The Associations have additional concerns, discussed below, about how the use of the FMP as a bright line for gathering undermines the Department's traditional functional test for determining whether equipment is part of the transportation system. The definition for gathering onshore ought to follow the proposal's definition of gathering for OCS leases. For now, however, if the FMP is to become the definition of gathering onshore, it should be subject to two safeguards:

For non-OCS leases, revise proposed definition of "gathering" to read:

(1) *Gathering ends at the first of two locations: the FMP or the boundary of the lease, unit, or communitized area from which the oil or gas is produced; and*

(2) *Moving an FMP further downstream from its original location does not alter the status of existing equipment as part of the transportation system.*

ii. OCS

One significant problem with ONRR's previous campaign to require that gathering continue until the production is measured for royalty purposes was that production from an OCS well may have several measurement points: a LACT unit for oil (whether on the lease or not), a meter for natural gas (whether on the lease or not), meters in processing plants if the gas is later processed, and points onshore where liquids and "flash gas" are separated and measured. And, as illustrated in our onshore comments above, the location where gathering ends changes each time one of those measurement points moves. Pipe that was first laid as transportation is changed to gathering over the course of its useful life. The risk of that change occurring thwarts rational investment planning.

There is much to like in the proposal for OCS gathering. The Associations support the change to the gathering definition for OCS leases to properly recognize the movement of production to the closest of three points as the point where gathering ends and transportation begins. MMS previously determined, after a significant amount of research and comments, that the pre-2016 valuation regulations allowed these costs as transportation allowances. In discussions with industry prior to the 1999 Deepwater Memo, it was recognized that tying subsea completions 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 possible if the construction of a platform was required. Further, it was recognized that the products would be transported/severed off the lease in a commingled stream and then separated on the host platform. ONRR recognized subsea transportation as an allowed deduction for royalty bearing products under the regulatory definition of "gathering." The revision to the gathering definition in the proposed rule returns to this understanding.

iii. A Functional Standard for Integral Transportation Costs Would Better Accommodate Offshore Facilities, but Should Apply as Well to Onshore

ONRR has proposed amending its regulations to better define costs that are considered "integral to the transportation system," a term that has previously been substantially litigated. As with the definition of gathering, the proposed rule would distinguish between onshore and offshore treatment: while the clarifications concerning flow assurance costs and pipeline repairs/restoration would apply to both jurisdictions, the remaining amendments concerning costs considered integral to transportation would apply only to OCS leases.

ONRR also proposes to provide greater specificity regarding facility components that are considered integral to transportation, including oil export pumps, flow assurance equipment, compressors and gas dehydrator systems (to the extent they enhance gas quality beyond marketable condition), and the platform space/buoyancy associated with these pieces of equipment. Providing examples of allowable equipment can be helpful and could improve consistency in administration. Our concern, however, is that the proposed language lists only a few allowable platform costs and excludes a substantial amount of equipment that has historically been approved as integral to transportation. While fixed lists do provide certainty, such a list could also make it difficult to accommodate facility configurations, technologies, or engineering solutions that evolve over time but are demonstrably attributable and integral to transportation. We suggest retaining a standard that permits lessees to claim the reasonably allocated and supported portion of platform costs attributable to an integral part of the transportation system, with the proposed list serving as illustrative examples rather than an exhaustive universe of allowable costs.

iv. The Directly Allocable Requirement Could Be Refined to Avoid Unintended Burdens

The proposed rule further specifies that costs must be "directly allocable" to qualify as integral to transportation. ONRR explains that allowable platform costs must have a "clear connection to the allowed transportation equipment and can be accurately quantified." We appreciate the objective of ensuring that claimed costs have a clear nexus to transportation and can be supported with appropriate documentation. We see two significant problems.

First, it is easy for an auditor to assert that "directly allocable" means that if equipment serves both transportation and production, then it is somehow disqualified from an allowance. This dispute will then be left to the multi-year appeals process.

Second, we are concerned that a strict “directly allocable” standard without a clear accounting standard to back it up could lead to further litigation rather than less. For example, compressor station platforms in the Gulf of America may be located miles downstream from where gas was produced and may serve almost solely a transportation function after production has already met marketable condition requirements. These facilities cannot be unmanned and therefore necessarily include living quarters, helipads, lighting, and other common infrastructure. Here, there is no question that this equipment performs a second function, such as “production,” for it is solely serving transportation. But under the proposed rule, as written, the costs of much of that equipment would be disallowed because they are not on the itemized list.

To return to our first concern, the same applies to facilities that perform both production and transportation functions, which are common offshore. In many cases, it would be inefficient and impractical to construct and operate separate facilities for each function. Joint facilities and shared infrastructure can create substantial cost savings and other operational efficiencies. A requirement that each cost be directly traceable to an individual piece of transportation equipment may not reflect the way these large, capital-intensive facilities are engineered, constructed, and operated. Additionally, given some of the projects are ongoing or nearing completion and have already been accounted for, it may not be possible to go back and revise invoices or accounting entries to unbundle them into directly traceable costs.

As a result, costs that have otherwise qualified as integral to the transportation system may not be able to meet a “directly allocable” burden because they are not separately invoiced or singularly assigned to a specific piece of equipment. The Association understand and support ONRR’s goal of making transportation reviews and audits more consistent. In this regard, we are in favor of reverting the language to the “integral to transportation” language of the prior regulations.

v. Reasonable Cost Allocations Provide an Established and Administrable Approach

One of the costs ONRR proposes to recognize as allowable transportation is “[p]latform buoyancy required to support the weight of” transportation equipment. The Interior Board of Land Appeals (IBLA) addressed this issue in 1997, disagreeing with the Minerals Management Service (ONRR’s predecessor) that the platform itself could not be considered a reasonable transportation cost because it is inherently necessary for production and was one of the "ordinary incidents of lease operation." The IBLA instead found it reasonable to allocate a portion of the costs of the hull of a floating platform to transportation equipment because the hull was an "integral" part of the transportation system. This decision illustrates a practical approach under which a portion of a shared facility cost can be recognized where the lessee can establish a reasonable relationship to transportation.

Companies over the years have developed various approaches and methodologies for allocating shared costs and ONRR has approved methodologies for doing so. Revising the allowable costs section to narrow what is allowable while also increasing the burden for the allocation of shared expenses will turn settled practices on their heads. By way of example, the rule appears to indicate it is adding new costs to be allowed when the "new" items are items that were either long ago, or recently, resolved in court as allowable under the existing regulations. The current draft appears to codify those items the courts approved while removing existing allowable items. We do not believe that was the intent of these regulations.

vi. Retaining a Functional Standard Would Preserve Flexibility While Providing Clear Audit Criteria

We believe the proposed rule can provide greater certainty while preserving a practical, fact-specific framework for transportation deductions. Rather than excluding any cost that is not expressly listed or cannot be directly allocated to a single item of transportation equipment, ONRR could retain the requirement that facility components be attributable to an integral part of the transportation system, while expressly permitting reasonable allocations for shared costs. This approach would continue to give ONRR a clear basis for reviewing transportation claims while reducing the risk that legitimate, reasonable transportation costs are excluded solely because of the way an offshore facility is designed or accounted for.

The Associations recommend the following targeted changes:

Replacing sections §§ 1206.111(b)(13), 1206.112(c)(6), 1206.153(b)(13), and 1206.154(c)(2) with the following:

Facility costs. You may deduct actual costs that are integral to a transportation system or can reasonably be allocated to a transportation system. To be considered a reasonable allocation methodology, it must also reasonably allocate costs to production or placing production in marketable condition, where appropriate.

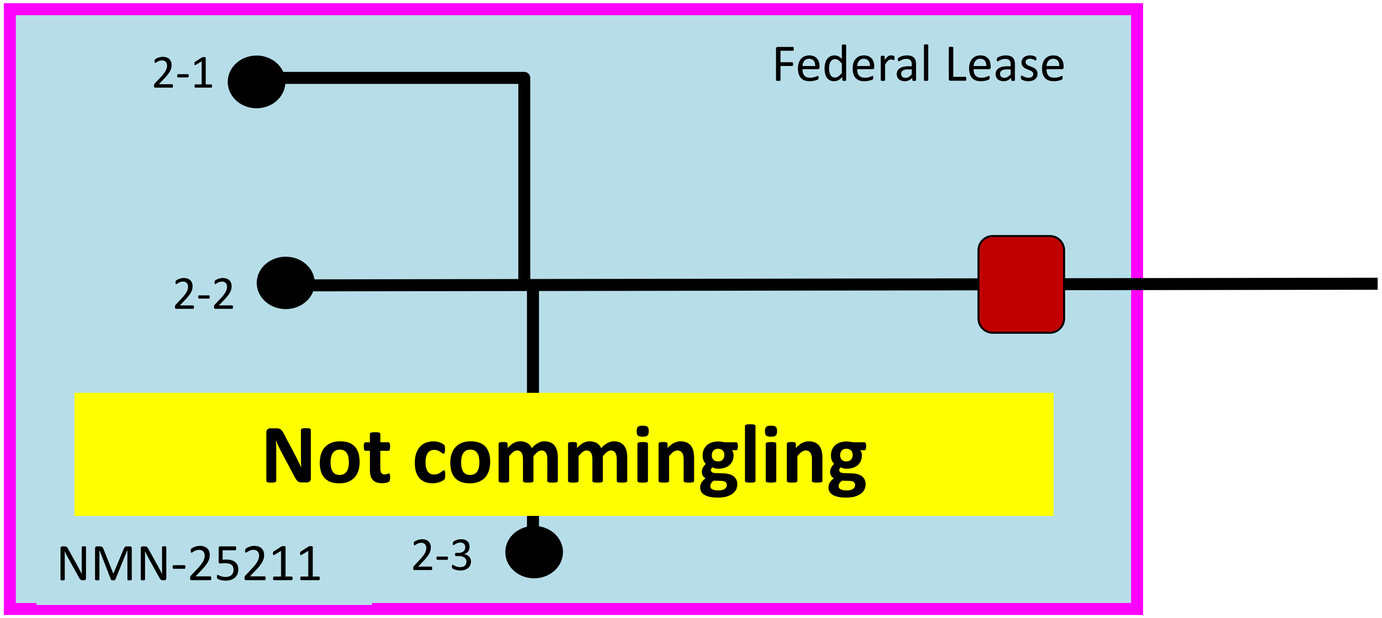
Striking §§ 1206.111(c)(9) and 1206.153(c)(9) in their entirety.

