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[4310-T2]

DEPARTMENT OF THE INTERIOR

Office of Natural Resources Revenue

30 CFR Parts 1202 and 1206

[Docket No. ONRR-2012-0004]

RIN 1012-AA13

Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform

AGENCY: Office of Natural Resources Revenue, Interior.

ACTION: Proposed rule.

SUMMARY: The Office of Natural Resources Revenue (ONRR) proposes to change the regulations governing valuation for royalty purposes of oil and gas produced from Federal onshore and offshore leases and coal produced from Federal and Indian leases. The proposed rule also consolidates definitions for oil, gas, and coal product valuation into one subpart applicable to the Federal oil and gas and Federal and Indian coal subparts.

DATES: You must submit comments on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**.

ADDRESSES: You may submit comments to ONRR on this proposed rulemaking by any method below. Please refer to the Regulation Identifier Number (RIN) 1012-AA13 in your comments. (See also Public Availability of Comments under Procedural

Matters.)

- Electronically go to *www.regulations.gov*. In the entry titled "Enter Keyword or ID," enter "ONRR-2012-0004," then click "Search." Follow the instructions to submit public comments. ONRR will post all comments.
- Mail comments to Armand Southall, Regulatory Specialist, P.O. Box 25165, MS 61030A, Denver, Colorado 80225.
- Hand-carry comments, or use an overnight courier service, to the Office of Natural Resources Revenue, Building 85, Room A-614, Denver Federal Center, West 6th Ave. and Kipling St., Denver, Colorado 80225.

FOR FURTHER INFORMATION CONTACT: For comments or questions on procedural issues, contact Armand Southall , ONRR, telephone (303) 231-3221, or email at armand.southall@onrr.gov. The authors of the proposed rule are Sarah Inderbitzin, Richard Adamski, Michael DeBerard, Peter Christnacht, Kimbra Davis, and Lance Wenger.

SUPPLEMENTARY INFORMATION:

I. Background

In 2007, the Royalty Policy Committee (RPC) Subcommittee on Royalty Management issued a report titled "Mineral Revenue Collection from Federal and Indian Lands and the Outer Continental Shelf." The Subcommittee's report recommended clarification of the regulations governing onshore gas and transportation deductions to provide more certainty for ONRR, BLM, and industry, which should result in better compliance. More specifically, the Subcommittee recommended revisions to the gas valuation regulations and guidelines to address the cost-bundling issue and to facilitate the calculation of gas transportation and gas processing deductions. The Subcommittee also recommended the use of market indices for gas valuation in the context of non-arm's-length transactions in lieu of benchmarks, which have been used since 1988.

The Subcommittee's report also recommended "revis(ing) and implement(ing) the regulations and guidance for calculating prices used in checking royalty compliance for solid minerals, with particular attention to non-arm's-length transactions."

The current Federal oil valuation regulations have been in effect since 2000, with a subsequent amendment relating primarily to the use of index pricing in some circumstances. The current Federal gas valuation regulations have been in effect since March 1, 1988, with various subsequent amendments relating primarily to the transportation allowance provisions. The current Federal and Indian coal valuation regulations have been in effect since March 1, 1989, with minor subsequent amendments relating primarily to the Federal black lung excise taxes, abandoned mine lands fees, State and local severance taxes, and washing and transportation allowance provisions. In the years since we wrote these regulations, the Secretary of the Interior's (Secretary) responsibility to determine the royalty value of minerals produced has not changed, but the industry and marketplace have changed dramatically. ONRR proposes these amendments to our valuation regulations to permit the Secretary to discharge the Department of the Interior's (Department) royalty valuation responsibility in an environment of continuing and accelerating change in the industry and the marketplace. The Secretary's responsibilities regarding oil and gas production from Federal leases and coal production from Federal and Indian leases require development of flexible valuation methodologies that lessees can accurately comply with in a timely manner.

To increase the effectiveness and efficiency of our rules, ONRR is proposing proactive and innovative changes. We intend for this proposed rulemaking to provide regulations that (1) offer greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees and mineral revenue recipients; (2) are more understandable; (3) decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) provide early certainty to industry and ONRR that companies have paid every dollar due. Therefore, ONRR proposes to amend the current regulations at 30 CFR part 1202, subpart F, and part 1206, subparts C, D, F, and J, governing the valuation, for royalty purposes, of oil, gas, and coal produced from Federal leases and coal produced from Indian leases.

On May 27, 2011, ONRR published Advance Notices of Proposed Rulemaking (ANPRs) regarding the valuation, for royalty purposes, of oil, gas, and coal produced from Federal leases and coal produced from Indian leases (76 FR 30878, 30881). ONRR received responses to the Federal oil and gas valuation ANPR from 19 State, industry, industry trade association, and the general public commenters. ONRR then conducted 3 public workshops on Federal oil and gas valuation in September and October 2011 in Houston, Texas, Washington, DC, and Denver, Colorado. At the workshops, ONRR asked attendees to discuss, among other things, the use of index prices to value oil and gas, alternatives to the current requirement to track actual costs to determine transportation allowances, and alternate methods for valuing wellhead gas volumes to eliminate the requirement to trace the value of liquids removed from processed gas.

ONRR received responses to the Federal and Indian coal valuation ANPR from 11 industry representative, Tribe, State, community group (representing several member groups), coal publication, and trade organization commenters. ONRR then conducted 3 public workshops on Federal and Indian coal valuation in October 2011 in Denver, Colorado; St. Louis, Missouri; and Albuquerque, New Mexico. At those workshops, ONRR asked attendees to discuss, among other things, (1) possible alternatives to the current methods that we use to value arm's-length and non-arm's-length coal sales, (2) coal comparability factors, (3) possible alternatives to the current methods we use to value coal cooperative sales of coal, (4) use of index prices to value coal, and (5) possible alternatives to the current requirements to track actual costs to determine transportation and washing allowances.

ONRR considered the input from the ANPRs and the workshops and proposes this consolidated rulemaking to improve the current regulations. The proposed rule would not alter the underlying principles of the current regulations. By proposing these amendments, the Department reaffirms that the value, for royalty purposes, of crude oil and natural gas produced from Federal leases and coal produced from Federal and Indian leases is determined at or near the lease and that gross proceeds from arm's-length contracts are the best indication of market value. Like the current regulations, these proposed regulations would not restrict ONRR to a comparison of arm's-length sales of other production occurring in the field or area to value production not sold under an arm's-length contract. Thus, like the current regulations, in this proposed rule, ONRR may begin with a "downstream" price or value and determine value at the lease by allowing deductions for the cost of transporting production to downstream sales points or markets, or by allowing appropriate adjustments for location or quality.

Federal and Indian lessees are not obligated to sell their production downstream of the lease. A lessee is at liberty to sell production at or near the lease, even if selling downstream might yield a higher royalty value than selling it at the lease. If a lessee chooses to sell downstream, the choice to sell downstream does not make otherwise non-deductible costs deductible (for example marketable condition and marketing costs). See *Independent Petroleum Ass'n of America. v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002), *cert. denied sub nom., Independent Petroleum Ass'n of America. v. Watson,* 537 U.S. 1105 (2003) ("*Independent Petroleum Ass'n v. DeWitt*"); *Devon Energy Corp v. Norton*, No. 04-CV-0821 (GK), 2007 WL 2422005 (D.D.C. Aug. 23, 2007), *aff'd sub nom., Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied,* 130 S. Ct. 86 (2009) ("*Devon*") and cases cited therein.

As noted above, the changes proposed in this rule reflect an effort by ONRR to update its royalty valuation regulations to, among other things, simplify processes and provide early clarity regarding royalties owed. However, even with the changes outlined in this rule, royalty valuations will continue to be complex, and the markets for oil, gas, and coal will continue to evolve. Therefore, ONRR continues to be interested in opportunities to further streamline the valuation process, while also bringing added transparency to the system. In particular, we seek ideas and comments on:

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

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

ONRR recognizes that the costs and benefits of making further changes to its valuation regulations (beyond those specifically proposed in this rule) will depend on the specific commodity at issue (*i.e.*, oil, gas or coal), as well as geographic or other factors. Thus, detailed comments that elaborate on specific situations where further valuation changes should be considered would be particularly useful to ONRR as it proceeds with this rulemaking as well as any future rules that may be considered.

II. Explanation of Proposed Amendments

Based on comments ONRR received on the ANPRs and at the public workshops, and other relevant information, we propose this consolidated rule to improve the current regulations to ensure greater clarity, efficiency, certainty, and consistency in production valuation.

The general consensus of comments received on the ANPR about arm's-length oil sales was that actual proceeds are the best indicator of value, and ONRR should not change to index prices. Most commenters agreed the valuation methodology for non-arm's-length sales of Federal oil is working, as is using actual costs to determine transportation allowances. Thus, ONRR is not currently proposing major changes to oil valuation methodologies except to eliminate both unused valuation options, such as tendering, and associated definition(s), and to make the oil rule consistent with our proposed changes to the proposed Federal gas rule.

The comments we received regarding gas produced from Federal leases were, in certain instances, polarized. Very large companies generally support index pricing as an option if it is revenue-neutral and there are no required true-ups (end-of-year comparison of the index value to actual sales and payment on the higher of the two). Independent gas producers and States generally disagreed with the major companies and did not support index pricing because they believe it may not reflect actual value and may not be revenue neutral. The majority of respondents generally support using actual costs for gas transportation and processing deductions to maintain revenue neutrality. In response, ONRR proposes no major changes for the valuation of arm's-length gas sales. However, for non-arm's-length gas sales, ONRR proposes to eliminate current benchmarks (a series of indicators of market value). Instead, ONRR proposes valuation methodology options based on how gas is sold using the first arm's-length-sale price (affiliate resales), optional index prices, or weighted average pool prices.

The general consensus of ANPR commenters for coal valuation was not to change royalty valuation of arm's-length sales and not to use coal index values because of their very limited applicability. Commenters suggested modifying the non-arm's-length coal benchmarks and eliminating seldom-used benchmarks. Commenters agreed ONRR should keep Federal and Indian rules separate. Therefore, at this time, ONRR is proposing no changes to the valuation of arm's-length coal sales.

For non-arm's-length coal sales, ONRR proposes to eliminate the current benchmarks. Instead, ONRR proposes to value coal on the gross proceeds received from the first arm's-length sale. ONRR also proposes to value sales of coal between coal cooperative members using the first arm's-length sale or a netback methodology. In addition, if there is no coal sale, and lessees or their affiliates use the coal to generate electricity and sell the electricity, then ONRR proposes to value the coal for royalty purposes based on the gross proceeds the lessee or its affiliate receive for the power plant's arm's-length sales of the electricity, less applicable deductions. ONRR proposes the same changes for both Federal and Indian coal, with some minor exceptions, but would continue to maintain separate regulations.

ONRR also proposes other changes to our regulations, although we did not specifically request comments on these changes in the ANPRs or at the workshops. One such proposed change is adding a new "default provision" to address valuation when ONRR determines (1) a contract does not reflect total consideration, (2) the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration due to misconduct or breach of the duty to market for the mutual benefit of the lessee and the lessor, or (3) it cannot ascertain the correct value of production because of a variety of factors, including, but not limited to, a lessee's failure to provide documents. In these cases, the Secretary may enforce his/her authority and exercise considerable discretion to establish the reasonable value of production using a variety of discretionary factors and any other information the Secretary believes is appropriate.

Finally, we rewrote all sections of the current regulations in Plain Language to meet the criteria of Executive Orders 12866 and 12988 and the Presidential Memorandum of June 1, 1998, and to make our rules more clear, consistent, and readable. All citations to the current ONRR regulations in title 30 of the *Code of Federal Regulations* (CFR) in this preamble refer to the July 1, 2012, CFR.

III. Section-by-Section Analysis

Before reading the additional explanatory information below, please turn to the proposed rule language that immediately follows the List of Subjects in 30 CFR parts 1202 and 1206 and signature page in this proposed rule. The Department will codify this language in the CFR if we finalize the proposed rule as written.

After you read the proposed rule, please return to the preamble discussion below. The preamble contains more information about the proposed rule, such as why we define a term in a certain manner and why we chose one valuation method over another.

The derivation table below only shows a crosswalk of the recodified sections of the current and the proposed regulations in part 1206.

DERIVATION TABLE FOR PART 1206

The requirements of section:	Are derived from section:
Subpart C	
1206.20	1206.101; 1206.151; 1206.251; 1206.451
1206.101	1206.102
1206.102	1206.103
1206.103	1206.104
1206.106	1206.105
1206.107	1206.106
1206.108	1206.107
1206.109	1206.108
1206.110	1206.109
1206.111	1206.110
1206.112	1206.111
1206.113	1206.112
1206.114	1206.113
1206.115	1206.114
1206.116	1206.115
1206.117	1206.116
1206.118	1206.117
Subpart D	
1206.140	1206.150
1206.141(a)(1)–(4)	1206.152(a)(1)
1206.141(b)(1)–(3)	1206.152(a)(2)
1206.141(b)(4)	1206.152(b)(1)(iv)
1206.142(a)(4)	1206.153(a)(1)
1206.142(b)	1206.153(a)(2)
1206.142(c)	1206.153(b)(1)(i)
1206.143(a)(1) and (b)	1206.152(b)(1)(ii); 1206.153(b)(1)(ii)
1206.143(a)(2)	1206.152(f); 1206.153(f)
1206.143(c)	1206.152(b)(1)(iii); 1206.153(b)(1)(iii)
1206.144	1206.152(c)(1)–(3); 1206.153(c)(1)–(3)
1206.145	1206.152(e)(1) and (2); 1206.153(e)(1) and (2); 1206.157(c)(1)(ii) and (c)(2)(iii);

	1206.159(c)(1)(ii) and (c)(2)(iii)
1206.146	1206.152(i); 1206.153(i)
1206.147	1206.152(k); 1206.153(k)
1206.148	1206.152(g); 1206.153(g)
1206.149	1206.152(l); 1206.153(l)
1206.150	1206.154
1206.151	1206.155
1206.152(a)	1206.156(a)
1206.152(b)	1206.156(b); 1206.57(a)(2) and (b)(3)
1206.152(c)(1)	1206.157(a)(2) and (b)(4)
1206.152(f)	1206.157(a)(4)
1206.153(b)	1206.157(f)
1206.153(c)	1206.157(g)
1206.154(a)	1206.157(b)
1206.154(e) — (h)	1206.157(b)(2)(i)–(iii)
1206.154(i)	1206.157(b)(2)(iv)
1206.154(i)(3)	1206.157(b)(2)(v)
1206.155	1206.157(c)(1)(i), (ii)
1206.156	1206.157(c)(2)(i)–(iv)
1206.157(a)(1) and (c)	1206.156(d)
1206.157(a)(2) and 1206.158	1206.157(e)
1206.159(a)(1)	1206.158(a)
1206.159(b)	1206.158(b)
1206.159(c)(1) and (2)	1206.158(c)(1) and (2)
1206.159(d)	1206.158(d)(1)
1206.160	1206.159(a)
1206.161	1206.159(b)
1206.162	1206.159(c)(1)
1206.163	1206.159(c)(2)
1206.164	1206.159(d)
1206.165	1206.159(e)
Subpart F	
1206.250	1206.250
1206.251	1206.254; 1206.255; 1206.260
1206.252(d)	1206.258(a); 1206.261(b)
1206.260(a)(1) and	1206.261(a)
(b)	1206.261(a)(2)
1206.260(c)(2)	1206.261(c)(3)
1206.260(d)	1206.261(c)(1), (c)(2), and (e)
1206.260(e)	1206.262(a)(4)
1206.260(f)	1206.262(a)(2) and (a)(3)
1206.260(g)	1206.262(a)(1)
1206.261	1206.262(b)
1206.262	1206.262(c)(1)
1206.263	1206.262(c)(2)
1206.264	1206.262(d)
1206.265	1206.262(e)
1206.266	1206.258(a)
1206.267(a)	1206.258(c); 1206.260
1206.267(b)(2)	1206.259(a)(4)

1206.267(c)..	…….……1206.259(a)(2) and (a)(3)
1206.267(d)..	….………………………1206.258(e)
1206.267(e)..	………………………1206.259(a)(1)
1206.268..	..…………………………1206.259(b)
1206.269..	………………………1206.259(c)(1)
1206.270..	………………………1206.259(c)(2)
1206.271..	…………………………1206.259(d)
1206.272..	…………………………1206.259(e)
1206.273..	
Subpart J	
1206.450..	………………………………1206.450
1206.451..	…….1206.453; 1206.454; 1206.459
1206.460..	………………………1206.461(a)(1)
1206.463..	..…………………………1206.461(c)

A. Section-By-Section Analysis of 30 CFR Part 1202—Royalties, Subpart F—Coal

ONRR proposes to amend subpart F regarding Federal and Indian coal production volumes on which you must pay royalties. The proposed rule merely moves current 30 CFR 1206.253 and 1206.452 to 30 CFR part 1202, subpart F to a new §1202.251. We also rewrote the current sections in Plain Language without substantive change.

