

**DEPARTMENT OF THE INTERIOR****Office of Natural Resources Revenue****30 CFR Parts 1202 and 1206**

[Docket No. ONRR–2017–0001; DS63644000 DR2000000.CH7000 178D0102R2]

RIN 1012–AA20

**Repeal of Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform****AGENCY:** Office of Natural Resources Revenue, Interior.**ACTION:** Final rule.

**SUMMARY:** The Office of Natural Resources Revenue (ONRR) is repealing the *Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Final Rule*, published July 1, 2016, and effective January 1, 2017.

Simultaneously, ONRR is reinstating the valuation regulations governing the valuation of Federal oil, Federal gas, and Federal and Indian coal that were in effect before January 1, 2017.

**DATES:** This rule is effective on September 6, 2017.

**FOR FURTHER INFORMATION CONTACT:** For questions on technical issues, contact Elizabeth Dawson at (303) 231–3653, Amy Lunt at (303) 231–3746, Peter Christnacht at (303) 231–3651, or Karl Wunderlich at (303) 231–3663.

**SUPPLEMENTARY INFORMATION:****I. Background***A. General*

This final rule repeals in its entirety the *Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Final Rule* (2017 Valuation Rule) that ONRR published in the **Federal Register** on July 1, 2016 (81 FR 43338), and that was effective on January 1, 2017. The 2017 Valuation Rule made changes to existing regulations governing royalty valuation and reporting practices for oil, gas, and coal. As stated in the 2017 Valuation Rule's preamble, the purpose of implementing the rule was (1) to offer greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees and mineral revenue recipients; (2) to ensure that Indian mineral lessors receive the maximum revenue from coal resources on their land, consistent with the Secretary's trust responsibility and lease terms; (3) to decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) to provide early certainty to industry and to ONRR that companies have paid every dollar due. 81 FR 43338.

After the 2017 Valuation Rule was published, however, ONRR discovered several significant defects in the rule that would have undermined its purpose and intent. In addition, during the same time period (July 1, 2016, to the present) we received numerous comments from the regulated community and other members of the public, both in response to the proposed rule of repeal that we published in the **Federal Register** on April 4, 2017, and in other public forums, that were highly critical of certain provisions in the rule. In light of the defects that we discovered in the rule and after carefully considering all of the comments we received, we have decided to repeal the 2017 Valuation Rule in its entirety, principally for the following three reasons:

First, the 2017 Valuation Rule has a number of defects that make certain provisions challenging to comply with, implement, or enforce. Absent their repeal, the rule would compromise ONRR's mission to collect and account for mineral royalty revenues; could affect royalty distributions to ONRR's State and Tribal partners; and would impose a costly and unnecessary burden on Federal and Indian lessees.

Second, On March 28, 2017, the President issued E.O. 13783—Promoting Energy Independence and Economic Growth, 82 FR 16093. The executive order directs Federal agencies to review all existing regulations and other agency actions and, ultimately, to suspend, revise, or rescind any such regulations or actions that unnecessarily burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. Based on our own internal review, as well as on the comments we received both before and during the process of promulgating this rule of repeal, we have concluded that certain provisions of the 2017 Valuation Rule would unnecessarily burden the development of Federal oil and gas and Federal and Indian coal beyond the degree necessary to protect the public interest or otherwise comply with the law.

Third, on March 29, 2017, the Secretary of the Interior (Secretary) announced that he will reestablish the Royalty Policy Committee (RPC) under the Federal Advisory Committee Act. The RPC will advise ONRR on current and emerging issues related to the determination of fair market value and the collection of royalties from energy and natural resources on Federal and Indian lands. The RPC will be composed of Federal representatives and stakeholders from energy and

mineral interests, academia, public interest groups, States, Indian Tribes, and individual Indian mineral interest owners. The RPC will provide a forum for engaging with key stakeholders and the public on many of the same issues we attempted to address in the 2017 Valuation Rule. ONRR expects that further internal assessment and analysis combined with consultations facilitated by the RPC's reestablishment will lead to the development and promulgation of a new, revised valuation rule that will address the various problems that have now been identified in the rule we are repealing.

At the same time that we are repealing the 2017 Valuation Rule, we are reinstating the regulations governing the valuation of oil, natural gas, and coal produced from Federal leases and coal produced from Indian leases that were in effect before January 1, 2017. These regulations will apply prospectively to oil, gas, and coal produced on or after the effective date that we have specified in the **DATES** section of this preamble. We intend to apply and construe the prior regulations in a manner consistent with the preambles published in conjunction with the original rulemakings and in accordance with administrative and judicial decisions interpreting these regulations.

Finally, upon taking effect, this repeal of the 2017 Valuation Rule will supersede the notification of the postponement of the effectiveness of the rule that we published in the **Federal Register** on February 27, 2017. 82 FR 11823. When this repeal takes effect, the so-called administrative stay of the rule will be lifted.

*B. Secretary's Authority To Promulgate Regulations or Reinstatement Prior Regulations Under FOGRMA*

Section 301 of the Federal Oil and Gas Royalty Management Act (FOGRMA), as amended, codified at 30 U.S.C. 1751, grants the Secretary broad authority to prescribe such rules and regulations, issued in conformity with the Administrative Procedure Act (APA), as he deems reasonably necessary to create a thorough system for collecting and accounting for Federal and Indian mineral royalties. FOGRMA creates the legal framework for the collection and accounting system, but FOGRMA also grants the Secretary, acting through ONRR, broad discretion as to how to build it out. Put another way (as courts sometimes have), FOGRMA grants the Secretary, acting through ONRR, broad discretion to regulate interstitially to interpret and implement the statute.

There is not a single right way for ONRR to exercise its congressionally

delegated authority to interpret and implement FOGRMA; on the contrary, there are many ways in which ONRR may legitimately accomplish its task, as long as the way it chooses is consistent with the statutory language and the congressionally prescribed legal framework. ONRR believes that the prior regulations, which will be reinstated by this final rule, are fully consistent with FOGRMA and other applicable federal statutes and are an effective and efficient means of valuing Federal and Indian minerals, as evidenced by their long and successful use before the promulgation of the 2017 Valuation Rule.

### *C. Chronology of Events Following Promulgation of 2017 Valuation Rule*

On July 1, 2016, ONRR published the final 2017 Valuation Rule in the **Federal Register**. Although the rule took effect on January 1, 2017, first reports and royalty payments under it were not due until February 28, 2017.

To facilitate the transition to the new regulations, ONRR conducted eleven training sessions for industry reporters in different locations between October 17, 2016, and December 15, 2016. We designed the training sessions to educate affected parties on how to value production and report and pay royalties under the 2017 Valuation Rule. The trainings also provided a forum in which lessees could ask us questions about the rule and how ONRR would implement and enforce it. At the same time that ONRR was conducting the trainings and reviewing comments and questions about the rule, ONRR was also receiving numerous written requests for guidance that asked many of the same questions that were being raised at the live sessions.

The feedback we received through the training sessions and guidance requests revealed certain unforeseen defects in, or unintended consequences of, portions of the 2017 Valuation Rule. Lessees raised multiple questions that ONRR had not previously considered and was not prepared or able to answer, particularly with respect to the coal valuation provisions. For example, lessees argued that valuing coal based on the first arm's-length sale of coal as electricity is a difficult task because the sale price of electricity does not reflect the value of coal in a simple, predictable fashion—electricity markets are too diverse and complex to trace electricity prices back to the lease. Lessees also asked questions about how to value coal production in certain non-arm's-length transactions under the new definition of "coal cooperative." And lessees asked ONRR specific questions that we had

not previously considered about how, and under what circumstances, we would implement the default provision with respect to oil, gas, and coal. At bottom, by the middle of December 2016 we had become aware that the rule contained several defects that, at a minimum, would seriously complicate, and probably compromise, ONRR's ability to implement and enforce certain provisions.

On December 29, 2016, three different sets of petitioners, some of whom had previously requested guidance from ONRR, filed three separate petitions challenging the 2017 Valuation Rule in the United States District Court for the District of Wyoming. The petitioners alleged that the rule created widespread uncertainty about reporting and payment of royalties, and in some respects, was unreasonably difficult to comply with. The petitioners' arguments echoed the questions and concerns that had been raised at the reporter training sessions and in various guidance requests.

By late January 2017 we recognized that implementing the 2017 Valuation Rule would be contrary to the rule's stated purpose of offering greater simplicity, certainty, clarity, and consistency in product valuation. We also recognized that the defects in the rule were significant enough that implementation could undermine and compromise ONRR's mission to collect, account for, and verify mineral royalties for the United States and its State and Tribal partners.

With the February 28, 2017, reporting deadline approaching and while we were actively considering internally what to do about the previously identified defects in the 2017 Valuation Rule, the petitioners in the litigation sent ONRR a letter (dated February 17, 2017) requesting that ONRR postpone the rule's effective date. Prompted by that request, but based on ONRR's own independent assessment of the defects in the rule and the harm that could result by requiring lessees to comply with it, we decided that it was in the best interest of the regulated community, the royalty beneficiaries, and the public in general to preserve the regulatory status quo while the litigation was pending. Accordingly, on February 27, 2017, we published in the **Federal Register** a notification postponing the effectiveness of the rule pursuant to 5 U.S.C. 705 of the APA, pending judicial review. 82 FR 11823.

Meanwhile, the nation had elected a new President in November 2016, and the new administration had taken office on January 20, 2017. On March 28, 2017, the President issued E.O. 13783—

Promoting Energy Independence and Economic Growth, 82 FR 16093, which directed the heads of executive agencies to review all existing regulations, orders, guidance documents, policies, and other similar agency actions that potentially burden the development or use of domestically produced energy resources and, ultimately, to suspend, revise, or rescind those agency actions that do so unnecessarily. The executive order provided additional impetus to our ongoing review of the 2017 Valuation Rule, and we discovered some additional substantive problems with the rule.

As a result of all of those developments, on April 4, 2017, we published in the **Federal Register** a notice proposing to repeal the 2017 Valuation Rule in its entirety and soliciting public comment on the proposal. 82 FR 16323. At the same time, we recognized that certain provisions in the 2017 Valuation Rule had been, and continued to be, well received. Therefore, concurrent with the proposed repeal, we also published an Advance Notice of Proposed Rulemaking soliciting public comment on two scenarios: (1) If the 2017 Valuation Rule were repealed, whether a new valuation rule is needed and, if so, what particular issues the new valuation rule should address; and (2) if the 2017 Valuation Rule were not repealed, what changes should be made to the rule (82 FR 16325, April 4, 2017).

The comment period for the proposed repeal rule closed on May 4, 2017. We received more than a thousand comments from 2,342 commenters both for and against repeal. We carefully considered all of the comments we received and, for the reasons discussed further below, have decided at this time to repeal the 2017 Valuation Rule in its entirety. ONRR will continue to assess the substantive issues addressed in the 2017 Valuation Rule and expects to in the near future promulgate a new, revised valuation rule that will address the various problems that have been identified in the rule we are repealing.

### *D. Substantive Defects in, and Administrative Challenges Posed by, the 2017 Valuation Rule*

#### *1. Valuing Coal Using the Sale Price of Electricity*

The 2017 Valuation Rule required lessees to value certain non-arm's-length sales of Federal and Indian coal based on the first arm's-length sale of electricity. For several reasons we have concluded that this provision of the rule is unnecessarily complicated and burdensome to implement or enforce.

ONRR has long valued oil, gas, and coal based on the first arm's-length sale of the resource because we believe that such sales are the best indicator of market value. In promulgating the 2017 Valuation Rule, ONRR incorrectly assumed that it would be reasonable for lessees to "net back" to the value of coal from arm's-length electrical sales, the same way that lessees "net back" to value from the first arm's-length sale by an affiliate. We also incorrectly assumed that using such sales would accurately reflect the value of coal because the majority of coal mined from Federal and Indian lands is used to generate electricity. But we failed to fully consider other factors that determine what a generating company charges for its electricity. The price of electricity also reflects the company's costs to construct, operate, and maintain its depreciable capital assets; its costs to operate and maintain other necessary infrastructure; its costs to comply with applicable Federal and State laws; and its corporate overhead and other internal corporate costs. All of those factors may (and do) vary from company to company and from state to state. Unlike an arm's-length sale of coal, where the sale price directly and accurately reflects the value of the coal, the sale price of electricity is determined by many factors in addition to the price of coal.

Moreover, electricity is generated, transmitted, and distributed through regional grids where the electricity is maintained for delivery at specified voltages and frequencies. The regional grids function as pools that are fed by electricity generated from a variety of different resources, including natural gas, solar, wind, geothermal, and coal. The electricity is then sold in wholesale markets in a variety of ways, including, but not limited to, firm and non-firm sales, long-term and short-term sales, interruptible sales, and daily spot-market sales. The markets also include ancillary services, such as spinning and non-spinning reserves, voltage and frequency control, and load following. Each of these sales commands a different price. We have concluded at this time that the approach taken in the 2017 Valuation Rule establishes an unreasonable requirement for the lessee or ONRR to dissect these services and sales, and trace those sales back to coal produced from the lease, particularly because electricity generated from coal is pooled with electricity generated from other resources before it is sold. In short, it would be very challenging for lessees to calculate and pay royalties based on the sale price of electricity and

similarly challenging for ONRR to verify the accuracy of those calculations.

Finally, the 2017 Valuation Rule failed to address the increasingly common situation in which gross proceeds accrue to a lessee's affiliate. The rule stated that lessees value their Federal and Indian coal production on "the gross proceeds accruing to you for the power plant's arm's-length sales of the electricity less applicable transportation and washing deductions." (Emphasis added.) As used in that regulation, the word "you" referred to the lessee, which the rule defined as "any person to whom the United States, an Indian Tribe, and/or individual mineral owner issues a lease, and any person who has been assigned all or part of record title, operating rights, or an obligation to make royalty or other payments by the lease." For Federal and Indian coal, the definition of lessee included "an operator, payor, or other person with no lease interest who makes royalty payments on the lessee's behalf." The rule was silent, however, on how to value coal when the gross proceeds accrued to a lessee's affiliate. This oversight would have undermined ONRR's mission and responsibility to collect and verify royalties, which would have had a direct impact on revenue accruing to ONRR's State and Tribal partners.

## 2. Definition of "Coal Cooperative"

The 2017 Valuation Rule defined "coal cooperatives" to capture the arm's-length value of coal in those limited circumstances in which unaffiliated companies cooperate to market and exchange coal for mutual economic advantage. But the term was defective in several respects. At bottom, the definition was overly broad and ambiguous and created too much confusion to be effective or enforceable. And because the definition was too broad, it asked lessees to perform an unreasonably difficult task, that is, to value coal based on the sale price received by a third-party company that was neither affiliated, nor in a contractual relationship, with the lessee.

More specifically, the 2017 Valuation Rule did not define what entities are included in a coal cooperative, nor did the rule adequately identify what type of behavior, conduct, or economic relationships constitute a coal cooperative. Thus, the rule did not provide lessees with meaningful direction to enable them to determine whether they are part of a coal cooperative and, if so, what other entities may also be part of that cooperative. Indeed, the definition was so broad that it would have captured

almost any entity engaged in the production, marketing, and transportation of coal, regardless of how far removed that entity was from the lessee. Consequently, it would have been unreasonable for either ONRR or the lessee to determine where the coal cooperative began and where it ended. By extension, it would have been unreasonable for either ONRR or the lessee to determine when the first arm's-length sale occurred. As a result, lessees could not have valued their coal, and ONRR (or States or Tribes, acting under authority by ONRR) could not have verified that value. That inadvertent and unfortunate confusion was, of course, directly contrary to ONRR's intent when it promulgated the rule.

What is more, the definition would have required lessees to perform an unreasonably difficult task. For example, a federal lessee in a coal cooperative could sell its coal to an unaffiliated third party that is also in the cooperative. But because the parties are part of the same cooperative, we would not have considered that sale to be an arm's-length transaction. The third party then could have transferred the coal to an affiliate, who could have sold the coal at arm's-length. Under those circumstances, the rule would have required the lessee to value its coal based on the sales price received by the third-party's affiliate, a company that was neither affiliated, nor in a contractual relationship, with the lessee. Under this scenario, the lessee probably could not have obtained the sales price information it needed to determine the royalty-bearing value of its coal.

Last, the definition of coal cooperative was unnecessary because it attempted to solve a problem that was already addressed by the prior (and soon-to-be-reinstated) regulations. In the example, under the prior regulations ONRR would still obtain fair market value for the coal because the lessee and third party lack opposing economic interests, and we therefore would apply the provision in the regulations for valuing coal in non-arm's-length transactions. Under that provision, depending on the circumstances, ONRR could still value the coal based on the first arm's-length transaction under the fourth benchmark in 30 CFR 1206.257(c)(2) (Federal coal) or 1206.456(c)(2) (Indian coal).

## 3. Default Provision

Statutes and lease terms grant the Secretary considerable authority and discretion to establish the reasonable value of Federal and Indian minerals. By promulgating the so-called default provision, ONRR was attempting to offer greater clarity, consistency, and

predictability by defining when, where, and how the Secretary would exercise his discretionary authority to use an alternative methodology to value minerals. We attempted to explain that we would invoke the default provision only in specific and limited situations when we could not determine whether a lessee had properly paid royalties under the regulations. Those situations include when a lessee fails to provide documents during an audit, when a lessee engages in misconduct, when a lessee breaches its duty to market, or any other situation that compromises our ability to reasonably determine the fair market value of the oil, gas, or coal. But because we described those circumstances so broadly, without limits or meaningful guidance, the rule created more confusion and uncertainty than it resolved.

We also failed to appreciate the numerous administrative challenges posed by the default provision. For example, the 2017 Valuation Rule did not identify who within ONRR has the authority to invoke the default provision or whether that decision must be approved or may be appealed. The rule defined “misconduct” so broadly that lessees, ONRR, and ONRR’s State and Tribal partners were left without any meaningful guidance on what type of misconduct triggered the default provision. At the same time, the rule was silent on whether ONRR must make a formal finding of misconduct before the default provision is invoked, who has the authority make such a finding, and whether such a finding is subject to review. We believe that those ambiguities would have led to very inconsistent applications of the rule.

The 2017 Valuation Rule also did not address whether the default provision was a tool of last resort or a vehicle to collect and verify royalties more efficiently. For example, the rule offered no guidance on what would happen if ONRR invoked the default provision to value production because the lessee failed to provide documents necessary to value the production, and the lessee later produces those documents. Nor did the rule fully explain how the default provision interacted with ONRR’s civil penalty regulations. For example, if a lessee knowingly or willfully fails to provide documents during an audit, the rule was silent on

whether ONRR would issue a civil penalty for failing to permit an audit, or whether ONRR would complete the audit by valuing the production under the default provision, or both. These challenges, and many others, made the default provision confusing to lessees and would have made it difficult, for ONRR to implement and enforce.

Finally, with or without the default provision, ONRR already has the authority to establish the value of Federal and Indian minerals when we cannot determine whether a lessee properly paid royalties. While the default provision was a well-intended attempt to provide certainty and predictability by clarifying and codifying that authority, we now recognize that the default provision created more confusion, uncertainty, and apprehension than it resolved.

#### 4. Requirement That Arm’s-Length Contracts Be in Writing and Signed by All Parties

The 2017 Valuation Rule required both lessees and their affiliates to reduce all contracts, contract revisions, or amendments to writing and have them signed by all of the parties. The rule further stated that where the lessee did not have in place a written contract signed by all of the parties, ONRR could use the default provision to value the oil, gas, or coal at issue.

Based on the comments we received, we have reconsidered our position on this requirement. We now agree with the majority of commenters that this provision of the rule is unnecessary, overly burdensome, and potentially defective. First, this provision overlooked the fact that unwritten agreements or unsigned, written agreements may be binding, legally enforceable contracts. Second, this provision contradicted the definition of “contract” in the rule itself, which defined “contract” as “any oral or written agreement . . . that is enforceable by law” and which did not require the contract to be signed by the parties. Third, the preamble stated that ONRR could discount or ignore an arm’s-length contract if the contract were not in writing and signed by all of the parties, which ran counter to ONRR’s long-held position that arm’s-length sales are the best indicator of market value. Fourth, the rule required the

lessees’ affiliates to have all of their contracts, contract revisions, and amendments reduced to writing and signed by all of the parties, despite the fact that the affiliates are not Federal or Indian lessees and the rule was not purporting to regulate them. And fifth, the rule burdened lessees and their affiliates with an unnecessary and potentially costly obligation to conform contracts to meet ONRR’s specifications, which could increase the cost of production and delay the delivery of mineral resources.

#### 5. Valuation Guidance and Determinations

The 2017 Valuation Rule required Federal oil and gas and Indian coal lessees to request valuation determinations from ONRR that, because of an oversight in the rule, we would no longer have the regulatory authority to issue. The prior regulations authorized ONRR to issue a binding valuation determination in response to a request from an oil, gas, or coal lessee. The 2017 Valuation Rule, however, inadvertently stripped ONRR of that authority or, at the very least, was unclear as to whether ONRR could continue to exercise that authority.

More specifically, sections 1206.108 (Federal oil), 1206.148 (Federal gas), 1206.258 (Federal coal), and 1206.458 (Indian coal) all provided that a lessee could request a valuation determination from ONRR. The rule then provided that ONRR could do one of three things in response to the request: (1) Request that the Assistant Secretary for Policy Management and Budget issue a determination; (2) decide that ONRR will issue non-binding guidance; or (3) notify the lessee that ONRR will not provide a determination or guidance. The rule was silent, however, on whether ONRR could issue a valuation determination in response to a request. Thus, under the 2017 Valuation Rule ONRR arguably had no authority to continue to issue valuation determinations.

This was particularly problematic because several sections in the 2017 Valuation Rule required lessees to request valuation determinations from ONRR, and several other provisions required ONRR to issue such determinations. Those references appear in the following sections:

Federal gas	Federal oil	Federal coal	Indian coal
1206.141(e) 1206.142(f) 1206.153(d) 1206.160(b)(2)	1206.111(d)	1206.252(b)(2) 1206.261(c) 1206.268(c)	1206.452(b)(2) 1206.461(c) 1206.468(c)

Federal gas	Federal oil	Federal coal	Indian coal
1206.160(c)			

At bottom, this oversight means that lessees cannot comply with the 2017 Valuation Rule and ONRR cannot enforce it, which undermines the purpose and intent of the rule. Even if ONRR could issue valuation determinations in the absence of a regulation, these sections fail to specify whether ONRR’s determinations are binding on ONRR or the lessee, and if so, whether the lessee may appeal the determination. Other provisions of the regulations cross-reference the terms “valuation determinations” and “determinations” without defining those terms or stating whether those terms are synonymous or distinct. In addition, section 1206.458, which applies to Indian coal, incorrectly provides that the Assistant Secretary for Policy, Management and Budget will issue a valuation determination regarding Indian coal. But only the Assistant Secretary for Indian Affairs has the authority to issue a valuation determination for questions concerning Indian lands. All in all, the numerous defects and the lack of consistency in the regulations governing valuation determinations undermined the purpose and intent of the rule and would have created confusion and inefficiencies and imposed additional burdens on both ONRR and the regulated community.