Attachment 1

BLM Update of Gas/ Oil Measurement

Richard Estabrook, BLM
Washington Office (Ukiah, CA)

Petroleum Accountants Society of Oklahoma
February 9, 2017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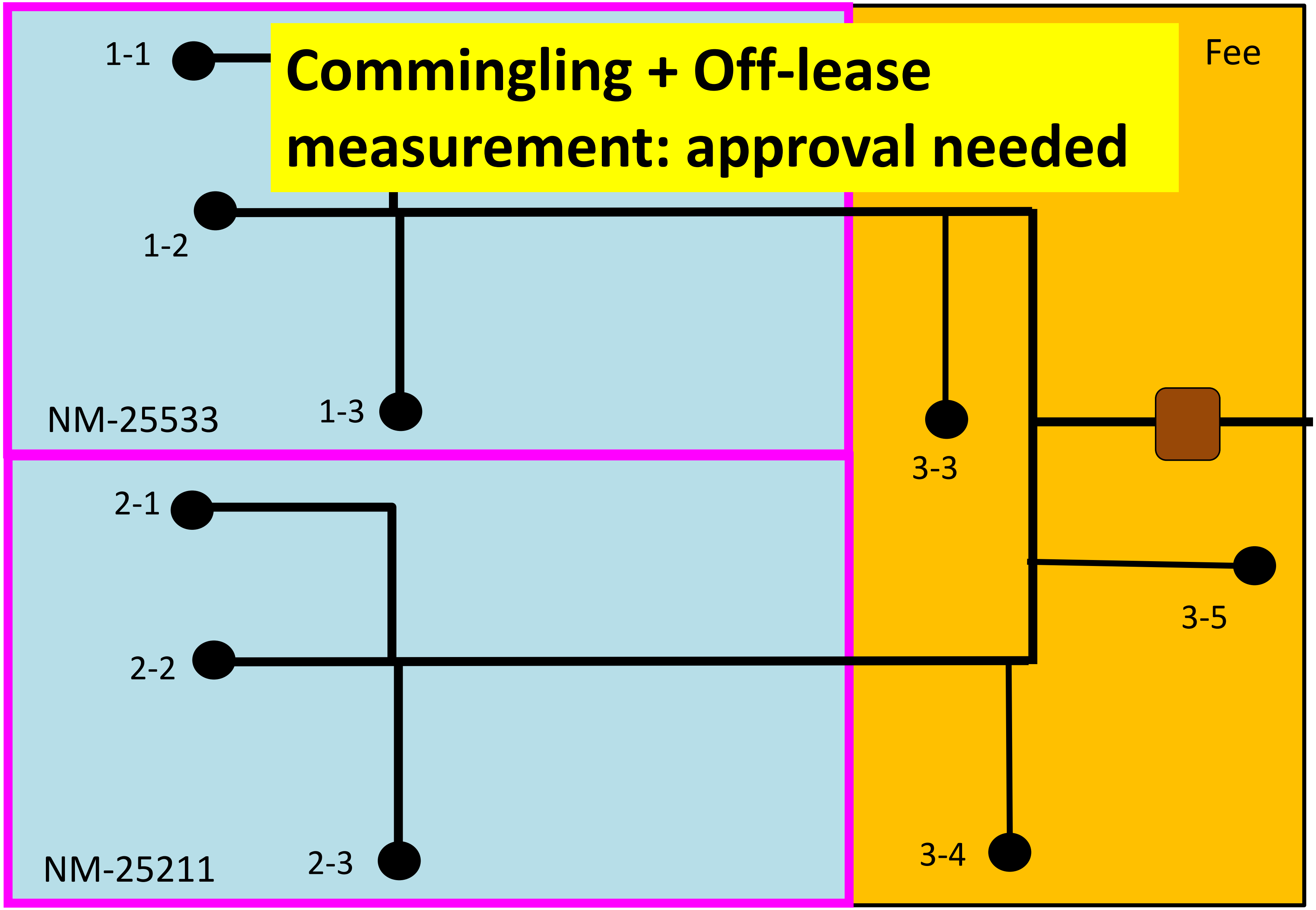
2-2
Not commingling
2-3
NMN-25211


Commingling + Off-lease measurement: approval needed
Fee
1-1
1-2
1-3
NM-25533
2-1
2-2
2-3
NM-25211
3-3
3-5
3-4

MARKETABLE CONDITION/UNBUNDLING

A. Background

Over the last 30 years, no royalty issue has been more challenging than having a lessee separate a service fee from a pipeline or processing plant into the portion ONRR will allow as a transportation or processing deduction from the portion it will deny as needed to make production marketable. This 30-year project of "unbundling" what is allowed from what is disallowed is perhaps ONRR's greatest disincentive to those trying to expand production on federal oil and gas leases.

The Department's proposal is appreciated, but unfortunately only scratches the surface of the problem, for it addresses only the preference to use quality specifications in published tariffs.

B. ONRR's Proposal

§ 1206.146 What are my responsibilities to place production into marketable condition and to market production?

Amendment: Amended in part: new paragraph (c) added.

§ 1206.146 What are my responsibilities to place production into marketable condition and to market production?

(a) ….

(b) ….

(c) Your gas or gas plant products are in marketable condition when they meet the required quality specifications for either:

(1) Delivery to a Mainline Pipeline. If your gas or gas plant products are delivered to a mainline pipeline that transports gas to market, it must meet the quality specifications set by that pipeline operator. These are typically the specifications required for delivery at the outlet of a gas processing plant;

(2) Delivery other than Mainline Pipeline. If your gas or gas plant products are delivered to market by means other than through a mainline pipeline, then your gas is in marketable condition when it meets the specifications required by the receiving transporter or purchaser; or

(3) Alternative Market for Unprocessed Gas. If your gas is never processed and you can reasonably support that a market exists at another location, you can use the quality specifications required at that alternative delivery point.

C. Particular Comments

i. ONRR Should Adopt § 1206.146(c) and Confirm that the Obligation Is Met Once.

It has been the Department's interpretation that natural gas only has to be compressed to marketable condition pressure one time to satisfy the lessee's duty to place production in marketable condition. *See* Department of the Interior, *Valuation Determination for Coalbed Methane Production from the Kitty, Spotted Horse, and Rough Draw Fields, Powder River Basin, Wyoming* at 30 (2003) ("in general, Devon is not required to condition the production to marketable condition more than once at its own expense"). In practice, ONRR disavows that this principle applies when gas is recompressed at the outlet of a gas processing plant.

ONRR asks whether to add language identifying where the specifications for marketable condition are established.[1] Lessees must place production in marketable condition at no cost to the lessor; but the question is where that is measured, and ONRR acknowledges that its "current regulations do not specify a location where quality standards are used to establish marketable condition requirements."[2] The proposal below supplies that location.

Production that meets the applicable specification under paragraph (c)(1), (2), or (3) is in marketable condition and does not have to be put in marketable condition a second or even a third time. Conditioning performed after that point does not create a new marketable condition obligation under § 1206.146. The Associations ask ONRR to confirm that reading when it adopts paragraph (c). For reasons explained in greater detail below, they recommend adding a section (d) to codify the 2003 Devon Valuation Determination:

(d) Marketable condition is determined for each quality specification; marketable condition is not determined by gas stream as a whole. A lessee does not need to place any component of the gas into marketable condition more than once.

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[1] 91 Fed. Reg. at 39,769.

[2] *Id.* at 39,761.

ii. A Definition of "Mainline Pipeline" Is Not Necessary.

ONRR also asks whether a definition of "Mainline Pipeline" would be beneficial.[3] The Associations do not think a definition is needed. Paragraph (c) already does the work a definition would do. Paragraph (c)(1) governs processed gas and paragraph (c)(2) governs every other delivery, by the specification the receiving transporter or purchaser requires.[4] In the case of OCS production for example, gas moved to shore for processing is measured the same way whether or not its line is called a mainline pipeline and a definition would add a term to argue over without changing that result.

iii. ONRR Should Adopt the § 1206.146(c)(3) Alternative Market Provision for Unprocessed Gas.

The Associations support the alternative market provision for gas that "is never processed."[5] Where gas is sold without processing there is no plant outlet or mainline pipeline to supply a specification, and an established alternative market is the right measure.[6]

iv. ONRR Should Let a Lessee Establish a Specification by a Reasonable Method.

Paragraph (c) says where certain marketable condition specifications can be determined. It does not say how to determine a specification that is not stated in the tariff or agreement, or a specification the lessee cannot readily obtain. ONRR illustrates one potential gap: a mainline tariff sets out gas quality requirements, but "[t]he tariff may not define the minimum pressure."[7]

A lessee should still be able to report a supportable figure that ONRR can verify. ONRR addresses a similar situation in the preamble to this proposed rule, letting a lessee "use a reasonable method to calculate and allocate" platform buoyancy costs

[3] 91 Fed. Reg. at 39,769.
[4] *Id.* at 39,782 (proposed § 1206.146(c)(2)).
[5] *Id.* at 39,782 (proposed § 1206.146(c)(3)).
[6] *Xeno, Inc.*, 134 IBLA 172, 183 (1995); *Kerr-McGee Corp.*, 22 IBLA 124, 128 (1975).
[7] 91 Fed. Reg. at 39,760 (the pressure at which the pipeline accepts delivery).

and document those methods when requested.[8] The Associations recommend the same approach in § 1206.146 as a new paragraph (c)(4):

> <u>(4) If the specification under paragraph (c)(1), (2), or (3) of this section is not stated in, or is not readily available from, the applicable tariff or transportation agreement, you may use a reasonable method to determine or estimate it and should provide documentation supporting your determination upon request.</u>

Paragraph (c)(4) serves only to answer what a lessee does when the specification cannot be found, and it leaves the allowance provisions exactly where the proposal puts them. We would recommend adding language that allows a party to use its methodology until such time as ONRR reviews and either affirms it or issues an appealable denial. Additionally, a decision to deny should have a go-forward impact only if the methodology had a reasonable basis.