B. Section-By-Section Analysis of 30 CFR Part 1206—Product Valuation, Subpart A—General Provisions and Definitions, Subpart C—Federal Oil, Subpart D—Federal Gas, Subpart F—Federal Coal, and Subpart J—Indian Coal

ONRR proposes to amend subparts A, C, D, F, and J relating to the valuation of oil and gas produced from Federal leases and coal produced from Federal and Indian leases.

Subpart A—General Provisions

1206.20 What definitions apply to subparts C, D, F, and J?

ONRR proposes to consolidate the definitions from Federal Oil (30 CFR 1206.101), Federal Gas (30 CFR 1206.151), Federal Coal (30 CFR 1206.251), and Indian Coal (30 CFR 1206.451). The consolidated definitions reside in a proposed §1206.20 under proposed Subpart A—General Provisions and Definitions.

ONRR proposes to consolidate the existing definitions for these products to provide greater clarity and eliminate redundancy. Where common terms exist in the four subparts, ONRR modifies the definitions to incorporate the active voice and to use plain and simple language similar to the language reflected in the 2000 Federal crude oil rule. For example, the term *arm's-length contract* applies the modern language of the 2000 Federal crude oil rule and extends its applicability to Federal gas and Federal and Indian coal. Where a definition has different meanings for different subparts, we define the term for each subpart in that definition. For example, see the definition of "gross proceeds" below. Terms we currently reference in only one subpart, for example *ANS* (Alaska North Slope), remain unmodified, except we propose to locate these definitions in the consolidated definitions in §1206.20. Finally, ONRR proposes to add new definitions.

We identify all new definitions in the table below and show if each existing definition remains unchanged, is modified, or is eliminated.

Summary of Terms and Status

Term	Status			
	Modified	Not Modified	Added New Definition	Removed Definition
Ad valorem lease		X		
Affiliate	X			
Allowance				X
ANS		X		
Area	X			
Arm's-length contract	X			
Audit	X			
BIA		X		
BLM		X		
BOEM			X	
BSEE			X	
Coal		X		
Coal cooperative			X	
Coal washing		X		

Compression		X		
Condensate	X			
Constraint			X	
Contract	X			
Designee		X		
Exchange agreement		X		
FERC			X	
Field	X			
Gas		X		
Gas plant products		X		
Gathering	X			
Geographic region			X	
Gross proceeds	X			
Index	X			
Index pricing point	X			
Index zone			X	
Indian allottee				X
Indian Tribe	X			
Individual Indian mineral owner			X	
Keepwhole contract			X	
Lease	X			
Lease products	X			
Lessee	X			
Like quality			X	
Like quality coal				X
Like-quality lease products				X
Location differential		X		
Market center		X		
Marketable condition		X		
Marketing affiliate				X
Mine		X		
Minimum royalty				X
Misconduct			X	
Net-Back method				X
Net output	X			
Net profit share				X
Netting	X			
NGLs			X	
NYMEX price		X		
Oil		X		
ONRR		X		
ONRR-approved commercial price bulletin			X	
ONRR-approved publication	X			
Outer Continental Shelf		X		

Payor			X	
Person	X			
Posted price				X
Processing	X			
Processing allowance			X	
Prompt month		X		
Quality differential		X		
Region			X	
Residue gas		X		
Rocky Mountain Region		X		
Roll	X			
Sale	X			
Sales type code				X
Section 6 lease		X		
Short ton			X	
Spot market price				X
Spot price		X		
Spot sales agreement				X
Tendering program				X
Tonnage			X	
Trading month		X		
Transportation allowance	X			
Warranty contract				X
Washing allowance			X	
WTI differential		X		

We explain the new and modified terms and definitions below. For most modified terms, we rewrote the terms in Plain Language and make no substantive change.

Subpart C—Federal Oil

1206.100 What is the purpose of this subpart?

This proposed section is the same as current 30 CFR 1206.100.

1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-length contract?

This proposed section is the same as current 30 CFR 1206.102 except for two substantive changes. First, proposed paragraph (a) contains the same provisions as existing §1206.102(a) with one modification. Proposed paragraph (a) adds that the value in this paragraph does not apply "if ONRR decides to value your oil under §1206.105." Proposed §1206.105 is ONRR's new proposed default valuation mechanism.

ONRR also proposes to add a new provision to paragraph (c)(1) allowing ONRR to decide a lessee's oil value if the lessee fails to make the election in this paragraph. Under the current regulations, if a contract is either non-arm's-length or an exchange agreement, a lessee can choose one of two different valuation methods. ONRR proposes to add a new provision to clarify the current regulations by explaining the consequences if a lessee fails to properly make the election. For example, if a lessee improperly classifies its contract as an arm's-length contract under the current regulations, the lessee will most likely pay royalties on the price specified in its contract. However, if the lessee or ONRR subsequently determines the contract actually was non-arm's-length or an exchange agreement, the existing regulations do not specify if the lessee may make the election retroactively. To remove this ambiguity, ONRR proposes to eliminate the lessee's election in these situations and provide that ONRR can determine the lessee's oil value under the new default valuation mechanism in §1206.105.

1206.102 How do I value oil not sold under an arm's-length contract?

This proposed section is the same as current 30 CFR 1206.103 except for two substantive changes. The first substantive change is to paragraph (a), which explains when you may value oil under this section. Proposed paragraph (a) requires you to use this section to value your oil "unless ONRR decides to value your oil under §1206.105." Proposed §1206.105 is ONRR's new proposed default valuation mechanism.

ONRR also proposes to remove current 30 CFR 1206.103(b)(1) containing the option for lessees to use a tendering program to value oil they produce from Federal leases in the

Rocky Mountain Region. Since the final oil valuation regulations were published in March 2000, ONRR is aware of only one company that valued its oil using this provision. At that time, we received feedback from oil producers that it was administratively inefficient to implement a tendering program for valuation purposes. We do not believe any oil producer has used this provision since then. Therefore, because industry has abandoned its use of this provision, we propose to remove tendering from the options available to value Federal oil produced in the Rocky Mountain Region.

Finally, ONRR proposes to amend paragraphs (d) and (e) of §1206.103 in the current regulations. Under the current regulations, lessees may apply paragraphs (d) and (e) to value their production with ONRR approval. ONRR proposes to amend paragraphs (d) and (e) to instead state that ONRR may decide to use these paragraphs to value production under §1206.105.

1206.103 What publications are acceptable to ONRR?

The substantive requirements of this proposed section are the same as current 30 CFR 1206.104. However, we propose to remove our requirement to publish a notice of acceptable publications in the *Federal Register*. Instead, we propose to provide acceptable publications on our website.

1206.104 How will ONRR determine if my royalty payments are correct?

In this section, ONRR proposes amendments to the text of its gross proceeds provisions to rewrite them in Plain Language and to make them consistent with other valuation regulations. Thus, rather than repeat the requirements or procedures in each applicable section of this rule, ONRR proposes to have this section apply to this entire subpart. However, the substantive requirements of proposed paragraphs (d), (e) and (f) remain unchanged. We propose the same changes to the Federal gas amendments that we propose in this section, so please refer to the discussion of the substantive changes we propose to make to the Federal gas regulation in §1206.143 below for more information.

1206.105 How will ONRR determine the value of my oil for royalty purposes?

ONRR proposes to add a new "default" valuation §1206.105 under which ONRR can value your oil if we decide to do so pursuant to the criteria under §1206.104 or any other provision in this subpart. If ONRR determines value under this new default section, we may consider any information we deem relevant. Also, this proposed section enumerates factors ONRR may consider if we decide we will determine value, for royalty purposes, under this section, which may include, but not be limited to:

(a) The value of like-quality oil in the same field or nearby fields or areas;

(b) The value of like-quality oil from the same plant;

(c) Public sources of price or market information ONRR deems reliable;

(d) Information available and reported to ONRR, including but not limited to, on Form ONRR-2014 and Form ONRR-4054;

(e) Costs of transportation or processing, if ONRR determines they are applicable; or

(f) Any information ONRR deems relevant regarding the particular lease operation or the salability of the oil.

This proposed section allows ONRR to consider any criteria we deem relevant, as well as criteria similar to the current gas valuation benchmarks under 30 CFR 1206.152(c)(1) and (2) and 1206.153(c)(1) and (2). Like the valuation regulations in effect prior to the 1988 rulemaking that resulted in the current gas valuation regulations, 30 CFR 206.103 (1984) (onshore) and 206.150 (1984) (offshore), under proposed §1206.105, ONRR has the authority and responsibility to establish the reasonable value of production for royalty purposes and possesses considerable discretion in determining that value. *Independent Petroleum Ass'n v. DeWitt*, 279 F.3d at 1039 - 1040, and cases cited therein. Thus, under this proposed section, ONRR has broad authority to value your oil in the manner we deem most appropriate considering the factors we deem most appropriate.

We add the same default provision to Federal gas in §1206.144, Federal coal in §1206.254, and Indian coal in §1206.454.

1206.106 What records must I keep to support my calculations of value under this subpart?

1206.107 What are my responsibilities to place production into marketable condition and to market production?

The two proposed sections above are the same as current 30 CFR 1206.105 and 1206.106, except we rewrite the sections in Plain Language.

1206.108 How do I request a value determination?

This proposed section is the same as current 30 CFR 1206.107 except we make some substantive changes to provide greater clarity to the process a lessee may use to request valuation guidance and determinations, as well as the effect of ONRR's response to such requests. Because we are making the same changes to the Federal gas amendments in this proposed rulemaking, please refer to proposed §1206.148 of the Federal gas regulation below for more information.

1206.109 Does ONRR protect information I provide?

This proposed section is the same as current 30 CFR 1206.108, except we rewrite the section in Plain Language.

1206.110 What general transportation allowance requirements apply to me?

This proposed section is the same as current 30 CFR 1206.109 except we reword the section name and make the following substantive changes. First, in proposed paragraph (a)(2)(ii), we add a new provision that states you may not take a transportation allowance for the movement of oil produced on the OCS from the wellhead to the first platform. Because we are making the same change to the Federal gas amendments we propose in this rulemaking, please refer to §1206.152(a)(2)(ii) of the Federal gas regulation below for more information.

Second, we propose in paragraph (b) to clarify that if you request to use a different cost allocation than that in paragraph (b), and we approve your request, you can only use your proposed allocation methodology prospectively. We make this proposed change to clarify that you may not request retroactive changes to your royalty reporting and payment. We make the same change to proposed §§1206.112(b), 1206.112(i)(1), 1206.112(j), 1206.113(c)(2), 1206.150(c)(4), 1206.152(b), 1206.154(b)(3), 1206.154(i)(1), 1206.161(b)(3), 1206.151(h)(1), 1206.262(b)(3), 1206.262(h)(1), 1206.269(b)(3), 1206.269(h)(1), 1206.462(b)(3), 1206.462(h)(1), 1206.463(d)(4)(i), 1206.469(b)(3), 1206.469(h)(1), and 1206.470(d)(4)(i).

Third, in paragraph (d)(1) of this section, we propose to remove current 30 CFR 1206.109(c)(2) that allows a lessee to request to exceed the limit on transportation allowances of 50 percent of the value of the oil. We also propose to terminate existing approvals to exceed the 50 percent limit under paragraph (d)(2). Because we are making the same change to the Federal gas amendments in this proposed rulemaking, please refer to §1206.152(e) below for more information.

Fourth, like the default provision for valuation we discuss above under §1206.104, proposed paragraph (f) provides that ONRR may determine your transportation allowance under §1206.105 if (1) there is misconduct by or between the contracting parties, (2) the total consideration the lessee or its affiliate pays under an arm's-length contract does not reflect the reasonable cost of transportation because the lessee breached its duty to market oil for the mutual benefit of the lessee and the lessor by transporting oil at a cost that is unreasonably high, or (3) ONRR cannot determine if the lessee properly calculated a transportation allowance for any reason. Because we are making the same change to the Federal gas amendments we propose in this rulemaking, please refer to the discussion of §1206.152(g) below for more information on this provision.

Finally, we also propose a new provision under paragraph (g) to clarify that you do not need ONRR's approval before reporting a transportation allowance for costs you incur. This is consistent with existing practice.

1206.111 How do I determine a transportation allowance if I have an arm's-length transportation contract?

This proposed section is the same as current 30 CFR 1206.110, except for three substantive changes. ONRR proposes to eliminate the provision in current 30 CFR 1206.110(b)(4) that allows a lessee to include the costs of carrying line fill on its books as a component of arm's-length transportation allowances. Rather, we propose to specifically preclude including this cost in transportation allowances under new paragraph (c)(9) of this section. We propose to eliminate allowing this cost because we believe this is a cost to market the oil we disallow as a deduction under our existing valuation regulations. Line fill occurs after the royalty measurement point and is necessary for the pipeline operator to get Federal oil production to market. We request comments on whether this is a marketing cost.

We also propose to add a new paragraph (d) that applies if you have no contract in writing for the arm's-length transportation of oil. In that case, ONRR determines your transportation allowance under §1206.105. Under the proposed rule, you may propose to ONRR a method to determine the allowance using the procedures in §1206.108(a) and may use that method to determine your allowance until ONRR issues its determination. This proposed paragraph does not apply if a lessee performs its own transportation. Instead, proposed §1206.112 for non-arm's-length transportation allowances, applies.

Finally, ONRR proposes to eliminate the provision in current 30 CFR 1206.110(g) that allows a lessee to report transportation costs, in certain circumstances, as a transportation factor. We propose that a lessee must report separately all transportation costs under both arm's-length and non-arm's-length sales contracts as a transportation allowance on Form ONRR-2014. ONRR believes requiring lessees to report all deductions for transportation costs separately as allowances on Form ONRR-2014 is more transparent, supports ONRR's increased data mining efforts to promote accurate upfront royalty reporting, and assists State and Federal auditors in their compliance work.

1206.112 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

This proposed section is the same as current 30 CFR 1206.111 except for the following substantive changes.

We replace current 30 CFR 1206.111(b)(3) and (b)(4) with proposed paragraph (b)(3)(i) of this section, which allows you to elect to calculate depreciation and a return on undepreciated capital investment in a transportation system under proposed paragraph (b)(3)(i)(1) or a return on undepreciated capital investment with no depreciation under proposed paragraph (b)(3)(i)(2). The proposed regulation provides that once you make an election, you may not change it without ONRR's approval. In addition, proposed paragraph (b)(3)(ii) replaces current 30 CFR 1206.111(b)(5). Currently, 30 CFR 1206.111(b)(5) allows you to continue deducting 10 percent of the cost of capital expenditures once you have depreciated the asset below 10 percent under current 30 CFR 1206.111(j). However, under proposed paragraph (i)(1)(iii) of this section, instead of allowing a 10 percent deduction, we base the return on undepreciated capital investment on the reasonable salvage value of the asset. ONRR believes this method more reasonably reflects the actual costs for oil transportation systems. Also, it makes the treatment of depreciation consistent with other royalty valuation rules, including the current Federal gas rule at 30 CFR 1206.157(g) (proposed §1206.154(i)).