6. Flared Gas Valuation

Under the 2017 Valuation Rule, lessees who are required to pay royalty on flared gas would have been required to value the vented and flared gas using an index price for the area if one is available. If an index price were not available, then the lessee would have been required to propose a method to ONRR under the default provision. In those circumstances, we expected that the proposed method would value the vented and flared gas based on the arm’s-length sale price the lessee received for other gas sold from the same lease. ONRR now recognizes that this regulation would have imposed an unnecessary and potentially costly administrative burden on certain lessees. It would also have run counter to ONRR’s belief and position that arm’s-length transactions are the best indicator of value.

For example, there is no viable index price in North Dakota. Thus, lessees in North Dakota would have been required to propose a method to ONRR under the default provision. For lessees that also

sell gas produced from the same lease at arm’s-length, we assumed that the lessee would propose to value its vented and flared gas on the price it received in the arm’s-length sale. Thus, those lessees would have reported one volume, on one line, pursuant to a single valuation method.

Lessees in the San Juan Basin in New Mexico, however, would have been held to a different standard. Because there is a viable index price in the San Juan Basin, lessees there would be required to value their gas using the index price. That is true even if the lessee were selling the same gas from the same lease at arm’s length to third-party buyers. Under those circumstances, the lessee would be required to report two separate volumes, on two separate lines, using two separate valuation methods. This inconsistency, and the additional administrative burden it would impose on certain lessees, was not our intent when we promulgated the rule.

In sum, the 2017 Valuation Rule would have imposed an unnecessary and potentially costly administrative burden on certain lessees. At the same time, the rule would run counter to ONRR’s long-held belief and position that prices under arm’s-length contracts are the best measure of value.

7. Changes in Administration and Energy Policy

The nation elected a new President in November 2016, and the new administration took office on January 20, 2017. Through various public announcements the new administration quickly signaled that it would adopt and follow a national energy policy different than that of its predecessor, one that emphasized and prioritized the reduction of Federal regulatory burdens on industry. On March 28, 2017, President Donald J. Trump issued E.O. 13783—Promoting Energy Independence and Economic Growth (Executive Order) (82 FR 16093, Mar. 31, 2017). The Executive Order begins by stating broadly that “[i]t is in the national interest to promote clean and safe development of our Nation’s vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.” The Executive Order then continues, “Accordingly, it is the policy of the United States that executive

departments and agencies (agencies) immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.” To that end, the Executive Order directs the heads of all agencies to “review all existing regulations, orders, guidance documents, policies, and any other similar agency actions (collectively, agency actions) that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources.” The Executive Order defines “burden” to mean “to unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources.”

Pursuant to the Executive Order, ONRR included the 2017 Valuation Rule in its review of regulations that potentially burden the development or use of domestically produced energy resources. As a result of that review, we concluded that the rule, as a whole, would unduly burden or unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the production, utilization, or delivery of Federal oil or gas or Federal or Indian coal. For example, because we realized that valuing coal based on the arm’s-length sale of electricity is a very challenging task, we concluded that Federal and Indian coal lessees would incur unnecessary and unwarranted costs in trying to comply with those provisions in the 2017 Valuation Rule. Likewise, because we had realized that the definition of “coal cooperative” in the rule was too broad and ambiguous to comply with or enforce, we concluded that lessees in cooperatives would incur unnecessary and unwarranted costs in an effort to determine the royalty-bearing value of their coal. These defects alone would have resulted in significant costs that would have served as a financial disincentive to producing coal from Federal or Indian lands.

In sum, a number of provisions of the 2017 Valuation Rule would have unnecessarily obstructed, delayed,

curtailed, or otherwise imposed significant costs on the production, utilization, or delivery of Federal oil and gas and Federal and Indian coal. The repeal of the 2017 Valuation Rule therefore is consistent with the policy announced in the Executive Order and the direction that the Executive Order provides to executive agencies. The Department takes seriously its responsibility to ensure that taxpayers receive the full value from Federal mineral leases, which is why ONRR intends to continue to consider future changes and develop a new rulemaking after further analysis and consultations with our key stakeholders and the general public.

## II. Comments on Proposed Rules

On April 4, 2017, ONRR published a Notice of Proposed Rulemaking (NPRM) to invite public comment on the possible repeal of the 2017 Valuation Rule. 82 FR 16323. During the 30-day public comment period, we received more than one thousand pages of written comments from over 2,342 commenters. We received comments from industry, industry trade groups, Members of Congress, State governors and agencies, local municipalities, Tribes, local businesses, public interest groups, and individual commenters. The majority of comments—both those opposing and those supporting repeal—addressed the Federal and Indian coal valuation provisions in the 2017 Valuation Rule.

Comments opposing repeal of the 2017 Valuation Rule generally argued that repealing the 2017 Valuation Rule would result in undervaluing our nation's oil, gas, and coal resources; would result in a waste of government resources; and would violate certain provisions in the APA.

Comments supporting repeal of the 2017 Valuation Rule generally faulted the following elements of the rule: (a) The method that lessees must use to calculate value on coal sold under non-arm's-length contracts; (b) ONRR's definition of "contract" and "misconduct"; (c) the default provision; (d) changes to transportation and processing allowances; (e) the option to value Federal gas sold under non-arm's-length transactions based on index prices; and (f) percentage-of-proceeds contracts.

### A. General Comments

*Public Comment:* Many commenters who work in the coal industry or live in coal-mining-dependent communities, including a tribe, maintained that the 2017 Valuation Rule went too far. They argued that the 2017 Valuation Rule

imposed unwarranted valuation methods, which, they contended, hinder transparency and create complex and subjective oil, gas, and coal valuations. They claimed that the 2017 Valuation Rule would cause economic harm to the oil, gas, and coal industries, including the loss of jobs.

ONRR also received a few comments advocating that oil, gas, and coal production should stop and that the minerals should "stay in the ground."

*ONRR Response:* We agree that the 2017 Valuation Rule's process for using the sale price of electricity to value coal would be too complex to comply with, implement, or enforce. We also agree that other aspects of the 2017 Valuation Rule, including the default provision and the definition of coal cooperative, are too broad to be implemented effectively, which could make reporting and paying royalties more burdensome and less predictable and transparent.

Although we appreciate the comments regarding keeping fossil fuels in the ground and the socioeconomic impact of the 2017 Valuation Rule on communities that rely on coal production, both issues are beyond the scope of this rulemaking.

*Public Comment:* An industry trade group commented that complexities in the 2017 Valuation Rule would make it difficult for small businesses to comply. The commenter also claimed that smaller companies would not be able to take deductions, resulting in a higher royalty rate.

*ONRR Response:* For the reasons stated previously, we agree that implementing the rule would increase the costs of compliance and unnecessarily burden the production of Federal and Indian mineral resources. We also agree that those increased compliance costs could disproportionately impact smaller companies that have fewer resources to comply.

*Public Comment:* We received comments from two States asserting that repealing the rule would unfairly reduce the royalties that the States receive under the 2017 Valuation Rule.

Conversely, we received a comment from another State asserting that not repealing the rule would result in decreased production that would adversely affect its royalty share.

*ONRR Response:* Based on our economic analysis, we recognize that repealing the 2017 Valuation Rule will result in a decrease in royalties (between 0.8 percent and 1.0 percent) to our State partners compared to what they would receive if ONRR implemented and enforced the rule. ONRR will continue to assess options

for updating our valuation regulations and expects to, in the near future, propose new rules that could offset, in whole or in part, the decrease in royalties shared with State partners in future years compared to what would otherwise result from the repeal of the 2017 Valuation Rule. As discussed previously, the rule has a number of defects that make certain provisions challenging to comply with, implement, or enforce. ONRR's attempt to implement or enforce the rule as written would have compromised our ability to collect and account for mineral royalty revenues, which in turn may have affected distributions to other royalty beneficiaries. It would also have imposed an additional financial and administrative burden on our State and Tribal partners, who audit and verify royalty payments.

We also agree with the State commenter that implementing the 2017 Valuation Rule could result in some decreased production, particularly for coal, because the burden of complying with certain provisions of the rule would serve as a disincentive to production. This too would result in decreased royalty distributions to our State and Tribal partners. All told, we believe that the modest economic gains that might result from implementing the rule are far outweighed by the potentially significant burden on industry, ONRR, and our State and Tribal partners from implementing and enforcing a rule with significant defects.

*Public Comment:* Industry trade groups claimed that the 2017 Valuation Rule was unnecessarily complex, which would increase the costs of complying with the regulation. The groups maintained that the complexity and costs would discourage industry from entering into Federal or Indian leases.

*ONRR Response:* ONRR agrees that several unforeseen defects in the 2017 Valuation Rule have the potential to significantly increase the cost and administrative burden of compliance, which could create a disincentive to entering into, and producing oil, gas, and coal from, Federal or Indian leases.

*Public Comment:* We received comments encouraging collaboration with our stakeholders in any future rulemaking. Many industry commenters encouraged working through the RPC to advise ONRR on valuation policies.

*ONRR Response:* As discussed previously, the Secretary has recently re-established the RPC to collaborate with our stakeholders in any future rulemaking. The RPC will provide a forum for engaging with the public on many of the same issues we attempted to address in the 2017 Valuation Rule.

We look forward to working with our stakeholders in the RPC on a future rulemaking.

#### B. Fair Return to Government

*Public Comment:* Many commenters and comments disagreed about the need either to revise or to repeal the 2017 Valuation Rule. Some public interest groups and some members of the public asserted that ONRR's regulations have undervalued royalties for many years and that the changes made in the rule would ensure that royalties are based on fair market value. Industry trade groups and other members of the public maintained that the rule would result in values that inflate the value of the resources.

*ONRR Response:* We disagree that repealing the rule will prevent the government from receiving a fair market value for its mineral resources. The prior (and soon-to-be-reinstated) regulations have been in place for more than twenty years and serve as a reasonable, reliable, and consistent method for valuing Federal and Indian minerals for royalty purposes. This is evidenced by the fact that when we promulgated and published the final 2017 Valuation Rule, we estimated that it would generate less than 1 percent in additional royalties. 81 FR 43359. Moreover, as we discussed in proposing the 2017 Valuation Rule, we were attempting to make "proactive and innovative changes" to the rules "to increase the effectiveness and efficiency of the rules." We believe today, as we always have, that the prior (and soon-to-be-reinstated) regulations provide a fair market return for Federal and Indian minerals. That said, we will continue to look for opportunities to improve our regulations, including opportunities to improve the return to taxpayers and Indian mineral owners and to streamline processes for both ONRR and industry.

*Public Comment:* A public interest group maintained that our regulations should use a market value based on the value of the resource where it is ultimately consumed. The comment asserted that ONRR does not collect royalties at the market and that we should more aggressively pursue a value at the market instead of a value at the lease.

*ONRR Response:* While we appreciate the comment, whether ONRR should use a market value based on the value of the resource where it is ultimately consumed is outside the scope of this rulemaking.

#### C. Administrative Procedure Act (APA)

One member of Congress, two State officials, and several public interest groups asserted that ONRR failed to comply with certain requirements in the APA.

*Public Comment:* Some commenters stated that ONRR's decision to postpone the effectiveness of the 2017 Valuation Rule indicates ONRR's intent to repeal the rule, without regard to any comments received in a rulemaking process, in violation of APA rulemaking requirements.

*ONRR Response:* The 2017 Valuation Rule was effective on January 1, 2017. On February 27, 2017, for the reasons discussed in the preamble to this rule, including the filing of three separate petitions challenging the rule in the United States District Court for the District of Wyoming, ONRR postponed the effectiveness of the rule, pending judicial review. 82 FR 11823. ONRR did not decide to repeal the 2017 Valuation Rule, however, until after we had reviewed and considered of all comments that we received in response to the proposed rule of repeal, which we published in the **Federal Register** on April 4, 2017. 82 FR 16323.

*Public Comment:* We also received comments contending that ONRR did not provide a reasoned basis to repeal the rule.

*ONRR Response:* We are providing a reasoned basis to repeal the rule in the preamble to this rule. Before we proposed to repeal the 2017 Valuation Rule, we identified several defective provisions in the rule that would have made these provisions unnecessarily complicated and burdensome to comply with, implement, or enforce. When we published the proposed rule of repeal on April 4, 2017, we identified some of those defects and specifically invited public comment on them as well as on other aspects of the 2017 Valuation Rule.

*Public Comment:* Public interest groups and some individuals claimed that the 30-day comment period in the NPRM is unreasonable and violates the APA. The commenters asserted that ONRR went to great effort to promulgate the 2017 Valuation Rule and was now proposing to repeal it with only a 30-day comment period.

*ONRR Response:* Under the APA's rulemaking procedures, agencies must publish a notice of proposed rulemaking in the **Federal Register**; allow interested persons an opportunity to comment on the proposed rule; and, after considering those comments, publish the final rule. The APA requires an opportunity to submit "written data, views, or

arguments," yet there is no required minimum comment period under the APA. See 5 U.S.C. 553(c). Through this rulemaking we are complying with the requirements set forth in the APA. We provided a reasonable amount of time to allow interested parties a sufficient opportunity to consider the repeal and its supporting analysis and to provide meaningful comments.

*Public Comment:* One commenter asserted that ONRR must analyze the record compiled to issue the rule and provide a reasoned explanation for the repeal. According to the commenter, ONRR has not cited any new scientific or technical information in support of repeal.

*ONRR Response:* The comment is not clear on whether it refers to the record for the 2017 Valuation Rule or the record for the repeal of the 2017 Valuation Rule. Regardless, we provided the purpose and justification for both rules and responded to comments that we received during both rulemakings. Specifically, we analyzed the record compiled during the 2017 Valuation Rule rulemaking. 81 FR 43338. In the preamble and responses to comments for this final rule, ONRR also analyzed the record compiled for the proposed repeal. We have determined to repeal the 2017 Valuation Rule for the reasons stated herein.

#### D. Government Efficiency

*Public Comment:* One member of Congress and a public interest group asserted that repealing the rule amounts to wasting government resources because ONRR is abandoning the work that it performed while promulgating the 2017 Valuation Rule. These commenters also argued that if there are problems with the rule, ONRR should address those problems separately and not necessarily abandon the rule in its entirety.

*ONRR Response:* We disagree that repealing the rule is a waste of government resources. As noted previously, the 2017 Valuation Rule has several defects that make certain provisions unnecessarily complicated and burdensome to comply with, implement, or enforce. We have concluded that those defects are significant enough that implementing the rule would compromise our mission to collect and account for mineral royalty revenues for Federal oil and gas and Federal and Indian coal. The cost of implementing the rule and subsequently trying to fix the defects in one or more separate rulemakings would far exceed the cost of repealing and replacing the rule.

We also disagree that ONRR is abandoning the work that it previously performed. As noted previously, the Secretary is reestablishing the RPC to increase stakeholder engagement on many of the same issues the 2017 Valuation Rule attempted to address. We hope and expect that this new round of public engagement will lead to the development of a new valuation rule. The work that ONRR performed while promulgating the 2017 Valuation Rule, as well as the stakeholder comments during that rulemaking, will no doubt serve as valuable resources for the RPC as it fulfills its charge to advise ONRR on current and emerging issues related to the determination of fair market value and the collection of royalties from resources on Federal and Indian lands.

#### E. Federal and Indian Coal Valuation

For coal not sold under arm's-length contracts, the 2017 Valuation Rule removed the ability for lessees to use the benchmarks found in the prior (and soon-to-be-reinstated) regulations. Instead, under the 2017 Valuation Rule lessees had to value their coal on the first arm's-length sale of the coal. In cases where that first arm's-length sale was for the sale of electricity, lessees had to use the prices that they received for electricity to "net back" to the value of the coal at the lease.

##### 1. Valuing Coal Based on Benchmarks

*Public Comment:* ONRR received numerous comments from industry, government officials, industry trade groups, public interest groups, and the general public regarding how lessees should value Federal and Indian coal not sold at arm's length.

Some commenters maintained that the prior rule's non-arm's-length valuation benchmarks fail to capture the true value of coal that lessees sell in non-arm's-length transactions. The commenters posited that the benchmarks do not allow ONRR to determine royalty value based on a coal lessee's affiliate's subsequent arm's-length sale, including overseas sales, resulting in the coal industries taking advantage of a "loophole." These commenters maintained that the most effective method to determine the value of Federal and Indian coal not sold under arm's-length contracts is to use the first arm's-length sale of coal sold by the lessee's affiliate.

ONRR also received comments from industry, government officials, industry trade groups, and the general public that supported repealing the rule because they found the old benchmarks to be time-tested and robust. These commenters maintained that the 2017

Valuation Rule's method to determine value for royalty purposes when Federal and Indian lessees do not sell their coal at arm's-length was difficult to implement and did not establish an appropriate value, for royalty purposes, of Federal or Indian coal at the mine. One commenter asserted that the rule amounted to an unlawful royalty on the value of services that an affiliate provides to the lessee.

*ONRR Response:* We believe that arm's-length transactions generally are the best indicators of market value because they provide a consistent and accurate measure of value. But we do not agree that the benchmarks in the prior (and soon-to-be-reinstated) regulations create a "loophole" that permits coal lessees to shirk their royalty obligations. Indeed, ONRR has used the benchmarks to order additional royalties due based on an affiliate's arm's-length sale, including in those circumstances in which the coal is sold by the affiliate in the international market. While we recognize that the benchmarks are sometimes difficult to apply, we also recognize that benchmarks are a proven and time-tested method for determining the fair value of Federal and Indian coal that the lessee does not sell at arm's-length.

##### 2. Valuing Coal Based on "Net Back" From Electric Sales

*Public Comment:* Numerous coal companies and a coal industry trade group expressed a range of concerns about using electric sales to value coal sold in non-arm's-length situations without competing economic interests. In particular, these commenters highlighted extraordinary complexities in electric markets and the electric producers' resource portfolios. They objected to valuing coal by way of electricity, which the commenters asserted is a separate commodity subject to its own unique market factors and forces and regulatory requirements, and argued that geothermal regulations were inappropriate as a means for determining transmission and production allowances. Overall, industry commenters argued that the 2017 Valuation Rule's effort to value coal through arm's-length sales of electricity was overly burdensome if not functionally impossible. A number of comments from the general public also asserted that valuing coal as electricity would make electricity more expensive because the increased royalty burden would be passed on to the consumer.

*ONRR Response:* ONRR has carefully considered these comments and, as discussed in the preamble to this rule, has concluded and agrees that the 2017

Valuation Rule's process for "netting back" to the value of coal from arm's-length electrical sales is an unnecessarily complicated and burdensome task to perform and does not necessarily result in an accurate valuation of the coal.

##### 3. Other Issues Related to Valuing Coal

*Public Comment:* Two companies, one State government representative, three industry trade groups, and one member of the public supporting the repeal observed that the 2017 Valuation Rule handles coal lessees differently than oil and gas lessees and claimed that this treatment is discriminatory. They pointed out that, like coal, gas can be used to generate electricity, but that, unlike coal, ONRR does not require Federal or Indian gas lessees to value their gas production based on electricity sales "netted back" to the lease.

*ONRR Response:* We did not intend to discriminate against coal by valuing the coal based on electricity sales. Coal, oil, and gas are all different commodities, subject to different market factors and forces and regulatory requirements. In our experience, the first arm's-length sale of much Federal or Indian coal is as electricity. That is rarely the case for Federal or Indian oil and gas.

*Public Comment:* One company suggested that the costs to comply with the 2017 Valuation Rule's non arm's-length coal valuation provisions would offset any increase in royalty that ONRR would receive. The company further claimed that ONRR's own analysis shows that the royalties received from these provisions would be minimal if not negative.

*ONRR Response:* We agree that the 2017 Valuation Rule's requirement to value coal based on electric sales is overly burdensome and would result in substantial compliance costs.

#### F. Definitions

##### 1. Misconduct

The 2017 Valuation Rule included a new definition of "misconduct" to use in conjunction with the default provision.

*Public Comment:* One member of the public took issue with the 2017 Valuation Rule's definition of the term "misconduct." The commenter maintained that the term has derogatory implications that could affect a lessee's reputation. The commenter noted that the definition added tension between ONRR and the industry that it regulates.

*ONRR Response:* We defined "misconduct" to clarify when ONRR would use its discretion to determine the value of production under the



default provision. We now believe the definition is too ambiguous because it provides almost no guidance as to what type of conduct qualifies as misconduct. At the same time, the rule is silent on whether ONRR must make a formal finding of misconduct before the default provision is invoked, who has the authority make such a finding, and whether such a finding is reviewable on appeal. Taken together, these ambiguities could lead to inconsistent applications of the rule, which would undermine the purpose and intent of the rule. While we cannot surmise how a finding of misconduct would impact a lessee's reputation, we do agree with the commenter that the ambiguity of the definition perpetuated (and perhaps aggravated) the tension and apprehension that we were attempting to rectify.

## 2. Coal Cooperative

The 2017 Valuation Rule added a new definition of the term "coal cooperative" that included formal or informal organizations of companies or other entities sharing in a common interest to produce and market coal or coal-based products, the latter generally being electricity.

*Public Comment:* One company asserted that, by determining in advance that transactions between coal cooperatives are non-arm's-length, ONRR failed to take into account its longstanding criteria for determining whether entities are affiliated. The commenter further contended that ONRR has not provided any evidence to support that coal cooperatives are engaging in non-arm's-length transactions. The company concludes that this is arbitrary, capricious, and contrary to law.

*ONRR Response:* For the reasons discussed in the preamble to this rule, we agree that the definition of coal cooperatives in the 2017 Valuation Rule is overly broad and ambiguous and would create too much confusion to be effective or enforceable. We also agree that the definition is unnecessary because ONRR can evaluate such transactions on a case-by-case basis under the prior (and soon-to-be-reinstated) regulations.

### G. Default Provision

The 2017 Valuation Rule included the so-called default provision, which allowed ONRR great discretion to value a lessee's oil, gas, and coal production in circumstances in which we could not determine whether a lessee properly paid royalties under the regulations. We explained that such circumstances included, but were not limited to, the

lessee's failure to provide documents, the lessee's misconduct, the lessee's breach of the duty to market, or any other situation that significantly compromises the Secretary's ability to reasonably determine the correct value using other measures of value.