The Associations have broader concerns about the proposal.

First, using a pipeline tariff to set the market pretends that the only marketable gas is "residue gas" after the gas stream is processed. Under that pretense the quality specifications that pipelines use to protect their equipment are converted into requirements of the sales markets.

As a first example, an interstate pipeline may require shippers to compress gas to a minimum of 800 pounds per square inch (psi) to enter the pipeline. But that pressure is not the pressure required by the ultimate purchaser. ONRR's position is that marketable condition is determined by the sales market "into which the gas was ultimately sold[.]" *Encana Oil & Gas (USA), Inc.*, 185 IBLA 133, 139 (2014).

Natural gas from federal leases is most often sold in a distant residential or industrial market. Natural gas may enter a residential building *at a pressure no greater than one-quarter psi, a commercial building at a pressure no greater than 5 psi*. The 800-psi requirement is not a requirement of the sales market, simply of the pipeline's operational needs. ONRR's focus on quality specifications in a pipeline's published tariffs ignores that there may be markets either upstream or downstream of the "mainline pipeline" with different quality specifications that are the ones to be consulted to determine marketable condition.

[8] *Id.* at 39,759.

As a second example, the Denver-Julesberg Basin in northeast Colorado has a market near the areas of production where companies seeking gas rich in natural gas liquids will come at some distance from the processing facilities to purchase gas from producers. The business model of these purchasers is to ship the gas to processing plants for removal of the NGLs for further marketing. So, the purchasers take title at the point of purchase, often imposing minimums on the Btu content of the gas, not maximums. The NGL-rich gas is the sales product, not a mix of residue gas and impurities. And these purchasers pay extra for the liquids content in the gas. These are real arm's-length markets. The pressure needed to enter the local buyer's line is not the pressure needed for entry into an interstate "mainline" pipeline. But ONRR wants to treat these activities as if they were merely service contracts in masquerade. As a result, ONRR inappropriately imposes additional royalty costs on producers.

Second, as explained above, ONRR continues not to follow a binding 2003 *Devon* decision of the Assistant Secretary that holds that producers need to place production into marketable pressure only once and, if it reaches marketable pressure more than once, the producers may choose which event of compression it will deduct.

Instead, ONRR insists that a producer place gas into marketable pressure before it reaches a processing plant, then again when the gas leaves the plant to enter a pipeline for sale. ONRR insists this is required by its "residue boosting" regulation at 30 C.F.R. § 1202.151(b); 30 C.F.R. § 1206.153(c)(8). However, the very language ONRR relies on is expressly subject to other gas valuation regulations, which include, of course, the marketable condition rule as interpreted in the 2003 *Devon* decision.

The existing sections were adopted during an era of less sophisticated processing methods. They were born in a time prior to widespread use of cryogenic gas processing that relies on temperature and pressure changes to extract natural gas liquids. Most processing occurs at cryogenic gas processing facilities. Under this method of liquid extraction, the gas is pressurized prior to the plant or at the plant inlet, and then the pressure and temperature are dramatically reduced to extract the natural gas liquids. The remaining residue gas stream is repressurized and delivered into a residue pipeline at the tailgate of the plant. Decompression and recompression are part of the processing of gas and should not be treated as another round of meeting marketable condition.

Third, if the proposed rule intends to reduce the disincentives to investment in oil and gas on federal leases, the most significant change needed is to clarify permissible methods of "unbundling" charges ONRR believes include costs of making production marketable.

Unbundling is ONRR's answer to the problem of a third-party service provider, such as a gas gatherer, charging a single fee, say 10 cents per thousand cubic feet, to provide more than one service, say not only moving the gas through a pipe, but also removing carbon dioxide. If ONRR determines that some of the removal of the carbon dioxide is needed to make gas marketable, then (a) how much of the single fee is to remove carbon dioxide and (b) how much of the cost of removal is to remove enough to make the gas marketable?

Early in the 2000s, ONRR's predecessor made a major conceptual error, one maintained by ONRR to this day. To unbundle a third-party's charge, ONRR requires lessees to use ONRR's non-arm's-length methodology it requires for facilities owned by the lessee. The flaw? Lessees have their own cost and technical specifications. They do not have it for third-party equipment. Third parties treat that cost information as highly confidential. While ONRR can force the third parties to produce that information to ONRR by issuing subpoenas, federal law bars ONRR from disclosing it to lessees. And when the lessee cannot unbundle because it cannot obtain the third party's actual costs, ONRR denies the bundled fee in full.

This practice, unfortunately, is unconstitutional and obviously has disincentivized lessees to collaborate with the government. The Associations strongly encourage the Department to codify an alternative approach that ONRR has previously attempted in part. That alternative is to work with producers to reasonably estimate the third party's costs without requiring the third party's data. The problem with this approach has been that ONRR has refused to be bound by this alternative approach and, upon subsequent audit, has faulted the lessee for not supporting deductions with the third party's "actual" cost data. We ask that the Department give serious consideration to unbungling the unbundling problem.

We therefore urge the following additional language to § 1206.146:

<u>(e) If a lessee has made an initial reasonable effort using available information to unbundle costs that may include payment for services required to place production in marketable condition, ONRR shall not disallow the deductions on the ground that the lessee failed to use confidential third-party information.</u>

<u>(f) A lessee may seek ONRR's concurrence in a proposal to unbundle costs for compliance with the marketable condition rule. A lessee may use that proposal to</u>

pay royalty until ONRR denies its concurrence. ONRR may not deny the proposal on the ground that the lessee has failed to use confidential third-party information.

(g) If ONRR concurs, the lessee's unbundling may be audited to assure compliance with the method, not to require the use of another method of unbundling.

INDEX PRICING

A. Background

The current regulations on valuing a non-arm's-length sale give the lessee a choice. It may start valuation with the first arm's-length sale by an affiliate, less transportation and processing allowances, taking into account the vagaries of the marketable condition rule. Or the lessee in certain regions may pay an index price for the region. The lessee must use the highest bidweek price available from either where the lessee actually sold the gas or where it could have sold the gas. The bidweek price must be drawn from one of three sources: Platt's, Argus, or Natural Gas Intelligence. From that price the lessee may deduct prescribed costs in lieu of actual transportation and processing costs.

ONRR proposes to allow this index price option to be used in arm's-length sales as well as non-arm's-length sales. It also proposes to change the index price from the highest bidweek price to the average or "midpoint" price. 91 Fed. Reg. at 39756.

The proposed rule would increase the deductions allowed from the bidweek price to *20 percent, but not more than 74 cents per MMBtu for sales from the OCS Gulf of America and by 13 percent, but not more than 45 cents per MMBtu, for sales from all other areas*. These numbers appear to be based on 2020-2024 data from ONRR's received monthly reports. The Associations are unable to provide meaningful comments without the data and an explanation of the methodology this proposal is based on.

Finally, ONRR proposes to add a new 30 C.F.R. § 1206.141(g) stating that if the lessee uses the index-price option, "ONRR reserves the right to collection actual transaction data in the future to assess the validity of the index-based valuation options." See 91 Fed. Reg. at 39781.

B. Particular Comments

i. Background

The proposed expansion of the index-based valuation option to arm's-length sales provides lessees with additional flexibility and may reduce administrative burden associated with royalty reporting. The proposal recognizes that some lessees may prefer a standardized valuation methodology rather than calculating royalty value based on gross proceeds and associated transportation and processing adjustments. The concept behind the proposal is welcomed. However, certain aspects of the proposal should be revised to ensure that the rule achieves its stated objectives while maintaining valuation accuracy and regulatory certainty.

Because the Associations cannot offer informed comments on the percentages and caps proposed, we offer the concern that many of our members operating in New Mexico, for example, will have to use the deduction of "13 percent [of the bidweek price] but not more than 45 cents per MMBtu," yet the already are charged more than 45 cents per MMBtu for moving gas production downstream from the facility measurement point that ONRR often uses as the start of transportation. If the bidweek price is $2 per MMBtu, the deduction is 26 cents even if the producer is paying 49 cents per MMBtu. (In considering this problem, please also take into account the points made in the enclosure titled "Negative Price Gas Sales.")

ii. Electing the Valuation Method

The provisions in proposed §§ 1206.141(c) and 1206.142(d) that prohibit a lessee from changing its valuation election more than once every two years should be removed or substantially revised. Markets do not move at the speed of government. Revisions are needed to keep a good concept from becoming a dragged anchor on a lessee's ability to respond.

The proposed rule is intended to provide lessees with additional flexibility and a simplified reporting option. However, requiring a lessee to remain committed to a valuation election for a minimum of two years may significantly limit the ability of lessees to respond to changing market conditions and operational circumstances. Commodity prices, transportation arrangements, processing economics, contract terms, and production characteristics can change materially over a two-year period. As a result, a valuation methodology that appears appropriate at the time of election may no longer produce a reasonable indication of value months later.

The preamble to the proposed rule acknowledges that gross proceeds received under an arm's-length contract are the best indicator of value and that index-based valuation may be less reliable than actual sales prices in certain circumstances. If a lessee determines that its actual gross proceeds have materially diverged from the index-based value being reported, the proposed rule would prevent the lessee from returning to the valuation methodology that ONRR itself considers the best indicator of value. The proposed two-year limitation could therefore require lessees to continue reporting under a methodology that no longer reflects their actual commercial circumstances.

ONRR should provide an exception that allows a lessee to change its election before the expiration of the two-year period when material changes in market conditions, contractual arrangements, operational circumstances, or other objective factors demonstrate that the elected methodology is no longer representative of value.

ONRR should also reconsider its prohibition on retroactive elections. In many cases, lessees do not possess all relevant information necessary to evaluate the effectiveness of a valuation methodology at the time the initial royalty report is filed. Final plant statements, contract amendments, and other information affecting valuation may not become available until after reporting has occurred. Consequently, lessees are often in the best position to evaluate the accuracy of a valuation methodology only after complete information for the reporting period has been received.