In proposed paragraph (c)(2)(ii)**,** we prohibit you from including actual or theoretical line loss as a transportation cost. ONRR proposes to eliminate the provision in the current regulations at 30 CFR 1206.111(b)(6)(v) which allows a lessee to reduce the royalty volume measured at the royalty measurement point by actual or theoretical line loss occurring after the royalty measurement point. This change is consistent with long-standing mineral leasing laws that require royalty on the volume of production removed from the lease. Mineral Leasing Act, 30 U.S.C. 181-287; Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351-359 (onshore acquired lands); Indian leasing statutes, 25

U.S.C. 396a—396g (tribal leases); 25 U.S.C. 396 (allotted leases); and the Outer Continental Shelf Lands Act, 43 U.S.C. 1331-1356. This change also makes Federal oil valuation consistent with ONRR's other product valuation regulations.

Under proposed paragraph (c)(2)(iii), ONRR eliminates the provision in current 30 CFR 1206.111(b)(6)(ii) which allows a lessee to include the costs of carrying line fill on its books as a component of non-arm's-length transportation allowances. We believe this is a cost to market the oil, which we disallow as a deduction under current valuation regulations. Line fill occurs after the royalty measurement point and is necessary for the pipeline operator to get Federal oil production to market. We request comments on whether this is a marketing cost.

Proposed paragraph (i)(1) allows you to calculate depreciation and a return on undepreciated capital investment using either a straight-line method (based on either the life of the equipment or the life of the reserves that the transportation system services) or a unit of production method. This depreciation method was in ONRR's oil valuation regulations in effect for producer-owned transportation systems prior to the effective date of the 2000 Federal oil valuation regulations. This new proposed paragraph (i)(1) would replace the provision in current 30 CFR 1206.111(h), which allows a lessee to depreciate a transportation asset a second time after the lessee already fully depreciated that asset. The current Federal oil valuation regulations authorize fully depreciated transportation assets to be recapitalized a second time when they are purchased from the original owner. ONRR proposes to remove this provision. Under proposed paragraph (i)(1)(ii), ONRR allows depreciation of pipeline assets only one time. If the pipeline asset is sold, we allow the purchaser to continue the remaining allowance depreciation schedule if applicable. This change makes Federal oil valuation consistent with ONRR's other product valuation regulations.

Proposed paragraph (i)(1)(iii)(B) changes the return on undepreciated capital investment from10 percent to the reasonable salvage value of the asset multiplied by the rate of return in proposed paragraph (i)(3) of this section.

New proposed paragraph (i)(2) provides an alternative to depreciating the asset under paragraph (i)(1). Under this option, you may elect to use a cost equal to the allowable initial capital investment in the transportation system, multiplied by the rate of return in proposed paragraph (i)(3) of this section. If you chose this option, you may not include depreciation as a cost in your allowance. ONRR removed the provision limiting this option to transportation assets put in place after March 1, 1988. When ONRR published its Federal oil valuation regulations on May 5, 2004, it changed the requirements for transportation allowances. In recognition that certain transportation facilities had been given approval prior to these regulations' effective date (August 1, 2004), ONRR made the new requirements apply only to facilities that were placed in service on or after the effective date of these regulations. Now, almost ten years later, ONRR believes that none of facilities affected by the 2004 rule change are still eligible for depreciation under the requirements in effect prior to August 1, 2004. Therefore, we remove this language from the proposed regulations.

Proposed paragraph (i)(3) would amend current 30 CFR 1206.111(i)(2) to change the Standard & Poor's BBB bond rate we allow as an approximation of the cost of capital for non-arm's-length transportation. Currently, 30 CFR 1206.111(i)(2) allows a lessee to compute the rate of return on the undepreciated cost of capital by multiplying the undepreciated amount remaining by 1.3 times the Standard & Poor's BBB bond rate. ONRR proposes to decrease the multiplier of the Standard & Poor's BBB bond rate from 1.3 to 1.0. In the final Federal oil valuation regulations published in March 2000, we increased the multiplier of the Standard & Poor's BBB bond rate from 1.0 to 1.3. We propose to change it back to 1.0 times the BBB bond rate because we believe this rate better reflects the cost of borrowing to finance capital expenditures involved in pipeline construction. It also is consistent with our other product valuation regulations.

When a company or affiliate invests in shipping its own production, it considers if it can more profitably transport its own production or contract with a third party to provide the service. At this stage in production development, a company has a solid asset to demonstrate its ability to repay the capital investment necessary to construct the pipeline. ONRR consulted with FERC and has concluded that the BBB bond rate is an adequate representation for the cost of capital for the construction of producer-owned pipelines.

1206.113 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?

1206.114 How will ONRR identify market centers?

1206.115 What are my reporting requirements under an arm's-length transportation contract?

Proposed §§1206.113 through 1206.115 are the same as current 30 CFR 1206.112 through 1206.114, but we rewrite the sections in Plain Language and update the examples in current 30 CFR 1206.112(d) using November 2012 prices.

1206.116 What are my reporting requirements under a non-arm's-length transportation contract?

This proposed section is the same as current 30 CFR 1206.115 except we make each sentence a paragraph. We also add a new paragraph (d) that explains you must follow the reporting requirements for arm's-length contract under §1206.115 if you are authorized under §1206.112(j) to not use your actual costs.

1206.117 What interest and penalties apply if I improperly report a transportation allowance?

This proposed section is the same as current 30 CFR 1206.116 except we make each sentence a paragraph and add "penalties" to the heading to better describe the section.

1206.118 What reporting adjustments must I make for transportation allowances?

1206.119 How do I determine royalty quantity and quality?

These two proposed sections, 30 CFR 1206.118 and 1206.119, are the same as current §§1206.117 and 1206.119, respectively, but we rewrite the sections in Plain Language.

1206.120 How are operating allowances determined?

We propose to remove current 30 CFR 1206.120 on how to determine operating allowances because it is unnecessary. If a lease has provisions for operating allowances, that lease term will govern valuation under proposed §1206.100(d)(4) of this subpart.

Subpart D—Federal Gas

ONRR proposes to add new §§1206.140 through 1206.149 to this subpart to codify, clarify, and enhance current ONRR Federal gas valuation practices.

1206.140 What is the purpose and scope of this subpart?

We propose to redesignate the current regulations at §1206.150 to §1206.160. Also, in this proposed rule, we rewrote the redesignated sections in Plain Language. Proposed

§1206.140 is the same as current 30 CFR 1206.150 except for three changes. First, we propose to add a new paragraph (b) to explain that the terms "you" and "your" in this subpart refer to the lessee. Second, we propose to redesignate paragraphs (b) and (c) as paragraphs (c) and (d). Finally, we propose to remove existing regulations in paragraph (d), which state this subpart is intended to ensure leases are administered in accordance with governing mineral leasing laws and lease terms. We believe current paragraph (d) is unnecessary and duplicative of our authority to promulgate this rule.

1206.141 How do I calculate royalty value for unprocessed gas I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

This proposed section explains the valuation of unprocessed gas for royalty purposes. Proposed paragraph (a)(1) explains that this section applies to unprocessed gas—meaning gas that is never processed—consistent with the current gas regulations.

Proposed paragraph (a)(2) explains this section applies to gas you are not required to value under proposed §1206.142, or that ONRR does not value under proposed §1206.144. Proposed §1206.142(a) explains what gas ONRR considers processed for valuation purposes, and proposed §1206.144 explains ONRR's new proposed default valuation mechanism. We discuss proposed §§1206.142 and 1206.144 below.

Under proposed paragraph (a)(3), we state this section also applies to processed gas you must value prior to processing under §1206.151 of this part. Proposed §1206.151 contains the dual accounting provisions for Federal gas in current 30 CFR 1206.155.

Under proposed paragraph (a)(4), we consider unprocessed gas any gas you sell prior to processing if price is based on an amount per MMBtu or Mcf, and not on the value of residue gas and gas plant products. Therefore, this proposed paragraph applies to the valuation of gas when price is not based on a processed gas price.

Paragraph (b) proposes a new valuation methodology based on the first arm's-length sale of the gas. ONRR promulgated the current gas valuation regulations in 1988 to achieve market value based on transactions between independent, non-affiliated parties. The Department has long believed the values established in arm's-length transactions are the best indication of market value, and the 1988 rules reflect that belief.

Although the Secretary's responsibility to determine the royalty value of minerals produced has not changed, the industry and marketplace have changed dramatically since we wrote the 1988 regulations. As discussed below, industry and marketplace changes, as well as litigation necessitate changes to ONRR's valuation regulations. Indeed, ONRR already amended the Indian gas (30 CFR part 1206, subpart E) and Federal oil (30 CFR part 1206, subpart C) valuation regulations to simplify those regulations and provide early certainty by valuing those products based on the first arm's-length sale and/or on publicly available prices.

When we developed the 1988 rules, producers most commonly sold natural gas at the wellhead to natural gas pipeline companies, which transported and sold the gas to local distribution companies. However, from mid-1980 to early 1990, a series of FERC rulemakings resulted in deregulation of some pipeline systems. As a result, industry now sells directly to end users or distributors, and pipelines only provide transportation services. Producers also created marketing affiliates to which they initially transferred production.

For lessee sales to affiliates, the current Federal gas valuation regulations require a lessee to value production based on a series of "benchmarks" to be applied in a prescribed order (30 CFR 1206.152(c)). The first benchmark is the gross proceeds accruing to the lessee in a sale under its non-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 (30 CFR 1206.152(c)(1)). This method has posed practical difficulties since companies are not privy to other companies' "comparable" sales transactions. In addition, ONRR and lessees have found it difficult to determine what portion of lease production a lessee must sell at arm's-length to reliably determine the value of the remaining production. Likewise, the remaining benchmarks at 30 CFR 1206.152(c)(2) and (3) have proven difficult for industry to follow and ONRR to administer. ONRR proposes to replace the current regulations in §1206.152(c)(1), (2), and (3) with proposed paragraph (b).

To simplify and clarify valuation of non-arm's-length sales, proposed paragraph (b) bases value on the first arm's-length sale with applicable allowances. The first arm's-length sale may occur immediately, or may follow one or more non-arm's-length transfers or sales of the gas. However, under the proposed rule, you will use the first arm's-length sale regardless of whether you sell or transfer gas to one or more affiliates or other persons in non-arm's-length transactions before the first arm's-length sale, and regardless of the number of those non-arm's-length transactions. This arm's-length sales value will apply unless you exercise the index-based option in proposed paragraph (c) of this section we discuss below.

Proposed paragraph (b)(1) would state value is the gross proceeds accruing to you under an arm's-length contract, less applicable allowances.

Similarly, under proposed paragraph (b)(2), if you sell or transfer your Federal gas production to your affiliate, or some other person at less than arm's length, and that person or its affiliate then sells the gas at arm's length, royalty value will be the other person's (or its affiliate's) gross proceeds under the first arm's-length contract. For example, a lessee might sell its Federal gas production to a person who is not an "affiliate" as defined, but with whom its relationship is not one of "opposing economic interests" and therefore is not at arm's length. An illustrative example is when a number of working interest owners in a large field form a cooperative venture that purchases all of the working interest owners' production and resells the combined volumes to a purchaser at arm's-length. *Xeno, Inc.*, 134 IBLA 172 (1995), involved a similar situation. If none of the working interest owners own 10 percent or more of the new entity, the new entity would not be an "affiliate" of any of them. Nevertheless, the relationship between the new entity and the respective working interest owners is not at arm's length because of the lack of opposing economic interests regarding the contract. In this case, we believe it appropriate to value the production based on the arm's-length sale price the cooperative venture receives for the gas. Therefore, under proposed paragraph (b)(2), you must value the production based on the gross proceeds accruing to you, your affiliate, or other person to whom you transferred the gas (or its affiliate) when the gas ultimately is sold at arm's length, unless you elect to use the index pricing option we propose under §1206.141(c) of this section or ONRR decides to value your gas under the new default valuation provision in proposed §1206.144 discussed below.

In summary, to provide early certainty and simplification, ONRR proposes to amend its valuation regulations for Federal gas to provide that, with certain exceptions, the first arm's-length sale is the value for royalty purposes consistent with valuation of non-arm's-length sales of Federal oil production under current 30 CFR 1206.102(a).

Proposed paragraph (b)(3) explains valuation if you, your affiliate, or another person sell under multiple arm's-length contracts for gas produced from a lease that is valued under this proposed paragraph (b). In this case, unless you exercise the index-based option we provide in paragraph (c) of this section, because you sold non-arm's length to your affiliate or another person, under the proposed rule, you must value the gas based on the volume-weighted average of the value established under this paragraph for each contract for the sale of gas produced from that lease. This is identical to current 30 CFR 1206.102(b) applicable to valuation of Federal oil. In addition, we believe this provision is consistent with ongoing practice under the current gas valuation rule.

Proposed paragraph (b)(4) contains the provisions of the current gas valuation rule at 30 CFR 1206.152(b)(1)(iv) that explains how to value over-delivered volumes under a cash-out program, but we rewrite this provision in Plain Language.

ONRR proposes to add a new paragraph (c) containing an index price valuation methodology that a lessee may elect to use in lieu of valuing its gas under proposed paragraphs (b)(2) and (b)(3) of this section based on the gross proceeds accruing to its affiliate or other person under the first arm's-length sale. The proposed methodology is based on publicly available index prices less a specified deduction to account for processing and transportation costs. Under the proposed rule, this valuation methodology also applies to "no contract" situations we describe below under paragraph (e).

We believe this index price option simplifies the current valuation methodology and provides early certainty. Many pipelines and service providers now charge producers "bundled" fees that include both deductible costs of transportation and non-deductible costs to place production into marketable condition. Both ONRR and lessees with arm's-length transportation contracts have found allocating the costs between placing the gas in marketable condition and transportation is administratively burdensome and time consuming. Similarly, when processing plants charge bundled fees that include non-deductible costs, the cost allocation is administratively burdensome and time consuming.

Litigation also has complicated the application of ONRR's gas valuation regulations. Although litigation has clarified what constitutes marketable condition, its application is fact specific and time consuming. *See Devon* and cases cited therein.

The proposed index-based option provides a lessee with an alternative that is simple, certain, and avoids the requirements to "trace" production when there are numerous non-arm's-length sales prior to an arm's-length sale and unbundle fees. Under this proposed paragraph (c), the lessee may choose to value its gas only in an area that has an active index pricing point published in a publication that ONRR approves. The lessee may elect to value its gas under this proposed paragraph, and that election is binding on the lessee for 2 years. ONRR would post a list of approved publications at *www.onrr.gov*. ONRR proposes to use Platts and Natural Gas Intelligence as ONRR-approved publications but invites comments on whether these publications are appropriate, as well as whether there are other publications that ONRR should use.

If the lease is in an area with active index pricing points, the lessee must determine the applicable index pricing point or points. We used the language in proposed paragraphs (c)(1)(i) and (ii) "If you **can** only transport to one index pricing point" and "If you **can** transport gas to more than one index pricing point," respectively (emphasis added), because, under the proposed rule, we intend that for an index pricing point to be applicable, the lessee must be able to physically transport its gas by pipeline to that index pricing point. Further, an index pricing point would be applicable as long as the lessee **could** physically transport their gas by pipeline to that index pricing point (emphasis added). This means that under the proposed rule, the index pricing point applies even if the lessee could not transport its gas to that index pricing point because the pipeline is constrained (for example when all available capacity on a pipeline through which the lessee's gas might flow to that index pricing point was already under contract to other parties).

For example, assume you have a lease in the West Delta area of the Gulf of Mexico and your lease is physically connected by pipeline to the Mississippi Canyon Pipeline. In this case, your gas is physically capable of flowing to the Toca Plant (through the Southern Natural Gas Pipeline), the Yscloskey Plant (through the Tennessee Gas Pipeline), or the Venice Plant, and you have multiple index pricing points to which your gas can physically flow. Also, assume the highest reported monthly bid week price among the multiple index pricing points is the Tennessee Gas 500 Leg Price at the tailgate of the Yscloskey Plant. Finally, assume you cannot flow your gas through the Tennessee Gas Pipeline (to the Yscloskey Plant) because all available capacity on that pipeline is under contract to other persons, and the pipeline has no capacity available to you for the production month—in other words, it is constrained. In this example, you would use the highest reported monthly bid week price at the tailgate of the Yscloskey

Plant as the value under this paragraph even though your gas did not flow to that index pricing point during the production month.