*Public Comment:* Companies and industry trade groups overwhelmingly opposed the default provision. Many general public commenters also opposed it. The commenters asserted that the default provision gave ONRR "overly broad" discretion to determine the value of production. An oil and gas industry trade group asserted that the default provision allowed ONRR to "second guess" lessees' reporting and payment in subsequent years, potentially causing lessees to incur late payment interest and penalties. A State official raised concerns that the default provision could have a chilling effect on coal production from Federal and Indian lands.

Public interest groups and other members of the general public approved of the default provision, at least in principle. These commenters asserted that eliminating the default provision would hinder ONRR's ability to ensure a fair value of Federal and Indian mineral resources, specifically for coal. One public interest group stated that the default provision simply codified the Secretary's authority to determine royalty value and clarified when and how ONRR anticipated using that authority.

*ONRR Response:* The comments alone demonstrate how the default provision created far more confusion, uncertainty, and apprehension than we intended or anticipated. Under FOGDRA, as amended, the Secretary indisputably has the authority and discretion to determine the reasonable value of Federal and Indian minerals. By promulgating the default provision, we attempted to offer greater clarity, consistency, and predictability by defining when, where, and how ONRR would value production in those circumstances in which we could not determine whether a lessee properly paid royalties under the regulations. We drafted the rule broadly to encompass every scenario in which ONRR would be forced to invoke the default provision. We realize now that in doing so, we provided little in the way of meaningful guidance on how and when ONRR would invoke its authority. Moreover, because the rule was so broad, it created the perception that ONRR would look past the valuation regulations and value production under the default provision regardless of whether the lessee properly reported

and paid royalties under our regulations. This widespread confusion defeated the very purpose and intent of including a default provision in the rule.

Also, we disagree with those commenters who claimed that eliminating the default provision would hinder ONRR's ability to ensure a fair value of Federal and Indian mineral resources. Indeed, with or without the default provision, ONRR has the authority to establish the value of Federal and Indian minerals when we cannot determine whether a lessee properly paid royalties under the regulations. ONRR exercised this authority under our prior regulations, and we will continue to exercise that authority now that those regulations will be reinstated. Typically we use this authority in limited circumstances to establish a reasonable value of production using market-based transaction data, which has always been the basis for our royalty valuation rules. Therefore, the repeal of the default provision will have the same small and speculative royalty impact as its implementation.

### H. Allowances

In the 2017 Valuation Rule ONRR eliminated the regulation allowing us to approve transportation allowances in excess of 50 percent of the value of a lessee's oil production. The rule also eliminated lessees' ability to net transportation costs in their gross proceeds calculations ("transportation factors"). The 2017 Valuation Rule also eliminated both our ability to grant extraordinary processing allowances and to approve requests for lessees to exceed the 66 $\frac{2}{3}$  percent limitation on processing allowances.

*Public Comment:* Coal companies and coal industry trade groups asserted that coal transportation allowances were poorly defined. They also objected to the 2017 Valuation Rule's requirement that they use the geothermal allowance regulations to "net back" to the value of coal where the first arm's-length sale is electricity. Oil and gas industry unanimously opposed the rule's cap on transportation and processing allowances of 50 percent and 66 $\frac{2}{3}$  percent, respectively.

Public interest groups generally opposed repealing the allowance provisions in the 2017 Valuation Rule. Some commenters suggested that allowance caps create more transparency and are easier to enforce. One public interest group advocated for eliminating all allowances, suggesting that they are a form of subsidy. Another public interest group reiterated its view

that coal transportation and washing allowances should, like oil and gas, be limited to 50 percent and 66 $\frac{2}{3}$  percent, respectively. A member of the general public asserted that ONRR should give standard deductions for transportation and coal washing to reduce administrative burden and to ensure a fair return to taxpayers.

*ONRR Response:* We appreciate the variety of responses, but whether ONRR should eliminate all transportation allowances or establish a standard allowance are questions that are outside the scope of this rulemaking. The United States shares in certain expenses that occur downstream or away from the lease, including costs associated with transportation, gas processing, and coal washing, because the United States benefits from lessees selling their production at a market instead of at the lease.

We agree that, in practice, the requirement that coal lessees use the geothermal allowance regulations to “net back” to the value of coal where the first arm’s-length sale is electricity is unnecessarily complicated and burdensome. While we disagree that the provisions in the 2017 Valuation Rule that would have capped oil and gas transportation allowances were arbitrary and capricious, we recognize that each cap would impose additional costs on some operators.

*Public Comment:* ONRR received comments from industry trade groups stating that the 2017 Valuation Rule arbitrarily reversed a longstanding deep-water-gathering policy that permitted lessees to take transportation allowances for moving oil and gas production on the OCS.

In contrast, a public interest group asserted the deep-water-gathering policy allowed improper deductions under ONRR’s regulatory scheme prior to the 2017 Valuation Rule. The commenter maintained that repealing the 2017 Valuation Rule removes language that ensures appropriate deep-water transportation allowances.

*ONRR Response:* By repealing the 2017 Valuation Rule and reinstating the prior regulations, ONRR’s longstanding deep-water-gathering policy will remain in effect, and ONRR will continue to implement it to the extent that it is consistent with the prior regulations. Nonetheless, ONRR believes that the deep-water-gathering policy is a matter that is appropriate to revisit and reconsider. ONRR will be further considering this matter, including through consultations as part of the RPC process.

### *I. Index-Based Gas Valuation Option*

The 2017 Valuation Rule added an index-price valuation method that lessees who do not sell their gas under an arm’s-length sale could have elected to use in lieu of valuing their gas on their first arm’s-length sale. ONRR based the method on publicly-available index prices, less a specified deduction to account for processing and transportation costs.

*Public Comment:* An industry trade group and a member of the public cited the shortcomings in the index-based gas valuation option as one reason for repealing the 2017 Valuation Rule. While they supported the use of index-based valuation in concept, they argued that the index-based valuation option in the rule is unreasonable and, at times, arbitrary for the following reasons: (1) ONRR did not provide the option to arm’s-length lessees; (2) the index option could result in a price so high that it would disincentivize lessees from using it; (3) the adjustments for transportation and processing were too low; and (4) ONRR did not provide any standards for when and why it might change the adjustments.

*ONRR Response:* We agree with the commenters that this is an area requiring further analysis. Given the mutual interest in exploring index-based valuation options, we believe the newly re-commissioned RPC will provide a valuable forum to engage our stakeholders in a meaningful way on this topic.

### *J. Percentage of Proceeds Contracts*

Lessees sometimes sell their gas under arm’s-length length percentage-of-proceeds (POP) contracts for a price that is based on a specific percentage of the proceeds that the purchaser receives after processing the gas. The 2017 Valuation Rule required lessees with POP contracts to report and pay royalties as processed gas. This rule of repeal allows lessees to report and value POP contract sales as unprocessed gas.

*Public Comment:* An industry trade group maintained that lessees would find it difficult to value gas sold under arm’s-length POP contracts because they lack access to information from the midstream processors and/or purchasers.

*ONRR Response:* Our experience is that the value lessees receive under a POP contract is usually net of certain costs incurred to place the gas into marketable condition. The 2017 Valuation Rule did not change the lessee’s obligation to ensure that it is not deducting costs to place gas in marketable condition at no cost to the

Federal government; repealing the rule likewise does not change that obligation. Nonetheless, we believe that how to value gas sold under arm’s-length POP contracts is an appropriate topic for the RPC, and we look forward to engaging with members of the public and industry stakeholders to explore different options for reporting POP contracts.

### *K. Requirement of Written, Signed Contracts*

Although the 2017 Valuation Rule defined “contract” to include legally enforceable oral agreements, the rule itself required a lessee or its affiliate to have all of its contracts, contract revisions or amendments in writing and signed by all of the parties. If the lessee did not have a written contract, signed by all of the parties, then ONRR could use the default provision to determine value.

*Public Comment:* Several commenters disagreed with the 2017 Valuation Rule’s requirement that all contracts for the sale, transportation, processing, or washing of oil, gas, or coal be in writing and signed by all parties to the contract. These commenters maintained that such a restriction ignores that unwritten and unsigned contracts are legally enforceable.

*ONRR Response:* We adopted the requirement that all contracts be in writing and signed by all parties to enhance our ability to verify the accuracy of royalty reports and payments. For the reasons stated in the preamble to this rule, we reconsidered our position and now agree that this provision is unnecessary, overly burdensome, and potentially defective. The prior (and soon-to-be-reinstated) regulations do not require all contracts to be in writing and signed by all parties. But, under 30 CFR 1207.5, we will continue to require lessees to place in written form and maintain copies of all sales contracts and to maintain copies of other contracts and agreements for accounting or auditing purposes.

## **III. Procedural Matters**

### *A. Summary Cost and Royalty Impact Data*

The economic impact analysis that we prepared in the 2017 Valuation Rule used 2010 royalty data. These economic impacts reflected market conditions—commodity price, volumes, etc.—that existed in 2010. In evaluating the economic impacts of repealing the rule, we used more recent royalty data. Using data from 2015 versus 2010 provides an estimate that is more in line with current market projections of future

commodity prices. The market for these resources changed between 2010 and 2015, with the value of the resources generally decreasing. Not surprisingly, our updated analysis shows a somewhat smaller decrease in royalty payments compared to the analysis that accompanies the 2017 Valuation Rule. Overall, our estimates for the previous rule, using 2010 data, projected costs to industry of \$74.78 million per year (with roughly corresponding benefits to the Treasury and States); this rule, using 2015 data, the projected costs to industry from the 2017 Valuation Rule total \$67.4 million per year; thus repeal of the rule results in \$67.4 million in benefits to industry (with roughly corresponding benefits to the Treasury and States).

We estimated the costs and benefits that this rule will have on all potentially affected groups: Industry, the Federal government, Indian lessors, and State and local governments. This repeal has cost impacts that will result in decreased royalty collections. The net impact of these provisions is an estimated annual decrease in royalty collections of between \$60.1 million and \$74.8 million. This represents between 0.8 percent and 1.0 percent of the total Federal oil, gas, and coal royalties that we collected in 2015. Although the 2017 Valuation Rule was stayed before the first reporting and payments were due, some lessees had already implemented changes in their related systems and reporting procedures. Therefore, some lessees

may incur additional costs from implementing this rule because some lessees may have to undo the system changes that they put in place in anticipation of first reporting under the 2017 Valuation Rule on February 28, 2017. We are unable to quantify that cost at this time.

Unless otherwise indicated, the numbers in the following tables are rounded to three significant digits.

1. Industry

The table below lists ONRR's itemized low, mid-range, and high estimates of the costs and benefits that industry would incur in the first year. Industry would receive these benefits in the same amount each year thereafter.

SUMMARY OF ROYALTY IMPACTS TO INDUSTRY

Rule provision	Low	Mid	High
Gas—restore benchmarks:			
Remove affiliate resale .....	\$0	\$1,360,000	\$2,710,000
Remove index .....	10,600,000	10,600,000	10,600,000
NGLs—restore benchmarks:			
Remove affiliate resale .....	0	754,000	1,510,000
Remove index .....	(2,210,000)	(2,210,000)	(2,210,000)
Gas transportation 50 percent limitation exceptions reinstated .....	87,000	87,000	87,000
Processing allowance 66⅔ percent limitation exceptions reinstated .....	42,700	42,700	42,700
POP contracts processing allowance exceptions of 66⅔ percent reinstated .....	9,470,000	9,470,000	9,470,000
Extraordinary processing allowance reinstated .....	14,200,000	14,200,000	14,200,000
Deep-water-gathering reinstated .....	23,900,000	28,100,000	32,300,000
Oil transportation 50 percent limitation exceptions reinstated .....	0	0	0
Oil and gas line losses allowance reinstated .....	3,140,000	3,140,000	3,140,000
BBB bond rate change removed .....	5,740,000	5,740,000	5,740,000
Coal—non-arm's-length netback reinstated .....	(1,030,000)	0	1,030,000
Removing index option administrative costs .....	(303,000)	(303,000)	(303,000)
Removing deep-water-gathering administrative costs .....	(3,560,000)	(3,560,000)	(3,560,000)
<b>Total .....</b>	<b>60,100,000</b>	<b>67,400,000</b>	<b>74,800,000</b>

Note: totals from this table and others in this analysis may not add due to rounding.

Benefit—Reinstatement of the Valuation Benchmarks for Non-Arm's-Length Dispositions of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

To perform this economic analysis, we first extracted royalty data that we collected on residue gas, unprocessed gas, and coalbed methane (product codes 03, 04, and 39, respectively) for calendar year 2015. We did not include 2016 in any of our data sets because lessees are still adjusting their reports for that year and the reported data is still going through ONRR's edits.

We then extracted gas royalty data for non-arm's-length transactions reported with the sales type code NARM. We also extracted gas royalty data for sales type code POOL because royalty reporters may also use this code to report certain

non-arm's-length transactions. Based on our experience with auditing transactions that use sales type code POOL, only a relatively small portion of transactions are non-arm's-length. Therefore, we used 10 percent of the POOL volumes in our economic analysis of the volumes of gas sold at non-arm's length.

Based on our experience auditing production sold under non-arm's-length contracts, we find that industry would incur a royalty decrease between \$0.00 and \$0.05 per MMBtu under our proposal to use the benchmarks instead of the affiliate's first arm's-length resale to value gas production for royalty purposes. We address the royalty impact of the index-based option below.

We generated a range of potential royalty decreases by assuming no change in royalties for the low estimate, \$0.025 per MMBtu for the mid-range estimate, and \$0.05 per MMBtu for the high estimate. We then multiplied the NARM volume and 10 percent of the POOL volume reported to ONRR in 2015 by the potential royalty decrease.

The results below are an estimated benefit to industry due to an annual royalty decrease of between zero and approximately \$5.4 million. We reduced this estimate by one-half and assumed the mid-point of \$0.025 totaling \$1.36 million. This assumes that 50 percent of the lessees selling production under non-arm's-length arrangements would have chosen this option under the 2017 Valuation Rule.

	2015 MMBtu volume (non-rounded)	Royalty decrease (\$)		
		Low (\$0.00)	Mid (\$0.025)	High (\$0.05)
NARM volume .....	97,869,053	\$0	\$2,446,726	\$4,893,453
10% POOL volume .....	10,614,876	0	265,372	530,744
Total .....	108,483,929	0	2,712,098	5,424,196
50% of lessees choose this option .....	.....	0	1,360,000	2,710,000

Benefit—Termination of the Index-Based Option To Value Non-Arm’s-Length Sales of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

To estimate the royalty impact of removing the index-based option, we calculated a monthly weighted average price net of transportation using NARM and 10 percent of the POOL gas royalty data from seven major geographic areas with active index prices: The Green River Basin, San Juan Basin, Piceance and Uinta Basins, Powder River Basin, Wind River Basin, Permian Basin, and Offshore Gulf of Mexico (GOM). These areas account for approximately 95 percent of all Federal gas produced. To calculate the estimated impact, we performed the following steps: First, identified the *Platts Inside FERC* highest reported monthly price for the index price applicable to each area—

Northwest Pipeline Rockies for Green River, El Paso San Juan for San Juan, Northwest Pipeline Rockies for Piceance and Uinta, Colorado Interstate Gas for Powder River and Wind River, El Paso Permian for Permian, and Henry Hub for GOM. Second, we subtracted the transportation deduction that we specified in the 2017 Valuation Rule from the highest index price that we identified in the first step. Third, we subtracted the average monthly net royalty price reported to us for unprocessed gas from the highest index price for the same month that we calculated in the second step. Fourth, we then multiplied the royalty volume by the monthly difference that we calculated in the third step to calculate a monthly royalty difference for each region. And fifth, we totaled the difference that we calculated in the fourth step for the regions.

In 2015, the estimated royalties due using the index-based option was greater than the reported royalties in every month during our analysis.

We estimate the benefit to industry due to this change to be a decrease in royalty payments of approximately \$10.6 million annually. This estimate represents an average decrease of approximately 9.8 percent, or \$0.026 per MMBtu, based on an annual royalty volume of 154,104,793 MMBtu (for NARM and 10 percent POOL reported sales type codes). This would have been the first time that we offered this option; therefore, we did not know how many payors would choose it. We reduced this estimate by one-half, assuming that 50 percent of lessees with non-arm’s-length sales would have chosen this option.

	GOM gas	Other gas	Total
2015 royalties .....	\$72,216,537	\$143,618,273	\$215,834,810
Royalty under index option .....	79,359,207	157,684,860	237,044,067
Difference .....	7,142,670	14,066,587	21,209,257
Per unit change (\$/MMBtu) .....	0.030	0.025	0.026
% Change .....	9.9%	9.8%	9.8%
50% of lessees choose this option .....	.....	.....	10,600,000

Benefit—Reinstatement of the Valuation Benchmarks for Non-Arm’s-Length Dispositions of Federal NGLs

Like the valuation changes that we discussed previously, for Federal unprocessed, residue, and coalbed methane gas valuation, this rule will value processed Federal NGLs under the prior valuation benchmarks rather than either (1) tracing the first arm’s-length sale or (2) using the index-based option discussed previously. Lessees will no longer have the option to value royalties using an index price value derived from

an NGL commercial price bulletin less a theoretical processing allowance that included theoretical transportation and fractionation of the NGLs. We again used the 2015 NARM and POOL NGL data that lessees reported to ONRR for this analysis.

We performed the same analysis for valuation using the first arm’s-length sale for Federal unprocessed, residue, and coalbed methane gas, as we discussed. We identified the non-arm’s-length volumes that would qualify for this option (for NARM and 10 percent POOL reported sales type codes) and

estimated a cents-per-gallon royalty decrease. Based on our experience, we estimate that the NGL resale margin, similar to gas, would range from zero to \$0.03 per gallon. Thus, our estimated royalty decrease is zero for the low, \$0.015 per gallon for the mid-range, and \$0.03 per gallon for the high range. The results below show a mid-range decrease of \$754,000 in royalty obligations using these assumptions, and, again, we reduced them by one-half under the assumption that 50 percent of lessees would have chosen this option.

	2015 gallons (rounded to the nearest gallon)	Royalty decrease (\$)		
		Low (\$0.00 cents)	Mid (\$0.15)	High (\$0.03)
NARM volume .....	66,911,096	\$0	\$1,003,666	\$2,007,333

	2015 gallons (rounded to the nearest gallon)	Royalty decrease (\$)		
		Low (\$0.00 cents)	Mid (\$0.15)	High (\$0.03)
10% of POOL volume .....	33,675,717	0	505,136	1,010,272
Total .....	100,586,813	0	1,508,802	3,017,604
50% of lessees choose this option .....	.....	0	754,000	1,510,000

**Cost—Termination of the Index-Based Option To Value Non-Arm’s-Length Dispositions of Federal NGLs**

Like the Federal unprocessed, residue, and coalbed methane gas changes that we discussed, lessees will no longer have the option to pay royalties on Federal NGLs production using an index-based value, less a

theoretical processing allowance that includes transportation and fractionation. We used the same 2015 NARM and POOL transaction data for NGLs for this analysis. We were unable to compare NGL prices reported on the form ONRR–2014 to those in commercial price bulletins because the prices that lessees report on the form ONRR–2014 are a single rolled-up price

for all NGLs and the bulletins price each NGL product (such as ethane and propane) separately. Therefore, we calculated a weighted price, or basket price, from the published prices based on typical NGL product volumes, as well as based our analysis on the royalty changes that result from removal of the theoretical processing allowance provided under this option.

%	GOM NGLs	Other NGLs	Total
2015 royalties .....	\$22,292,763	\$9,884,982	\$32,177,746
Royalty under index option .....	\$20,165,669	\$7,585,605	\$27,751,273
Difference .....	(\$2,127,095)	(\$2,299,378)	(\$4,426,472)
Per-unit change (\$/gal) .....	(\$0.004)	(\$0.008)	(\$0.006)
Percent change .....	–9.5%	–23.3%	–13.8%
50% of lessees choose this option .....	.....	.....	(\$2,210,000)

**Cost—Termination of the Index-Based Option To Value Non-Arm’s-Length Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs**

ONRR expects that industry will incur additional administrative costs from losing the option to use the index-based option to value non-arm’s-length dispositions of Federal unprocessed gas, residue gas, coalbed methane, and NGLs. Lessees will have to calculate the value of their production using the valuation benchmarks, increasing the time that it takes to calculate the correct price. Lessees will also have to calculate

their specific transportation rate for gas, and processing allowance for NGLs, rather than using the ONRR-specified theoretical values.

For the 50 percent of lessees that we estimated would use this option, we estimate that eliminating the index-based option will increase the time burden per line reported by 50 percent to 1.5 minutes for lines that industry electronically submits and 3.5 minutes for lines that they manually submit. In 2015, ONRR received approximately 16 percent more lines than from the data used in the prior rule. We used tables

from the Bureau of Labor Statistics (BLS) (<https://www.bls.gov/oes/current/oes132011.htm#nat>), which we updated to use current BLS data to estimate the hourly cost for industry accountants in a metropolitan area. We added a multiplier of 1.4 for industry benefits. The industry labor cost factor for accountants will be approximately \$53.42 per hour = \$38.16 [mean hourly wage] × 1.4 [benefits cost factor]. Using a labor cost factor of \$53.42 per hour, we estimate that the annual administrative cost to industry will be approximately \$303,000.

	Time burden per line reported (min)	Estimated lines reported using index option (50%)	Annual burden hours
Electronic reporting (99%) .....	1.5	221,780	5,544
Manual reporting (1%) .....	3.5	2,240	131
Industry labor cost/hour .....	.....	.....	\$53.42
Total cost to industry .....	.....	.....	\$303,000

**Benefit—Allow Transportation Allowances in Excess of 50 Percent of the Value of Federal Gas**

Prior to the 2017 Valuation Rule, the Federal gas valuation regulations limited lessees’ transportation allowances to 50 percent of the value of the gas unless they requested and

received approval to exceed that limit. The 2017 Valuation Rule eliminated the lessees’ ability to exceed that limit. This rule reinstates the lessees’ ability to request and receive approval to exceed the 50 percent limitation. To estimate the impacts associated with this change, we first identified all calendar year 2015

reported gas transportation allowances rates that exceeded the 50-percent limit. We then adjusted those allowances down to the 50-percent limit and totaled that value to estimate the economic impact of this provision. The result was an annual estimated benefit to industry of \$87,000.