Allowing reasonable retroactive elections would improve valuation accuracy and enable lessees to make more informed decisions. Such flexibility would better align with ONRR's objective of ensuring that royalty value reasonably reflects market value.

For these reasons, ONRR should eliminate the two-year minimum election period, shorten the required commitment period, or provide exceptions that allow both prospective and retroactive changes.

iii. The Recordkeeping

While it may seem like a humble proposal to reserve the Department’s right to require the lessee to produce records of those who use the index price option, it is unnecessary. It is also written in a way to invite well-grounded suspicion that ONRR will interpret it later to retroactively change a lessee’s reliance on a lawful valuation option if the auditors think a gross-proceeds valuation would have been higher. Proposed sections 1206.141(g) and 1206.142(h) provide:

> If you elect to value your gas under paragraph [(c) or (d)] of this section, ONRR reserves the right to collect actual transaction data in the future to assess the validity of the index-based valuation option.

FOGRMA gives the Department ample investigative authority into royalty payment practices. Agency requests for sworn responses or subpoenas of documents can be issued even if the agency lacks "probable cause" to think a lessee has failed to follow the rules. 30 U.S.C. § 1717(a). The agency may inquire "merely on suspicion that the law is being violated, or even just because it wants assurance that it is not." *United States v. Morton Salt Co.*, 338 U.S. 632, 642-43 (1950). But the investigative options in those sections have built into them procedural safeguards and potential prompt judicial oversight. This proposed paragraph is written to create a new authority outside the statute and the usual scope of auditing.

The most important point the Department must recognize is that, if ONRR later decides that the index-price option is not working out as ONRR hoped, it must use notice-and-comment rulemaking to change it. The paragraph should not be adopted, but if it is, it must make clear that auditors cannot use the "reserved right" as a basis retroactively to force the lessee to pay a higher price.

Now, if the Department were to consider the following points, it would conclude that proposed paragraphs (g) and (h) should not be adopted as proposed.

The proposal explains that ONRR may require records to evaluate whether the index-based valuation option remains aligned with value reflected in arm's-length transactions. 91 Fed. Reg. at 39757. However, the proposal does not explain the circumstances under which records may be requested, the standards ONRR will use to evaluate the information received, or the potential consequences of a determination that the index-based valuation option no longer approximates market value.

To promote regulatory certainty and consistent application of the regulations, ONRR should establish clear regulations regarding:

- The circumstances under which gross proceeds records or other supporting documentation may be requested;
- The methodology ONRR will use to evaluate whether the index-based valuation option remains representative of value;
- The standards that would support a determination that a change in valuation methodology is warranted;
- The consequences of such a determination; and
- Provide the ability for a party to appeal that determination if they wish.

This analysis is not necessary if the Department makes clear that the lessee's choice to use the index option will not be overturned retroactively, and prospectively only through rulemaking. Lessees that elect to use an ONRR-authorized valuation methodology and comply with all applicable reporting requirements should be entitled to rely on that methodology for the periods in which it was permitted.

This protection is particularly important given the proposed prohibition on changing valuation elections more than once every two years. It would be inequitable to impose significant retroactive liabilities on lessees for using a valuation methodology expressly authorized by ONRR while simultaneously restricting their ability to change methodologies in response to evolving information or market conditions.

Accordingly, if ONRR subsequently determines that the index-based valuation option no longer appropriately reflects value, any required change in methodology should apply prospectively after the Department has amended the regulations.
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NEGATIVE PRICE GAS SALES

A. Background

ONRR proposes adding new subsections to 30 C.F.R. §§ 1206.141 & 1206.142. These would modify a bar. The two subsections, §§ 1206.141(f) and 1206.142(g), would "expressly state that a lessee cannot report royalty values of less than zero for Federal unprocessed gas, residue gas, and NGLs[,]" 91 Fed. Reg. at 39756. The preamble offers no explanation for why there is a limit at all.

Perhaps, when viewed without any context, it may seem self-evident that royalties on gas should never be less than zero. The Department appears to view the proposed clarification as an improvement for this reason. However, the assumption overlooks the economic reality of negative reside gas pricing and consequences that follow a prohibition of recognizing those losses.

More specifically, ONRR explains:

> ONRR proposes additions to adjust the transportation deductions for the Federal gas index-based valuation option found in §§ 1206.141 and 1206.142 to include language that the reported value of unprocessed gas, residue gas, and NGLs may not be less than zero. The value language is updated from the proposed 2020 Rule which included "at or less than zero." ONRR is updating this language to address when the value of gas received under a lessee's contract may be a negative value, and ONRR seeks to clarify that a lessee may not report a negative value in those cases but may report zero.

91 Fed. Reg. at 39757. The change is implemented in proposed 30 C.F.R. §§ 1206.141(f) and 1206.142(g): "Under no circumstances may your gas be valued for royalty purposes less than zero." 91 Fed. Reg. at 39781, 39782.

B. Comments

Although the proposal lists this as a feature of the index-pricing methodology, the placement of the language also applies to royalties using the traditional gross proceeds method. The "less than zero" limit *for gas* is a threat to production of oil from federal lands where the oil has appreciable amounts of gas in solution with the oil in the reservoir, so-called “associated gas.”

In these areas the value of the production is overwhelmingly from the oil. But the gas separates at the surface under atmospheric pressure and again at processing plants where various valuable natural gas liquids (NGLs) are broken out. Where injecting the gas back into the reservoir is not feasible, venting the gas is forbidden, flaring the gas is either forbidden or (as in New Mexico) forbidden in practice, and export gas lines are unavailable at reasonable cost, the lessee either has to shut in the oil well or sell the residue gas at a negative price. To preserve the value of the oil and the NGLs and the associated residue gas, the lessee has no alternative. In some basins, with the Permian around the Waha gas trading hub being the most recognizable example, negative gas prices can be not episodic but enduring for some months. Requiring the lessee to absorb these losses alone creates a disincentive to invest in Federal lands and may encourage operators to curtail production or shut in wells during periods of negative residue gas pricing. The result can be lower overall royalty collections from oil, NGL, and gas production.

This phenomenon of disparities in revenue is clear. Using calendar 2024 data, because the preliminary Regulatory Impact Analysis does so, one sees that ONRR collected over $12 billion in oil royalties and not quite $1 billion in gas royalties. Source: revenuedata.onrr.gov.

The Associations oppose the continuation of the regulation leaving this solely the lessee’s burden.

There are several ways to address negative pricing by aligning ONRR valuation practices with market realities. The Associations’ preferred approach is to allow months with negative residue gas pricing to generate a credit that can be carried forward and applied against future months with positive residue gas pricing. This alternative is optimal because it preserves the separation of the three distinct revenue streams and their associated costs: oil, NGLs, and residue gas. In addition, a loss-carryforward mechanism would help smooth the economics of early production months, when infrastructure constraints and market conditions can further exacerbate negative pricing periods.

A carryforward mechanism would preserve production and maximize royalty revenues. It should not be viewed as a delay in royalty collection because in periods of negative residue gas pricing, operators may be compelled to curtail or shut in otherwise economic wells. Since oil and NGL production are dependent upon continued gas production, such curtailments reduce royalty payments across all production streams, particularly during the early months of a well's life when production volumes are highest. **By mitigating the impact of temporary negative residue gas pricing, a carryforward mechanism would support continued production and likely increase aggregate royalty receipts over time.**

If ONRR believes a carryforward mechanism requires additional administrative safeguards, the rule could simply provide that negative residue gas values generate a lease-specific credit that may be applied only against future positive residue gas values from the same lease or unit, that such credits transfer with any assignment of the lease, expire upon lease termination, and may never result in a royalty refund or a royalty value below zero in any reporting month. Further, we suggest a time limit of 24 months for carryforward credits to be used to target the disproportionate peak of a well's early months production.

The Associations recommend that ONRR create a separate accounting code that would treat a negative-value sale of gas as a line to be reported as a deduction from the sale of the natural gas liquids with which it is associated.

To illustrate the disincentive from not adopting this proposal, the Associations attach a spreadsheet showing an example drawn from a New Mexico federal lease producer's experience as Attachment 1. The spreadsheet reconstructs the production month of May 2026. On the right side of the sheet is a plant statement received from the midstream company. On the left is the breakdown of what the data means for the federal royalty impact on the lessee.

Please turn first to the plant statement on the right side of Attachment 1. The plant statement is not within the spreadsheet's cells, but for ease we refer to the "nearest" cell reference for guidance through the Attachment.

In the particular month shown in the plant statement, the volume of residue gas was 85,152 MMBtu. (Near cell 37N.) The NGL volumes are shown in the box entitled "Producer NGL Settlement." (Near cell rows 25 through 31 through columns V through AC.)

The lessee received $470,275 for the sale of the NGLs. (Near cell 36AB.) But the lessee had to pay for the midstream company to take the residue gas in a sum of $287,604. (Near cell 37AB.) That equals $3.3775 per MMBtu. (Near cell 39N, entry for "Price".) As a result, the lessee received NGL revenues of $470,275, paid

$113,133 in standard midstream fees, and paid $287,604 to dispose of the residue gas. The "Net Settlement" to the lessee is $69,536. (Near cell 39AB.)

Now please turn to the left side of the sheet. After displaying the sales receipts and the ONRR-permitted allowances, cells in rows 125 through 129 and columns G and H show two things relevant to the proposed rule.

First, under the 2016 Rule, the lessee would have owed (after "conventional" unbundling) $60,491 in royalties to ONRR. Under the proposed rule, after the deductions, that number declines to $48,514. That is a savings, not even counting the administrative cost of conventional unbundling. So that, viewed in isolation, makes continued operations on federal lands in New Mexico more competitive than they were before.