Under proposed paragraph (c), the lessee could not use index pricing points if it could not physically transport its gas to that index pricing point because there is not a pipeline or series of pipelines that physically connect to the lease and flow from the lease to the index pricing point. ONRR would exclude the use of these index pricing points because they do not represent points at which the lessee can sell its gas, and it is difficult to adjust these prices for location differentials between the index pricing points and the lease.

If the lessee can transport its gas to only one index pricing point, the value under proposed paragraph (c)(1)(i) is the highest reported monthly bid week price for that index pricing point in the ONRR-approved publication for the production month. If the lessee can transport its gas to more than one index pricing point, the value under proposed paragraph (c)(1)(ii) is the highest reported monthly bid week price for the index pricing points to which the lessee could transport its gas, in the ONRR-approved publication for the production month. However, under paragraph (c)(1)(iii), if there are sequential index pricing points on a pipeline, the lessee would use the first index pricing point at or after the lessee's gas enters the pipeline.

ONRR recognizes that index pricing points are normally located off the lease, and frequently at lengthy distances from the lease. Thus, under proposed paragraph (c)(1)(iv), ONRR allows a lessee to reduce the highest reported monthly bid week price by a set amount to account for transportation costs a lessee would incur to move the gas from the lease to an applicable index pricing point. ONRR proposes to allow a lessee to reduce the highest reported monthly bid week prices by 5 percent for sales from the OCS

Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu. ONRR proposes these percent reductions based on the average gas transportation rates that lessees have reported to ONRR from 2007 through 2010 for OCS and all other areas.

ONRR proposes to allow a lessee to choose the index price methodology to value its gas under this paragraph for the following reasons: (1) it relies on a market price at which gas is sold from the area during the production month; (2) it recognizes costs that a lessee must incur to transport gas from the lease to an index pricing point; and (3) it makes payment and verification of royalties paid simple and efficient, thereby saving both lessees and ONRR significant administrative costs. Further, ONRR believes this alternative methodology provides ONRR with a reasonable market value for the lessee's gas that avoids requiring a lessee and ONRR to track every resale of the lessee's gas during the production month, especially when those sales can involve several transactions hundreds of miles downstream from the lease. As we state above, it also avoids the unbundling of transportation and processing costs.

ONRR proposes to use the highest reported monthly bid week price with a reduction for transportation costs. We propose this because it generally represents the gross proceeds net of transportation allowances accruing to lessees that ONRR believes are most likely to choose this option to value their gas based on information lessees and others reported on Form ONRR-2014 for the period from 2007 through 2011.

Proposed paragraph (c)(1)(v) states that, after you select an ONRR-approved publication available at *www.onrr.gov*, you may not select a different publication more often than once every 2 years. ONRR also proposes, under paragraph (c)(1)(vi), to exclude individual index prices from this option if we determine that the index price does not accurately reflect the value of production. ONRR plans to disallow the use of index prices with low liquidity, such as those classified as Tier 3 in the Platts publications. ONRR would post a list of excluded index pricing points at *www.onrr.gov*. We would appreciate comments on this proposal.

Proposed paragraph (c)(2) explains that you may not take any other deductions from the value calculated under this paragraph (c) because you would already receive a reduction for transportation under proposed paragraph (c)(1)(iv).

Proposed paragraph (d)(1) provides that, if you have no written contract or no sale of gas subject to this section and there is an index pricing point for the gas, then you must value your gas under the index pricing provisions of paragraph (c) of this section unless ONRR values your gas under §1206.144. This provision includes, but is not limited to, when: (1) the lessee sells its gas to an affiliate and the affiliate uses the gas in its facility; (2) the lessee sells its gas to an affiliate and the affiliate resells the gas to another affiliate of either the lessee or itself and that affiliate uses the gas in its facility; (3) the lessee uses the gas as fuel for its other leases in the field or area; or (4) the lessee delivers gas to another person as payment of an overriding royalty interest that other person holds.

Proposed paragraph (d)(2) addresses situations in which you have no contract for the sale of gas subject to this section and there is not an index pricing point for the gas. In these situations, ONRR will decide the value under §1206.144. However, when this occurs, under paragraph (d)(2)(i), we require that you propose to ONRR a method to determine the value using the procedures in proposed §1206.148(a). Proposed §1206.148(a) describes the information you must provide to ONRR when you request a valuation determination. Proposed paragraph (d)(2)(ii) allows you to use your proposed method until ONRR issues a decision. After ONRR issues a determination, under paragraph (d)(2)(iii), you will have to make any adjustment under proposed §1206.143(a)(2). You have to make adjustments only if ONRR decides you must use a different methodology than you propose under paragraph (d)(2)(i).

1206.142 How do I calculate royalty value for processed gas I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

ONRR proposes a new §1206.142 including a new paragraph (a) that amends and expands what is processed gas for royalty valuation purposes. Currently, when gas is sold under an arm's-length contract prior to processing, and the lessee neither retains nor exercises any rights to the gas after processing (in other words, an outright sale before the plant), such gas is valued as unprocessed gas. Included are contracts where the title passes before processing, but payment is based on the values of residue gas and gas plant products after processing. Percentage-of-Proceeds (POP) contracts (contracts 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) are the most common of these contracts, but ONRR has observed a myriad of variations of such contracts. Because this gas is valued as unprocessed gas under the current regulations, there are no limits on the minimum value of such gas for royalty purposes, except for gas sold under arm's-length POP contracts, which has a minimum value of 100 percent of the residue gas. No such limitation applies to contracts that do not specifically qualify as POP contracts.

For example, if the sales value is based on a percentage of an index price for residue gas and/or NGLs, the current regulations base value simply on the gross proceeds the lessee receives under the contract. In essence, the unprocessed gas regulations allow such sales arrangements to reduce the value of residue gas below the 100-percent minimum value required under the processed gas regulations and below the 1-percent minimum value for NGLs (assuming ONRR approves an exception under the current rules in excess of 66⅔ percent of the NGL value) required for processed gas.

ONRR has seen numerous contract arrangements that provide payment terms based on: (1) a percentage of the volume or value of residue gas, plant products, or any combination of the two actually recovered at the plant; (2) the full volume and value of residue gas and/or plant products recovered at the plant, less a flat fee per MMBtu of wet gas entering the plant; (3) a combination of (1) and (2); and (4) the value of a percentage of the theoretical volumes of residue gas and/or plant products contained in the wet gas stream (so-called casing head gas contracts). Because the many contract variations base the underlying value on processed gas values, ONRR believes we should require a lessee to value gas sold under such contracts as processed gas for royalty purposes. This proposal provides the protection the current processed gas regulations have against excessive transportation and processing allowances and prevents a lessee from structuring contracts to avoid these requirements. Such a change also clarifies if gas is processed gas or unprocessed gas.

In summary, under proposed paragraph (a)(1), ONRR will consider gas you or your affiliate do not sell or otherwise dispose of under an arm's-length contract before processing "processed gas." Paragraph (a)(1) also applies to non-arm's-length sales of gas before processing and transfers to a plant without a contract like the current regulations.

Proposed paragraph (a)(2) applies to the situations described above when payment is based on any constituent products resulting from processing, such as residue gas, NGLs, sulfur, or carbon dioxide. We would value POP contracts, percentage-of-index contracts, casing head gas contracts, and contracts with any such variations of payment based on volumes or value of those products as processed gas. With the exception of POP contracts, this constitutes a departure from current practice.

Proposed paragraph (a)(3), while not a change in current regulatory practice, explicitly states that the lessee must value gas processed under a keepwhole contract as processed gas. Under proposed §1206.20, we define a keepwhole contract as a processing agreement under which the processor compensates the lessee by delivering to the lessee a quantity of residue gas after processing equivalent to the quantity of gas the processor received prior to processing, normally based on heat content, less gas used as plant fuel and gas that is unaccounted for and/or lost. The lessee does not receive NGLs under these contracts. Over the past several years, ONRR has witnessed much confusion over how to value gas sold under such contracts for royalty purposes. This provision makes it clear that the lessee must value gas processed under a keepwhole contract as processed gas. That is, royalty would be based on 100 percent of the value of residue gas, 100 percent of the value of gas plant products, plus the value of any condensate recovered downstream of the point of royalty settlement prior to processing, less applicable transportation and processing allowances.

To illustrate how to calculate the processing allowance in these cases, assume you deliver 32,000 MMBtu of natural gas to the gas processing plant. Also assume 7,000 MMBtu represents the shrinkage volume (the MMBtu equivalent of the NGLs recovered), and the plant recovers and retains 92,000 gallons of NGLs from your gas. Further, assume the plant returns 7,000 MMBtu of gas to you at the tailgate of the plant in addition to the residue gas that results after processing your gas to “keep you whole.” Finally, assume the 7,000 MMBtu of gas returned to you is worth $42,000 and the NGLs the plant retained are worth $63,000. In this example, the cost you incur to process the gas is $21,000 ($63,000 - $42,000). If you incur additional costs, for example a $0.03 per MMBtu fee times the 32,000 MMBtu you deliver to the plant for processing, then you add those additional costs (in this example, $960) to the $21,000 cost calculated above to determine your total processing costs (in this example $21,960).

Proposed paragraph (a)(4) simply restates current 30 CFR 1206.153(a)(1) regarding arm’s-length contracts and reservations of rights to process gas the lessee or its affiliate exercises.

ONRR also proposes paragraph (b), which contains the same requirements as current 30 CFR 1206.153(a)(2), but we rewrite it in Plain Language, without substantive change.

Like the valuation of unprocessed gas under proposed §1206.141(b), proposed paragraph (c) provides that the value of residue gas or any gas plant product under this section is the gross proceeds accruing to you or your affiliate under the first arm’s-length contract. Also, like proposed §1206.141(b), this value does not apply if you exercise the index-based option we provide in paragraph (d) of this section or if ONRR decides to value your residue gas or any gas plant product under the new default valuation provision in §1206.144. Proposed paragraphs (c)(1), (2), (3), and (4) explain to which transactions this paragraph applies. See the discussion of the identical proposal for proposed §§1206.141(b)(1), (2), (3), and (4) above.

Proposed paragraph (d) contains the index-based valuation option for valuation of your residue gas and NGLs. Under this proposed rule, you may elect to value either your residue gas or your NGLs under the index-based option, or you may elect to value both of them under this option if your residue gas or NGLs meet the requirements for using the optional valuation methodology we discuss above. Like the current Federal oil regulations (30 CFR 1206.102(d)(1)(ii)) and proposed §1206.141(c), you cannot change your election to use this paragraph (d) to value your gas more often than once every two years.

Proposed paragraph (d)(1) applies to residue gas. It has the same index price option as proposed §§1206.141(c)(i) through (vi) we discuss above using index pricing points.

Proposed paragraph (d)(2) contains the index-based pricing option for NGLs. Under paragraph (d)(2)(i), if you sell NGLs in an area with one or more ONRR-approved commercial price bulletins available at *www.onrr.gov*, you may choose one bulletin, and your value for royalty purposes would be the monthly average price for that bulletin for the production month. We consider you to be selling NGLs in an area with an ONRR-approved commercial price bulletin if actual sales of NGLs that the plant processing your gas recovers are made using NGLs prices in an ONRR-approved commercial price bulletin. For example, in ONRR's experience, actual sales of NGLs recovered in plants in New Mexico commonly reference Mt. Belvieu prices in Platts, while actual sales of NGLs recovered in plants in certain parts of Wyoming reference Mt. Belvieu or Conway, Kansas prices. If your gas is processed at one of these plants with these types of actual sales arrangements, under this proposed rule, ONRR will consider you to be selling NGLs in an area with an ONRR-approved commercial price bulletin. In that case, you may elect to value your NGLs using the index price method if your NGLs meet the requirements for using that method. ONRR will monitor actual sales of NGLs and eliminate any area where an active market using NGLs prices in an ONRR-approved commercial price bulletin ceases to exist.

Under proposed paragraph (d)(2)(ii), you may reduce the index-based value you calculate under paragraph (d)(2)(i) by a specified amount to account for a theoretical processing allowance and transportation and fractionation (T&F). Therefore, the reduction includes two components we calculated—an allowance based on processing allowance information lessees report to ONRR and T&F based on our review of gas plant contracts and gas plant statements.

For the processing allowance component, ONRR examined processing allowances that lessees and others reported from January 2007 through October 2011. We segregated the data into 2 subsets—the first being the Gulf of Mexico (GOM) and the second being onshore Federal leases and OCS leases other than those in the GOM. We segregated the leases geographically because the GOM is closer to major market centers at Mt. Belvieu, Napoleonville, and Geismer/Sorrento and, generally, has its own processing, transportation, and fractionation regimen that is distinct from the rest of the country. We do not believe it is fair or accurate to benchmark processing for the entire country based on the economics of GOM processing.

We could not segregate non-arm's-length processing allowances because lessees do not identify processing allowances as arm's-length or non-arm's-length when they report to ONRR. Rather, we calculated a weighted average cents per gallon processing allowance by month for both GOM and all other Federal leases. Using the weighted average cents per gallon processing allowance we calculated, we determined the average allowance rate over the 5-year period, along with the maximum and minimum monthly rates as follows:

	GOM	**Other**
Average Rate	17 ¢/gal	22 ¢/gal
Maximum Rate	29 ¢/gal	32 ¢/gal
Minimum Rate	10 ¢/gal	15 ¢/gal

Because we intend for this option to provide a simple method for ONRR to calculate and provide to lessees, we used the minimum, rather than the average rate, for the processing allowance portion of the deduction. For both the GOM and all other Federal leases, the minimum rate is 7 cents less than the average rate. ONRR believes that: (1) the minimum allowance best protects the public interest and (2) a lessee experiencing higher costs than this rate does not have to elect to use this option and the lower cost allowance. Moreover, ONRR believes that 7 cents is a reasonable tradeoff given the simplicity, certainty, and commensurate administrative savings this option would provide a lessee.

For the T&F part of the reduction, ONRR examined contracts that specified T&F. If contracts did not specify T&F, we looked at the gas plant statements. If the statements listed T&F as a line item, we used that line item as the T&F. If the statements did not list T&F as a line item, we calculated the difference between the price on the plant statement and an appropriate published price to approximate the T&F. We then averaged these T&F costs for GOM, New Mexico, and other as follows:

	GOM	**New Mexico**	**Other**
Average T&F	5 ¢/gal	7 ¢/gal	12 ¢/gal

We broke out New Mexico because the T&F fees for New Mexico plants were consistently around 7 cents per gallon and were considerably less than for other onshore plants. We then added the processing allowances we calculated and the T&F. Based on the 5-years' worth of data discussed above, we calculated the total NGLs reductions lessees could use under this option are as follows:

	GOM	**New Mexico**	**Other**
NGLs Deduction	15 ¢/gal	22 ¢/gal	27 ¢/gal

Under paragraph (d)(2)(ii), rather than publish the reductions in the CFR, ONRR proposes to post the reductions at *www.onrr.gov* for the geographic location of your lease. ONRR proposes to calculate the reductions using the methodology explained above. This process would give ONRR the flexibility to quickly recalculate and provide revised reductions to lessees in response to market changes. This methodology would be binding on you and ONRR. Under paragraph (d)(4), ONRR would update the allowable reductions periodically using this methodology and post changes at *www.onrr*.gov.

Proposed paragraph (d)(2)(iii) explains that after you select an ONRR-approved commercial price bulletin available at *www.onrr.gov*, you may not select a different commercial price bulletin more often than once every two years. Under proposed paragraph (d)(3), you may not take any other deductions from the value you used under this paragraph (d) because it already includes reductions for transportation and processing.

Proposed paragraph (e) mirrors proposed §1206.141(d). It explains how you must value your processed gas if you have no written contract for the sale of gas or no sale of the gas subject to this section.