**Benefit—Allow Transportation Allowances in Excess of 50 Percent of the Value of Federal Oil**

Prior to the 2017 Valuation Rule, the Federal oil valuation regulations limited lessees' transportation allowances to 50 percent of the value of the oil unless they requested and received approval to exceed that limit. The 2017 Valuation Rule eliminated the lessees' ability to exceed that limit. This rule reinstates the lessees' ability to request and receive approval to exceed the 50-percent limitation. To estimate the costs associated with this change, we searched for calendar year 2015-reported oil transportation allowance rates that exceeded the 50-percent limit. We did not find any lines for oil transportation that exceeded the 50 percent, so there will be no impact to industry. But companies may exceed the 50-percent limit in the future.

**Benefit—Allow Processing Allowances in Excess of 66⅔ Percent of the Value of the NGLs for Federal Gas**

Prior to the 2017 Valuation Rule, the Federal gas valuation regulations limited lessees' processing allowances to 66⅔ percent of the value of the NGLs unless they requested and received approval to exceed that limit. The 2017 Valuation Rule eliminated lessees' ability to exceed that limit. This rule reinstates the lessees' ability to request and receive approval to exceed the 66⅔-percent limitation. To estimate the cost to industry associated with this change, we first identified all calendar year 2015-reported processing allowances greater than 66⅔ percent. We then adjusted those allowances down to the

66⅔-percent limit and totaled that value to estimate the economic impact of this provision. The result was an annual estimated benefit to industry of \$42,700.

**Benefit—Arm's-Length POP Contracts Not Subject to the 66⅔ Percent Processing Allowance Limit for Federal Gas**

In this rule and the rule in effect prior to the 2017 Valuation Rule, lessees with POP contracts paid royalties based on their gross proceeds as long as they paid a minimum value equal to 100 percent of the value of the residue gas. Under the 2017 Valuation Rule, we do not allow lessees with POP contracts to deduct more than the 66⅔ percent of the value of the NGLs. This rule reinstates the previous regulation's provision allowing lessees with POP contracts to pay royalties based on their gross proceeds, as long as those gross proceeds are, at a minimum, equal to 100 percent of the value of the residue gas. For example, a lessee with a 70-percent POP contract receives 70 percent of the value of the residue gas and 70 percent of the value of the NGLs. The 30 percent of each product that the lessee gives up to the processing plant in the past could not, when combined, exceed an equivalent value of 100 percent of the NGLs' value. By repealing the 2017 Valuation Rule, the combined value of each product that the lessee gives up to the processing plant could, again, potentially exceed two-thirds of the NGLs' value.

Lessees report POP contracts to ONRR using sales type codes APOP for arm's-length POP contracts and NPOP for non-arm's-length POP contracts. Because

lessees report arm's-length POP contract sales as unprocessed gas, there are no reported processing allowances for us to analyze, and we cannot determine the breakout between residue gas and NGLs. Lessees do report residue gas and NGLs separately for non-arm's-length POP contracts. However, these reported volumes constitute only 0.07 percent of all the natural gas royalty volumes reported to ONRR. We deemed the non-arm's-length POP volume to be too low to adequately assess the impact of this provision on both arm's-length POP and non-arm's-length POP contracts.

Therefore, we examined all reported calendar year 2015 onshore residue gas and NGLs royalty data and assumed that it was processed and that lessees paid royalties as if they sold the residue gas and NGLs under a POP contract. We restricted our analysis to residue gas and NGL volumes produced onshore because we are not aware of any offshore POP contracts. We first totaled the residue gas and NGLs' royalty value for calendar year 2015 for all onshore royalties. We then assumed that these royalties were subject to a 70-percent POP contract. Based on our experience, a 70/30 split is typical for many POP contracts. We calculated 30 percent of both the value of residue gas and the NGLs to approximate a theoretical 30-percent processing deduction. We then compared the 30-percent total of residue gas and NGLs values to 66⅔ percent of the NGLs value (the maximum allowance under the 2017 Valuation Rule). The table below summarizes these calculations, which we rounded to the nearest dollar:

	2015 royalty value prior to allowances	70%	30%
Residue gas .....	\$494,401,673	\$346,081,171	\$148,320,502
NGLs .....	132,618,537	92,832,976	39,785,561
<b>Total .....</b>	<b>627,020,209</b>	<b>438,914,147</b>	<b>188,106,063</b>
66.67% limit .....	88,412,358	(132,618,537 × ⅔)	
Difference .....	99,693,705	(\$188,106,063 – \$88,412,357)	

Our analysis shows that the theoretical processing deduction for 30 percent of the value of residue gas and NGLs (\$188 million) under our assumed onshore POP contract allowance would exceed the 66⅔ cap (\$88 million) under this rule.

In our analysis for the 2017 Valuation Rule, the theoretical deduction did not exceed the allowance cap, and we estimated that this change would result

in no impact. The 2015 data, however, did show that the theoretical deduction exceeded the allowance cap, and there will be an economic impact by repealing the 2017 Valuation Rule. This is primarily due to the changing price relationship between gas and NGLs.

We estimated that the benefit to industry would be \$9.47 million by taking the royalty value that exceeds the POP contract allowance (\$100 million)

and dividing by the total of non-POP volume (1,582,143,530 MMBtu) to calculate a per-MMBtu rate of \$0.06. We then applied the \$0.06 rate to the POP contract total volume of 157,764,948 MMBtu to get the estimated increase of \$9.47 million. For the sake of this analysis, we assumed that all processing costs incurred were allowable.

2015 MMBtu volume .....	1,582,143,530	
Rate/MMBtu over limit .....	\$0.06	(\$99,693,705/1,582,143,530)
POP MMBtu volume .....	157,764,948	
Total impact to industry .....	\$9,470,000	(\$.06 × 157,764,948)

**Benefit— Reinstatement of Policy Allowing Transportation Allowances for Deep-Water-Gathering Systems for Federal Oil and Gas**

The deep-water-gathering policy discussed previously allows companies to deduct certain expenses for subsea gathering from their royalty payments, even though those costs do not meet ONRR’s definition of transportation. This rule would result in ONRR continuing to apply the policy to the extent that it is consistent with the prior (and soon-to-be-reinstated) regulations. Lessees would therefore be allowed to claim additional allowances, which would decrease their royalties due. To analyze the impact to industry of reinstating this policy, we used data from BSEE’s ArcGIS TIMS (*Technical Information Management System*) database to estimate that 113 subsea pipeline segments serving 140 leases currently qualify for an allowance under the policy. We assumed all segments were the same—in other words, we did not take into account the size, length, or type of pipeline. For our analysis we also considered only pipeline segments that were in active status and leases in producing status. To determine a range (shown in the tables below as low, mid, and high estimates) for the impact for industry, ONRR estimated a 15 percent error rate in our identification of the 113 eligible pipeline segments, resulting in a range of 96 to 130 eligible pipeline segments.

Historical ONRR audit data was available for 13 subsea gathering segments, which served 15 leases covering time periods from 1999 through 2010. We used this data to determine an average initial amount of capital investment in pipeline segments. We used the initial capital investment amount to calculate depreciation and a return on undepreciated capital investment (ROI) for the eligible pipeline segments. We calculated depreciation using a straight-line depreciation schedule based on a 20-year useful life of the pipeline. We calculated ROI using 1.0 times the average BBB Bond rate for January 2012, which was the most recent full month of data at the time we performed this analysis. We based the calculations for depreciation and ROI on the first year a pipeline was in service.

From the same audit data, we calculated an average annual operating and maintenance (O&M) cost. We increased the O&M cost by 12 percent to account for overhead expenses. Based on experience and audit data, we assumed that 12 percent is a reasonable increase for overhead. We then decreased the total annual O&M cost per pipeline segment by nine percent because an average of nine percent of offshore wellhead oil and gas production is water, which is not royalty bearing. Finally, we used an average royalty rate of 14 percent, which is the volume weighted average royalty rate for all non-Section 6 leases in the Gulf of Mexico. Based on the these

calculations, the average annual allowance per pipeline segment is approximately \$226,664. This represents the estimated amount per pipeline segment ONRR would no longer allow lessees to take as a transportation allowance based on our rescission of the Deep Water Policy in this proposed rulemaking.

The total cost to industry would be the \$226,664 annual allowance per pipeline segment that we would allow under this proposed rulemaking times the number of eligible segments. To calculate a range for this total, we multiplied the average annual allowance by the low (96), mid (113), and high (130) number of eligible segments. The low, mid, and high annual allowance estimates we would allow are \$21.8 million, \$25.6 million, and \$29.5 million, respectively.

Of the currently eligible leases, 56 out of 140, or about 40 percent, qualified for deep water royalty relief under the policy. However, due to varying lease terms, royalty relief programs, price thresholds, volume thresholds, litigation, and other factors, ONRR estimated that only one-half of the 56 leases eligible for royalty relief (20 percent of the 56) actually received royalty relief. Therefore, we decreased the low, mid, and high estimated annual benefit to industry by 20 percent. The table below shows the estimated royalty impact of this section of the proposed rule based on the allowances we will allow under this rule.

	Low	Mid	High
Estimated Royalty Impact .....	\$23,900,000	\$28,100,000	\$32,300,000

**Cost—Reinstatement of Policy Allowing Transportation Allowances for Deep-Water- Gathering Systems for Federal Oil and Gas**

We estimate the restoration of transportation allowances for deep-water-gathering systems would eliminate the industry administrative benefit under the 2017 Valuation Rule as lessees would have to perform this

calculation. We assume that the cost to perform this calculation is significant because in our experience industry has often hired outside consultants to calculate their subsea transportation allowances. Using this information, we estimate each company with leases eligible for transportation allowances for deep water gathering systems would allocate one full-time FTE annually to perform this calculation, whether they

use consultants or perform the calculation in-house. We used the Bureau of Labor Statistics to estimate the hourly cost for industry accountants in a metropolitan area (\$38.16 mean hourly wage) with a multiplier of 1.4 for industry benefits to equal approximately \$53.42 per hour (\$38.16 × 1.4). Using this labor cost per hour, we estimate the annual administrative cost to industry would be approximately:

	Annual burden hours per company	Industry labor cost/hour	Companies reporting eligible leases	Estimated cost to industry
Deep Water Gathering .....	2,080	\$53.42	32	\$3,560,000

**Benefit—Reinstating Extraordinary Processing Cost Allowances for Federal Gas**

As we discussed previously, we are reinstating the provision in our regulations that allows lessees to request an extraordinary processing cost allowance and to allow any extraordinary processing cost allowances that we previously granted. We have granted two such approvals in the past, so we know the lease universe that is claiming this allowance and were able to retrieve the processing allowance data that lessees deducted from the value of residue gas produced from the leases. We then calculated the annual total processing allowance that lessees have claimed for 2012 through 2015 for the leases at issue. We then averaged the yearly totals for those four years to estimate an annual benefit to industry of \$14.2 million in decreased royalties.

**Benefit—Increasing the Rate of Return Used To Calculate Non-Arm’s-Length Transportation Allowances From 1 to 1.3 Times the Standard and Poor’s BBB Bond for Federal Oil and Gas**

For Federal oil transportation, we do not maintain or request data identifying whether transportation allowances are arm’s length or non-arm’s length. However, in our experience, lessees transport a significant portion of Gulf of Mexico (GOM) oil through their own pipelines. In addition, many onshore transportation allowances include costs of trucking and rail and, most likely, this change would not impact those. Therefore, to calculate the costs associated with this change, we assumed that 50 percent of the GOM transportation allowances are non-arm’s length and that ten percent of transportation allowances everywhere else (onshore and offshore other than the GOM) are non-arm’s length. We also assumed that, over the life of the pipeline, allowance rates are made up of

one-third rate of return on undepreciated capital investment, one-third depreciation expenses, and one-third operation, maintenance, and overhead expenses.

In 2015, the total oil transportation allowances that Federal lessees deducted were approximately \$100 million from the GOM and \$12.5 million from everywhere else. Based on these totals and our assumptions regarding the makeup of the allowance components, the portion of the non-arm’s-length allowances attributable to the rate of return will be approximately \$16,600,000 for the GOM ( $\$100,000,000 \times \frac{1}{3} \times 50\%$ ) and \$416,000 ( $\$12,500,000 \times \frac{1}{3} \times 10\%$ ) for the rest of the country. Based on these assumptions, industry will receive an increase in yearly oil transportation allowance deductions of approximately \$3,920,000 ( $\$17,000,000 \times (1.3 - 1.0)/1.3$ ). That is, we estimate that the net benefit to industry for oil transportation allowances as a result of this change will be an approximately \$3,920,000 in decreased royalties due.

Like Federal oil, we do not maintain or request information on whether Federal gas transportation allowances are arm’s-length or non-arm’s length. However, unlike Federal oil, in our experience, it is not common for GOM gas to be transported through lessee-owned pipelines. Therefore, we assumed that only 10 percent of all gas transportation allowances are non-arm’s length and made no distinction between the GOM and everywhere else. All other assumptions for natural gas are the same as those that we made for oil.

In 2015, the total gas transportation allowances that Federal lessees deducted were approximately \$238 million. Based on that total and our assumptions regarding the makeup of the allowance components, the portion of the non-arm’s-length allowances attributable to the rate of return will be approximately \$7.93 million ( $\$238,000,000 \times \frac{1}{3} \times 10\%$ ). Therefore,

industry will see an increase in yearly gas transportation allowance deductions of approximately \$1.82 million ( $\$7.93 \text{ million} \times (1.3 - 1.0)/1.3$ ). That is, the net decreased cost to industry for gas transportation allowances will be approximately \$1,820,000.

The combined impact to industry for this change will be \$5,740,000 in decreased royalties due.

**No Change—Disallow a Rate of Return on Reasonable Salvage Value for Federal Oil, Gas, and Coal**

In the 2017 Valuation Rule, ONRR estimated that this provision would have no impact to industry. ONRR likewise estimates that the repeal has no impact.

**Benefit—Allow Line Loss as a Component of Non-Arm’s-Length Oil and Gas Transportation**

This rule also reinstates the regulatory provision allowing lessees to deduct the costs of pipeline losses, both actual and theoretical, when calculating non-arm’s-length transportation allowances. For this analysis, we assumed that pipeline losses are 0.2 percent of the volume transported through the pipeline, based on a survey of pipeline tariff. This 0.2 percent of the volume transported would also equate to 0.2 percent of the value of the Federal royalty volume of oil and gas production transported.

For Federal oil produced in calendar year 2015, the Federal royalty value subject to transportation allowances was \$2,746,256,148 in the GOM and \$1,039,271,142 everywhere else. Using our previous assumption that 50 percent of GOM and 10 percent of everywhere else’s transportation allowances are non-arm’s length, we estimated that the value of the line loss will be \$2.96 million, as we detailed in the table below. Therefore, the annual benefit to industry will be approximately \$2.96 million.

**OIL LINE LOSS ROYALTY IMPACT**

		Line loss %	Royalty decrease
50% of GOM royalty value .....	\$1,373,128,209	0.2	\$2,750,000
10% of everywhere else royalty value .....	103,927,114	0.2	208,000



OIL LINE LOSS ROYALTY IMPACT—Continued

	Line loss %	Royalty decrease
Total .....		2,960,000

For Federal gas produced in calendar year 2015, the Federal gas royalty value subject to transportation allowances was

\$888,676,828. Using our previous assumption that 10 percent of Federal gas transportation allowances are non-

arm’s length, we estimated that the value of the line loss and annual benefit to industry would be \$178,000.

GAS LINE LOSS ROYALTY IMPACT

	Line loss %	Royalty decrease
10% of royalty value .....	\$88,867,683	0.2 \$178,000

The total estimated royalty decrease for both oil and gas due to this change will be \$3.14 million [\$2,960,000 (oil) plus \$178,000 (gas) = \$3,140,000].

Benefit—Depreciating Oil Pipeline Assets Only Once

Under the non-arm’s-length transportation allowance section of this rule and the rule in effect prior to the 2017 Valuation Rule, for Federal oil, if an oil pipeline is sold, the purchasing company might use the purchase price to establish a new depreciation schedule, provided that the purchasing company is a royalty payor claiming a non-arm’s-length transportation allowance. In theory, this change results in additional royalty savings for companies. However, based on our experience monitoring the oil markets, we find that the sale of oil pipeline assets is rare. We are also not aware of any planned future sales of oil pipelines that this rule change will impact. Therefore, although there will be a benefit to industry under this rule, we cannot quantify the cost at this time.

No Change—Eliminating the Use of the First Arm’s-Length Sale to Value Non-Arm’s-Length Sales of Federal Coal and Sales of Federal Coal Between Parties That Lack Opposing Economic Interest—“Coal Cooperatives” in the 2017 Valuation Rule

In the 2017 Valuation Rule, ONRR did not estimate any impacts to industry for the change in regulations for this provision. This repeal will reinstate the valuation regulations as they were prior to the 2017 Valuation Rule’s publication. Therefore, ONRR does not estimate any impact to industry at this time.

No Change—Eliminating the Use of Arm’s-Length Electricity Sales to Value Non-Arm’s-Length Dispositions of Federal Coal and Dispositions of Federal Coal Parties That Lack Opposing Economic Interest—“Coal Cooperatives” in the 2017 Valuation Rule

In the 2017 Valuation Rule, ONRR did not estimate any impacts to industry for the change in regulations for this provision. This repeal will reinstate the valuation regulations as they were prior to the 2017 Valuation Rule’s publication. Therefore, ONRR does not estimate any impact to industry at this time.

No Change—Eliminating the Default Provision to Value Non-Arm’s-Length Sales of Federal Coal in Lieu of Sales of Electricity

For these situations, valuation of Federal coal will be determined under the non-arm’s-length benchmarks after this repeal of the 2017 Valuation Rule. Because the default provision establishes a valuation method that approximates the market value of the coal very similar to the benchmarks, we estimate that the royalty effect of this rule on lessees of Federal coal will be nominal.

No Change—Using the First Arm’s-Length Sale to Value Non-Arm’s-Length Sales of Indian Coal

In the 2017 Valuation Rule, ONRR did not estimate any impacts to industry for the change in regulations for this provision. This repeal will reinstate the valuation regulations as they were prior to the 2017 Valuation Rule’s publication. Therefore, we do not estimate any impact to industry at this time.

No Change—Using Sales of Electricity to Value Non-Arm’s-Length Sales of Indian Coal

In the 2017 Valuation Rule, ONRR did not estimate any impacts to industry for the change in regulations for this provision. This repeal will reinstate the valuation regulations as they were prior to the 2017 Valuation Rule’s publication. Therefore, we do not estimate any impact to industry at this time.

No Change—Using First Arm’s-Length Sale to Value Sales of Indian Coal Between Coal Cooperative Members

In the 2017 Valuation Rule, ONRR did not estimate any impacts to industry for the change in regulations for this provision. This repeal will reinstate the valuation regulations as they were prior to the 2017 Valuation Rule’s publication. Therefore, we do not estimate any impact to industry at this time.

No Change—Elimination of the Default Provision to Value Federal Oil, Gas, and Coal and Indian Coal

In the 2017 Valuation Rule, we anticipated that we would have used the default provision only in specific cases where conventional valuation procedures have not worked to establish a value for royalty purposes. We also stated that assigning a royalty impact figure to any of the instances where we would have used the default provisions was speculative because (1) each instance would have been case-specific, (2) we could not anticipate when we would have used the option, and (3) we could not anticipate the value that we would have required companies to pay. Additionally, we estimated that the royalty impact would have been relatively small because the default provision would always have established a reasonable value of

production using market-based transaction data, which has always been the basis for our royalty valuation rules. Therefore, removal of the default provision will have a similarly small and speculative royalty difference.

2. State and Local Governments

We estimate that the States and local governments that this rule impacts will incur a decrease in royalty receipts. The details of this impact are outlined below.

States and local governments receiving revenues for offshore Outer Continental Shelf Lands Act Section 8(g) leases will continue to receive royalties as under the regulations preceding the 2017 Valuation Rule, as will States receiving revenues from onshore Federal lands. Based on the ratio of Federal revenues disbursed to States and local governments for section 8(g) leases and the onshore States we detail in the table below, ONRR assumed the same proportion of revenue decreases for each proposal that will impact those State revenues for most of the provisions.

ROYALTY DISTRIBUTIONS BY LEASE TYPE

	On-shore %	Offshore %	8(g) %
Federal .....	50	100	73
State .....	50	0	0
Section 8(g) .....	0	0	27

Some provisions of this rule affect Federal, State, and local government revenues, while others, such as reinstating extraordinary processing cost allowances, affect only onshore States' and Federal revenues. The table summarizing the State and local government royalty decreases that we provide in section 5 details these differences.

3. Indian Lessors

ONRR estimates that the changes to the coal regulations that apply to Indian lessors will have no impact on their royalties.

4. Federal Government

The impact to the Federal government, like the States and local governments, will be a net decrease in

royalties as a result of these changes. The royalty decrease incurred by the Federal government will be the difference between the total royalty decrease to industry and the royalty decrease affecting the States and local governments. The net yearly impact on the Federal government will be approximately \$55.8 million, which we detail in section (5) below.

5. Summary of Royalty Impacts and Costs to Industry, State and Local Governments, Indian Lessors, and the Federal Government

In the table below, the negative values in the industry column represent their estimated royalty collection decrease for Federal, State, and local governments, while the positive values in the other columns represent the increase in royalty savings for industry. Please note that the estimated impacts to Federal, State, and local governments do not include the administrative savings provisions of the economic analysis discussed above. Those provisions are only realized by industry. For the purposes of this summary table, we used the midpoint estimates for these impacts.

Rule Provision	Industry	Federal	State	State 8(g)
Gas—restore benchmarks:				
Remove affiliate Resale .....	\$1,360,000	(\$865,000)	(\$483,000)	(\$11,600)
Remove index .....	\$10,600,000	(\$6,750,000)	(\$3,760,000)	(\$90,600)
NGLs—restore benchmarks:				
Remove affiliate Resale .....	\$754,000	(\$529,000)	(\$220,000)	(\$4,830)
Remove index .....	(\$2,210,000)	\$1,550,000	\$646,000	\$14,200
Gas transportation 50% limitation exceptions reinstated .....	\$87,000	(\$55,400)	(\$30,900)	(\$744)
Processing allowance 66⅔% limitation exceptions reinstated .....	\$42,700	(\$29,900)	(\$12,500)	(\$274)
POP contracts' processing allowance exceptions of 66⅔% limitation reinstated .....	\$9,470,000	(\$6,640,000)	(\$2,770,000)	(\$60,700)
Extraordinary processing allowance reinstated .....	\$14,200,000	(\$7,100,000)	(\$7,100,000)	\$0
Deep-water-gathering reinstated .....	\$28,100,000	(\$28,100,000)	\$0	\$0
Oil transportation 50% limitation exceptions reinstated .....	\$0	\$0	\$0	\$0
Oil and gas line losses allowance reinstated .....	\$3,140,000	(\$2,560,000)	(\$562,000)	(\$17,200)
BBB bond rate change removed .....	\$5,740,000	(\$4,680,000)	(\$1,030,000)	(\$31,500)
Coal provisions .....	\$0	\$0	\$0	\$0
<b>Total .....</b>	<b>\$71,300,000</b>	<b>(\$55,800,000)</b>	<b>(\$15,300,000)</b>	<b>(\$200,000)</b>

Note: totals from this table and others in this analysis may not add due to rounding.