Second, however, is that the cost the lessee is required to bear alone under the no less than zero rule drowns out the benefit of the proposed deductions. The lessee received a total of $69,536 for its residue gas and NGLs. ***From that it must pay $48,514 in royalties. ONRR takes 70% (see cell 129G) of the lessee's proceeds.*** Obviously, that is a disincentive to production on federal lands and a ***powerful incentive*** to invest in private lands across the border in Texas. One of the main purposes of the 1996 Royalty Simplification and Fairness Act was to remove that disincentive from investing in federal lands.

The Associations urge the Department to address this problem. In addition to the carryforward approach proposed above, another way is to recognize that negative prices for residue gas, when they do occur, are essential to keep federal production of oil and NGLs coming. Therefore, the rules should be amended to allow a lessee to pay royalties after netting out the loss on the residue gas from the gain on the revenues from the sale of the NGLs. If that cannot be done, then the lessee should be provided with the option of claiming the loss as an allowance from the revenues on the sale of the oil, the production of which is made possible by the negative value on the residue gas.

The Associations therefore recommend the Department add a provision to each section, the language below follows § 141(f) for unprocessed, but analogous language should follow § 142(g):

<u>§ 141(g) (or § 142(h): Notwithstanding the prior subsection, you may report any sale on residue gas at a negative price (i) to use as a carry-forward to credit against future positive gas prices within the next 24 months, (ii) as a net price after subtracting the</u>

loss from the sale of NGLs, or (iii) as a deduction from the royalty value of oil production with which the negative gas sales price is associated. You must have available for later audit a brief explanation and supporting documentation showing the negative-priced sale was reasonably incurred.

Attachment 1

VOLUME AND VALUE REPORTING

Residue Volume (PC 03)

Residue MMBtu	Total Plant Fuel MMBtu	Unbundling Plant Fuel Allocation		Disallowed/Allowed Plant Fuel MMBtu (B * C)	Total Residue MMBtu (A + E)
A	B	C	D	E	F
93,848.00	3,735.00	91.80%	Non-Allowed	3,428.73	97,276.73
		8.20%	Allowed	306.27	
				3,735.00	

Residue Value (PC 03)

MMBtu	Residue Gas Price	Sales Value (A * B)
A	B	C
97,276.73	$ (3.37750)	0.00

NGL Value (PC 07)	Gallons	NGL Price	Sales Value (A * B)	NGL Price Paid	NGL Value Paid (A * D)	Difference Attributable to TF&S (C - E)
	A	B	C	D	E	F
Ethane	327,752.00	0.20316	66,586.10	0.09806	32,139.36	34,446.74
Propane	193,330.00	0.82134	158,789.66	0.71624	138,470.68	20,318.98
Iso Butane	28,879.00	1.26969	36,667.38	1.16459	33,632.19	3,035.18
Normal Butane	74,836.00	1.22447	91,634.44	1.11937	83,769.17	7,865.26
Natural Gasoline	90,260.00	2.12444	191,751.95	2.01934	182,265.63	9,486.33
Total	715,057.00		545,429.53		470,277.04	75,152.49

Field Fuel Value (PC 15)

MMBtu	Residue Gas Price	Sales Value (A * B)
A	B	C
0.00	$ (3.37750)	0.00

ALLOWANCE REPORTING

Transportation Allowance	MCF	Rate/Price	Total Transportation Cost (A * B)	Allowed UCA	Allocated Transportation Cost (C * D)	Royalty Rate	Transportation Allowance (E * F)
	A	B	C	D	E	F	G
Transportation Rate Cost	119,521.00	$ 0.47330	56,569.29	90.00%	50,912.36		
Field Fuel Value	0.00	$ (3.37750)	0.00	90.00%	0.00		
Total					50,912.36	12.50%	6,364.05
TF&S			37,576.25	90.00%	33,818.62	12.50%	4,227.33

Transportation Allowance to each product based on MMBtu	Product Code	MMBtu	Allocation based on MMBtu	Allowed Transportation Cost	Royalty Rate	Total Transportation Allowance (D * E)	Transportation Allowance Allocated among Products (C * F)
	A	B	C	D	E	F	G
	03	93,848.00	60.79%				3,868.92
	07	60,524.00	39.21%				6,722.45
	15	0.00	0.00%				0.00
		154,372.00		50,912.36	12.50%	6,364.05	10,591.37

Processing Allowance	MCF	Bundled Processing Rate	Total Processing Cost (A * B)	Allowed UCA	Allocated Processing Cost (C * D)	Royalty Rate	Processing Allowance (E * F)
	A	B	C	D	E	F	G
Product Extraction	119,521.00	$ 0.47330	56,569.29	8.20%	4,638.68	12.50%	579.84
NMGPT			0.00	100.00%	0.00	12.50%	0.00
TF&S			37,576.25	8.20%	3,081.25	12.50%	385.16
							964.99

ROYALTY REPORTING

Product Code	NGL Sales Volume (Gal)	Gas Sales Volume (MMBtu)	Sales Value	Royalty Value Prior to Allowances (D * 12.5%)	Transportation Allowance	Processing Allowance	Royalty Value Less Allowances
A	B	C	D	E	F	G	H
03 Residue		97,276.73	0.00	0.00	0.00		0.00
07 Natural Gas Liquids	715,057.00		545,429.53	68,178.69	-6,722.45	-964.99	60,491.25
15 Field Fuel		0.00	0.00	0.00	0.00		0.00
							60,491.25

Assumptions:	Residue Volume	LAUF is included in the Residue MMBtu. Published UCA's allow 8.2% of plant fuel as a deduction.
	NGL Volume	Gross volume after Plant Recovery %
	Field Fuel Volume	Unprocessed gas on statement
	Residue Price	Actual price received per MMBtu
	NGL Price	Index price per contract
	TF&S	Difference between contract index price and actual price received
	TF&S Split	We used a reasonable estimate of 50% transportation and 50% processing since data is not available from the plant operator
	Transportation UCA	UCA published on ONRR website

CALCULATION AS PROPOSED BY ONRR

VOLUME AND VALUE REPORTING

Residue Volume	Residue MMBtu	Total Plant Fuel MMBtu	Unbundling Plant Fuel Allocation		Disallowed/Allowed Plant Fuel MMBtu (B * C)	Total Residue MMBtu (A + E)
	A	B	C	D	E	F
	93,848.00	3,735.00	91.80%	Non-Allowed	3,428.73	97,276.73
			8.20%	Allowed	306.27	
					3,735.00	

	MMBtu	Residue Gas Price	Sales Value (A * B)
	A	B	C
Residue Value (PC 03)	97,276.73	$ (5.66000)	0.00

	Gallons	NGL Price	Sales Value (A * B)
NGL Value (PC 07)	A	B	C
Ethane	327,752.00	0.20316	66,586.10
Propane	193,330.00	0.82134	158,789.66
Iso Butane	28,879.00	1.26969	36,667.38
Normal Butane	74,836.00	1.22447	91,634.44

Natural Gasoline	90,260.00	2.12444	191,751.95
Total	715,057.00		545,429.53

	MMBtu	Residue Gas Price	Sales Value (A * B)
Field Fuel Value (PC 15)	A	B	C
	0.00	$ (5.66000)	0.00

ALLOWANCE REPORTING

Transportation Allowance	13% of Value	$0.45 of MMBtu	Allowed Transportation	$0.07/gal	Royalty Rate	Royalty Deduction
Residue	0.00	43,774.53	0.00		0.125	0.00
NGL				50,053.99	0.125	6,256.75
Field Fuel	0.00	0.00	0.00		0.125	0.00

Processing Allowance	$0.15/gal				Royalty Rate	Royalty Deduction
NGL	107,258.55				0.125	13,407.32

ROYALTY REPORTING

Product Code	NGL Sales Volume (Gal)	Gas Sales Volume (MMBtu)	Sales Value	Royalty Value Prior to Allowances (D * 12.5%)	Transportation Allowance	Processing Allowance	Royalty Value Less Allowances
A	B	C	D	E	F	G	H
03 Residue		97,276.73	0.00	0.00	0.00		0.00
07 Natural Gas Liquids	715,057.00		545,429.53	68,178.69	-6,256.75	-13,407.32	48,514.62
15 Field Fuel		0.00	0.00	0.00	0.00		0.00
							48,514.62

	Net Settlement	Royalty Rate	Net Due ONRR
Net amount due on amount paid	69,536.40	**0.12500000**	8,692.05
Net Royalty Rate of 2016 Ruling		**0.86992203**	60,491.25
Net Royalty Rate of Proposed Ruling		**0.69768669**	48,514.62

[redacted]

[redacted]

T27d Plant Settlement Meter (Enhanced)

Original (Acct/Prod Month 05/2026)

[redacted]

Paystation:	[redacted]	Location:	[redacted]	Contract%:	1.0000
Contract:	[redacted]	Pipeline:	[illegible]	Plant Pressure Base:	14.7300
Business Month:	May, 2026	Operator:	[redacted]	WH BTU Factor:	1.3228
Production Month:	May, 2026	CCT:	[redacted]	Residue BTU:	0.9995
				Meter Pressure Base:	14.7300

Gas Settlement	MCF	MMBTU
Meter	119,521	158,108
Paystation	119,521	158,108
Bypass	0	0
Field Fuel	0	0
Pipeline Deduction	0	0
Gas Lift	0	0
System Gain/Loss	6,574	8,696
Net Delivered to Plant	112,947	149,412
Shrinkage	24,931	60,524
Plant Fuel	2,824	3,735
PTR Transport Fuel	0	0
Flare	0	0
Frac Fuel	0	0
PVR Reconcile	0	0
Plant Loss/Gain	0	0
Gas Returned:		
Bypass	0	0
Pipeline Deduction	0	0
Residue	85,193	85,152
PTR Charged by Pipe	34,328	72,956
Residue Volume	85,193	85,152
Settlement %	100.00	100.00
Settlement Residue	85,193	85,152
Price		-3.3775
Total Gas Purchase		**-$287,604.85**