1206.143 How will ONRR determine if my royalty payments are correct?

In this section, ONRR proposes amendments to the current gross proceeds provisions, rewriting them in Plain Language and making them consistent with our other product valuation regulations (such as geothermal resources and Federal oil). Like those published regulations, rather than repeating the requirements or procedures in each applicable section of this proposed rule, ONRR proposes to apply this section to this entire subpart. However, the substantive requirements of proposed paragraphs (d), (e), and (f) remain unchanged. Below we discuss the paragraphs with substantive changes.

Proposed paragraph (a)(1), like our current regulations, states "ONRR may monitor, review, and audit the royalties you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value . . . ." However, we propose to add paragraph (a)(1) that states in addition to directing you to use a different measure of value, we also may decide your value under §1206.144 as we discuss below.

Proposed paragraph (b), like our current regulations, explains "[w]hen the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the gas, residue gas, or gas plant products." However, we propose to add a new paragraph (b) that if ONRR determines a contract does not reflect the total consideration, ONRR may decide your value under §1206.144 as we discuss below.

Proposed paragraph (c) broadly defines three circumstances when ONRR will calculate the value of your gas using the method specified in the new proposed "default" valuation §1206.144. During its compliance activities, ONRR encounters a wide range of situations in which lessees have inaccurately calculated value. By broadly defining the circumstances in which ONRR may calculate value, this proposed rule ensures ONRR can fulfill its statutory mandate under FOGRMA to ensure that lessees accurately calculate, report, and pay royalties (30 U.S.C. 1701 and 1711).

Proposed paragraphs (c)(1) and (c)(2) contain the provisions regarding misconduct and breach of the duty to market in current 30 CFR 1206.152(b)(1)(i) and 1206.153(b)(1)(iii). Under the current regulations, if ONRR determines there is misconduct between the parties, or that the lessee has breached its duty to market, then the lessee must value its gas under the current benchmarks for non-arm's-length sales of gas in 30 CFR 1206.152(c)(2) or (c)(3) (unprocessed gas) and 1206.153(c)(2) or (c)(3) (processed gas). However, as we discuss above, ONRR proposes to eliminate the benchmarks in this rulemaking. We propose instead that if ONRR determines there is misconduct between the parties to a contract or the lessee has breached its duty to market, we may decide your value under §1206.144 as we discuss below.

As we discuss above in proposed §1206.20, *misconduct,* for purposes of proposed paragraph (c)(1), means any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior regardless of the mental state of the lessee or any individual employed by, or associated with, the lessee. *Misconduct*, in this subpart, would be different than, and in addition to, any violations subject to civil penalties under FOGRMA, 30 U.S.C. 1719, and its implementing regulations in part 1241 of this chapter. Behavior that constitutes *misconduct*, under this part 1206, would not need to be willful, knowing, voluntary, or intentional. This is a valuation mechanism, not an enforcement tool. Under this proposed rule, if ONRR determines that *misconduct* has occurred, ONRR will calculate value under § 1206.144. However, if ONRR determines the *misconduct* was knowing or willful, it also could pursue civil penalties under part 1241 of this chapter.

Under proposed paragraph (c)(2), ONRR defines what is a breach of the duty to market. The proposed rule specifies that ONRR may determine value under §1206.144 if a lessee sells gas, residue gas, or gas plant products at an unreasonably low price. The proposed rule explains what ONRR could consider an "unreasonably low" price. A lessee has a duty to market gas for the mutual benefit of the United States, as lessor, and the lessee. An unreasonably low price may reflect a failure of the lessee to perform that duty. Proposed paragraph (a)(2) defines a sales price as "unreasonably low" "if it is 10 percent less than the lowest reasonable measures of market price, including, but not limited to, index prices and prices reported to ONRR for like-quality gas, residue gas, or gas plant products." ONRR's authority to exercise this provision is discretionary; ONRR "may" decide your value if it determines your price is unreasonably low. In exercising its discretion, ONRR may consider any information that shows a price appears unreasonably low, and, thus, is not an accurate reflection of fair market value.

ONRR also proposes a new paragraph (c)(3). Under proposed paragraph (c)(3), ONRR may value your gas, residue gas, or gas plant products under §1206.144 if ONRR cannot determine if you properly valued your gas, residue gas, or gas plant products under §1206.141 or §1206.142 for any reason. This is a broad "catch-all" provision ONRR may use to decide the value of gas, residue gas, or gas plant products when it cannot determine if a lessee properly valued its production. ONRR will exercise this discretionary authority to meet its mandate under 30 U.S.C. 1711 to ensure accurate accounting for Federal oil and gas royalties under the different circumstances it encounters during its compliance verification activities. It is the lessee's responsibility to provide ONRR with information sufficient for us to ensure that royalties are accurately calculated. Under this provision, ONRR will still meet its statutory mandate even when a lessee fails to provide sufficient information. However, like proposed paragraph (c)(1) of this section, this is an ONRR valuation mechanism that is in addition to any civil penalty authority ONRR has under part 1241 of this chapter

We propose a new paragraph (g)(1) that requires the lessee or its affiliate to make all contracts in writing before it can use the contracts as the basis for the lessee's valuation of its gas produced from Federal leases. This proposed requirement will apply to any contract revisions or amendments. Further, ONRR proposes that all parties to the contract must sign the contracts, contract revisions, or amendments before lessees can use them as the basis for the lessee's valuation of its gas under these regulations.

ONRR believes this proposed requirement is critical to the proper application of the valuation regulations. Lessees should provide to ONRR the actual, written contracts signed by all parties because those contracts document the very transactions on which the regulations require lessees to base values and allowances. Without the applicable sales, transportation, and/or processing contracts, neither the lessee nor ONRR can verify that Federal royalties are properly paid. Because ONRR would only require a lessee to provide its actual contractual arrangements that it uses to conduct its business, this requirement should place no burden on a lessee.

ONRR proposes a new paragraph (g)(2) providing that ONRR may decide the value 1of a lessee's gas if the lessee or its affiliate fails to make all contracts, contract revisions, or amendments in writing. If the lessee cannot produce the written, signed contracts that would otherwise serve as the basis of the lessee's valuation of its gas under the regulations, ONRR may decide to determine the appropriate value of the lessee's gas under newly proposed §1206.144 as we discuss below.

Finally, ONRR proposes to add paragraph (g)(3) to make clear the new provision requiring contracts to be in writing and signed by all parties is in addition to any other recordkeeping requirements the lessee must satisfy under this title, and that this new requirement supersedes any provision in this title to the contrary.

1206.144 How will ONRR determine the value of my gas for royalty purposes?

ONRR proposes a new "default" valuation §1206.144 that ONRR may use to value your gas, residue gas, or gas plant products for royalty purposes. Because we propose the same default provision for federal oil, please refer to §1206.105 above for more information.

1206.145 What records must I keep to support my calculations of royalty under this subpart?

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

1206.147 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.148 How do I request a valuation determination or guidance? See discussion below.

1206.149 Does ONRR protect information I provide?

1206.150 How do I determine royalty quantity and quality?

ONRR proposes to rewrite in Plain Language the regulations for recordkeeping, marketable condition and marketing, audit, confidentiality, and quantity and quality requirements and procedures. Also, ONRR proposes to make these sections consistent with other product valuation regulations, such as the geothermal and Federal oil regulations. In addition, rather than repeat the requirements or procedures in each applicable section of this rule, ONRR proposes to have these sections apply to this entire subpart. The substantive requirements remain unchanged.

1206.148 How do I request a valuation determination or guidance?

ONRR proposes a new §1206.148 on how to request a valuation determination or guidance. This section is the same as §1206.108 applicable to Federal oil we discuss above, with several substantive changes. Proposed §1206.148 replaces and expands the provisions contained in current 30 CFR 1206.152(g) and 1206.153(g). The newly proposed section provides greater clarity on the process lessees may use to request valuation guidance and determinations, as well as on the effect of ONRR's response to such requests. Adding proposed §1206.148 will make the procedures for gas valuation requests consistent with the procedures ONRR proposes for Federal oil and Federal and Indian coal.

Under proposed paragraph (a), a lessee may request a valuation determination or guidance from ONRR regarding any gas produced. Paragraph (a)(1) through (3) explains that the lessee's request must be in writing; identify all leases involved, all interest owners in the leases, and the operator(s) for those leases; and completely explain all relevant facts. In addition, under paragraphs (a)(4) through (6), a lessee must provide all relevant documents, its analysis of the issue(s), citations to all relevant precedents, including adverse precedents, and its proposed valuation method.

In response to a lessee's request, under proposed paragraph (b), ONRR may (1) decide that it will issue guidance, (2) inform the lessee in writing that it will not provide a determination or guidance, or (3) request that the Assistant Secretary for Policy, Management, and Budget issue a determination. This proposal changes the current Federal oil regulations under 30 CFR 1206.107(b), which has caused confusion over whether an ONRR-issued determination is a binding appealable order or non-appealable guidance. Under this proposed rule, ONRR clarifies that we only issue non-binding guidance for valuation of Federal oil and gas and Federal and Indian coal. This proposal is consistent with ONRR's existing practice of having only the Assistant Secretary sign decisions that are binding on the Department. Also, ONRR proposes to remove the regulatory language that we will "reply to requests expeditiously." Our practice is to reply as quickly as possible, so we do not make it a regulatory requirement.

Proposed paragraphs (b)(3)(i) and (ii) identify situations in which ONRR and the Assistant Secretary typically do not provide a determination or guidance, including, but not limited to, requests for guidance on hypothetical situations and matters that are the subject of pending litigation or administrative appeals.

Under proposed paragraph (c)(1), a determination the Assistant Secretary of Policy, Management and Budget signs binds both the lessee and ONRR unless the Assistant Secretary modifies or rescinds the determination. After the Assistant Secretary issues a determination, under proposed paragraph (c)(2), the lessee must make any adjustments to its royalty payments that follow from the determination. If the lessee owes additional royalties, it must pay the additional royalties due plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter. In addition, proposed paragraph (c)(3) explains that a determination the Assistant Secretary signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

Proposed paragraph (d) explains that, if ONRR issues guidance, the guidance is not binding on ONRR, delegated States, or the lessee with respect to the specific situation addressed in the guidance. This is a change from the current Federal oil regulation at 30 CFR 1206.107(d) that makes a determination ONRR issues binding on ONRR and delegated States but not the lessee. Moreover, guidance, ONRR's decision whether to issue guidance, and ONRR's decision whether to request a determination by the Assistant Secretary would not be appealable decisions or orders under 30 CFR part 1290. This is the same as current 30 CFR 1206.107(d)(1). However, as provided under current 30 CFR 1206.107(d)(2), under proposed paragraph (d)(2) of this section, if ONRR issues an order requiring the lessee to pay royalty on the same basis as the guidance, the lessee could appeal the order under 30 CFR part 1290.

Under proposed paragraph (e), ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to make a determination or provide guidance. Also, under proposed paragraph (f), if a statute or regulation on which ONRR based any determination or guidance is changed, the changed statute or regulation takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the determination or guidance. Therefore, under this proposed provision, determinations and guidance are not open-ended.

1206.151 How do I perform accounting for comparison?

ONRR proposes to move the regulations in current 30 CFR 1206.155 to proposed §1206.151, but we rewrite this section in Plain Language. This section requires a lessee to pay royalties on the greater of the value of the unprocessed gas or the value of its processed gas if the lessee, its affiliate, a person to whom the lessee transferred gas under a non-arm's-length contract, or a person to whom the lessee transferred gas without a contract processes the lessee's or its affiliate's gas and does not sell the residue gas at arm's length. However, ONRR requests comments on whether we need this proposed requirement for two reasons. First, proposed §§1206.142 and 1206.143 of this subpart recognize the real market value of gas today is the combined value of its constituent components—residue gas and gas plant products. And, the proposed regulations value gas sold on that basis as processed gas. There appears to be a limited market for unprocessed gas, unless it is sold based upon the constituent products contained therein, hence accounting for comparison may not be needed. Second, because the criteria that triggers dual accounting—a non-arm's-length sale of residue gas after processing—is not used to value gas under this proposed rule, dual accounting may no longer be appropriate because the residue gas is valued based on the first arm's-length sale or index-based option.

ONRR also proposes to keep the requirement in current 30 CFR 1206.155 that lessees must perform dual accounting if required by lease terms. ONRR believes this provision is consistent with proposed §1206.140(c)(4), which specifically recognizes the primacy of lease terms over the terms of the regulations when they are inconsistent.

Before we discuss each section of proposed §§1206.152 through 1206.158 regarding transportation allowances, we believe it is helpful to discuss some general changes we make. The proposed regulations move the current regulations regarding transportation allowances from 30 CFR 1206.156 and 1206.157 to proposed §§1206.152 through 1206.158. The proposed gas transportation allowance regulations are changed, primarily in structure, but there also are a few substantive changes. The structure of the proposed gas transportation allowance regulations is modeled after the current Federal oil transportation allowance regulations to achieve consistency between the two. In most cases, the regulatory requirements do not change. We reorganize the current provisions and rewrite them in Plain Language. Like the current oil transportation allowance regulations, this structure provides more regulatory section headings, better organization, and greater visibility to locate regulatory requirements applicable to the lessee's particular transportation allowance situations. Also, we reorganize or combine many paragraphs that were embedded within a current section into a new section for greater visibility. We propose to segregate individual multiple requirements within paragraphs into separate paragraphs to improve visibility and identification.

1206.152 What general transportation allowance requirements apply to me?

Proposed §1206.152 retains the provisions in current §1206.156 ("Transportation allowances—general"), makes Federal gas regulations consistent with Federal oil regulations, and consolidates provisions applicable to both arm's-length and non-arm's-length transportation in the current regulations rather than repeating those provisions in the respective sections explaining those allowances. We also rewrite the current regulations in Plain Language and only discuss substantive changes and additions below.

Proposed paragraph (a) contains the same requirements as current §1206.156(a) and includes a new provision that "[y]ou may not deduct transportation costs you incur to move a particular volume of production to reduce royalties you owe on production for which you did not incur those costs." Consistent with current regulations, this provision prevents the lessee from claiming transportation costs incurred for a segment of transportation when the gas did not actually flow on that segment. A lessee could only claim transportation costs attributable to the actual movement of the lease production on that transportation segment.

We also propose new paragraphs (a)(1) and (a)(2)(i), which are consistent with the current Federal oil rule §1206.109(a)(2). New paragraph (a)(1) states you may take a transportation allowance when you value unprocessed gas under §1206.141(b) or residue gas and gas plant products under §1206.142(b) based on a sale at a point off the lease, unit, or communitized area where the gas is produced. New paragraph (a)(2)(i) states that you may take a transportation allowance when the movement to the sales point is not gathering. Neither change to the current rule is substantive because both codify existing practice and case law.

Proposed new paragraph (a)(2)(ii) states that "[f]or gas produced on the OCS, the movement of gas from the wellhead to the first platform is not transportation." It is well established that the movement of oil and gas that ONRR determines is "gathering" is not allowable as a transportation allowance. *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961); *Kerr-McGee Corp.*, 147 IBLA 277 (1999). However, on May 20, 1999, the then-Associate Director for the former MMS's Royalty Management Program issued "Guidance for Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters" (Deep Water Policy). The Deep Water Policy provides the following guidelines: (1) current regulations must be followed; (2) movement costs are allocated between royalty and non-royalty bearing substances; (3) movement prior to a central accumulation point is considered gathering, movement beyond the point is considered transportation; (4) leases and units are treated similarly; (5) the movement is to a facility that is not located on a lease adjacent to the lease on which the production originates; and (6) allowances for subsea completions not located in water deeper than 200 meters are considered on a case-by-case basis.