B. Regulatory Planning and Review (Executive Orders 12866 and 13563 and Executive Order 13771 on Reducing Regulation and Controlling Regulatory Costs Dated January 30, 2017)

Executive Order (E.O.) 12866 provides that the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget (OMB) will review all significant rules. OIRA has determined that this rule is significant because it may materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the

rights and obligations of recipients thereof.

Executive Order 13563 reaffirms the principles of E.O. 12866, while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. This Executive Order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant,

feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We developed this rule in a manner consistent with these requirements.

This final rule is considered a deregulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs (82 FR 9339, Feb. 3, 2017). Although there are some costs to industry associated with this rule, the

rule still results in an overall savings to industry. Details on the estimated savings and costs associated with the rule can be found in the rule's economic analysis.

### C. Regulatory Flexibility Act

The Department of the Interior (Department) certifies that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). See the 2017 Valuation Rule, Procedural Matters, item 1, starting at 81 FR 43359, and item 3, starting at 81 FR 43367.

This rule will affect only lessees under Federal oil and gas leases and Federal and Indian coal leases.

The Department certifies that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), see item 1 above for the analysis.

This rule will affect lessees under Federal oil and gas leases and Federal and Indian coal leases. Federal and Indian mineral lessees are, generally, companies classified under the North American Industry Classification System (NAICS), as follows:

- Code 211111, which includes companies that extract crude petroleum and natural gas
- Code 212111, which includes companies that extract surface coal
- Code 212112, which includes companies that extract underground coal

For these NAICS code classifications, a small company is one with fewer than 500 employees. Approximately 1,920 different companies submit royalty and production reports from Federal oil and gas leases and Federal and Indian coal leases to us each month. Of these, approximately 65 companies are large businesses under the U.S. Small Business Administration definition because they have more than 500 employees. The Department estimates that the remaining 1,855 companies that this rule affects are small businesses.

As we stated earlier, based on 2015 sales data, this rule is a benefit to industry of approximately \$71 million dollars per year. Small businesses accounted for about 20 percent of the royalties paid in 2015. Applying that percentage to industry costs, we estimate that this final rule will benefit all small-business lessors approximately \$14,200,000 per year. The amount will vary for each company depending on the volume of production that each small business produces and sells each year.

In sum, we do not estimate that this rule will result in a significant economic effect on a substantial number of small entities because this rule will benefit affected small businesses a collective total of \$14,200,000 per year.

### D. Small Business Regulatory Enforcement Fairness Act

This rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule:

(1) Does not have an annual effect on the economy of \$100 million or more. We estimate that industry will annually benefit between \$60,100,000 and \$74,800,000. These figures are a reversal of the impacts described in the 2017 Valuation Rule, under Procedural Matters, item 1, starting at 81 FR 43359, and item 4, 81 FR 43368, but has been adjusted to include more current data. Therefore, the economic impact on industry, State and local governments and the Federal government will be below the \$100 million threshold that the Federal government uses to define a rule as having a significant impact on the economy.

(2) Will not cause a major increase in costs or prices for consumers; individual industries; Federal, State, or local government agencies; or geographic regions. See Procedural Matters, item 1.

(3) Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. This rule will benefit U.S.-based enterprises.

### E. Unfunded Mandates Reform Act

This rule does not impose an unfunded mandate on State, local, or Tribal governments or the private sector of more than \$100 million per year. This rule does not have a significant or unique effect on State, local, or Tribal governments or the private sector. Therefore, we are not required to provide a statement containing the information that the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires. See Procedural Matters, item 1.

### F. Takings (E.O. 12630)

Under the criteria in section 2 of E.O. 12630, this rule does not have any significant takings implications. This rule will not impose conditions or limitations on the use of any private property. This rule will apply to Federal oil, Federal gas, Federal coal, and Indian coal leases only. Therefore, this rule

does not require a Takings Implication Assessment.

### G. Federalism (E.O. 13132)

Under the criteria in section 1 of E.O. 13132, this rule does not have sufficient Federalism implications to warrant the preparation of a Federalism assessment. The management of Federal oil and gas leases, and Federal and Indian coal leases is the responsibility of the Secretary of the Interior. This rule does not impose administrative costs on States or local governments. This rule also does not substantially and directly affect the relationship between the Federal and State governments. Because this rule does not alter that relationship, this rule does not require a Federalism summary impact statement.

### H. Civil Justice Reform (E.O. 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

(a) Meets the criteria of § 3(a), which requires that we review all regulations to eliminate errors and ambiguity and write them to minimize litigation.

(b) Meets the criteria of § 3(b)(2), which requires that we write all regulations in clear language using clear legal standards.

### I. Consultation With Indian Tribes (E.O. 13175 and Departmental Policy)

The Department strives to strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian Tribes and recognition of their right to self-governance and Tribal sovereignty. Under the criteria in E.O. 13175, we evaluated this final rule and determined that it will have no potential effects on Federally-recognized Indian Tribes. Specifically, we determined that this rule will restore the historical valuation methodology for coal produced from Indian leases. Accordingly:

(1) We mailed letters, on April 3, 2017, to the Crow Tribe of Montana, Hopi Tribe of Arizona, and Navajo Nation to consult with the Tribes on both the Notice of Proposed Rulemaking and Advance Notice of Proposed Rulemaking for the proposed repeal of 2017 Indian coal valuation regulations.

(2) We consulted with the Navajo Nation on May 24, 2017, in Window Rock, Arizona.

(3) We consulted with the Crow Tribe on May 26, 2017, in Crow Agency, Montana.

(4) We consulted with the Hopi on June 21, 2017, in Kykotsmovi, Arizona.

**J. Paperwork Reduction Act**

This rule:

(1) Does not contain any new information collection requirements.

(2) Does not require a submission to the OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). See 5 CFR 1320.4(a)(2).

This rule will leave intact the information collection requirements that OMB already approved under OMB Control Numbers 1012-0004, 1012-0005, and 1012-0010.

**K. National Environmental Policy Act**

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. We are not required to provide a detailed statement under the National Environmental Policy Act of 1969 (NEPA) because this rule qualifies for a categorical exclusion under 43 CFR 46.210(i) in that this is “. . . of an administrative, financial, legal, technical, or procedural nature. . . .” This rule also qualifies for categorically exclusion under Departmental Manual, part 516, section 15.4.(C)(1) in that its impacts are limited to administrative, economic, or technological effects. We also have determined that this rule is not involved in any of the extraordinary circumstances listed in 43 CFR 46.215 that require further analysis under NEPA. The procedural changes resulting from the repeal of the 2017 Valuation Rule will have no consequence on the physical environment. This rule does not alter, in any material way, natural resources exploration, production, or transportation.

**L. Effects on the Nation's Energy Supply (E.O. 13211)**

This rule is not a significant energy action under the definition in E.O. 13211; therefore, a Statement of Energy Effects is not required.

**List of Subjects****30 CFR Part 1202**

Coal, Continental shelf, Government contracts, Indian lands, Mineral royalties, Natural gas, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

**30 CFR Part 1206**

Coal, Continental shelf, Government contracts, Indian lands, Mineral royalties, Oil and gas exploration, Public lands—mineral resources,

Reporting and recordkeeping requirements.

**Gregory J. Gould,**

*Director for Office of Natural Resources Revenue.*

**Authority and Issuance**

For the reasons discussed in the preamble, ONRR amends 30 CFR parts 1202 and 1206 as set forth below:

**PART 1202—ROYALTIES**

■ 1. The authority citation for part 1202 continues to read as follows:

**Authority:** 5 U.S.C. 301 *et seq.*, 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

**Subpart B—Oil, Gas, and OCS Sulfur, General**

■ 2. In § 1202.51, revise paragraph (b) to read as follows:

**§ 1202.51 Scope and definitions.**

\* \* \* \* \*

(b) The definitions in subparts B, C, D, and E of part 1206 of this title are applicable to subparts B, C, D, and J of this part.

**Subpart F—Coal**

■ 3. Remove § 1202.251.

**PART 1206—PRODUCT VALUATION**

■ 4. The authority citation for part 1206 continues to read as follows:

**Authority:** 5 U.S.C. 301 *et seq.*, 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

■ 5. Revise subpart A, consisting of § 1206.10, to read as follows:

**Subpart A—General Provisions and Definitions****§ 1206.10 Information collection.**

The information collection requirements contained in this part have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* The forms, filing date, and approved OMB clearance numbers are identified in § 1210.10.

■ 6. Revise subpart C to read as follows:

**Subpart C—Federal Oil**

Sec.

1206.100 What is the purpose of this subpart?

1206.101 What definitions apply to this subpart?

1206.102 How do I calculate royalty value for oil that I or my affiliate sell(s) under an arm's-length contract?

1206.103 How do I value oil that is not sold under an arm's-length contract?

1206.104 What publications are acceptable to ONRR?

1206.105 What records must I keep to support my calculations of value under this subpart?

1206.106 What are my responsibilities to place production into marketable condition and to market production?

1206.107 How do I request a value determination?

1206.108 Does ONRR protect information I provide?

1206.109 When may I take a transportation allowance in determining value?

1206.110 How do I determine a transportation allowance under an arm's-length transportation contract?

1206.111 How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?

1206.112 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?

1206.113 How will ONRR identify market centers?

1206.114 What are my reporting requirements under an arm's-length transportation contract?

1206.115 What are my reporting requirements under a non-arm's-length transportation arrangement?

1206.116 What interest applies if I improperly report a transportation allowance?

1206.117 What reporting adjustments must I make for transportation allowances?

1206.119 How are the royalty quantity and quality determined?

1206.120 How are operating allowances determined?

**Subpart C—Federal Oil****§ 1206.100 What is the purpose of this subpart?**

(a) This subpart applies to all oil produced from Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS). It explains how you as a lessee must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If you are a designee and if you dispose of production on behalf of a lessee, the terms “you” and “your” in this subpart refer to you and not to the lessee. In this circumstance, you must determine and report royalty value for the lessee's oil by applying the rules in this subpart to your disposition of the lessee's oil.

(c) If you are a designee and only report for a lessee, and do not dispose of the lessee's production, references to “you” and “your” in this subpart refer to the lessee and not the designee. In this circumstance, you as a designee

must determine and report royalty value for the lessee's oil by applying the rules in this subpart to the lessee's disposition of its oil.

(d) If the regulations in this subpart are inconsistent with:

- (1) A Federal statute;
- (2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation;
- (3) A written agreement between the lessee and the ONRR Director establishing a method to determine the value of production from any lease that ONRR expects at least would approximate the value established under this subpart; or

(4) An express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(e) ONRR may audit and adjust all royalty payments.

**§ 1206.101 What definitions apply to this subpart?**

The following definitions apply to this subpart:

*Affiliate* means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that ONRR may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, ONRR will consider the following factors in determining whether there is control under the circumstances of a particular case:

- (i) The extent to which there are common officers or directors;
- (ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: the percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;
- (iii) Operation of a lease, plant, or other facility;
- (iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*ANS* means Alaska North Slope (ANS).

*Area* means a geographic region at least as large as the limits of an oil field, in which oil has similar quality, economic, and legal characteristics.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted under generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*BOEM* means the Bureau of Ocean Energy Management of the Department of the Interior.

*BSEE* means the Bureau of Safety and Environmental Enforcement of the Department of the Interior.

*Condensate* means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without processing. Condensate is the mixture of liquid hydrocarbons resulting from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions, between two or more persons, that is enforceable by law and that with due consideration creates an obligation.

*Designee* means the person the lessee designates to report and pay the lessee's royalties for a lease.

*Exchange agreement* means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location. Exchange agreements may or may not specify prices for the oil involved. They frequently specify dollar amounts reflecting location, quality, or other differentials. Exchange agreements include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be

two separate sales within the same agreement. Examples of other types of exchange agreements include, but are not limited to, exchanges of produced oil for specific types of crude oil (e.g., West Texas Intermediate); exchanges of produced oil for other crude oil at other locations (Location Trades); exchanges of produced oil for other grades of oil (Grade Trades); and multi-party exchanges.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least the outermost boundaries of all oil and gas accumulations known within those reservoirs, vertically projected to the land surface. State oil and gas regulatory agencies usually name onshore fields and designate their official boundaries. BOEM names and designates boundaries of OCS fields.

*Gathering* 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 the lease, unit, or communitized area that BLM or BSEE approves for onshore and offshore leases, respectively.

*Gross proceeds* means the total monies and other consideration accruing for the disposition of oil produced. Gross proceeds also include, but are not limited to, the following examples:

- (1) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government;
- (2) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf;
- (3) Reimbursements for harboring or terminaling fees;
- (4) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation;
- (5) Payments made to reduce or buy down the purchase price of oil to be produced in later periods, by allocating such payments over the production whose price the payment reduces and including the allocated amounts as proceeds for the production as it occurs; and

(6) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or

removal of oil or gas—or the land area covered by that authorization, whichever the context requires.

*Lessee* means any person to whom the United States issues an oil and gas lease, an assignee of all or a part of the record title interest, or any person to whom operating rights in a lease have been assigned.

*Location differential* means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

*Market center* means a major point ONRR recognizes for oil sales, refining, or transshipment. Market centers generally are locations where ONRR-approved publications publish oil spot prices.

*Marketable condition* means oil sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area.

*Netting* means reducing the reported sales value to account for transportation instead of reporting a transportation allowance as a separate entry on form ONRR-2014.

*NYMEX price* means the average of the New York Mercantile Exchange (NYMEX) settlement prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows:

(1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the prompt month corresponding to each such day; and

(2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

*Oil* means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs, remains liquid at atmospheric pressure after passing through surface separating facilities, and is marketed or used as a liquid. Condensate recovered in lease separators or field facilities is oil.

*ONRR-approved publication* means a publication ONRR approves for determining ANS spot prices or WTI differentials.

*Outer Continental Shelf (OCS)* means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43

U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Prompt month* means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

*Quality differential* means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

*Rocky Mountain Region* means the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and other oil-producing fields in the “Four Corners” area that lie within Colorado and Utah.

*Roll* means an adjustment to the NYMEX price that is calculated as follows:  $\text{Roll} = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2)$ , where:  $P_0$  = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month;  $P_1$  = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and  $P_2$  = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is March. March was the prompt month (for year 2003) from January 22 through February 20. April was the first month following the month of production, and May was the second month following the month of production.  $P_0$  therefore is the

average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 22 and February 20.  $P_1$  is the average of the daily NYMEX settlement prices for deliveries during April published for each business day between January 22 and February 20.  $P_2$  is the average of the daily NYMEX settlement prices for deliveries during May published for each business day between January 22 and February 20. In this example, assume that  $P_0 = \$28.00$  per bbl,  $P_1 = \$27.70$  per bbl, and  $P_2 = \$27.10$  per bbl. In this example (a declining market),  $\text{Roll} = .6667 \times (\$28.00 - \$27.70) + .3333 \times (\$28.00 - \$27.10) = \$.20 + \$.30 = \$.50$ . You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is July. July 2003 was the prompt month from May 21 through June 20. August was the first month following the month of production, and September was the second month following the month of production.  $P_0$  therefore is the average of the daily NYMEX settlement prices for deliveries during July published for each business day between May 21 and June 20.  $P_1$  is the average of the daily NYMEX settlement prices for deliveries during August published for each business day between May 21 and June 20.  $P_2$  is the average of the daily NYMEX settlement prices for deliveries during September published for each business day between May 21 and June 20. In this example, assume that  $P_0 = \$28.00$  per bbl,  $P_1 = \$28.90$  per bbl, and  $P_2 = \$29.50$  per bbl. In this example (a rising market),  $\text{Roll} = .6667 \times (\$28.00 - \$28.90) + .3333 \times (\$28.00 - \$29.50) = (-\$ .60) + (-\$ .50) = -\$1.10$ . You add this negative number to the NYMEX price (effectively a subtraction from the NYMEX price).

*Sale* means a contract between two persons where:

(1) The seller unconditionally transfers title to the oil to the buyer and does not retain any related rights such as the right to buy back similar quantities of oil from the buyer elsewhere;

(2) The buyer pays money or other consideration for the oil; and

(3) The parties' intent is for a sale of the oil to occur.

*Spot price* means the price under a spot sales contract where:

(1) A seller agrees to sell to a buyer a specified amount of oil at a specified price over a specified period of short duration;

(2) No cancellation notice is required to terminate the sales agreement; and

(3) There is no obligation or implied intent to continue to sell in subsequent periods.

*Tendering program* means a producer's offer of a portion of its crude oil produced from a field or area for competitive bidding, regardless of whether the production is offered or sold at or near the lease or unit or away from the lease or unit.

*Trading month* means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, [www.nymex.com](http://www.nymex.com), in which case the NYMEX definition will apply.

*Transportation allowance* means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

*WTI differential* means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

(1) *Example.* Assume the production month was March 2003. Industry trade publications performed their price surveys and determined differentials during January 26 through February 25 for oil delivered in March. The WTI differential (for example, the West Texas Sour crude at Midland, Texas, spread versus WTI) applicable to valuing oil produced in the March 2003 production month would be determined using all the business days for which differentials were published during the period January 26 through February 25 excluding weekends and holidays (22

days). To calculate the WTI differential, add together all of the daily mean differentials published for January 26 through February 25 and divide that sum by 22.

(2) [Reserved]

**§ 1206.102 How do I calculate royalty value for oil that I or my affiliate sell(s) under an arm's-length contract?**

(a) The value of oil under this section is the gross proceeds accruing to the seller under the arm's-length contract, less applicable allowances determined under § 1206.110 or § 1206.111. This value does not apply if you exercise an option to use a different value provided in paragraph (d)(1) or (d)(2)(i) of this section, or if one of the exceptions in paragraph (c) of this section applies. Use this paragraph (a) to value oil that:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract, unless you exercise the option provided in paragraph (d)(2)(i) of this section.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for each contract for the sale of oil produced from that lease.

(c) This paragraph contains exceptions to the valuation rule in paragraph (a) of this section. Apply these exceptions on an individual contract basis.

(1) In conducting reviews and audits, if ONRR determines that any arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, ONRR may require that you value the oil sold under that contract either under § 1206.103 or at the total consideration received.

(2) You must value the oil under § 1206.103 if ONRR determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) ONRR will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.

(B) The fact that the price received by the seller under an arm's-length contract

is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless ONRR finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil from the lease.

(d)(1) If you enter into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, and following the exchange(s) you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you may use either § 1206.102(a) or § 1206.103 to value your production for royalty purposes.

(i) If you use § 1206.102(a), your gross proceeds are the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s). You must adjust your gross proceeds for any location or quality differential, or other adjustments, you received or paid under the arm's-length exchange agreement(s). If ONRR determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, ONRR may require you to value the oil under § 1206.103. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(ii) When you elect under § 1206.102(d)(1) to use § 1206.102(a) or § 1206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) sold under arm's-length contracts following arm's-length exchange agreements. You may not change your election more often than once every 2 years.

(2)(i) If you sell or transfer your oil production to your affiliate and that affiliate or another affiliate then sells the oil under an arm's-length contract, you may use either § 1206.102(a) or § 1206.103 to value your production for royalty purposes.

(ii) When you elect under § 1206.102(d)(2)(i) to use § 1206.102(a) or § 1206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that your affiliates resell at arm's length. You may not change your election more often than once every 2 years.

(e) If you value oil under paragraph (a) of this section:

(1) ONRR may require you to certify that your or your affiliate's arm's-length

contract provisions include all of the consideration the buyer must pay, either directly or indirectly, for the oil.

(2) You must base value on the highest price the seller can receive through legally enforceable claims under the contract.

(i) If the seller fails to take proper or timely action to receive prices or benefits it is entitled to, you must pay royalty at a value based upon that obtainable price or benefit. But you will owe no additional royalties unless or until the seller receives monies or consideration resulting from the price increase or additional benefits, if:

(A) The seller makes timely application for a price increase or benefit allowed under the contract;

(B) The purchaser refuses to comply; and

(C) The seller takes reasonable documented measures to force purchaser compliance.

(ii) Paragraph (e)(2)(i) of this section will not permit you to avoid your royalty payment obligation where a purchaser fails to pay, pays only in part, or pays late. Any contract revisions or amendments that reduce prices or benefits to which the seller is entitled must be in writing and signed by all parties to the arm's-length contract.

**§ 1206.103 How do I value oil that is not sold under an arm's-length contract?**

This section explains how to value oil that you may not value under § 1206.102 or that you elect under § 1206.102(d) to value under this section. First determine whether paragraph (a), (b), or (c) of this section applies to production from your lease, or whether you may apply paragraph (d) or (e) with ONRR approval.

(a) *Production from leases in California or Alaska.* Value is the average of the daily mean ANS spot prices published in any ONRR-approved publication during the trading month most concurrent with the production month. (For example, if the production month is June, compute the average of the daily mean prices using the daily ANS spot prices published in the ONRR-approved publication for all the business days in June.)

(1) To calculate the daily mean spot price, average the daily high and low prices for the month in the selected publication.

(2) Use only the days and corresponding spot prices for which such prices are published.

(3) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 1206.112.

(4) After you select an ONRR-approved publication, you may not

select a different publication more often than once every 2 years, unless the publication you use is no longer published or ONRR revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options for valuing your production under different factual situations. You must consistently apply paragraph (b)(1), (2), or (3) of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease or a portion of the lease is not part of a unit or communitization agreement) that you cannot value under § 1206.102 or that you elect under § 1206.102(d) to value under this section.

(1) If you have an ONRR-approved tendering program, you must value oil produced from leases in the area the tendering program covers at the highest winning bid price for tendered volumes.

(i) The minimum requirements for ONRR to approve your tendering program are:

(A) You must offer and sell at least 30 percent of your or your affiliates' production from both Federal and non-Federal leases in the area under your tendering program; and

(B) You must receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

(ii) If you do not have an ONRR-approved tendering program, you may elect to value your oil under either paragraph (b)(2) or (3) of this section. After you select either paragraph (b)(2) or (3) of this section, you may not change to the other method more often than once every 2 years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new 2-year period.