Analysis	CO2	Nitrogen	H2S
Mol %	0.0676	1.6812	0.0001

CO2 MT
4.26

NGL Settlement

	GPM	Theo Gallons	Plant Rcvry %	Gross Gallons	Gross Price	T&F Fee	Net Price	Gross Proceeds
Ethane	3.4139	385,591	0.850	327,752	0.20316	0.10510	0.09806	32,138.08
Propane	1.7830	201,385	0.960	193,330	0.82134	0.10510	0.71624	138,471.32
Iso Butane	0.2609	29,468	0.980	28,879	1.26969	0.10510	1.16459	33,631.69
Nor Butane	0.6761	76,364	0.980	74,836	1.22447	0.10510	1.11937	83,769.62
Iso Pentane	0.1825	20,613	0.990	20,407	2.12444	0.10510	2.01934	41,208.17
Nor Pentane	0.2067	23,346	0.990	23,113	2.12444	0.10510	2.01934	46,672.48
Nat Gasoline	0.4180	47,212	0.990	46,740	2.12444	0.10510	2.01934	94,383.65
Cond				0	0.00000		0.00000	0.00
Total	6.9411	783,979		715,057				470,275.01

Processor NGL Settlement

	POP %	Gallons	Net Price	Net Proceeds
Ethane	0.00	0	0.09806	0.00
Propane	0.00	0	0.71624	0.00
Iso Butane	0.00	0	1.16459	0.00
Nor Butane	0.00	0	1.11937	0.00
Iso Pentane	0.00	0	2.01934	0.00
Nor Pentane	0.00	0	2.01934	0.00
Nat Gasoline	0.00	0	2.01934	0.00
Cond	100.00	0	0.00000	0.00
Total		0		0.00

Producer NGL Settlement

	POP %	Gallons	TIK	Net Price	Net Proceeds
Ethane	100.00	327,752	0	0.09806	32,138.08
Propane	100.00	193,330	0	0.71624	138,471.32
Iso Butane	100.00	28,879	0	1.16459	33,631.69
Nor Butane	100.00	74,836	0	1.11937	83,769.62
Iso Pentane	100.00	20,407	0	2.01934	41,208.17
Nor Pentane	100.00	23,113	0	2.01934	46,672.48
Nat Gasoline	100.00	46,740	0	2.01934	94,383.65
Cond	0.00	0	0	0.00000	0.00
Total		715,057	0		470,275.01

Total NGL Settlement **$470,275.01**

Fees/Adjustments	Volume	Rate	Amount
Gathering	119,521	0.4733	($56,566.88)
Processing	119,521	0.4733	($56,566.88)
Total Fee/Adjustment Settlement			**($113,133.76)**

Meter Settlement Summary	
Total NGL Settlement	$470,275.01
Total Gas Purchases	($287,604.85)
Total Fee/Adjustment Settlement	($113,133.76)
Net Settlement	**$69,536.40**

DEPRECIATION

The Associations generally support ONRR's proposed depreciation reforms because they would improve recovery of allowable capital costs for acquired assets, but recommends targeted revisions to reduce administrative burden, protect lessees during agency review, preserve appropriate depreciation-method options, and clarify related definitions and rate-of-return provisions.

A. The Associations Support Allowing Lessees to Select Depreciation Schedules for Acquired Assets, Subject to Practical Implementation Changes.

The proposed rule allows lessees to propose a compliant depreciation schedule for acquired assets, even if the original lessee did not have one. Previously, a lessee could be denied the opportunity to include the costs of acquired assets in an allowance if the lessee did not have access to such a depreciation schedule or the original depreciation schedule was noncompliant.

The Associations support this change. In 2000 and 2004, amendments to the royalty regulations were intended to benefit subsequent purchasers of transportation systems by allowing depreciation based on purchase transactions and preventing inequitable loss of allowable transportation costs. ONRR has been interpreting those regulations to deny depreciation where prior owners failed to establish or maintain depreciation schedules, even though no one had previously claimed the deductions and the assets remained economically undepreciated. Allowing a new depreciation schedule where no prior schedule exists does not prejudice the government because it does not create a duplicate deduction or allow depreciation that was previously taken. The proposed rule requires that a prior depreciation schedule be adopted if one exists to protect against those risks.

i. The Associations advocate for annualized reporting for depreciation and operating expense schedules.

ONRR proposes to require non-arm's-length allowances to be reported in the month following production, so expenses are recognized in the period incurred. Monthly reporting would create substantial practical and administrative burdens without materially improving cost recovery or auditability. Lessees often depreciate many assets with different in-service dates, methods, salvage assumptions, and other variables, and updating those calculations each month would significantly increase reporting complexity. Monthly operating-expense reporting would also produce artificial fluctuations caused by the timing of maintenance, turnarounds, and other uneven expenses rather than by meaningful changes in transportation or processing services. Annual depreciation schedules and annual operating-expense reconciliations would better reflect overall costs, reduce disputes over timing differences, simplify ONRR's audit review, and still ensure that lessees recover only allowable costs.

ii. ONRR should allow lessees to depreciate acquired assets based on their own investment.

The Associations support ONRR's proposal to allow the capital cost of acquired assets to be included in non-arm's-length allowances, but the proposed rule should not make that recovery depend on records that only a prior owner—or ONRR—may possess. Acquiring lessees often will face tremendous difficulty or inability in determining whether a predecessor included an asset in a prior depreciation expense or return on investment, particularly where assets have undergone multiple transactions. Requiring that showing would impose a significant acquisition-related burden and could deter investment in these assets and prevent lessees from using the alternative in-service-date provision even when they have incurred a real and current capital cost.

ONRR should instead allow an acquiring lessee to establish a depreciable basis for acquired capital assets based on a reasonable allocation of its own investment, while preserving protections against duplicate depreciation. That approach better aligns with GAAP, supports ONRR's stated goals of reducing administrative burden and encouraging investment in federal lands and waters, and reflects the practical limits of tracing prior-owner depreciation. A lessee that purchases and operates an asset should be able to recover the allowable royalty-bearing share of that investment, regardless of whether historical prior-owner records are unavailable or incomplete.

iii. ONRR should add safeguards if it retains pre-approval for acquired-asset depreciation schedules.

If ONRR retains a proposal-and-approval process for acquired-asset depreciation schedules, the final rule should include core procedural safeguards: (1) a deadline for ONRR review, (2) deemed approval if that deadline passes, (3) an express right to appeal, and (4) protection from accrual interest while a complete proposal is pending. As drafted, the rule gives lessees only thirty days to correct reporting if ONRR rejects or modifies a proposed schedule, while imposing no corresponding deadline on ONRR. That imbalance creates uncertainty, exposes lessees to open-ended interest, and could discourage use of a provision intended to allow recovery of otherwise allowable capital costs.

The Associations therefore recommend a 90-day review deadline, with the proposed schedule deemed approved if ONRR does not act within that period. During review, the lessee should be permitted to use the proposed schedule, and interest under 30 U.S.C. § 1721(a) should not accrue on amounts attributable solely to the agency's review period.

The Associations also recommend clarifying that any decision approving, modifying, or rejecting a proposed schedule is an appealable agency action. That clarification would ensure lessees have a clear administrative remedy when ONRR makes a determination that materially affects their royalty obligations.

B. IPAA Generally Supports Allowing an Alternative In-Service Date but Opposes Prohibiting use of the Unit-of-Production Method for Alternative In-Service Date Elections.

i. IPAA supports the ability to use an alternative in-service date for acquired assets.

The Associations support these changes. ONRR's proposed rule would allow lessees to select an alternative in-service date for assets that have not previously been depreciated, ensuring they can recover the full royalty-share of capital costs through non-arm's-length transportation, processing, or washing allowances. ONRR proposes to add a definition in sections 1206.20 and 1206.251 for "alternative in-service date" that cross-references these changes.

The proposal does not increase the total depreciation available but shifts the depreciation period forward to address situations where reporting limitations or prior disallowances would otherwise prevent lessees from realizing the full economic benefit of those capital investments.

Under the current regulation, ONRR's practice has been to require that depreciation of transportation assets begin on the date the asset is placed into service, even though the transportation allowance regulations do not require it. Allowing lessees the flexibility to use a later in-service date does not present a risk to the government or the taxpayer or unfairly benefit the lessee, because it does not increase the total depreciation available. The present value of depreciation actually decreases when the starting date is delayed.

Industry generally supports the changes to allow additional flexibility regarding how depreciation is calculated for non-arm's length transportation so that otherwise allowable capital costs are not going unclaimed.

ii. IPAA urges removal of the restriction on use of the Unit-of-Production method when electing an alternative in-service date.

The proposed rule would forbid lessees from selecting the unit-of-production depreciation method when applying an alternative in-service date. The Associations recommend removing that restriction. A lessee that elects an alternative in-service date should retain the same depreciation-method options available to other lessees, including the unit-of-production method where it provides a systematic and rational allocation of capital costs. There is no reason to deny this method to a lessee simply because it acquired an asset.

That approach is consistent with ONRR's proposed definition of depreciation as the systematic and rational allocation of capital cost, less reasonable salvage value, over the periods in which the asset provides economic benefits. For assets whose use is driven by throughput rather than time, the unit-of-production method may be the more appropriate way to match depreciation with the production and depletion of the underlying reserves. ONRR also recognizes that methodology elsewhere in the proposed rule, which underscores that it should not be categorically unavailable solely because a lessee uses an alternative in-service date.

The proposed prohibition also appears unsupported by the preamble or other rationale. Although the preamble explains the purpose of the alternative in-service-date election and addresses the effect of other related provisions, it does not provide a rationale for barring the unit-of-production method. Including that limitation without explanation could create uncertainty and invite disputes, contrary to the rulemaking's stated goal of improving clarity and reducing controversy.

In fact, allowing the unit-of-production method with an alternative in-service date would not increase the total depreciation available. Under ONRR's proposed definitions, the unit-of-production depreciation rate is determined by dividing capital cost by the units of production for which the fixed asset was designed, with units of production determined at or before the in-service date. That formula caps cumulative depreciation at the total capital cost available to claim; it changes only the timing of deductions. For those reasons, ONRR should allow lessees using an alternative in-service date to use the unit-of-production method when it otherwise provides a systematic and rational allocation of capital costs.