Both the current Federal oil and gas valuation rules define gathering as "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." 30 CFR 1206.101 (Federal oil) and 1206.151 (Federal gas). Under the Deep Water Policy, ONRR considered a subsea manifold located on the OCS in deep water to be a "central accumulation point" regardless of whether it was actually a central accumulation or treatment point as ONRR's regulations require. Since ONRR issued the

Deep Water Policy, lessees have been deducting the costs of moving bulk production from the subsea manifold to the platform where the oil and gas first surface. In addition, lessees have attempted to expand the Deep Water Policy to deem subsea wellheads "central accumulation points" and take transportation allowances from the sea bed floor to the first platform where the bulk production surfaces. Thus, lessees have taken transportation allowances under the Deep Water Policy, in some instances, for movement ONRR considers non-deductible "gathering" under its regulations.

In addition, the Interior Board of Land Appeals (IBLA) has concluded there are three definitive attributes of gas gathering lines: (1) they move lease production to a central accumulation point; (2) they connect to gas wells; and (3) they bring gas by separate and individual lines to a central point where it is delivered into a single line. *Kerr-McGee Corp.*, 147 IBLA at 282 (citations omitted). In *Kerr-McGee,* the IBLA stated that "even though production is moved across lease boundaries, because it is treated and sold on adjacent leases the costs of moving it there are properly regarded as gathering, not transportation." *Id.* at 283 (citations omitted). Under *Kerr-McGee*, almost all of the movement the Deep Water Policy allows as a transportation allowance is, in actuality, non-deductible "gathering" under ONRR's current valuation regulations.

We have determined that the Deep Water Policy is inconsistent with our regulatory definition of gathering and Departmental decisions interpreting that term. Therefore, we propose to rescind the Deep Water Policy in this rulemaking. We propose to accomplish this by making two changes. First, consistent with *Kerr-McGee,* we propose to add to the definition of "gathering" that any movement of bulk production from the wellhead to a platform offshore is gathering, not allowable transportation. Second, we propose to add a new paragraph (a)(2)(ii) to this section that states "[f]or gas produced on the OCS, the movement of gas from the wellhead to the first platform is not transportation." We also make this change to proposed Federal oil §1206.110(a)(2)(ii).

Proposed paragraph (b) of this section contains and consolidates current requirements in 30 CFR 1206.156(b) and 1206.157(a)(2) and (b)(3) regarding allocation of transportations costs based on your or your affiliate's cost of transporting each product if you transport one or more products in the gaseous phase in a transportation system.

Proposed paragraph (c)(1) contains and consolidates current requirements in 30 CFR 1206.157(a)(2) and (b)(4) which all apply to allocation of transportations costs when you or your affiliate transport both gaseous and liquid products in the same transportation system.

Under proposed paragraph (d), if you value unprocessed gas under §1206.141(c) or residue gas and gas plant products under §1206.142(d)—the index-based valuation options—you may not take a transportation allowance. This is because the index-based valuation provisions already incorporate the costs of transportation.

Proposed paragraph (e)(1), eliminates the current provision allowing lessees to request transportation allowances in excess of 50 percent of the sales value of the unprocessed gas, residue gas, or NGLs. Currently, ONRR limits transportation allowances and factors to 50 percent of the sales value of unprocessed gas, residue gas, or gas plant products unless we approve an exception to the limitation. To ensure a fair return to the public and to limit ONRR's administrative costs to process such requests, the proposed regulation eliminates the exception to the 50-percent limit. ONRR believes the current 50-percent limit on transportation-related costs is adequate in the vast majority of transportation situations. Thus, paragraph (e)(2) provides that any existing approvals for the exception to the limitation terminate on the effective date of the final rule. We will not grandfather any existing approval to exceed the 50-percent limit.

Proposed paragraph (f) continues the current requirement under 30 CFR 1206.157(a)(4), applicable to arm's-length transportation, that lessees must express transportation allowances for residue gas, gas plant products, or unprocessed gas in a dollar-value equivalent. We propose to also apply this requirement to non-arm's-length transportation consistent with existing practice. We further propose that if your or your affiliate's payments for transportation under a contract are not in dollars-per-unit, you must convert the consideration you or your affiliate paid to its dollar-value equivalent.

Like the default provision for valuation we discuss above under §1206.143(c), proposed paragraphs (g)(1), (2), and (3) provide that ONRR may determine your transportation allowance under §1206.144, if: (1) there is misconduct by or between the contracting parties; (2) the total consideration the lessee or its affiliate pays under an arm's-length contract does not reflect the reasonable cost of transportation because the lessee breached its duty to market the unprocessed gas, residue gas, or gas plant products for the mutual benefit of the lessee and the lessor by transporting such products at a cost that is unreasonably high; or (3) ONRR cannot determine if the lessee properly calculated a transportation allowance under §1206.153 or §1206.154, for any reason. Under proposed paragraph (g)(2), ONRR may consider an allowance to be unreasonably high if it is 10-percent higher than the highest reasonable measures of transportation costs, including, but not limited to, transportation allowances lessees and others report to ONRR and tariffs for gas, residue gas, or gas plant products transported through the same system.

Finally, we propose a new provision under paragraph (h) to make clear that you do not need ONRR's approval before reporting a transportation allowance for costs that you incur. This provision is in the current regulations that apply to arm's-length transportation at 30 CFR 1206.157(a), but we propose to apply it to non-arm's-length transportation as well. This is consistent with existing practice.

1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract?

Proposed §1206.153 explains how lessees must determine a transportation allowance under arm's-length transportation contracts. As we discuss above, we propose to restructure this section for consistency with the Federal oil transportation allowance regulations. In addition, we move the requirements for non-arm's-length transportation allowances to a separate §1206.154.

Proposed paragraph (a)(1) states that this section applies to both the lessee and its affiliate if the lessee chooses to use the affiliate's arm's-length sales contract for valuation and if that affiliate incurs transportation costs under an arm's-length transportation contract to move the lease production to the sales point. However, ONRR will determine your transportation allowance under §1206.152(g) if ONRR determines there is misconduct, the arm's-length transportation cost is unreasonably high, or ONRR cannot determine if your transportation allowance is proper. This provision gives ONRR greater discretion and flexibility to determine transportation allowances (for example, when arm's-length transportation service providers charge bundled fees). See the discussion of bundled fees in proposed §1206.141 above.

ONRR proposes to eliminate the provision in current 30 CFR 1206.157(a)(5) that allows lessees to report transportation costs, in certain circumstances, as a transportation factor. Rather, we propose that a lessee must report separately all transportation costs under both arm's-length and non-arm's-length sales contracts as a transportation allowance on Form ONRR-2014. ONRR believes that requiring lessees to report all deductions for transportation costs separately as allowances on Form ONRR-2014 is more transparent, supports ONRR's increased data mining efforts to promote accuracy, and assists State and Federal auditors with their compliance work. We propose this same change for oil produced from Federal lands.

Proposed paragraph (b) allows a lessee to include the same costs we allow under current 30 CFR 1206.157(f) in its transportation allowance. Under new paragraph (b)(11), we also propose that a lessee may include in its transportation allowance hurricane surcharges the lessee or its affiliate pay. This proposal is consistent with existing practice.

Under proposed paragraph (c), we specify transportation costs we would not allow a lessee to include in its transportation allowance. These non-allowable costs remain mostly the same as those we currently disallow under 30 CFR 1206.157(g). We believe it is already clear the cost of boosting gas (e.g. recompressing residue gas at the plant after processing) is not a deductible cost of transportation under current 30 CFR 1202.151(b) and the Assistant Secretary's decision at issue in *Devon.* Nevertheless, proposed paragraph (c)(8) specifically states that the costs of boosting residue gas are not allowable as a cost of transportation.

Finally, we propose a new paragraph (d) that applies if you have no written contract for the arm's-length transportation of gas. In that case, ONRR determines your transportation allowance under proposed §1206.144. Under this proposal, you have to propose to ONRR a method to determine the allowance using the procedures in §1206.148(a) and could use that method until ONRR issues its determination. This paragraph only applies when there is no contract for arm's-length transportation. Thus, it would not apply if lessees perform their own transportation. Rather, §1206.154 regarding non-arm's-length transportation allowances applies.

1206.154 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

We propose §1206.154 as a separate section explaining how to calculate transportation allowances under a non-arm's-length contract, such as where the lessee ships its production through its own pipeline or through a pipeline its affiliate owns. Under proposed paragraph (a), ONRR continues the provision in current 30 CFR 1206.157(b) that does not recognize contracts between the lessee and its affiliate or any other person without opposing economic interests regarding that contract. Like the current regulations, you will determine non-arm's-length transportation allowances based on your actual costs or the actual costs of the affiliated pipeline owner.

Proposed paragraph (b) generally explains costs you may include in your transportation allowance. Paragraph (b)(1) explains the lessee's or its affiliate's actual costs include capital costs and operating and maintenance expenses under paragraphs (e), (f), and (g) of this section. Proposed paragraph (b)(2) explains you also could include overhead under paragraph (h) of this section. Under proposed paragraph (b)(3), we revise the current regulation to clarify the methodology for the two options to calculate depreciation. Under this proposed rulemaking, we allow lessees to choose between depreciation and a return on undepreciated capital investment under paragraph (i)(1) of this section, or a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (i)(2) of this section. Finally, paragraph (b)(4) allows the lessee to continue to claim a rate of return on the reasonable salvage value of the transportation system after it is fully depreciated. For example, if the pipeline had a salvage value of 5 percent, the lessee may claim a rate of return on 5 percent of the system value, even though we would allow no further depreciation. See the discussion of reasonable salvage value in proposed §1206.112(i)(1)(iii).

We also propose to remove the provisions of current §1206.175 (b)(5) that allow a lessee with a non-arm's-length contract to use FERC or State-regulatory-agency approved tariffs as an exception from the requirement to calculate actual costs. We remove this provision to make it consistent with the current Federal oil valuation regulations. Under the proposed rule, lessees must compute their actual costs to determine transportation allowances under non-arm's-length contracts even when a regulatory agency has approved a tariff.

Proposed paragraph (c) further explains the transportation costs you may and may not include in a transportation allowance. Proposed paragraph (c)(1) states that, to the extent that you have not already included in your transportation allowances the allowable costs under paragraphs (e) through (g) of this section, you may include in your allowance the actual transportation costs we list under §1206.153(b)(2), (5), and (6) of this subpart (Gas supply realignment (GSR) costs, Gas Research Institute (GRI) fees, and Annual Charge Adjustment (ACA) fees that FERC imposes). ONRR proposes to disallow the remaining costs we allow a lessee to include in arm's-length transportation allowances under §1206.153(b) because the lessee would not or should not ordinarily incur the costs as a pipeline owner or be charged for those costs by its affiliate. However, there may be instances when specific costs integral to transportation could be included in the pipeline owner's operating and maintenance costs. ONRR invites comments on what types of costs, other than those identified in §1206.153(b)(2), (5), and (6), may be actual costs of transportation under non-arm's-length transportation arrangements.

ONRR also proposes to eliminate the current provision allowing lessees to deduct the costs of pipeline losses, both actual and theoretical, under non-arm's-length transportation situations. These regulations prohibited actual or theoretical pipeline losses prior to the 1997 gas transportation allowance revisions that incorporated new costs resulting from FERC Order No. 636. The advent of Order No. 636 should not have had any bearing on such non-arm's-length costs. Therefore, ONRR proposes to remove this provision. ONRR recognizes that pipeline losses are distinct from transportation fuel that is used on a pipeline to power compressors used for actual transportation. Under the proposal, ONRR continues to permit lessees to claim an allowance for actual fuel used for qualifying transportation purposes. In addition, we continue to disallow fuel for non-approved off-lease compressors and off-lease fuel for other processes necessary to place lease production in marketable condition.

Proposed paragraph (c)(2) explains that we do not allow a lessee to include in its non-arm's-length transportation allowances the same costs we do not allow to be included in arm's-length transportation allowances under proposed §1206.153(c).

Like the arm's-length provision, proposed paragraph (d) states that for non-arm's-length transportation allowances, the lessee may not duplicate allowable transportation costs when it calculates an allowance. For example, if the lessee includes GRI costs in its operating costs under paragraph (b), it may not also include those costs under paragraph (c).

Proposed paragraphs (e) through (h) contain the same requirements as current 30 CFR 1206.157(b)(2)(i), (ii), and (iii), but we rewrite the provisions in Plain Language and make them consistent with the current Federal oil regulations.

Proposed paragraph (i) retains the requirements of current 30 CFR 1206.157(b)(2)(iv) regarding depreciation, but we rewrite those provisions in Plain Language and make them consistent with the Federal oil regulations. ONRR proposes to eliminate the reference to transportation facilities first placed in service after March 1, 1988. When ONRR published its Federal gas valuation regulations on January 15, 1988, it changed the requirements necessary to receive transportation and processing allowances. In recognition that certain transportation and processing facilities had been given approval prior to those regulations' effective date (March 15, 1988), ONRR made the new requirements apply only to facilities that were placed in service on or after the effective date of those regulations. Now more than twenty years later, ONRR believes that none of the facilities placed in service before March 15, 1988, are still eligible for depreciation under the requirements in effect prior to March 15, 1988. Therefore, we propose to remove this outdated language from the proposed regulations.

Under paragraph (i)(3), ONRR proposes to revise the rate of return from 1.3 times the Standard & Poor's BBB bond rate in current 30 CFR 1206.157(b)(2)(v) to the rate without a multiplier, in other words 1 times the BBB bond rate. We make the same change to Federal oil, so please refer to our discussion of proposed §1206.112(i)(3).

1206.155 What are my reporting requirements under an arm's-length transportation contract?

This section would contain essentially the same provisions as current 30 CFR 1206.157(c)(1). However, ONRR proposes to add the term "affiliate" to paragraph (b). Under the new proposed valuation provisions, which use an affiliate's arm's-length sales contract, ONRR allows a transportation allowance to the arm's-length sales point and, therefore, needs the associated transportation contracts. In addition, ONRR proposes to eliminate the reference to allowances in effect prior to March 1, 1988, under current 30 CFR 1206.157(c)(1)(iii). As stated above, ONRR believes that none of facilities predating the 1988 rule change are still eligible for depreciation under the requirements in effect prior to March 15, 1988. Therefore, we are removing this language from the proposed regulations.

1206.156 What are my reporting requirements under a non-arm's-length transportation contract?

This section contains essentially the same provisions as current 30 CFR 1206.157(c)(2). In this proposed rule, ONRR eliminates the reference in current 30 CFR 1206.157(c)(2)(v) to allowances in effect prior to March 1, 1988.

1206.157 What interest or penalties apply if I improperly report a transportation allowance?

Under proposed §1206.157, ONRR consolidates the penalty and interest provisions for improper allowances. Currently, such provisions are contained under both the general transportation and determination of transportation allowances sections of the regulations. Proposed paragraph (a)(1) slightly modifies current 30 CFR 1206.156(d) by using the term “unauthorized” in the context of “If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due….” However, this change would not alter the meaning of the current provisions. Examples of unauthorized transportation allowances include, but are not limited to, exceeding the 50-percent limitation, including costs necessary to place the gas into marketable condition, or including other costs that are not integral to the transportation of lease production. Proposed paragraph (a)(2) states that a lessee may be entitled to a credit with interest if it understated its transportation allowance. This provision amends current 30 CFR 1206.157(e) to comply with RSFA’s provision that entitles lessees to interest on overpayments (30 U.S.C. 1721(h)).

Proposed paragraph (b) states that, if the lessee deducts a transportation allowance that exceeds 50 percent of the value of the gas, residue gas, or gas plant products transported, the lessee must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date it paid the additional royalties due. This changes the current requirement that interest is calculated from the date the allowance is taken until the lessee files a request for an exception. This change results from ONRR proposing to eliminate allowance exceptions.

Proposed paragraph (c) restates current 30 CFR 1206.156(d).

1206.158 What reporting adjustments must I make for transportation allowances?

Section 1206.158 restates the requirements of current 30 CFR 1206.157(e), except we rewrite the provisions in Plain Language.