(2) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliates' production from both Federal and non-Federal leases in the same field or area during that month.

(ii) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your

affiliates' arm's-length purchases or sales to the same gravity as that of the oil produced from the lease.

(3) Value is the NYMEX price (without the roll), adjusted for applicable location and quality differentials and transportation costs under § 1206.112.

(4) If you demonstrate to ONRR's satisfaction that paragraphs (b)(1) through (b)(3) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the ONRR Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.* (1) Value is the NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under § 1206.112.

(2) If the ONRR Director determines that use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula used by industry to calculate the roll changes, ONRR may terminate or modify use of the roll under paragraph (c)(1) of this section at the end of each 2-year period following July 6, 2004, through notice published in the **Federal Register** not later than 60 days before the end of the 2-year period. ONRR will explain the rationale for terminating or modifying the use of the roll in this notice.

(d) *Unreasonable value.* If ONRR determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, ONRR may establish reasonable royalty value based on other relevant matters.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.* (1) Instead of valuing your production under paragraph (a), (b), or (c) of this section, you may apply to the ONRR Director to establish a value representing the market at the refinery if:

(i) You transport your oil directly to your or your affiliate's refinery, or exchange your oil for oil delivered to your or your affiliate's refinery; and

(ii) You must value your oil under this section at the NYMEX price or ANS spot price; and

(iii) You believe that use of the NYMEX price or ANS spot price results in an unreasonable royalty value.

(2) You must provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to:



(i) Costs of acquiring other crude oil at or for the refinery;

(ii) How adjustments for quality, location, and transportation were factored into the price paid for other oil;

(iii) Volumes acquired for and refined at the refinery; and

(iv) Any other appropriate evidence or documentation that ONRR requires.

(3) If the ONRR Director establishes a value representing market value at the refinery, you may not take an allowance against that value under § 1206.112(b) unless it is included in the Director's approval.

**§ 1206.104 What publications are acceptable to ONRR?**

(a) ONRR periodically will publish in the **Federal Register** a list of acceptable publications for the NYMEX price and ANS spot price based on certain criteria, including, but not limited to:

(1) Publications buyers and sellers frequently use;

(2) Publications frequently mentioned in purchase or sales contracts;

(3) Publications that use adequate survey techniques, including development of estimates based on daily surveys of buyers and sellers of crude oil, and, for ANS spot prices, buyers and sellers of ANS crude oil; and

(4) Publications independent from ONRR, other lessors, and lessees.

(b) Any publication may petition ONRR to be added to the list of acceptable publications.

(c) ONRR will specify the tables you must use in the acceptable publications.

(d) ONRR may revoke its approval of a particular publication if it determines that the prices or differentials published in the publication do not accurately represent NYMEX prices or differentials or ANS spot market prices or differentials.

**§ 1206.105 What records must I keep to support my calculations of value under this subpart?**

If you determine the value of your oil under this subpart, you must retain all data relevant to the determination of royalty value.

(a) You must be able to show:

(1) How you calculated the value you reported, including all adjustments for location, quality, and transportation, and

(2) How you complied with these rules.

(b) Recordkeeping requirements are found at part 1207 of this chapter.

(c) ONRR may review and audit your data, and ONRR will direct you to use a different value if it determines that the reported value is inconsistent with the requirements of this subpart.

**§ 1206.106 What are my responsibilities to place production into marketable condition and to market production?**

You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.

**§ 1206.107 How do I request a value determination?**

(a) You may request a value determination from ONRR regarding any Federal lease oil production. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases;

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed valuation method.

(b) ONRR will reply to requests expeditiously. ONRR may either:

(1) Issue a value determination signed by the Assistant Secretary, Policy, Management and Budget; or

(2) Issue a value determination by ONRR; or

(3) Inform you in writing that ONRR will not provide a value determination. Situations in which ONRR typically will not provide any value determination include, but are not limited to:

(i) Requests for guidance on hypothetical situations; and

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A value determination signed by the Assistant Secretary, Policy, Management and Budget, is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a value determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, pay late payment interest under § 1218.54 of this chapter.

(3) A value determination signed by the Assistant Secretary is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) A value determination issued by ONRR is binding on ONRR and delegated States with respect to the specific situation addressed in the determination unless the ONRR (for ONRR-issued value determinations) or the Assistant Secretary modifies or rescinds it.

(1) A value determination by ONRR is not an appealable decision or order under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the value determination, you may appeal that order under 30 CFR part 1290.

(e) In making a value determination, ONRR or the Assistant Secretary may use any of the applicable valuation criteria in this subpart.

(f) A change in an applicable statute or regulation on which any value determination is based takes precedence over the value determination, regardless of whether the ONRR or the Assistant Secretary modifies or rescinds the value determination.

(g) The ONRR or the Assistant Secretary generally will not retroactively modify or rescind a value determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.108.

**§ 1206.108 Does ONRR protect information I provide?**

Certain information you submit to ONRR regarding valuation of oil, including transportation allowances, may be exempt from disclosure. To the extent applicable laws and regulations permit, ONRR will keep confidential any data you submit that is privileged, confidential, or otherwise exempt from disclosure. All requests for information must be submitted under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

**§ 1206.109 When may I take a transportation allowance in determining value?**

(a) *Transportation allowances permitted when value is based on gross proceeds.* ONRR will allow a deduction

for the reasonable, actual costs to transport oil from the lease to the point off the lease under § 1206.110 or § 1206.111, as applicable. This paragraph applies when:

(1) You value oil under § 1206.102 based on gross proceeds from a sale at a point off the lease, unit, or communitized area where the oil is produced, and

(2) The movement to the sales point is not gathering.

(b) *Transportation allowances and other adjustments that apply when value is based on NYMEX prices or ANS spot prices.* If you value oil using NYMEX prices or ANS spot prices under § 1206.103, ONRR will allow an adjustment for certain location and quality differentials and certain costs associated with transporting oil as provided under § 1206.112.

(c) *Limits on transportation allowances.* (1) Except as provided in paragraph (c)(2) of this section, your transportation allowance may not exceed 50 percent of the value of the oil as determined under § 1206.102 or § 1206.103 of this subpart. You may not use transportation costs incurred to move a particular volume of production to reduce royalties owed on production for which those costs were not incurred.

(2) You may ask ONRR to approve a transportation allowance in excess of the limitation in paragraph (c)(1) of this section. You must demonstrate that the transportation costs incurred were reasonable, actual, and necessary. Your application for exception (using form ONRR-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for ONRR to make a determination. You may never reduce the royalty value of any production to zero.

(d) *Allocation of transportation costs.* You must allocate transportation costs among all products produced and transported as provided in §§ 1206.110 and 1206.111. You must express transportation allowances for oil as dollars per barrel.

(e) *Liability for additional payments.* If ONRR determines that you took an excessive transportation allowance, then you must pay any additional royalties due, plus interest under § 1218.54 of this chapter. You also could be entitled to a credit with interest under applicable rules if you understated your transportation allowance. If you take a deduction for transportation on form ONRR-2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate entry, ONRR may assess you an amount under § 1206.116.

**§ 1206.110 How do I determine a transportation allowance under an arm's-length transportation contract?**

(a) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred as more fully explained in paragraph (b) of this section, except as provided in paragraphs (a)(1) and (2) of this section and subject to the limitation in § 1206.109(c). You must be able to demonstrate that your or your affiliate's contract is at arm's length. You do not need ONRR approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(1) If ONRR determines that the contract reflects more than the consideration actually transferred either directly or indirectly from you or your affiliate to the transporter for the transportation, ONRR may require that you calculate the transportation allowance under § 1206.111.

(2) You must calculate the transportation allowance under § 1206.111 if ONRR determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) ONRR will not use this provision to simply substitute its judgment of the reasonable oil transportation costs incurred by you or your affiliate under an arm's-length transportation contract.

(B) The fact that the cost you or your affiliate incur in an arm's-length transaction is higher than other measures of transportation costs, such as rates paid by others in the field or area, is insufficient to establish breach of the duty to market unless ONRR finds additional evidence that you or your affiliate acted unreasonably or in bad faith in transporting oil from the lease.

(b) You may deduct any of the following actual costs you (including your affiliates) incur for transporting oil. You may not use as a deduction any cost that duplicates all or part of any other cost that you use under this paragraph.

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid for administration of a quality bank.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(i) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 1206.102 or § 1206.103, as applicable; and

(ii) Multiply the value calculated under paragraph (b)(4)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 1206.111(i)(2) by 12.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(10) Costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain.

(c) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

(d) If your arm's-length transportation contract includes more than one liquid

product, and the transportation costs attributable to each product cannot be determined from the contract, then you must allocate the total transportation costs to each of the liquid products transported.

(1) Your allocation must use the same proportion as the ratio of the volume of each product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(2) You may not claim an allowance for the costs of transporting lease production that is not royalty-bearing.

(3) You may propose to ONRR a cost allocation method on the basis of the values of the products transported. ONRR will approve the method unless it is not consistent with the purposes of the regulations in this subpart.

(e) If your arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, then you must propose an allocation procedure to ONRR.

(1) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your form ONRR-2014 for the months that you used the rejected method and pay any additional royalty and interest due.

(2) You must submit your initial proposal, including all available data, within 3 months after first claiming the allocated deductions on form ONRR-2014.

(f) If your payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, you must convert whatever consideration is paid to a dollar-value equivalent.

(g) If your arm's-length sales contract includes a provision reducing the contract price by a transportation factor, do not separately report the transportation factor as a transportation allowance on form ONRR-2014.

(1) You may use the transportation factor in determining your gross proceeds for the sale of the product.

(2) You must obtain ONRR approval before claiming a transportation factor in excess of 50 percent of the base price of the product.

**§ 1206.111 How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?**

(a) This section applies if you or your affiliate do not have an arm's-length transportation contract, including situations where you or your affiliate

provide your own transportation services. Calculate your transportation allowance based on your or your affiliate's reasonable, actual costs for transportation during the reporting period using the procedures prescribed in this section.

(b) Your or your affiliate's actual costs include the following:

(1) Operating and maintenance expenses under paragraphs (d) and (e) of this section;

(2) Overhead under paragraph (f) of this section;

(3) Depreciation under paragraphs (g) and (h) of this section;

(4) A return on undepreciated capital investment under paragraph (i) of this section; and

(5) Once the transportation system has been depreciated below ten percent of total capital investment, a return on ten percent of total capital investment under paragraph (j) of this section.

(6) To the extent not included in costs identified in paragraphs (d) through (j) of this section, you may also deduct the following actual costs. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(i) Volumetric adjustments for actual (not theoretical) line losses.

(ii) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you as a shipper to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(A) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 1206.102 or § 1206.103, as applicable; and

(B) Multiply the value calculated under paragraph (b)(6)(ii)(A) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 1206.111(i)(2) by 12.

(iii) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(iv) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(v) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(vi) Fees paid to a non-affiliated quality bank administrator for administration of a quality bank.

(7) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(i) Fees paid for long-term storage (more than 30 days).

(ii) Administrative, handling, and accounting fees associated with terminalling.

(iii) Title and terminal transfer fees.

(iv) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(v) Fees paid to brokers.

(vi) Fees paid to a scheduling service provider.

(vii) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(viii) Theoretical line losses.

(ix) Gauging fees.

(c) Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(d) Allowable operating expenses include:

(1) Operations supervision and engineering;

(2) Operations labor;

(3) Fuel;

(4) Utilities;

(5) Materials;

(6) Ad valorem property taxes;

(7) Rent;

(8) Supplies; and

(9) Any other directly allocable and attributable operating expense which you can document.

(e) Allowable maintenance expenses include:

(1) Maintenance of the transportation system;

(2) Maintenance of equipment;

(3) Maintenance labor; and

(4) Other directly allocable and attributable maintenance expenses which you can document.

(f) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(g) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit-of-production method. After you make an election, you may not change methods without

ONRR approval. You may not depreciate equipment below a reasonable salvage value.

(h) This paragraph describes the basis for your depreciation schedule.

(1) If you or your affiliate own a transportation system on June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs for production after June 1, 2000, on your total capital investment in the system (including your original purchase price or construction cost and subsequent reinvestment).

(2) If you or your affiliate purchased the transportation system at arm's length before June 1, 2000, you must incorporate depreciation on the schedule based on your purchase price (and subsequent reinvestment) into your transportation allowance calculations for production after June 1, 2000, beginning at the point on the depreciation schedule corresponding to that date. You must prorate your depreciation for calendar year 2000 by claiming part-year depreciation for the period from June 1, 2000 until December 31, 2000. You may not adjust your transportation costs for production before June 1, 2000, using the depreciation schedule based on your purchase price.

(3) If you are the original owner of the transportation system on June 1, 2000, or if you purchased your transportation system before March 1, 1988, you must continue to use your existing depreciation schedule in calculating actual transportation costs for production in periods after June 1, 2000.

(4) If you or your affiliate purchase a transportation system at arm's length from the original owner after June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs on your total capital investment in the system (including your original purchase price and subsequent reinvestment). You must prorate your depreciation for the year in which you or your affiliate purchased the system to reflect the portion of that year for which you or your affiliate own the system.

(5) If you or your affiliate purchase a transportation system at arm's length after June 1, 2000, from anyone other than the original owner, you must assume the depreciation schedule of the person from whom you bought the system. Include in the depreciation schedule any subsequent reinvestment.

(i)(1) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating

the transportation allowance by the rate of return provided in paragraph (i)(2) of this section.

(2) The rate of return is 1.3 times the industrial bond yield index for Standard & Poor's BBB bond rating. Use the monthly average rate published in "Standard & Poor's Bond Guide" for the first month of the reporting period for which the allowance applies. Calculate the rate at the beginning of each subsequent transportation allowance reporting period.

(j)(1) After a transportation system has been depreciated at or below a value equal to ten percent of your total capital investment, you may continue to include in the allowance calculation a cost equal to ten percent of your total capital investment in the transportation system multiplied by a rate of return under paragraph (i)(2) of this section.

(2) You may apply this paragraph to a transportation system that before June 1, 2000, was depreciated at or below a value equal to ten percent of your total capital investment.

(k) Calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocate costs consistently and equitably to each of the liquid products transported. Your allocation must use the same proportion as the ratio of the volume of each liquid product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to ONRR a cost allocation method on the basis of the values of the products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(l)(1) Where you transport both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to ONRR.

(2) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your form ONRR-2014 for the months that you used the rejected method and pay any additional royalty and interest due.

(3) You must submit your initial proposal, including all available data, within 3 months after first claiming the

allocated deductions on form ONRR-2014.

**§ 1206.112 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?**

This section applies when you use NYMEX prices or ANS spot prices to calculate the value of production under § 1206.103. As specified in this section, adjust the NYMEX price to reflect the difference in value between your lease and Cushing, Oklahoma, or adjust the ANS spot price to reflect the difference in value between your lease and the appropriate ONRR-recognized market center at which the ANS spot price is published (for example, Long Beach, California, or San Francisco, California). Paragraph (a) of this section explains how you adjust the value between the lease and the market center, and paragraph (b) of this section explains how you adjust the value between the market center and Cushing when you use NYMEX prices. Paragraph (c) of this section explains how adjustments may be made for quality differentials that are not accounted for through exchange agreements. Paragraph (d) of this section gives some examples. References in this section to "you" include your affiliates as applicable.

(a) To adjust the value between the lease and the market center:

(1)(i) For oil that you exchange at arm's length between your lease and the market center (or between any intermediate points between those locations), you must calculate a lease-to-market center differential by the applicable location and quality differentials derived from your arm's-length exchange agreement applicable to production during the production month.

(ii) For oil that you exchange between your lease and the market center (or between any intermediate points between those locations) under an exchange agreement that is not at arm's length, you must obtain approval from ONRR for a location and quality differential. Until you obtain such approval, you may use the location and quality differential derived from that exchange agreement applicable to production during the production month. If ONRR prescribes a different differential, you must apply ONRR's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using ONRR's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(2) For oil that you transport between your lease and the market center (or between any intermediate points between those locations), you may take an allowance for the cost of transporting that oil between the relevant points as determined under § 1206.110 or § 1206.111, as applicable.

(3) If you transport or exchange at arm's length (or both transport and exchange) at least 20 percent, but not all, of your oil produced from the lease to a market center, determine the adjustment between the lease and the market center for the oil that is not transported or exchanged (or both transported and exchanged) to or through a market center as follows:

(i) Determine the volume-weighted average of the lease-to-market center adjustment calculated under paragraphs (a)(1) and (2) of this section for the oil that you do transport or exchange (or both transport and exchange) from your lease to a market center.

(ii) Use that volume-weighted average lease-to-market center adjustment as the adjustment for the oil that you do not transport or exchange (or both transport and exchange) from your lease to a market center.

(4) If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to ONRR an adjustment between the lease and the market center for the portion of the oil that you do not transport or exchange (or both transport and exchange) to a market center. Until you obtain such approval, you may use your proposed adjustment. If ONRR prescribes a different adjustment, you must apply ONRR's adjustment to all periods for which you used your proposed adjustment. You must pay any additional royalties owed resulting from using ONRR's adjustment plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(5) You may not both take a transportation allowance and use a location and quality adjustment or exchange differential for the same oil between the same points.

(b) For oil that you value using NYMEX prices, adjust the value between the market center and Cushing, Oklahoma, as follows:

(1) If you have arm's-length exchange agreements between the market center and Cushing under which you exchange to Cushing at least 20 percent of all the oil you own at the market center during the production month, you must use the volume-weighted average of the location

and quality differentials from those agreements as the adjustment between the market center and Cushing for all the oil that you produce from the leases during that production month for which that market center is used.

(2) If paragraph (b)(1) of this section does not apply, you must use the WTI differential published in an ONRR-approved publication for the market center nearest your lease, for crude oil most similar in quality to your production, as the adjustment between the market center and Cushing. (For example, for light sweet crude oil produced offshore of Louisiana, use the WTI differential for Light Louisiana Sweet crude oil at St. James, Louisiana.) After you select an ONRR-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or ONRR revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(3) If neither paragraph (b)(1) nor (b)(2) of this section applies, you may propose an alternative differential to ONRR. Until you obtain such approval, you may use your proposed differential. If ONRR prescribes a different differential, you must apply ONRR's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using ONRR's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(c)(1) If you adjust for location and quality differentials or for transportation costs under paragraphs (a) and (b) of this section, also adjust the NYMEX price or ANS spot price for quality based on premiums or penalties determined by pipeline quality bank specifications at intermediate commingling points or at the market center if those points are downstream of the royalty measurement point approved by BSEE or BLM, as applicable. Make this adjustment only if and to the extent that such adjustments were not already included in the location and quality differentials determined from your arm's-length exchange agreements.

(2) If the quality of your oil as adjusted is still different from the quality of the representative crude oil at the market center after making the quality adjustments described in paragraphs (a), (b), and (c)(1) of this section, you may make further gravity adjustments using posted price gravity tables. If quality bank adjustments do

not incorporate or provide for adjustments for sulfur content, you may make sulfur adjustments, based on the quality of the representative crude oil at the market center, of 5.0 cents per one-tenth percent difference in sulfur content, unless ONRR approves a higher adjustment.

(d) The examples in this paragraph illustrate how to apply the requirement of this section.

(1) *Example.* Assume that a Federal lessee produces crude oil from a lease near Artesia, New Mexico. Further, assume that the lessee transports the oil to Roswell, New Mexico, and then exchanges the oil to Midland, Texas. Assume the lessee refines the oil received in exchange at Midland. Assume that the NYMEX price is \$30.00/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is  $-\$.10$ /bbl; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of  $-\$.08$ /bbl; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is  $\$.40$ /bbl. In this example, the royalty value of the oil is  $\$30.00 - \$.10 - \$.08 - \$.40 = \$29.42$ /bbl.

(2) *Example.* Assume the same facts as in the example in paragraph (d)(1) of this section, except that the lessee transports and exchanges to Midland 40 percent of the production from the lease near Artesia, and transports the remaining 60 percent directly to its own refinery in Ohio. In this example, the 40 percent of the production would be valued at  $\$29.42$ /bbl, as explained in the previous example. In this example, the other 60 percent also would be valued at  $\$29.42$ /bbl.

(3) *Example.* Assume that a Federal lessee produces crude oil from a lease near Bakersfield, California. Further, assume that the lessee transports the oil to Hynes Station, and then exchanges the oil to Cushing which it further exchanges with oil it refines. Assume that the ANS spot price is  $\$20.00$ /bbl, and that the lessee's actual cost of transporting the oil from Bakersfield to Hynes Station is  $\$.28$ /bbl. The lessee must request approval from ONRR for a location and quality adjustment between Hynes Station and Long Beach. For example, the lessee likely would propose using the tariff on Line 63 from Hynes Station to Long Beach as the adjustment between those points. Assume that adjustment to be  $\$.72$ , including the sulfur and gravity bank adjustments, and that ONRR approves the lessee's request. In this example, the preliminary (because the location and quality adjustment is subject to ONRR review) royalty value of the oil is

\$20.00 – \$.72 – \$.28 = \$19.00/bbl. The fact that oil was exchanged to Cushing does not change use of ANS spot prices for royalty valuation.

**§ 1206.113 How will ONRR identify market centers?**

ONRR periodically will publish in the **Federal Register** a list of market centers. ONRR will monitor market activity and, if necessary, add to or modify the list of market centers and will publish such modifications in the **Federal Register**. ONRR will consider the following factors and conditions in specifying market centers:

(a) Points where ONRR-approved publications publish prices useful for index purposes;

(b) Markets served;

(c) Input from industry and others knowledgeable in crude oil marketing and transportation;

(d) Simplification; and

(e) Other relevant matters.

**§ 1206.114 What are my reporting requirements under an arm's-length transportation contract?**

You or your affiliate must use a separate entry on form ONRR–2014 to notify ONRR of an allowance based on transportation costs you or your affiliate incur. ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Recordkeeping requirements are found at part 1207 of this chapter.

**§ 1206.115 What are my reporting requirements under a non-arm's-length transportation arrangement?**

(a) You or your affiliate must use a separate entry on form ONRR–2014 to notify ONRR of an allowance based on transportation costs you or your affiliate incur.

(b) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable oil transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems. Section 1206.117 will apply when you amend your report based on your actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. Recordkeeping requirements are found at part 1207 of this chapter.

**§ 1206.116 What interest applies if I improperly report a transportation allowance?**

(a) If you or your affiliate deducts a transportation allowance on form

ONRR–2014 that exceeds 50 percent of the value of the oil transported without obtaining ONRR's prior approval under § 1206.109, you must pay interest on the excess allowance amount taken from the date that amount is taken to the date you or your affiliate files an exception request that ONRR approves. If you do not file an exception request, or if ONRR does not approve your request, you must pay interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

(b) If you or your affiliate takes a deduction for transportation on form ONRR–2014 by improperly netting an allowance against the oil instead of reporting the allowance as a separate entry, ONRR may assess a civil penalty under 30 CFR part 1241.