Finally, the restriction is also more limiting than comparable accounting and royalty frameworks. Depreciation-method selection generally is not conditioned on an asset's in-service date. For example, Texas law permits a reasonable depreciation charge for qualifying marketing facilities, and Texas Comptroller guidance recognizes multiple acceptable depreciation methodologies for calculating marketing-cost deductions, including straight-line depreciation, MACRS, and other properly substantiated methods consistent with Generally Accepted Accounting Principles (GAAP). *See* Tex. Comptroller of Pub. Accounts, Policy on Depreciation as a Marketing Cost for Natural Gas Severance Tax, STAR Accession No. 202607001M (July 8, 2026).

C. <u>Added Definitions</u>

The Associations generally support the addition of the proposed definitions but proposes that a few other terms be defined: (1) "depreciation expense," (2) "prior owner," (3) "original transporter/lessee," (4) "transportation system," and (5) "core business activities." Moreover, to the extent that the terms "prior owner" and "original transporter" are used interchangeably in the context of depreciating acquired assets, the Associations recommend choosing one term that can be used uniformly across the definition sections.

The Associations also recommend removing from the definition of Depreciation the statement that "depreciation begins at the in-service date" or altering it to read "depreciation begins at the in-service or alternative in-service date." The current language could create ambiguity or disputes because the same proposal separately permits use of an alternative in-service date.

D. <u>Other Issues</u>

Because this rulemaking reexamines the non-arm's-length allowance framework as a whole, ONRR should also revisit the components used to calculate capital costs, including the following topics.

i. Reviving use of FERC and state-approved rates

The Associations believe the non-arm's length transportation calculations can be further simplified by allowing Federal Energy Regulatory Commission ('FERC') or

State approved rates to be deducted when the lessee owns a regulated pipeline. The 2016 Valuation Rule eliminated the use of FERC or State approved transportation rates in calculating non-arm's length transportation. The Associations would like to see this provision restored to reduce the burden of filing duplicative information with both the FERC or State agencies and with the ONRR to justify non-arm's length transportation costs. Additionally, where a regulatory agency such as the FERC has adjudicated a particular tariff for transportation and found it to be a just and reasonable rate, the lessee should be able to use this rate as a basis for its transportation allowances as long as the tariff rate is still consistent with actual market conditions. Also, where the non-arm's length transportation involves affiliated pipeline companies, obtaining the information to perform the prescribed calculations could be problematic due to the governmental restrictions placed on pipeline companies in sharing information with shippers. ONRR's efficiency will be enhanced by relying on rates already approved by other regulators by reducing the time spent auditing a separate rate calculated exclusively for royalties.

The use of FERC-approved tariffs for federal royalty valuation was the subject of the October 24, 2001 *Torch Operating Co. v. Babbitt* decision ('*Torch*'). In this case, the U.S. District Court reviewed MMS's attempt to limit the use of filed FERC tariffs and reaffirmed the significance of the regulatory framework MMS had previously established. The court found that MMS had historically treated tariffs filed with and accepted by FERC as satisfying the regulatory requirement that a tariff be "approved by FERC." The court noted that MMS routinely granted transportation allowance requests based upon filed FERC tariffs and that this longstanding interpretation reflected the agency's original intent. ONRR revised the rules effective June 1, 2000, to remove the exception that was the subject of *Torch* and instituted a similar exception, but it added the requirement that *third parties are paying prices, including discounted prices, under the tariff to transport gas on the system under arm's-length transportation contracts* (30 CFR 1206.157(b)(5)(i)(B) (2015)) in order for the tariff to be used. Allowing the use of FERC- or State-reviewed tariff rates to claim non-arm's-length ONRR transportation allowances will remove duplicative work being performed by ONRR that FERC or a State agency is already doing.

ii. Restoring 1.3 times multiplier to the BBB bond rate

ONRR should restore the 1.3 multiplier to the BBB rate because that multiplier reflected the agency's own considered judgment and remains better supported than the unmultiplied rate adopted in 2016. MMS adopted the 1.3 multiplier for Federal oil in May 2004 and Federal gas transportation in 2005 after concluding that a market-based cost of capital should account for both debt and equity costs. *See* 69

Fed. Reg. 29432 (May 5, 2004); 70 Fed. Reg. 11869 (Mar. 9, 2005). MMS's Economics Division found that an appropriate range for gas pipelines was 1.1 to 1.5 times the BBB rate, and MMS selected 1.3 as the midpoint of that range. *See* 70 Fed. Reg. 11869, 11871. By contrast, an unmultiplied BBB debt rate reflects only one component of capital structure and does not represent the full cost of capital operators actually incur.

The 2016 rule reduced the multiplier from 1.3 to 1.0 based largely on changed economic conditions, including lower interest rates, and a desire for consistency across product lines. *See* 81 Fed. Reg. 43,338 (July 1, 2016). Those conditions no longer justify carrying forward the 2016 approach without reconsideration. Because ONRR is reexamining these provisions in this rulemaking, reasoned decision-making requires the agency to revisit whether the current rate still reflects actual capital costs. Consistency can be achieved by applying the 1.3 multiplier uniformly to oil, gas, and coal.

i. Missing Subsection

The Associations would like to point out there may be a missing subsection (i) in proposed section 1206.161.

E. <u>Conclusion</u>

The Associations appreciate ONRR's consideration of this comment and support the agency's efforts to improve the recovery of allowable capital costs. To further that objective, the Associations strongly support the ability to elect an alternative in-service date and respectfully recommends that ONRR: (1) remove the proposed restriction on the unit-of-production method when an alternative in-service date is used; (2) allow acquiring lessees to establish depreciation schedules based on their own investment in acquired assets; (3) incorporate appropriate procedural safeguards into the pre-approval process, including review deadlines, deemed approval, appeal rights, and relief from accruing interest during agency review; and (4) restore the rate of return to 1.3 times the Standard & Poor's BBB bond rate.

Collectively, these revisions would reduce administrative burden, improve regulatory certainty, promote recovery of allowable capital costs, and advance ONRR's stated objective of encouraging investment in the development of federal lands and waters.

AUDIT CLOSURE AND AUDITS

A. Background

Apart from the proposals on the Default Rule and elimination of the definition of "misconduct," the proposed rule does not address the audit process or audit finality.

ONRR is required to follow Generally Accepted Government Auditing Standards (GAGAS) when conducting audits before issuing orders to pay and orders to perform restructured accounting. IBLA vacates the ONRR Director's decisions when they fail to do so. *EPL Oil and Gas, LLC*, 200 IBLA 66, 68, 92-99 (2025). The proposed rule ought to specify some of the more salient requirements that auditors should follow to increase the probability that audits will be GAGAS-compliant.

B. GAGAS

i. Background

The Department has previously explained the audit process. All payments made to ONRR are subject to audit. The audit staff compares a payor's royalty reports and payments with backup data in the company office and information available from other sources to determine whether payments were made in compliance with applicable requirements.[1] Audits involve the verification of data reported to actual source documents. Audits begin with "audit engagement letters," which identify the matters subject to audit, including the relevant time period. After auditing, the federal or delegated state auditor may provide the auditee with an issue letter that includes proposed audit findings and, where applicable, determinations of underpayments and orders to perform restructured accountings. If the lessee

[1] The auditing system that developed under the Federal Oil and Gas Royalty Management Act has been fully described by several Departmental officials and employees in published presentations given at institutes hosted by the former Rocky Mountain Mineral Law Foundation. *See* Donald T. Sant, Minerals Mgmt. Serv., *Federal & Indian Oil & Gas Royalty Management*, at 22, 24-25, Rocky Mountain Mineral L. Found. (1992); Peter J. Schaumberg, Dept. of the Interior, *Royalty Valuation Procedures*, at 8-11, Rocky Mountain Mineral L. Found (1992); Ronald J. Pennington & Linda S. Whitfield, Minerals Mgmt. Serv., *Royalty & Production Reporting*, at 7-22, Rocky Mountain Mineral L. Found. (1992); Sam Wilson, Minerals Mgmt. Serv., *Minerals Management Service Royalty Management Audit Program*, Rocky Mountain Mineral L. Found. (1992).

responds to the issue letter, and the auditors continue to disagree, ONRR may issue an order for payment of royalties.

The governmental auditing standards follow this guidance and further state that "[a]uditors must obtain sufficient, appropriate evidence to provide a reasonable basis for their findings and conclusions." GAGAS § 6.56 (2018). "The concept of sufficient, appropriate evidence is integral to an audit." *Id.* "Sufficiency is a measure of the quantity of evidence used to support the findings and conclusions related to the audit objectives. In assessing the sufficiency of evidence, auditors should determine whether enough evidence has been obtained to persuade a knowledgeable person that the findings are reasonable." *Id.*

Also, "[a]uditors must issue audit reports communicating the results of each completed performance audit." *Id.* § 7.03 (2018). The purpose of audit reports, *inter alia*, is to communicate the results of audits to the audited entity. *See id.* § 7.05(1) (2018). "Auditors should use a form of the audit report that is appropriate for its intended use and is in writing or in some other retrievable form. For example, auditors may present audit reports using electronic media that are retrievable by report users and the audit organization. The users' needs will influence the form of the audit report." *Id.* § 7.03 (2018). And "[i]n the audit report, auditors should present sufficient, appropriate evidence to support the findings and conclusions in relation to the audit objectives." *See id.* § 7.14 (2018). Finally, "[i]f, after the report is issued, the auditors discover that they did not have sufficient, appropriate evidence to support the reported findings or conclusions, they should communicate in the same manner as that used to originally distribute the report to those charged with governance, the appropriate officials of the audited entity, the appropriate officials of the organizations requiring or arranging for the audits, and other known users, so that they do not continue to rely on the findings or conclusions that were not supported." *See id.* § 7.07 (2018). "The auditors should then determine whether to conduct additional audit work necessary to reissue the report, including any revised findings or conclusions[.]" *See id.*

ii. Comment

ONRR should add into its regulations the provisions of GAGAS cited above.

C. Audit Closure

i. Background

To spur more efficient enforcement by ONRR, the Royalty Simplification and Fairness Act preserved prior agency authority to close audit periods and foreclose further auditing even before the running of the seven-year statute of limitations. *See* 30 U.S.C. § 1724(e). Under that authority, ONRR would use its obligation under GAGAS to prepare a final audit report as notification, under § 1724(e)(1) that the audit period "is closed to further audit."