1206.159 What general processing allowances requirements apply to me?

Like the amendments to transportation allowances discussed above, ONRR proposes to rewrite the current processing allowance regulations at 30 CFR 1206.158 in Plain Language, make them consistent with Federal oil, and reorganize them for clarity and visibility. We are not planning to make any substantive changes in proposed paragraph (a)(1) and paragraph (b); they will contain the same provisions as current 30 CFR 1206.158 (a) and (b). However, we propose to add a new provision under paragraph (a)(2) to make clear that you do not need ONRR's approval before reporting a processing allowance for costs that you incur for arm's-length or non-arm's-length allowances. This is consistent with existing practice.

Proposed paragraph (c) continues the requirements of current 30 CFR 1206.158(c), with two substantive changes and one clarification to current 30 CFR 1206.158(c)(1). Current paragraph 1206.158 (c)(1) states that "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." We are removing the second sentence because we do not believe ONRR ever used this provision.

ONRR proposes to eliminate the exception under current 30 CFR 1206.158 (c)(3) allowing a lessee to request ONRR approval of a processing allowance that exceeds 66⅔ percent of the value of the plant products. We also propose to eliminate the provision allowing a lessee to request an extraordinary processing cost allowance under current 30 CFR 1206.158(d)(2). ONRR also proposes to terminate any approvals for the exception under proposed paragraph (c)(3) and the extraordinary cost processing allowance under proposed paragraph (c)(4) as of the effective date of the rule. Thus, we propose not to grandfather previously approved exceptions or extraordinary allowances. ONRR proposes these changes because, as with transportation allowances, ONRR believes the current 66⅔ percent limit on processing-related costs is adequate in the vast majority of situations. To date, we only have approved two extraordinary processing cost allowances. Given the age of the plants and improvements in technology, ONRR believes such extraordinary cost allowances no longer reflect current conditions. Furthermore, ONRR believes the current 66⅔ percent limitation on gas plant products ensures a fair return to the public.

Proposed paragraph (d) explains and clarifies that we continue to disallow deductions for costs necessary to place gas into marketable condition. ONRR proposes to retain the existing requirements of current 30 CFR 1206.158(d)(1) but proposes to recodify them as §1206.159(d)(1), (2), (3), and (4). Also, the proposed rule makes clear that any cost a lessee incurs for stabilizing condensate or recovering gas vapors from condensate or oil is disallowed. The methods industry employs to perform these services are not within the proper definition of "processing" under these regulations and are, in fact, costs incurred to place the condensate or oil into marketable condition. Likewise, we currently analyze whether hydrocarbon dew point controls are actually functions that fall within the definition of "processing" under the regulations before qualifying for a processing allowance against the value of the liquids recovered. In conjunction with these efforts to clarify the costs that qualify as a processing allowance, ONRR proposes to add Joule-Thomson Units (JT Units) used to recover NGLs from gas to the definition of "processing" under proposed §1206.20, regardless of the location of the JT Unit.

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

ONRR proposes this new section, which is essentially the same as current 30 CFR 1206.159(a), with no material modifications, except we add a new paragraph (c) we discuss below. Like transportation allowances, we are moving the requirements for non-arm's-length processing allowances to a separate §1206.161. Because the requirements for determining processing allowances under an arm's-length contract are essentially the same as those for determining transportation allowances under an arm's-length contract, we make the same changes to processing allowances in this section as those we propose for arm's-length transportation allowances. Refer to the preamble discussion of §1206.153 for an explanation of the changes.

We propose a new paragraph (c) that applies if you have no written contract for arm's-length processing of gas. In that case, ONRR will determine your processing allowance under §1206.144. You will have to propose to ONRR a method to determine the allowance using the procedures in §1206.148(a) and may use that method until ONRR issues a determination. This proposed paragraph only applies if there is no contract for arm's-length processing. It does not apply if a lessee performs its own processing. In that case, §1206.161 applies.

ONRR also proposes new §1206.161 through §1206.165 to subpart D to codify and enhance current Federal gas valuation practices.

1206.161 How do I determine a processing allowance if I have a non-arm's-length processing contract?

This section contains the same requirements as current 30 CFR 1206.159(b). Because the requirements for determining processing allowances under a non-arm's-length contract are essentially the same as those for determining transportation allowances under a non-arm's-length contract, we make the same changes to processing allowances in this section as those we propose for non-arm's-length transportation allowances. Refer to the preamble discussion of §1206.154 for an explanation of the changes.

ONRR proposes one material change to the current regulatory requirements. Under proposed paragraph (b)(4), we allow the lessee to continue claiming a rate of return on the reasonable salvage value of a processing plant after it is fully depreciated. For example, if the plant had a salvage value of 5 percent, the lessee could claim a rate of return on 5 percent of the plant value, even though we would allow no further depreciation. See the discussion of reasonable salvage value in proposed §1206.112(i)(1)(iii).

1206.162 What are my reporting requirements under an arm's-length processing contract?

1206.163 What are my reporting requirements under a non-arm's-length processing contract?

1206.164 What interest or penalties apply if I improperly report a processing allowance?

1206.165 What reporting adjustments must I make for processing allowances?

These four proposed sections are the same as the reporting-related requirements in current 30 CFR 1206.159(c), (d), and (e). Also, they are the same changes as those discussed above for transportation allowances under §§1206.155 through 1206.158.

Subpart F—Federal Coal

1206.250 What is the purpose and scope of this subpart?

This proposed section is the same as current 30 CFR 1206.250, but we rewrite the current section in Plain Language and make it consistent with the other product valuation regulations. The substantive requirements remain unchanged.

1206.251 How do I determine royalty quantity and quality?

This proposed section is the same as current 30 CFR 1206.254, 1206.255, and 1206.260, but we rewrite the sections in Plain Language and combine multiple sections into this proposed section. We do not propose any substantive change. However, under proposed paragraph (e), we clarify the calculation you will have to perform to allocate washed coal under current 30 CFR 1206.260 by attributing the washed coal to the leases from which it was extracted. Thus, proposed new paragraph (e) reads as set forth in the regulatory text.

1206.252 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

Current 30 CFR 1206.256 contains valuation standards for Federal coal leases having cents-per-ton royalty rates. The regulation we propose eliminates any reference to the valuation of coal from these leases because there are no longer any Federal cents-per-ton coal leases. Therefore, this proposed §1206.252, and the rest of the proposed regulations, provide lessees with instructions for valuing coal from ad valorem Federal coal leases.

Consistent with the current Federal coal valuation regulations, under the proposed regulations, a lessee generally values Federal coal based on the gross proceeds accruing to the lessee from the first arm's-length sale. However, like the proposed amendments to the Federal gas rule we discuss above, we propose to eliminate the benchmarks for valuation of non-arm's-length sales. We also propose to add the same "default" mechanism under §1206.254 discussed above. Please refer to proposed §§1206.141, 1206.142, and 1206.144 above for an explanation of the proposed changes.

The benchmarks applicable to value coal in non-arm's-length or no-sale situations have proven difficult to use in practice. In addition, the first benchmark does not allow the use of comparable arm's-length sales by the lessee or its affiliates, exacerbating the challenging process of obtaining and comparing relevant arm's-length sales contracts to value non-arm's-length sales. Furthermore, disputes arise over which sales are comparable, particularly because of the inherent ambiguity in applying the comparability factors.

ONRR is soliciting comments on how to simplify and improve the valuation of coal disposed of in non-arm's-length transactions and no-sale situations. We seek input on the merits of eliminating the benchmarks for valuation of non-arm's-length sales and comments on the following questions:

- Should the royalty value of coal initially sold under non-arm's-length conditions be based on the gross proceeds received from the first arm's-length sale of that coal in situations where there is a subsequent arm's-length sale?
- If you are a coal lessee, will adoption of this methodology substantively impact your current calculation and payment of royalties on coal and how?

- What other methodologies might ONRR use to determine the royalty value of coal not sold at arm's length that we may not have considered?

Under proposed paragraph (a), if the lessee sells coal to an affiliate or another person under a non-arm's-length sales contract, and the coal purchaser sells the coal under an arm's-length contract, the lessee must value the coal based on the first arm's-length contract, less applicable allowances, unless ONRR decides to value the coal under §1206.254 (the new "default" provision). Please refer to proposed §1206.141(b) above for an explanation of the proposed change.

A lessee that is part of a corporation with affiliates that produce coal and affiliates that consume the coal in an electrical generation plant may have transactions to transfer coal without a sale. If the affiliate consumes the coal to generate electricity, paragraph (a) of this proposed section would not provide a valuation methodology. Therefore, ONRR proposes paragraph (b) to explain how a lessee must value the coal in this circumstance.

Under proposed paragraph (b)(1), if a lessee or its affiliate sells electricity at arm's length, the royalty value is the sales value of the electricity, less applicable allowances. In proposed paragraph (b)(2), if a lessee or its affiliate did not sell electricity at arm's length, ONRR will determine the royalty value of the coal under the new "default" valuation provision in §1206.254. In this situation, a lessee must propose a valuation method to ONRR and may use that method until we issue a determination on the lessee's proposal.

We also propose a new paragraph (c) to explain how to value coal that a coal cooperative sells. Please refer to §1206.20 for the definition of a coal cooperative. A coal cooperative generally operates as a corporation, with members and owners associated for the purpose of obtaining a long-term, secure source of coal. This proposed rule will treat a coal cooperative and its members/owners as affiliated because they operate without opposing economic interests. Their collective need is to have a source of coal available to generate electric power and to be able to purchase that coal at reasonable prices, and, if possible, below-market prices. The coal cooperative's members are commonly electric power generation companies, or electric utility, generation, or transmission cooperatives. The coal cooperative may operate as a coal lessee, operator, or payor of these and may or may not be organized to make a profit. Coal cooperatives exist to avoid the vagaries and potentially higher prices of the free market.

One mechanism that some members of coal cooperatives use to maintain the lowest possible price for the coal mined and sold to other members is to refrain from making a profit on such transactions among members. A coal cooperative can underprice coal even when sales are arm's length, all other costs being equal. Thus, the proposed regulations include a new paragraph (c) to value coal sold in these circumstances.

Under proposed paragraph (c)(1), for sales of coal between the coal cooperative and coal cooperative members, if the coal is then sold at arm's-length, we require the lessee to value the coal under paragraph (a) of this section, regardless of the number of sales between the coal cooperative members or the coal cooperative and its members. For example, assume a coal cooperative sold its Federal coal to a coal cooperative member, and that coal cooperative member sold its coal to another coal cooperative member who then sold the coal at arm's-length. In that case, under the proposed rule, the coal would be valued under paragraph (a) of this section based on the first arm's-length sale.

Under proposed paragraph (c)(2), for sales of coal between the coal cooperative and coal cooperative members where the coal is consumed in a power generation plant to generate electricity owned by the coal cooperative or a coal cooperative member, we require a lessee to value the coal under proposed paragraph (b) of this section, regardless of the number of sales between coal cooperative members or between the coal cooperative and its members. For example, assume a coal cooperative sold its Federal coal to a coal cooperative member, and that coal cooperative member sold its coal to another coal cooperative member who then consumed the coal in its power generation plant and sold the electricity it generated. In that case, under the proposed rule, the coal would be valued under paragraph (b) of this section based on the sales of the electricity, less any allowable deductions.

ONRR believes all sales between cooperative members are non-arm's-length because they do not have opposing economic interests. However, we treat sales to non-members of the cooperative like any other arm's-length sale under paragraph (a) or paragraph (b) of this section. ONRR seeks comments on this valuation proposal.

Proposed paragraph (d) states that if you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, the sum of the washing and transportation allowances may never reduce the royalty value of the coal to zero. This is the same as current 30 CFR 1206.258(a) and 1206.261(b), but we rewrite these sections in Plain Language. Unlike the Federal oil and gas rules, ONRR is not proposing to limit Federal and Indian coal washing and transportation allowances to 50 percent of the value of the coal. We specifically request comments as to whether we should limit coal allowances to 50 percent of the value of the coal.

1206.253 How will ONRR determine if my royalty payments are correct?

1206.254 How will ONRR determine the value of my coal for royalty purposes?

1206.255 What records must I keep to support my calculations of royalty under this subpart?

1206.256 What are my responsibilities to place production into marketable condition and to market production?

1206.257 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.258 How do I request a valuation determination or guidance?

1206.259 Does ONRR protect information I provide?

ONRR proposes the same changes to §§1206.253 through 1206.259 as those we propose for Federal gas valuation regulations under §§1206.143 through 1206.149. Please refer to those proposed sections for an explanation of changes.

1206.260 What general transportation allowance requirements apply to me?

Proposed §1206.260 retains the provisions in current 30 CFR 1206.261 and makes the Federal coal regulations consistent with the Federal oil and gas regulations in this proposed rule. This section also consolidates provisions applicable to both arm's-length and non-arm's-length transportation in the current regulations, rather than repeating those provisions in the respective sections for those allowances. We also rewrite the current regulations in Plain Language and discuss only substantive changes or additions to this section below.

Proposed paragraph (a)(1) contains the same provision as current 30 CFR 1206.261(a) allowing you to take a deduction for the reasonable, actual costs to transport coal from the lease to a point off the lease or mine determined under §§1206.261 or 1206.262, as applicable. We propose a new provision under paragraph (a)(2) to make clear that you do not need our approval before reporting a transportation allowance for costs that you incur for arm's-length and non-arm's-length transportation. This proposal is consistent with existing practice. Proposed paragraph (b) would contain the remaining current requirements in 30 CFR 1206.261(a) regarding when you may take an allowance.

Proposed paragraph (c) explains when you cannot take an allowance. A new provision in paragraph (c)(1) states that you cannot take an allowance for transporting lease production that is not royalty bearing. This new provision is consistent with the existing and proposed Federal oil and gas regulations. Proposed paragraph (c)(2) contains the current requirement in 30 CFR 1206.261(a)(2) that you cannot take an allowance for in-mine movement of your coal. We also propose a new provision in paragraph (c)(3) that would state you may not deduct transportation costs to move a particular tonnage of production for which you did not incur those costs. This codifies our existing practice of only granting a transportation allowance if you actually move coal and pay for that movement.

Proposed paragraph (d) is the same as current 30 CFR 1206.261(c)(3) and permits you to claim a transportation allowance only when you sell the coal and pay royalties.

We propose to add paragraph (e) to contain and consolidate current requirements in 30 CFR 1206.261(c)(1), 1206.261(c)(2), and 1206.261(e) about allocation of transportations costs. This paragraph requires lessees to report their transportation costs on Form ONRR-4430 as a cost per ton of clean coal transported. We also explain how to calculate the cost per ton of clean coal transported.

In addition, we propose to add paragraph (f) to contain the requirement in current §1206.262(a)(4) that you must express arm's-length coal transportation allowances as a dollar-value equivalent per ton of coal transported. We also make the provision applicable to non-arm's-length transportation allowances, consistent with existing practice. Under the proposed regulations, we further explain that if you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert the consideration you or your affiliate paid to a dollar-value equivalent.

We propose to add paragraph (g), containing the same default provision as that for the Federal oil and gas transportation regulations discussed above under §§1206.110(f) and 1206.152(g), respectively. This proposal includes moving the requirements of current paragraphs 1206.262(a)(2) and 1206.262(a)(3) regarding additional consideration, misconduct, and breach of the duty to market to this new paragraph (g). We also propose to move the requirements for non-arm's-length transportation allowances to a separate §1206.262.

1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

Proposed section 1206.261 explains how lessees must determine transportation allowances under arm's-length transportation contracts. These requirements are in current 30 CFR 1206.262(a)(1). However, we rewrite this section in Plain Language and restructure it for consistency with the Federal gas transportation allowance regulations we discuss above in §1206.153.

We propose to add a new paragraph (c) that would apply if you have no written contract for the arm's-length transportation of coal. In that case, ONRR will determine your transportation allowance under §1206.254. You must propose to ONRR a method to determine the allowance using the procedures in §1206.258(a). You may use that method to determine your allowance until ONRR issues a determination. This paragraph does not apply if a lessee performs its own transportation. Rather, proposed §1206.262, regarding non-arm's-length transportation allowances, applies.