**§ 1206.117 What reporting adjustments must I make for transportation allowances?**

(a) If your or your affiliate's actual transportation allowance is less than the amount you claimed on form ONRR–2014 for each month during the allowance reporting period, you must pay additional royalties plus interest computed under § 1218.54 of this chapter from the date you took the deduction to the date you repay the difference.

(b) If the actual transportation allowance is greater than the amount you claimed on form ONRR–2014 for any month during the allowance form reporting period, you are entitled to a credit plus interest under applicable rules.

**§ 1206.119 How are royalty quantity and quality determined?**

(a) Compute royalties based on the quantity and quality of oil as measured at the point of settlement approved by BLM for onshore leases or BSEE for offshore leases.

(b) If the value of oil determined under this subpart is based upon a quantity or quality different from the quantity or quality at the point of royalty settlement approved by the BLM for onshore leases or BSEE for offshore leases, adjust the value for those differences in quantity or quality.

(c) Any actual loss that you may incur before the royalty settlement metering or measurement point is not subject to royalty if BLM or BSEE, as appropriate, determines that the loss is unavoidable.

(d) Except as provided in paragraph (b) of this section, royalties are due on 100 percent of the volume measured at the approved point of royalty settlement. You may not claim a reduction in that measured volume for actual losses beyond the approved point

of royalty settlement or for theoretical losses that are claimed to have taken place either before or after the approved point of royalty settlement.

**§ 1206.120 How are operating allowances determined?**

BOEM may use an operating allowance for the purpose of computing payment obligations when specified in the notice of sale and the lease. BOEM will specify the allowance amount or formula in the notice of sale and in the lease agreement.

■ 7. Revise subpart D to read as follows:

**Subpart D—Federal Gas**

Sec.

1206.150 Purpose and scope.

1206.151 Definitions.

1206.152 Valuation standards—unprocessed gas.

1206.153 Valuation standards—processed gas.

1206.154 Determination of quantities and qualities for computing royalties.

1206.155 Accounting for comparison.

1206.156 Transportation allowances—general.

1206.157 Determination of transportation allowances.

1206.158 Processing allowances—general.

1206.159 Determination of processing allowances.

1206.160 Operating allowances.

**Subpart D—Federal Gas**

**§ 1206.150 Purpose and scope.**

(a) This subpart is applicable to all gas production from Federal oil and gas leases. The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws and lease terms.

(b) If the regulations in this subpart are inconsistent with:

(1) A Federal statute;

(2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation;

(3) A written agreement between the lessee and the ONRR Director establishing a method to determine the value of production from any lease that ONRR expects at least would approximate the value established under this subpart; or

(4) An express provision of an oil and gas lease subject to this subpart; then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(c) All royalty payments made to ONRR are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the

administration of oil and gas leases is discharged in accordance with the requirements of the governing mineral leasing laws and lease terms.

#### § 1206.151 Definitions.

For purposes of this subpart:

*Affiliate* means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that ONRR may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, ONRR will consider the following factors in determining whether there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors;

(ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: The percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;

(iii) Operation of a lease, plant, pipeline, or other facility;

(iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, pipeline, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*Allowance* means a deduction in determining value for royalty purposes. *Processing allowance* means an allowance for the reasonable, actual costs of processing gas determined under this subpart. *Transportation allowance* means an allowance for the reasonable, actual costs of moving unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off the lease, unit area, or communitized area, or away from a processing plant. The transportation allowance does not include gathering costs.

*Area* means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*BOEM* means the Bureau of Ocean Energy Management of the Department of the Interior.

*BSEE* means the Bureau of Safety and Environmental Enforcement of the Department of the Interior.

*Compression* means the process of raising the pressure of gas.

*Condensate* means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by BOEM.

*Gas* means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor

volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

*Gas plant products* means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

*Gathering* means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or BSEE OCS operations personnel for onshore and OCS leases, respectively.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of the gas, residue gas, and gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

*Lease products* means any leased minerals attributable to, originating from, or allocated to Outer Continental Shelf or onshore Federal leases.

*Lessee* means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality lease products* means lease products which have similar chemical, physical, and legal characteristics.

*Marketable condition* means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

*Marketing affiliate* means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

*Minimum royalty* means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

*Net-back method* (or work-back method) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from the value of the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

*Net output* means the quantity of residue gas and each gas plant product that a processing plant produces.

*Net profit share* (for applicable Federal leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

*Netting* means the deduction of an allowance from the sales value by reporting a net sales value, instead of correctly reporting the deduction as a separate entry on form ONRR-2014.

*Outer Continental Shelf (OCS)* means all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Posted price* means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

*Processing* means any process designed to remove elements or

compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

*Residue gas* means that hydrocarbon gas consisting principally of methane resulting from processing gas.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or processing allowance.

*Section 6 lease* means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

*Spot sales agreement* means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

*Warranty contract* means a long-term contract entered into prior to 1970, including any amendments thereto, for the sale of gas wherein the producer agrees to sell a specific amount of gas and the gas delivered in satisfaction of this obligation may come from fields or sources outside of the designated fields.

#### **§ 1206.152 Valuation standards—unprocessed gas.**

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing (including all gas where the lessee's arm's-length contract for the sale of that gas prior to processing provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas). This section also applies to processed gas that must be valued prior to processing in accordance with § 1206.155 of this part. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, § 1206.153 of this part shall apply instead of this section.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined under this section less applicable allowances.

(b)(1)(i) The value of gas sold under an arm's-length contract is the gross proceeds accruing to the lessee except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate. Also, where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, the value of production, for royalty purposes, shall never be less than a value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits, ONRR will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then the ONRR may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the ONRR determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the gas production be valued pursuant to paragraph (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When ONRR determines that the value may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(iv) How to value over-delivered volumes under a cash-out program: This paragraph applies to situations where a pipeline purchases gas from a lessee



according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if ONRR determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (3) of this section.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by ONRR, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by ONRR.

(3) ONRR may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds under arm's-length contracts for like-quality gas in

the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then ONRR shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and ONRR will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized ONRR or State representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify ONRR if it has determined value pursuant to paragraph (c)(2) or (3) of this section. The notification shall be by letter to the ONRR Director for Office of Natural Resources Revenue or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a form ONRR-2014 using a valuation method authorized by paragraph (c)(2) or (3) of this section, and each time there is a change in a method under paragraph (c)(2) or (3) of this section.

(f) If ONRR determines that a lessee has not properly determined value, the lessee shall pay the difference, if any,

between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by ONRR. The lessee shall also pay interest on that difference computed pursuant to § 1218.54 of this chapter. If the lessee is entitled to a credit, ONRR will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from ONRR. In that event, the lessee shall propose to ONRR a value determination method, and may use that method in determining value for royalty purposes until ONRR issues its decision. The lessee shall submit all available data relevant to its proposal. The ONRR shall expeditiously determine the value based upon the lessee's proposal and any additional information ONRR deems necessary. In making a value determination ONRR may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After ONRR issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances.

(i) The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser

compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by ONRR of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to ONRR to support valuation proposals, including transportation or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

#### **§ 1206.153 Valuation standards—processed gas.**

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 1206.152 of this part. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 1206.102 of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. The lessee shall have the burden of demonstrating that

its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, ONRR will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then the ONRR may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the ONRR determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the residue gas or gas plant product be valued pursuant to paragraph (c)(2) or (3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When ONRR determines that the value may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(iv) How to value over-delivered volumes under a cash-out program: This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if ONRR determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (3) of this section.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by ONRR, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by ONRR.

(3) ONRR may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then ONRR shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and ONRR will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized ONRR or State representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify ONRR if it has determined any value pursuant to paragraph (c)(2) or (3) of this section. The notification shall be by letter to the ONRR Director for Office of Natural Resources or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a form ONRR-2014 using a valuation method authorized by paragraph (c)(2) or (3) of this section, and each time there is a change in a method under paragraph (c)(2) or (3) of this section.

(f) If ONRR determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by ONRR. The lessee shall also pay interest computed on that difference pursuant to § 1218.54 of this chapter. If the lessee is

entitled to a credit, ONRR will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from ONRR. In that event, the lessee shall propose to ONRR a value determination method, and may use that method in determining value for royalty purposes until ONRR issues its decision. The lessee shall submit all available data relevant to its proposal. The ONRR shall expeditiously determine the value based upon the lessee's proposal and any additional information ONRR deems necessary. In making a value determination, ONRR may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After ONRR issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until

monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by ONRR of value under this section shall be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to ONRR to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

#### **§ 1206.154 Determination of quantities and qualities for computing royalties.**

(a)(1) Royalties shall be computed on the basis of the quantity and quality of unprocessed gas at the point of royalty settlement approved by BLM or BSEE for onshore and OCS leases, respectively.

(2) If the value of gas determined pursuant to § 1206.152 of this subpart is based upon a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement, as approved by BLM or BSEE, that value shall be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined pursuant to § 1206.153 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value shall be adjusted for

the differences in quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease shall be determined according to the following procedure:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which computations of royalty are based is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease shall be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request ONRR approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Federal leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such loss is determined to

have been unavoidable by BLM or BSEE, as appropriate.

(2) Except as provided in paragraph (d)(1) of this section and § 1206.151(c), royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

**§ 1206.155 Accounting for comparison.**

(a) Except as provided in paragraph (b) of this section, where the lessee (or a person to whom the lessee has transferred gas pursuant to a non-arm's-length contract or without a contract) processes the lessee's gas and after processing the gas the residue gas is not sold pursuant to an arm's-length contract, the value, for royalty purposes, shall be the greater of:

(1) The combined value, for royalty purposes, of the residue gas and gas plant products resulting from processing the gas determined pursuant to § 1206.153 of this subpart, plus the value, for royalty purposes, of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 1206.102 of this subpart; or

(2) The value, for royalty purposes, of the gas prior to processing determined in accordance with § 1206.152 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases will govern as provided in § 1206.150(b) of this subpart. When accounting for comparison is required by the lease terms, such accounting for comparison shall be determined in accordance with paragraph (a) of this section.

**§ 1206.156 Transportation allowances—general.**

(a) Where the value of gas has been determined pursuant to § 1206.152 or § 1206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, ONRR shall allow a deduction for the reasonable actual costs incurred by the lessee to

transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 1206.157.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with § 1206.152 of this subpart, the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the unprocessed gas determined under § 1206.152 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 1206.153 of this subpart, the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the residue gas or gas plant product determined under § 1206.153 of this subpart. For purposes of this section, natural gas liquids will be considered one product.

(3) Upon request of a lessee, ONRR may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (2) of this section were reasonable, actual, and necessary. An application for exception (using form ONRR-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for ONRR to make a determination. Under no circumstances may the value for royalty purposes under any sales type code be reduced to zero.

(d) If, after a review or audit, ONRR determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee must pay any additional royalties, plus interest, determined in accordance with § 1218.54 of this chapter, or will be entitled to a credit, with interest. If the lessee takes a deduction for transportation on form ONRR-2014 by improperly netting the allowance against the sales value of the unprocessed gas, residue gas, and gas plant products instead of reporting the allowance as a separate entry, ONRR may assess a civil penalty under 30 CFR part 1241.

**§ 1206.157 Determination of transportation allowances.**

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue gas and/or gas plant products under that contract, except as provided in paragraphs (a)(1)(ii) and (iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. Such allowances shall be subject to the provisions of paragraph (f) of this section. The lessee must claim a transportation allowance by reporting it as a separate entry on the form ONRR-2014.

(ii) In conducting reviews and audits, ONRR will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then the ONRR may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the ONRR determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the transportation may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have

no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty bearing without ONRR approval.

(ii) Notwithstanding the requirements of paragraph (a)(2)(i) of this section, the lessee may propose to ONRR a cost allocation method on the basis of the values of the products transported. ONRR shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to ONRR. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until ONRR issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. ONRR shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information ONRR deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the form ONRR-2014.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, ONRR will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without ONRR approval.

(b) *Non-arm's-length or no contract.*

(1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a transportation

allowance by reporting it as a separate entry on the form ONRR-2014. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation.

With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The ONRR shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return must be 1.3 times the industrial rate associated with Standard & Poor's BBB rating. The BBB rate must be the monthly average rate as published in Standard & Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without ONRR approval.

(ii) Notwithstanding the requirements of paragraph (b)(3)(i) of this section, the lessee may propose to the ONRR a cost allocation method on the basis of the values of the products transported. ONRR shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to ONRR. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until ONRR issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. ONRR shall then determine the transportation allowance based upon the lessee's proposal and any additional information ONRR deems necessary. The lessee must submit the allocation proposal within 3

months of claiming the allocated deduction on the form ONRR-2014.

(5) You may apply for an exception from the requirement to compute actual costs under paragraphs (b)(1) through (4) of this section.

(i) ONRR will grant the exception if:

(A) The transportation system has a tariff filed with the Federal Energy Regulatory Commission (FERC) or a State regulatory agency, that FERC or the State regulatory agency has permitted to become effective, and

(B) Third parties are paying prices, including discounted prices, under the tariff to transport gas on the system under arm's-length transportation contracts.

(ii) If ONRR approves the exception, you must calculate your transportation allowance for each production month based on the lesser of the volume-weighted average of the rates paid by the third parties under arm's-length transportation contracts during that production month or the non-arm's-length payment by the lessee to the pipeline.

(iii) If during any production month there are no prices paid under the tariff by third parties to transport gas on the system under arm's-length transportation contracts, you may use the volume-weighted average of the rates paid by third parties under arm's-length transportation contracts in the most recent preceding production month in which the tariff remains in effect and third parties paid such rates, for up to five successive production months. You must use the non-arm's-length payment by the lessee to the pipeline if it is less than the volume-weighted average of the rates paid by third parties under arm's-length contracts.

(c) *Reporting requirements*—(1) *Arm's-length contracts.* (i) You must use a separate entry on form ONRR-2014 to notify ONRR of a transportation allowance.

(ii) ONRR may require you to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Recordkeeping requirements are found at part 1207 of this chapter.

(iii) You may not use a transportation allowance that was in effect before March 1, 1988. You must use the provisions of this subpart to determine your transportation allowance.

(2) *Non-arm's-length or no contract.*

(i) You must use a separate entry on form ONRR-2014 to notify ONRR of a transportation allowance.

(ii) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable gas

transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems. Paragraph (e) of this section will apply when you amend your report based on your actual costs.

(iii) ONRR may require you to submit all data used to calculate the allowance deduction. Recordkeeping requirements are found at part 1207 of this chapter.

(iv) If you are authorized under paragraph (b)(5) of this section to use an exception to the requirement to calculate your actual transportation costs, you must follow the reporting requirements of paragraph (c)(1) of this section.

(v) You may not use a transportation allowance that was in effect before March 1, 1988. You must use the provisions of this subpart to determine your transportation allowance.

(d) *Interest and assessments.* (1) If a lessee deducts a transportation allowance on its form ONRR-2014 that exceeds 50 percent of the value of the gas transported without obtaining prior approval of ONRR under § 1206.156, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to the date the lessee files an exception request with ONRR.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.54 of this chapter.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on form ONRR-2014 for each month during the allowance reporting period, the lessee shall be required to pay additional royalties due plus interest computed under § 1218.54 of this chapter from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual transportation allowance is greater than the amount the lessee has taken on form ONRR-2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected form ONRR-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allowance exceeds the allowance based on actual costs, the lessee must submit a corrected form ONRR-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by ONRR. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by ONRR.

(f) *Allowable costs in determining transportation allowances.* You may include, but are not limited to (subject to the requirements of paragraph (g) of this section), the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this paragraph.

(1) *Firm demand charges paid to pipelines.* You may deduct firm demand charges or capacity reservation fees paid to a pipeline, including charges or fees for unused firm capacity that you have not sold before you report your allowance. If you receive a payment from any party for release or sale of firm capacity after reporting a transportation allowance that included the cost of that unused firm capacity, or if you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the form ONRR-2014 by the amount of that payment. You must modify the form ONRR-2014 by the amount received or credited for the affected reporting period, and pay any resulting royalty and late payment interest due;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization

programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* However, theoretical losses are not deductible in non-arm's-length transportation arrangements unless the transportation allowance is based on arm's-length transportation rates charged under a FERC- or State regulatory-approved tariff under paragraph (b)(5) of this section. If you receive volumes or credit for line gain, you must reduce your transportation allowance accordingly and pay any resulting royalties and late payment interest due;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as "parking" or "banking"), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* ONRR allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§ 1206.152(i) and 1206.153(i) of this part.

(10) *Costs of surety.* You may deduct the costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain under an arm's-length transportation contract.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days;

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub;

(5) *Fees paid to brokers.* This includes fees paid to parties who arrange marketing or transportation, if such fees are separately identified from aggregator/marketer fees;

(6) *Fees paid to scheduling service providers.* This includes fees paid to parties who provide scheduling services, if such fees are separately identified from aggregator/marketer fees;

(7) *Internal costs.* This includes salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production; and

(8) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

#### § 1206.158 Processing allowances—general.

(a) Where the value of gas is determined pursuant to § 1206.153 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product

and processing plant relationship. Natural gas liquids (NGL's) shall be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. Where there is no residue gas ONRR may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 66 2/3 percent of the value of each gas plant product determined in accordance with § 1206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 1206.156 of this subpart).

(3) Upon request of a lessee, ONRR may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using form ONRR-4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation for ONRR to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. However, ONRR will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to ONRR for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can

demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

(ii) Prior ONRR approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to ONRR in a form and manner prescribed by ONRR.

(e) If ONRR determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee must pay any additional royalties, plus interest determined under § 1218.54 of this chapter, or will be entitled to a credit with interest. If the lessee takes a deduction for processing on form ONRR-2014 by improperly netting the allowance against the sales value of the gas plant products instead of reporting the allowance as a separate entry, ONRR may assess a civil penalty under 30 CFR part 1241.

#### § 1206.159 Determination of processing allowances.

(a) *Arm's-length processing contracts.*

(1)(i) For processing costs incurred by a lessee under an arm's-length contract, the processing allowance shall be the reasonable actual costs incurred by the lessee for processing the gas under that contract, except as provided in paragraphs (a)(1)(ii) and (iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a processing allowance by reporting it as a separate entry on the form ONRR-2014.

(ii) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the processor for the processing. If the contract reflects more than the total consideration, then the ONRR may require that the processing allowance be determined in accordance with paragraph (b) of this section.

(iii) If ONRR determines that the consideration paid pursuant to an arm's-length processing contract does not reflect the reasonable value of the processing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and lessor, then ONRR shall require that the processing allowance be

determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the processing may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's processing costs.

(2) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product shall be determined in accordance with the contract. No allowance may be taken for the costs of processing lease production which is not royalty-bearing.

(3) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to ONRR. The lessee may use its proposed allocation procedure until ONRR issues its determination. The lessee shall submit all relevant data to support its proposal. ONRR shall then determine the processing allowance based upon the lessee's proposal and any additional information ONRR deems necessary. No processing allowance will be granted for the costs of processing lease production which is not royalty bearing. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on form ONRR-2014.

(4) Where the lessee's payments for processing under an arm's-length contract are not based on a dollar per unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.*

(1) If a lessee has a non-arm's-length processing contract or has no contract, including those situations where the lessee performs processing for itself, the processing allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a processing allowance by reflecting it as a separate entry on the form ONRR-2014. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for processing during the reporting



period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. When a lessee has elected to use either method for a processing plant, the lessee may not later elect to change to the other alternative without approval of the ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a processing plant shall not alter the depreciation schedule established by the original processor/lessee for purposes of the allowance calculation. With or without a change in ownership, a processing plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The ONRR shall allow as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance

shall be provided for depreciation. This alternative shall apply only to plants first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing.

(4) A lessee may apply to ONRR for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(3) of this section. The ONRR may grant the exception only if: (i) The lessee has arm's-length contracts for processing other gas production at the same processing plant; and (ii) at least 50 percent of the gas processed annually at the plant is processed pursuant to arm's-length processing contracts; if the ONRR grants the exception, the lessee shall use as its processing allowance the volume weighted average prices charged other persons pursuant to arm's-length contracts for processing at the same plant.

(c) *Reporting requirements*—(1) *Arm's-length contracts.* (i) The lessee must notify ONRR of an allowance based on incurred costs by using a separate entry on the form ONRR-2014.

(ii) ONRR may require that a lessee submit arm's-length processing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(2) *Non-arm's-length or no contract.*

(i) The lessee must notify ONRR of an allowance based on the incurred costs by using a separate entry on the form ONRR-2014.

(ii) For new processing plants, the lessee's initial deduction shall include estimates of the allowable gas processing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant or, if such data are not available, the lessee shall use estimates based upon industry data for similar gas processing plants.

(iii) Upon request by ONRR, the lessee shall submit all data used to prepare the

allowance deduction. The data shall be provided within a reasonable period of time, as determined by ONRR.

(iv) If the lessee is authorized to use the volume weighted average prices charged other persons as its processing allowance in accordance with paragraph (b)(4) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest.* (1) If a lessee deducts a processing allowance on its form ONRR-2014 that exceeds 66  $\frac{2}{3}$  percent of the value of the gas processed without obtaining prior approval of ONRR under § 1206.158, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to the date the lessee files an exception request with ONRR.

(2) If a lessee erroneously reports a processing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.54 of this chapter.

(e) *Adjustments.* (1) If the actual processing allowance is less than the amount the lessee has taken on form ONRR-2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under § 1218.54 of this chapter from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual processing allowance is greater than the amount the lessee has taken on form ONRR-2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit with interest.

(2) For lessees processing production from onshore Federal leases, the lessee must submit a corrected form ONRR-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

(3) For lessees processing gas production from leases on the OCS, if the lessee's estimated processing allowance exceeds the allowance based on actual costs, the lessee must submit a corrected form ONRR-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by ONRR. If the lessee's estimated costs were less than the actual costs, the refund procedure will be specified by ONRR.

(f) *Other processing cost determinations.* The provisions of this section shall apply to determine processing costs when establishing value using a net back valuation

procedure or any other procedure that requires deduction of processing costs.

#### § 1206.160 Operating allowances.

Notwithstanding any other provisions in these regulations, an operating allowance may be used for the purpose of computing payment obligations when specified in the notice of sale and the lease. The allowance amount or formula shall be specified in the notice of sale and in the lease agreement.