Under GAGAS, the final audit report is the formal culmination of a financial audit, the type of audits ONRR conducts. It has been the Department's position since 1988 that, upon closure of the audit period reflected in an audit report, the audit is "considered final or binding as against the Federal Government, its beneficiaries, [and] the Indian Tribes[.]" Revision of Gas Royalty Valuation Regulation and Related Topics, 53 Fed. Reg. 1230, 1275 & 1277 (Jan. 15, 1988) (promulgating 30 C.F.R. §§ 206.152(k) and 206.153(k)).

ii. Comment

ONRR needs to return to the policies adopted in 1988, for they are consistent with its authority, that instruct ONRR to (1) issue final audit letters contemporaneously with ONRR orders after audit and (2) close the audit period to further review. *See* 53 Fed. Reg. at 1275, 1277; 30 C.F.R. § 1206.147.

ONRR APPEALS PROCESS

ONRR proposes minimal changes to its process, selecting the "standard of review" and "timeliness" as its foci.

A. Timeliness

ONRR's hope is that by adding language that it will issue decisions "in a timely manner" its appeals process will be streamlined, "consistent with the Director's continuing policy to expedite the appeals process when possible." 91 Fed. Reg. 39754, 39768 (June 30, 2026). To that end, it proposes to add to 30 C.F.R. § 1290.105 a subsection (f) stating that "[s]uch [appeals] decision will be made in a timely manner and not unreasonably withheld." 91 Fed. Reg. at 39792.

The Associations support the intent but do not support the proposed change. Although the public has not seen the Director's policy continuing policy elsewhere stated in writing, we note that the policy of acting "timely" and not unreasonably withholding decisions is the same policy that resulted in the Federal Oil and Gas Royalty Simplification and Fairness Act in 1996. The only way that broken policy could be fixed was through fixed timelines on recovery of royalties and length of time in which the Department could issue final decisions in appeals. *See generally* 30 U.S.C. § 1724. This amendment is an empty promise. We urge the Department to focus on the other reforms of "timeliness" we propose in Section C below.

B. Standard of Review

ONRR also seeks to clarify that the "ONRR Director will determine if there is credible evidence to support the Order" being appealed. 91 Fed. Reg. at 39768. Accordingly, proposed 30 C.F.R. § 1290.105(f) says the "ONRR Director will determine if there is credible evidence to support the Order and shall review all conclusions of law de novo." 91 Fed. Reg. at 39792.

The Associations strongly oppose this change because the "credible evidence" standard is unfortunately the worst idea since gravy without biscuits. As the courts have found, it is the lowest standard of evidentiary proof. *100Reporters v. U.S. Dep't of State*, 602 F. Supp. 3d 41, 70 (D.D.C. 2022) (citing "Leahy Vetting Guide" and noting the phrase is "a low evidentiary standard"). It is far less demanding than "substantial evidence" standard used by the federal courts under the Administrative Procedure Act.

The federal courts and the Interior Board of Land Appeals (IBLA) will be reviewing ONRR decisions for "substantial evidence," a standard that requires the agency to consider the whole record (not just one part of it) and explain why the agency is rejecting reliance on countervailing evidence. As a standard of proof the substantial evidence standard is akin to the preponderance of the evidence in civil litigation. *Steadman v. SEC*, 450 U.S. 91, 102 (1981); *see also generally Universal Camera Corp. v. NLRB*, 340 U.S. 474 (1951) (explaining substantial evidence under the APA).

The proposed evidentiary amendment invites the Director to rely on the least showing of factual support from the auditors. Credible evidence merely requires the auditors to produce one supporting fact credible enough that a person could rely on it in decision-making. Credible evidence may be viewed in isolation. All other credible evidence in the record may weigh heavily against relying on that one fact, but the Director could disregard it. Eventually, the case would go to court, and the court would reverse because the Director failed to explain why she ruled contrary to the weight of the evidence. There would follow a remand from the court and years more administrative proceedings.

The practicalities of the audit process show that reliance on credible evidence is likely to be a problem that is not rare but recurring. Facing statutory time limits, auditors often issue orders relying on a piece of evidence on which they have not sought the views of the audited lessees. It is the appeals process that allows lessees to provide contrary evidence. Under the credible evidence test, the Director would review that one piece of evidence. It was "credible" enough for an auditor to rely on it, allowing the Director to disregard the contrary information. *See, e.g.*, *Ovintiv USA, Inc. v. Haaland*, 665 F. Supp. 3d 59, 79 (D.D.C. 2023) (vacating ONRR decision when it looked a single fact without considering contrary evidence submitted by the lessee).

The Associations recommend the credible evidence standard not be adopted. ONRR should continue to give rational explanations of its treatment of all the evidence before it, including information provided to the Director for the first time. That is the hallmark of reasoned decisionmaking.

C. <u>Additional Issues</u>

i. Limitations on Initial Appeals

Under current statute, the Department has 33 months to issue a decision in an appeal. To implement the ONRR Director's policy of expediting the appeals process, the regulations should require ONRR to issue decisions in time to leave the IBLA twelve of the 33 months in which to rule. If ONRR fails to issue a decision in that time, then the regulation should vacate any order demanding less than $100,000. If the order demands more, ONRR would retain jurisdiction, but any subsequent ONRR ruling in that appeal would be deemed final for the Department. For example, if the order demanded $250,000 and ONRR took 28 months to rule on the appeal, then the Director's decision would be final for the Department and subject to immediate judicial review.

ii. Limitations on Decisions on Remand

Over the last eight years, many ONRR decisions that go to court, and several that simply go to the IBLA, have been reversed at least in part. The reversals are for failure to follow the correct rule of law or for offering justifications for ONRR's decision that are found irrational. These decisions are vacated and remanded to ONRR. Once the case is remanded, ONRR's position is that there is no time limit on how long it takes to respond.

The result is that ONRR can evade the time limitations of the Royalty Simplification and Fairness Act by issuing careless decisions; for once a court calls out its carelessness and remands a case, ONRR then believes in can act in God's good time.

The regulations ought to give ONRR no more than one year to respond to the remand. ONRR's failure to meet that deadline would result in permanent withdrawal of the remanded part of the Director's decision and the order it had held under review.

The Associations urge the Department to make the following changes to the proposed rule:

Do not adopt the proposed language adding a new subsection (f) to 30 C.F.R. § 1290.105; add the following language instead:

(f) If the Director has not issued an appealable order on the merits by the end of the 21st month of the 33-month period described in 30 U.S.C. § 1724(h), then the following procedure will govern:

(1) any order for which the amount demanded in an order, or the amount identified as evidence of the need for a restructured accounting order, is less than $100,000, shall be deemed vacated.

(2) any order for an amount greater than that identified in subsection (f)(1) shall be deemed final and appealable to the Interior Board of Land Appeals in accordance with 43 C.F.R. § 4.402(a).

(g) If any order from ONRR is remanded from a federal court, the Department will complete proceedings on review within one year of the entry of the order. If the Department fails to complete review, the remanded part of the order (if not already vacated by the court) will be deemed vacated.

DEFAULT VALUATION/MISCONDUCT ISSUE

A. Background

The 2016 Rule added a pair of provisions identifying circumstances under which ONRR would reject a lessee’s valuation, even if at arm’s length, because it determined the lessee had demonstrated “misconduct,” failed to honor its duty to “market for the mutual benefit of” the lessee and lessor, sell production for at least 10 percent lower than “the lowest reasonable measures of market price,” or failed to provide ONRR adequate documentation to support the valuation the lessee used. Under any of those circumstances, ONRR could select from a menu of six options to impose a new method of valuation. 30 C.F.R. §§ 1206.04, 1206.105.

The Department proposes to revise the Default Provision and repeal the menu of alternatives. It identifies ambiguities in how the rule is to be enforced. 91 Fed. Reg. at 39756. The Department indicates ONRR has invoked these provisions only once in the last five years. 91 Fed. Reg. at 39756.

B. Comments

The Associations support the repeal of these provisions. When coupled with the wide-open definition of “misconduct,” the regulation leaves every good-faith effort to comply subject to retroactive recalculation. This creates unneeded uncertainty. And this detriment is not offset by any public benefit. ONRR has not found it a useful enforcement option. Prior to the 2016 Rule, ONRR had collected many billions of dollars in oil and gas royalties without these provisions. ONRR's audit, compliance, and enforcement authorities remain fully available to address improper valuation.

The Department proposes to delete the definition of “misconduct” it had adopted in the 2016 rule. The proposed rule does not offer particular reasons for deleting the definition. One obvious reason is its overbreadth. ONRR can call anything “misconduct,” because it means “any failure to perform a duty owed to the United States.” Any disagreement ONRR may have with a lessee’s payment can be called a failure to perform a duty as ONRR sees it. The Association supports the repeal of this regulation.

Finally, the current regulations create what seems to be a “soft” presumption that a lessee has breached its “duty to market … for the mutual benefit of yourself and the lessor” if the lessee’s sales price is “10 percent less than the lowest reasonable measures of market prices” in “index prices or price reported to ONRR.” 30 C.F.R.

§ 1206.143(c)(2). *See* 91 Fed. Reg. at 39782. The rule proposes to delete this with respect to oil, but (perhaps through oversight) does not show a repeal as to gas.

The same reasoning supports the repeal of both. While the regulation says "ONRR may" consider the price unreasonably low, an auditor will use the 10 percent figure to demand a lessee pay the index price. A lessee cannot defend itself based on prices reported to ONRR by other partes as those prices are confidential under 18 U.S.C. § 1905. The ONRR practice of placing the burden on the lessee to justify its price in comparison to prices others received but which cannot be disclosed is arbitrary. If ONRR seeks to enforce a claim for breach of the duty to market, it should be required in the regulation to base the claim on information that can be disclosed to the lessee. Fundamental due process requires this. Because the Department cannot enforce this language at all, it should be repealed as to oil and gas both.