■ 8. Revise subpart F to read as follows:

#### Subpart F—Federal Coal

Sec.

- 1206.250 Purpose and scope.
- 1206.251 Definitions.
- 1206.252 Information collection.
- 1206.253 Coal subject to royalties—general provisions.
- 1206.254 Quality and quantity measurement standards for reporting and paying royalties.
- 1206.255 Point of royalty determination.
- 1206.256 Valuation standards for cents-per-ton leases.
- 1206.257 Valuation standards for ad valorem leases.
- 1206.258 Washing allowances—general.
- 1206.259 Determination of washing allowances.
- 1206.260 Allocation of washed coal.
- 1206.261 Transportation allowances—general.
- 1206.262 Determination of transportation allowances.
- 1206.263 [Reserved]
- 1206.264 In-situ and surface gasification and liquefaction operations.
- 1206.265 Value enhancement of marketable coal.

#### Subpart F—Federal Coal

##### § 1206.250 Purpose and scope.

(a) This subpart is applicable to all coal produced from Federal coal leases. The purpose of this subpart is to establish the value of coal produced for royalty purposes, of all coal from Federal leases consistent with the mineral leasing laws, other applicable laws and lease terms.

(b) If the specific provisions of any statute or settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart then the statute, lease provision, or settlement shall govern to the extent of that inconsistency.

(c) All royalty payments made to the Office of Natural Resources Revenue (ONRR) are subject to later audit and adjustment.

##### § 1206.251 Definitions.

*Ad valorem lease* means a lease where the royalty due to the lessor is based

upon a percentage of the amount or value of the coal.

*Allowance* means a deduction used in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual costs incurred by the lessee for coal washing. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant.

*Area* means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

*Arm's-length contract* means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(a) Ownership in excess of 50 percent constitutes control;

(b) Ownership of 10 through 50 percent creates a presumption of control; and

(c) Ownership of less than 10 percent creates a presumption of noncontrol which ONRR may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The ONRR may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Coal* means coal of all ranks from lignite through anthracite.

*Coal washing* means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air,

water, or heavy media separation; drying; and related handling (or combination thereof).

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for a Federal coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

*Lessee* means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality coal* means coal that has similar chemical and physical characteristics.

*Marketable condition* means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

*Mine* means an underground or surface excavation or series of excavations and the surface or underground support facilities that

contribute directly or indirectly to mining, production, preparation, and handling of lease products.

*Net-back method* means a method for calculating market value of coal at the lease or mine. Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

*Net output* means the quantity of washed coal that a washing plant produces.

*Netting* is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the form ONRR-4430.

*Person* means by individual, firm, corporation, association, partnership, consortium, or joint venture.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or washing allowance.

*Spot market price* means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

#### § 1206.252 Information collection.

The information collection requirements contained in this subpart have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* The forms, filing date, and approved OMB control numbers are identified in part 1210—Forms and Reports.

#### § 1206.253 Coal subject to royalties—general provisions.

(a) All coal (except coal unavoidably lost as determined by BLM under 43 CFR part 3400) from a Federal lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; *i.e.*, underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Federal leases shall be allocated to such leases regardless of whether it is stored on Federal lands. The lessee shall maintain accurate records to determine to which individual Federal lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

#### § 1206.254 Quality and quantity measurement standards for reporting and paying royalties.

For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information will be reported on appropriate forms required under 30 CFR part 1210—Forms and Reports.

#### § 1206.255 Point of royalty determination.

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Federal coal in marketable condition measured at the point of royalty measurement as determined jointly by BLM and ONRR.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. ONRR may ask BLM to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at § 1206.256(d) of this subpart.

#### § 1206.256 Valuation standards for cents-per-ton leases.

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal

used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determined by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of § 1206.257 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

#### § 1206.257 Valuation standards for ad valorem leases.

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the value of coal determined under this section, less applicable coal washing allowances and transportation allowances determined under §§ 1206.258 through 1206.262 of this subpart, or any allowance authorized by § 1206.265 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (3), and (5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then the ONRR may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If ONRR determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the coal production be valued pursuant to paragraph (c)(2)(ii), (iii), (iv), or (v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When ONRR determines that the value may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) ONRR may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to ONRR's satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2) (i), (ii), (iii), or (iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require ONRR's prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and ONRR will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized ONRR or State representatives, to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales value and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify ONRR if it has determined value pursuant to paragraphs (c)(2)(ii), (iii), (iv), or (v) of this section. The notification shall be by letter to the Director for Office of Natural Resources Revenue of his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the form ONRR-4430 using a valuation method authorized by paragraphs (c)(2)(ii), (iii), (iv), or (v) of this section, and each time there is a change in a method under paragraphs (c)(2)(iv) or (v) of this section.

(e) If ONRR determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and

the royalty payments that are due based upon the value established by ONRR. The lessee shall also be liable for interest computed pursuant to § 1218.202 of this chapter. If the lessee is entitled to a credit, ONRR will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from ONRR. In that event, the lessee shall propose to ONRR a value determination method, and may use that method in determining value for royalty purposes until ONRR issues its decision. The lessee shall submit all available data relevant to its proposal. The ONRR shall expeditiously determine the value based upon the lessee's proposal and any additional information ONRR deems necessary. That determination shall remain effective for the period stated therein. After ONRR issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances determined pursuant to §§ 1206.258 through 1206.262 and 1206.265 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless ONRR approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures,

which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by ONRR of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) Certain information submitted to ONRR to support valuation proposals, including transportation, coal washing, or other allowances under § 1206.265 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

**§ 1206.258 Washing allowances—general.**

(a) For ad valorem leases subject to § 1206.257 of this subpart, ONRR shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal, unless the value determined pursuant to § 1206.257 of this subpart was based upon like-quality unwashed coal. Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(b) If ONRR determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with § 1218.202 of this chapter, or shall be entitled to a credit without interest.

(c) Lessees shall not disproportionately allocate washing costs to Federal leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the

washed coal is sold and royalties are reported and paid.

**§ 1206.259 Determination of washing allowances.**

(a) *Arm's-length contracts.* (1) For washing costs incurred by a lessee under an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a washing allowance by reporting it as a separate line entry on the form ONRR-4430.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then the ONRR may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If ONRR determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the washing may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.*

(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract

situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a washing allowance by reporting it as a separate line entry on the form ONRR-4430. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes, rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of the ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or without a change in

ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) ONRR shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements*—(1) *Arm's-length contracts.* (i) The lessee must notify ONRR of an allowance based on incurred costs by using a separate line entry on the form ONRR-4430.

(ii) ONRR may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify ONRR of an allowance based on the incurred costs by using a separate line entry on the form ONRR-4430.

(ii) For new washing facilities or arrangements, the lessee's initial washing deduction shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the washing system or, if such data are not available, the lessee shall use estimates based upon industry data for similar washing systems.

(iii) Upon request by ONRR, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by ONRR.

(d) *Interest and assessments.* (1) If a lessee nets a washing allowance on the form ONRR-4430, then the lessee shall be assessed an amount up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this chapter.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on form ONRR-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under § 1218.202 of this chapter from the date when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual washing allowance is greater than the amount the lessee has taken on form ONRR-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected form ONRR-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

#### § 1206.260 Allocation of washed coal.

(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

#### § 1206.261 Transportation allowances—general.

(a) For ad valorem leases subject to § 1206.257 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, ONRR shall, as authorized by this section, allow a

deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

(1) Transport the coal from a Federal lease to a sales point which is remote from both the lease and mine; or

(2) Transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, ONRR determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with § 1218.202 of this chapter, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Federal leases.

#### § 1206.262 Determination of transportation allowances.

(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. The lessee must claim a transportation allowance by

reporting it as a separate line entry on the form ONRR-4430.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then the ONRR may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If ONRR determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the transportation may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract—*  
(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a transportation allowance by reporting it as a separate line entry on the form ONRR-4430. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable

investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) ONRR shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard

and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) A lessee may apply to ONRR for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (2) of this section. ONRR will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency or by a State regulatory agency (for Federal leases). ONRR shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, ONRR shall deny the exception request if:

(i) No Federal or State regulatory agency costs analysis exists and the Federal or State regulatory agency, as applicable, has declined to investigate under ONRR timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements—*(1) *Arm's-length contracts.* (i) The lessee must notify ONRR of an allowance based on incurred costs by using a separate line entry on the form ONRR-4430.

(ii) ONRR may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(2) *Non-arm's-length or no contract—*  
(i) The lessee must notify ONRR of an allowance based on the incurred costs by using a separate line entry on form ONRR-4430.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable coal transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by ONRR, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by ONRR.

(iv) If the lessee is authorized to use its Federal- or State-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments.* (1) If a lessee nets a transportation allowance on form ONRR-4430, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this chapter.

(e) *Adjustments.* (1) If the actual coal transportation allowance is less than the amount the lessee has taken on form ONRR-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under § 1218.202 of this chapter from the date when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual transportation allowance is greater than amount the lessee has taken on form ONRR-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected form ONRR-4430 to reflect actual costs, together with any payments, in accordance with instructions provided by ONRR.

(f) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

#### § 1206.263 [Reserved]

#### § 1206.264 In-situ and surface gasification and liquefaction operations.

If an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to ONRR. The ONRR will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until ONRR issues a value determination.

#### § 1206.265 Value enhancement of marketable coal.

If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in accordance with § 1206.257(h) of this subpart, the lessee shall notify ONRR that such processing is occurring or will occur. The value of that production shall be determined as follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of § 1206.257(c)(2)(i) through (iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with paragraph (a) of this section, then the value of production will be determined in accordance with § 1206.257(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by ONRR-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under § 1206.259(b)(2)(v) of this subpart.

■ 9. Revise subpart J to read as follows:

#### Subpart J—Indian Coal

Sec.

- 1206.450 Purpose and scope.
- 1206.451 Definitions.
- 1206.452 Coal subject to royalties—general provisions.
- 1206.453 Quality and quantity measurement standards for reporting and paying royalties.
- 1206.454 Point of royalty determination.
- 1206.455 Valuation standards for cents-per-ton leases.
- 1206.456 Valuation standards for ad valorem leases.
- 1206.457 Washing allowances—general.
- 1206.458 Determination of washing allowances.
- 1206.459 Allocation of washed coal.
- 1206.460 Transportation allowances—general.
- 1206.461 Determination of transportation allowances.
- 1206.462 [Reserved]
- 1206.463 In-situ and surface gasification and liquefaction operations.
- 1206.464 Value enhancement of marketable coal.

#### Subpart J—Indian Coal

##### § 1206.450 Purpose and scope.

(a) This subpart prescribes the procedures to establish the value, for royalty purposes, of all coal from Indian Tribal and allotted leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma).

(b) If the specific provisions of any statute, treaty, or settlement agreement between the Indian lessor and a lessee

resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart, then the statute, treaty, lease provision, or settlement shall govern to the extent of that inconsistency.

(c) All royalty payments are subject to later audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian coal leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

##### § 1206.451 Definitions.

*Ad valorem lease* means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

*Allowance* means an approved, or an ONRR-initially accepted deduction in determining value for royalty purposes. *Coal washing allowance* means an allowance for the reasonable, actual costs incurred by the lessee for coal washing, or an approved or ONRR-initially accepted deduction for the costs of washing coal, determined pursuant to this subpart. *Transportation allowance* means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant, or an approved ONRR-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.

*Area* means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

*Arm's-length contract* means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: Ownership in excess of 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol which ONRR may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.



Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. ONRR may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

*BIA* means the Bureau of Indian Affairs of the Department of the Interior.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Coal* means coal of all ranks from lignite through anthracite.

*Coal washing* means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Indian lessor. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Indian allottee* means any Indian for whom land or an interest in land is held in trust by the United States or who

holds title subject to Federal restriction against alienation.

*Indian Tribe* means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for an Indian coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

*Lessee* means any person to whom the Indian Tribe or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality coal* means coal that has similar chemical and physical characteristics.

*Marketable condition* means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

*Mine* means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

*Net-back method* means a method for calculating market value of coal at the lease or mine. Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

*Net output* means the quantity of washed coal that a washing plant produces.

*ONRR* means the Office of Natural Resources Revenue of the Department of the Interior.

*Person* means by individual, firm, corporation, association, partnership, consortium, or joint venture.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract,

or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or washing allowance.

*Spot market price* means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

#### **§ 1206.452 Coal subject to royalties—general provisions.**

(a) All coal (except coal unavoidably lost as determined by BLM pursuant to 43 CFR group 3400) from an Indian lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; *i.e.*, underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Indian leases shall be allocated to such leases regardless of whether it is stored on Indian lands. The lessee shall maintain accurate records to determine to which individual Indian lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

#### **§ 1206.453 Quality and quantity measurement standards for reporting and paying royalties.**

For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information will be reported on appropriate forms required under 30 CFR part 1210—Forms and Reports.

#### **§ 1206.454 Point of royalty determination.**

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Indian coal in marketable condition measured at the point of royalty

measurement as determined jointly by BLM and ONRR.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. ONRR may ask BLM or BIA to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at § 1206.455(d) of this subpart.

**§ 1206.455 Valuation standards for cents-per-ton leases.**

(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determined by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of § 1206.456 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

**§ 1206.456 Valuation standards for ad valorem leases.**

(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the

value of coal determined pursuant to this section, less applicable coal washing allowances and transportation allowances determined pursuant to §§ 1206.457 through 1206.461 of this subpart, or any allowance authorized by § 1206.464 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (3), and (5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then ONRR may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If ONRR determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the coal production be valued pursuant to paragraphs (c)(2)(ii), (iii), (iv), or (v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When ONRR determines that the value may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) ONRR may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to ONRR's satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the salability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2)(i), (ii), (iii), or (iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require ONRR's prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and ONRR will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) An Indian lessee will make available upon request to the authorized ONRR or Indian representatives, or to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify ONRR if it has determined value pursuant to paragraphs (c)(2)(ii), (iii), (iv), or (v) of this section. The notification shall be by letter to the Director for Office of Natural Resources Revenue or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the form ONRR-4430 using a valuation method authorized by paragraphs (c)(2)(ii), (iii), (iv), or (v) of this section, and each time there is a change in a method under paragraphs (c)(2)(iv) or (v) of this section.

(e) If ONRR determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by ONRR. The lessee shall also be liable for interest computed pursuant to 30 CFR 1218.202. If the lessee is entitled to a credit, ONRR will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from ONRR. In that event, the lessee shall propose to ONRR a value determination method, and may use that method in determining value for royalty purposes until ONRR issues its decision. The lessee shall submit all available data relevant to its proposal. ONRR shall expeditiously determine the value based upon the lessee's proposal and any additional information ONRR deems necessary. That determination shall remain effective for the period stated therein. After ONRR issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances determined pursuant to §§ 1206.457 through 1206.461 and 1206.464 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Indian lessor. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless ONRR approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by ONRR of value under this section shall be considered final or binding as against the Indian Tribes or allottees until the audit period is formally closed.

(k) Certain information submitted to ONRR to support valuation proposals, including transportation, coal washing, or other allowances pursuant to §§ 1206.457 through 1206.461 and 1206.464 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this

section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from ONRR or such lessor's lessee directly under the terms of the lease or applicable law.

#### § 1206.457 Washing allowances—general.

(a) For ad valorem leases subject to § 1206.456 of this subpart, ONRR shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal, unless the value determined pursuant to § 1206.456 of this subpart was based upon like-quality unwashed coal. Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(b) If ONRR determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with § 1218.202 of this chapter, or shall be entitled to a credit, without interest.

(c) Lessees shall not disproportionately allocate washing costs to Indian leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the washed coal is sold and royalties are reported and paid.

#### § 1206.458 Determination of washing allowances.

(a) *Arm's-length contracts.* (1) For washing costs incurred by a lessee pursuant to an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of form ONRR-4292, Coal Washing Allowance Report, in accordance with paragraph (c)(1) of this section. A washing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that form ONRR-4292 is filed with ONRR, unless ONRR approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then ONRR may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If ONRR determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the washing may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.*

(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior ONRR approval of washing allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed form ONRR-4292 in accordance with paragraph (c)(2) of this section. A washing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that form ONRR-4292 is filed with ONRR, unless ONRR approves a longer period upon a showing of good cause by the lessee. ONRR will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, ONRR may

direct a lessee to modify its actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or without a change in ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) ONRR shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied

by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent washing allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements—(1) Arm's-length contracts.* (i) With the exception of those washing allowances specified in paragraphs (c)(1)(v) and (vi) of this section, the lessee shall submit page one of the initial form ONRR-4292 prior to, or at the same time, as the washing allowance determined pursuant to an arm's-length contract is reported on form ONRR-4430, Solid Minerals Production and Royalty Report. A form ONRR-4292 received by the end of the month that the form ONRR-4430 is due shall be considered to be received timely.

(ii) The initial form ONRR-4292 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of form ONRR-4292 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless ONRR approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) ONRR may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(v) Washing allowances which are based on arm's-length contracts and

which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by ONRR in writing shall qualify as being in effect at the time these regulations become effective.

(vi) ONRR may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.*

(i) With the exception of those washing allowances specified in paragraphs (c)(2)(v) and (vii) of this section, the lessee shall submit an initial form ONRR-4292 prior to, or at the same time as, the washing allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on form ONRR-4430, Solid Minerals Production and Royalty Report. A form ONRR-4292 received by the end of the month that the form ONRR-4430 is due shall be considered to be timely received. The initial reporting may be based on estimated costs.

(ii) The initial form ONRR-4292 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the washing under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed form ONRR-4292 containing the actual costs for the previous reporting period. If coal washing is continuing, the lessee shall include on form ONRR-4292 its estimated costs for the next calendar year. The estimated coal washing allowance shall be based on the actual costs for the previous period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form ONRR-4292 must be received by ONRR within 3 months after the end of the previous reporting period, unless ONRR approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new wash plants, the lessee's initial form ONRR-4292 shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant, or if such data are not available, the lessee shall use estimates

based upon industry data for similar coal wash plants.

(v) Washing allowances based on non-arm's-length or no contract situations which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by ONRR in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by ONRR, the lessee shall submit all data used by the lessee to prepare its forms ONRR-4292. The data shall be provided within a reasonable period of time, as determined by ONRR.

(vii) ONRR may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(3) ONRR may establish coal washing allowance reporting dates for individual leases different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Washing allowances must be reported as a separate line on the form ONRR-4430, unless ONRR approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a washing allowance on its form ONRR-4430 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this chapter.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on form ONRR-4430 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to § 1218.202, retroactive to the first month the lessee is authorized to deduct a washing allowance. If the actual washing allowance is greater than the amount the lessee has estimated and taken during

the reporting period, the lessee shall be entitled to a credit, without interest.

(2) The lessee must submit a corrected form ONRR-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

**§ 1206.459 Allocation of washed coal.**

(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

**§ 1206.460 Transportation allowances—general.**

(a) For ad valorem leases subject to § 1206.456 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, ONRR shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

(1) Transport the coal from an Indian lease to a sales point which is remote from both the lease and mine; or

(2) Transport the coal from an Indian lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs

between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, ONRR determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with § 1218.202 of this chapter, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Indian leases.

#### **§ 1206.461 Determination of transportation allowances.**

(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of form ONRR-4293, Coal Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that form ONRR-4293 is filed with ONRR, unless ONRR approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then ONRR may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If ONRR determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the transportation may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior ONRR approval of transportation allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed form ONRR-4293 in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that form ONRR-4293 is filed with ONRR, unless ONRR approves a longer period upon a showing of good cause by the lessee. ONRR will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or

a cost equal to the depreciable investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of ONRR.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without ONRR approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) ONRR shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average as published in Standard and Poor's Bond Guide for the first month of the reporting period of which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) A lessee may apply to ONRR for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (2) of this section. ONRR will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency for Indian leases. ONRR shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, ONRR shall deny the exception request if:

(i) No Federal regulatory agency cost analysis exists and the Federal regulatory agency has declined to investigate pursuant to ONRR timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements—(1) Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (vi) of this section, the lessee shall submit page one of the initial form ONRR-4293 prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on form ONRR-4430, Solid Minerals Production and Royalty Report.

(ii) The initial form ONRR-4293 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of form ONRR-4293 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless ONRR approves a longer period (during which period the lessee

shall continue to use the allowance from the previous reporting period). Lessees may request special reporting procedures in unique allowance reporting situations, such as those related to spot sales.

(iv) ONRR may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(v) Transportation allowances that are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by ONRR in writing shall qualify as being in effect at the time these regulations become effective.

(vi) ONRR may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.*

(i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v) and (vii) of this section, the lessee shall submit an initial form ONRR-4293 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on form ONRR-4430, Solid Minerals Production and Royalty Report. The initial report may be based on estimated costs.

(ii) The initial form ONRR-4293 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed form ONRR-4293 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on form ONRR-4293 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments that are based on the lessee's knowledge of decreases or increases that will affect the allowance. Form ONRR-4293 must be received by ONRR within 3 months after the end of the previous reporting period, unless

ONRR approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial form ONRR-4293 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system, or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract-based transportation allowances that are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For purposes of this section, only those allowances that have been approved by ONRR in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by ONRR, the lessee shall submit all data used to prepare its form ONRR-4293. The data shall be provided within a reasonable period of time, as determined by ONRR.

(vii) ONRR may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(viii) If the lessee is authorized to use its Federal-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) ONRR may establish reporting dates for individual lessees different than those specified in this paragraph in order to provide more effective administration. Lessees will be notified as to any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on form ONRR-4430, unless ONRR approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a transportation allowance on its form ONRR-4430 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this chapter.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on form ONRR-4430 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest, computed pursuant to § 1218.202 of this chapter, retroactive to the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be entitled to a credit, without interest.

(2) The lessee must submit a corrected form ONRR-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

(f) *Other transportation cost determinations.* The provisions of this

section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

**§ 1206.462 [Reserved]**

**§ 1206.463 In-situ and surface gasification and liquefaction operations.**

If an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to ONRR. ONRR will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until ONRR issues a value determination.

**§ 1206.464 Value enhancement of marketable coal.**

If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in

accordance with § 1206.456(h) of this subpart, the lessee shall notify ONRR that such processing is occurring or will occur. The value of that production shall be determined as follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of § 1206.456(c)(2)(i) through (iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with paragraph (a) of this section, then the value of production will be determined in accordance with § 1206.456(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by ONRR-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under § 1206.458(b)(2)(v) of this subpart.

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