1206.262 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

ONRR proposes to revise §1206.262 to explain how lessees must determine transportation allowances under non-arm's-length transportation contracts using paragraphs (a) through (k) of this section. These requirements are in current 30 CFR 1206.262(b). We rewrite the current requirements in Plain Language and restructure and amend this section for consistency with the Federal gas transportation allowance regulations we discuss above in §1206.154. We also make several substantive changes discussed below.

The current coal rule at 30 CFR 1206.262(b)(3) provides that a lessee may request an exception from having to calculate actual costs for non-arm's-length or no-contract transportation allowances. The lessee may use the exception if there are Federal- or State-approved transportation rates. We propose to eliminate the exception for the following reasons: (1) no lessee has ever applied to use the exception; (2) the Federal Government no longer sets or approves rail transportation rates for coal; and (3) the administrative burden on ONRR to determine approved rates for every State in which coal is produced is too great.

The current coal rule at 30 CFR 1206.262(b)(2)(iv)(A) permits a return on undepreciated capital investment in the transportation system as one of the allowable costs a lessee may include in non-arm's-length or no-contract transportation allowances. However, under the current regulation, the return on investment ends after the capital costs are depreciated to (or below) a reasonable salvage value. In proposed paragraph (b)(4) of this section, we allow a lessee to continue to take a return on the reasonable salvage value under paragraph (i) of this section. Under proposed paragraph (i)(2), after you depreciated a transportation system to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value, multiplied by the Standard & Poor's BBB rate of return allowed under paragraph (k) of this section. We propose this change to make coal valuation regulations consistent with the Federal oil valuation amendments in proposed §1206.112(b)(3)(ii) and the Federal gas valuation amendments in proposed §1206.154(i)(1)(iii) (current Federal gas valuation regulation at §1206.157(g)).

1206.263 What are my reporting requirements under an arm's-length transportation contract?

1206.264 What are my reporting requirements under a non-arm's-length transportation contract?

1206.265 What interest and penalties apply if I improperly report a transportation allowance?

1206.266 What reporting adjustments must I make for transportation allowances?

ONRR proposes the same revisions to §§1206.263 through 1206.265 as those we propose for Federal gas valuation regulations under §§1206.155 through 1206.157, with two exceptions. ONRR also proposes to add §1206.266 to correspond with §1206.158. Please refer to those sections for an explanation of the proposed changes.

The first exception is that these sections keep the same reporting requirements as current 30 CFR 1206.262(c), 1206.262(d), and 1206.262(e). In addition, proposed §1206.265 (b)(1) replaces current 30 CFR 1206.262(d)(1) regarding assessments if you improperly net a transportation allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430. Under this proposed regulation, ONRR eliminates assessments because ONRR is now authorized to assess civil penalties for solid mineral leases under FOGRMA, 30 U.S.C. 1719 and 30 U.S.C. 1720a. Penalties are a more effective enforcement mechanism to ensure lessee compliance with reporting requirements because ONRR can assess civil penalties that are significantly higher than the maximum assessment the current regulation authorizes.

1206.267 What general washing allowance requirements apply to me?

ONRR proposes to add this section to contain the requirements of current 30 CFR 1206.258. This proposal makes the Federal coal valuation regulations consistent with Federal oil and gas valuations regulations, and consolidates provisions applicable to both arm's-length and non-arm's-length washing in the current valuation regulations, rather than repeating those provisions in the respective sections explaining those allowances. We also rewrite the current valuation regulations in Plain Language. We only discuss any substantive changes or additions to this section below.

Proposed paragraph (a) contains the same information as current 30 CFR 1206.258(a) allowing you to deduct the reasonable, actual costs to wash coal if you determine the value of your coal under proposed §1206.252. We also propose a new provision under paragraph (a)(2) to make clear you do not need ONRR's approval before reporting a washing allowance for costs that you incur consistent with existing practice.

Proposed paragraph (b) states what you cannot claim when you take a washing allowance. Paragraph (b)(1) of this section states that you cannot take an allowance for washing lease production that is not royalty-bearing. This new provision is consistent with the current and proposed Federal oil and gas valuation regulations and existing practices for coal valuation. Paragraph (b)(2) contains the current prohibition in 30 CFR 1206.258(c) that you cannot disproportionately allocate washing costs to Federal leases. New paragraph (b)(2) contains the allocation of washing allowance requirements under current 30 CFR 1206.260. However, new paragraph (b)(2) clarifies how to allocate washing costs by stating that you must allocate washing costs to washed coal attributable to each Federal lease by multiplying the input ratio, which you determine under proposed §1206.251(e)(2)(i), by the total allowable costs.

Proposed paragraph (c) contains the requirement of current 30 CFR 1206.259(a)(4) that you must express arm's-length coal washing allowances as a dollar-value equivalent per ton of coal washed. We also apply that provision to non-arm's-length washing allowances and make the section consistent with existing practices. In addition, under this proposed paragraph, we state that, if you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you have to convert the consideration you or your affiliate pay to a dollar-value equivalent.

We propose to add a new paragraph (d) containing the same default provision as that for the Federal oil, gas, and coal transportation regulations we discuss above under proposed §§1206.110(f), 1206.152(g), and §1206.260(g), respectively.

Proposed new paragraph (e) would contain the same provision as current 30 CFR 1206.258(e) that you may only claim a washing allowance when you sell the washed coal and report and pay royalties.

1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

ONRR proposes to add this section to contain the requirements under current 30 CFR 1206.259(a)(1), but we rewrite this section in Plain Language and restructure this section for consistency with the proposed Federal gas transportation allowance regulations we discussed above in §1206.153. This proposal includes moving the requirements of current §§1206.259(a)(2) and 1206.259(a)(3) regarding additional consideration, misconduct, and breach of the duty to market to the proposed §1206.267(d) we discussed above. We would move the requirements for non-arm's-length washing allowances to §1206.269.

We propose to add a new paragraph (c) that applies if you have no written contract for the arm's-length washing of coal. In that case, ONRR may determine your washing allowance under §1206.254. You must propose to ONRR a method to determine the allowance using the procedures in §1206.258(a). You may use that method to determine your allowance until ONRR issues a determination. This paragraph would not apply if a lessee performs its own washing. Rather, §1206.269 regarding non-arm's-length washing allowances applies.

1206.269 How do I determine washing allowances if I have a non-arm's-length washing contract?

ONRR proposes to add new §1206.269 to explain how lessees must determine a washing allowance under a non-arm's-length transportation contract using paragraphs (a) through (k) of this section. These requirements are in current 30 CFR 1206.259(b). We rewrite the current requirements in Plain Language and restructure, add, and amend this section for consistency with the Federal gas and coal transportation allowance regulations proposed above in §§1206.154 and 1206.262. We also propose to make several substantive changes we discuss below.

The current coal rule at 30 CFR 1206.259(b)(2)(iv)(A) permits a return on undepreciated capital investment in the wash plant as one of the allowable costs a lessee may include in non-arm's-length or no-contract transportation allowances. However, under the current regulation, the return on investment ends after the capital costs are depreciated to (or below) a reasonable salvage value. In proposed paragraph (b)(4) of this section, we allow lessees to continue to take a return on the reasonable salvage value under paragraph (i) of this section. Under proposed paragraph (i)(2), after you depreciated a wash plant to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by the Standard & Poor's BBB rate of return allowed under paragraph (k) of this section. We propose this change in order to make coal valuation regulations consistent with the Federal oil valuation amendments in proposed §1206.112(b)(3)(ii) the Federal gas valuation amendments in proposed §1206.154(i)(1)(iii) (current Federal gas valuation regulation at 30 CFR 1206.157(g)), and the Federal coal valuation regulation amendments proposed in §1206.262 (b)(4) and in paragraph (i)(2) of this section.

1206.270 What are my reporting requirements under an arm's-length washing contract?

1206.271 What are my reporting requirements under a non-arm's-length washing contract?

1206.272 What interest and penalties apply if I improperly report a washing allowance?

1206.273 What reporting adjustments must I make for washing allowances?

ONRR proposes to add §§1206.270 through 1206.273, which are the same as we propose for Federal gas valuation regulations under §§1206.155 through 1206.158, with two exceptions. These two exceptions are the same as we propose in §§1206.263 through 1206.266. Please refer to those sections for an explanation of the proposed changes.

Subpart J—Indian Coal

1206.450 What is the purpose and scope of this subpart?

This section would be the same as current 30 CFR 1206.450. We rewrite the current section in Plain Language and make this section consistent with the other product valuation regulations. As we explained above in §1206.20, we replace the term "Indian allottee" with "individual Indian mineral owner." However, the substantive requirements remain unchanged.

1206.451 How do I determine royalty quantity and quality?

This proposed section is the same as current 30 CFR 1206.453, 1206.454, and 1206.459, except that we rewrite the sections in Plain Language and combine multiple current sections into this proposed section. We are not proposing any substantive change.

1206.452 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

1206.453 How will ONRR determine if my royalty payments are correct?

1206.454 How will ONRR determine the value of my coal for royalty purposes?

1206.455 What records must I keep to support my calculations of royalty under this subpart?

1206.456 What are my responsibilities to place production into marketable condition and to market production?

1206.457 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.458 How do I request a valuation determination or guidance?

1206.459 Does ONRR protect information I provide?

ONRR proposes the same changes to §§1206.452 through 1206.459 as those we proposed for Federal coal valuation regulations under §§1206.252 through 1206.259. Please refer to those proposed sections for an explanation of the changes.

1206.460 What general transportation allowance requirements apply to me?

We propose the same changes to this section as those we propose for Federal coal under §1206.260, with two exceptions. Please refer to that section for an explanation of the proposed changes.

For Indian coal under current 30 CFR 1206.461(a)(1), a lessee must submit Form ONRR-4293, Coal Transportation Allowance Report, prior to taking an allowance. This provision is not in either the current or proposed Federal coal valuation regulations. However, ONRR proposes to retain this requirement for coal produced from Indian leases as part of our trust responsibility. This form submittal ensures that we continue the oversight and controls necessary on Indian leases.

The current Indian coal regulation at 30 CFR 1206.461(a)(1) also provide that a lessee who does not timely file Form ONRR-4293 may claim a transportation allowance retroactively for a period of not more than 3 months prior to the first day of the month that ONRR receives the lessee's Form ONRR-4293 "unless ONRR approves a longer period upon a showing of good cause by the lessee." We propose to remove the good cause exception. We have found this exception is difficult to administer and is not applicable. See *Alexander Energy Corp*., 153 IBLA 238 (2000), *Union Oil Company of California,* 167 IBLA 263 (2005).

In addition, current 30 CFR 1206.461(c)(1)(vi) provides that ONRR will allow non-arm's-length contract or no written arm's-length contract-based transportation allowances in effect at the time these regulations become effective, to continue until such allowances terminate. ONRR eliminated this provision for Federal coal leases in its 1996 Federal coal amendments but left this intact for Indian leases (61 FR 5481 (1996)). To be consistent, we propose to remove this provision. ONRR also eliminated this provision for Federal gas leases (70 FR 11869). Therefore, we propose to add a new paragraph (a)(3) stating "You may not use a transportation allowance that was in effect before the effective date of the final rule. You must use the provisions of this subpart to determine your transportation allowance."

1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

ONRR proposes the same changes to this section as we propose for Federal coal under §1206.261. Please refer to that section for an explanation of the proposed changes.

1206.462 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

We propose the same changes to this section as we propose for Federal coal under §1206.262, with one exception discussed below. Please refer to §1206.262 for an explanation of the proposed changes.

For Federal coal under proposed §1206.262, we allow a lessee to take a return on the reasonable salvage value of a transportation system. We are not proposing to make this change to Indian coal because we believe it would reduce the return to the Indian lessor while not providing a benefit to them. It would therefore not be in the best interest of the Indian lessor and be inconsistent with our trust responsibility.

1206.463 What are my reporting requirements under an arm's-length transportation contract?

We propose to make the same changes to this section as we propose for Federal coal under §1206.263 with one exception. Please refer to §1206.263 for an explanation of the proposed changes. We also propose substantive changes to current 30 CFR 1206. 461(c) regarding reporting arm's-length transportation allowances.

Unlike the Federal coal regulation, this proposed Indian coal regulation would retain the requirement for a lessee to submit Form ONRR-4293 prior to taking a transportation allowance. These same provisions are in current 30 CFR 1206.458(c). Form submittal is not a requirement for Federal leases, but the form submittal ensures we continue the oversight and controls necessary on Indian leases.

In addition to the changes we make to the reporting requirements under this section, consistent with the Federal coal valuation regulations, we propose to eliminate three provisions in the current Indian coal regulations. First, under the current 30 CFR 1206.461(c)(1)(iii), a lessee may request special reporting procedures in unique circumstances. ONRR eliminated this provision for Federal coal leases in its 1996 Federal coal amendments but left it intact for Indian leases. We do not believe any lessee has ever used this provision. Therefore, we propose to remove this provision.

Second, the current coal regulation under 30 CFR 1206.461(c)(1)(vi) states ONRR may establish coal transportation allowance reporting requirements for individual leases different from those specified in this subpart to provide more effective administration. ONRR eliminated this provision for Federal coal leases in its 1996 Federal coal amendments but left it intact for Indian leases. We do not believe ONRR has ever used this provision. Therefore, we propose to remove this provision.

Finally, current 30 CFR 1206.461(c)(1)(vi) provides that ONRR will allow non-arm's-length contract or no arm's-length contract-based transportation allowances that are in effect at the time these regulations become effective to continue until such allowances terminate. We propose to eliminate this provision and to replace it with a new §1206.460(a)(3) we discuss above.

1206.464 What are my reporting requirements under a non-arm's-length transportation contract?

We propose to make the same amendments to this section as those we propose for section §§1206.264 and 1206.463. Please refer to those proposed sections for an explanation of changes.

1206.465 What interest and penalties apply if I improperly report a transportation allowance?

We propose to make the same amendments to this section as those we propose for §1206.265. Proposed paragraph (b) of this section prohibits the netting of transportation costs from gross proceeds received for a particular sale. When eligible to take a transportation allowance, a lessee must report gross proceeds without a deduction for transportation costs, and may simultaneously claim a transportation allowance for the cost of transporting the royalty fraction of Indian coal sold. Current Indian coal valuation regulations do not contain this provision. ONRR considers the change to be an enhancement to the Indian coal regulations that is already in the current Federal coal valuation regulations at 30 CFR 1206.262(d).

1206.466 What reporting adjustments must I make for transportation allowances?

We propose the same amendments to this section we propose for §1206.266. Please refer to the proposed section for an explanation of the changes.

1206.467 What general washing allowance requirements apply to me?

We propose the same amendments to this section we propose for §§1206.267 and 1206.460. However, we propose to maintain the current requirement that a lessee must submit Form ONRR-4292, Coal Washing Allowance Report, prior to taking a washing allowance. Please refer to §§1206.267 and 1206.460 for an explanation of the changes.

1206.468 How do I determine a washing allowance if I have an arm's-length washing contract or no written arm's length contract?

We propose to make the same amendments to this section we propose for §§1206.268 and 1206.461. Please refer to §§1206.268 and 1206.461 for an explanation of the changes.

1206.469 How do I determine a washing allowance if I have a non-arm's-length washing contract?

We propose to make the same amendments to this section we propose for §§1206.269 and 1206.462, with one exception we discuss below. Please refer to §§1206.269 and 1206.462 for an explanation of the changes.

For Federal coal under proposed §1206.269, we propose to allow a lessee to continually take a return on the reasonable salvage value of a wash plant. We do not propose to make this change to Indian coal because we believe it would reduce the return to the Indian lessor while not providing a benefit to them. It would therefore not be in the best interest of the Indian lessor and be inconsistent with our trust responsibility.

1206.470 What are my reporting requirements under an arm's-length washing contract?

We propose to make the same amendments to this section we propose for §§1206.270 and 1206.463. Please refer to §§1206.270 and 1206.463 for an explanation of the changes.

1206.471 What are my reporting requirements under a non-arm's-length washing contract?

We propose to make the same amendments to this section we propose for §§1206.271 and 1206.464. Please refer to §§1206.271 and 1206.464 for an explanation of changes.

1206.472 What interest and penalties apply if I improperly report a washing allowance?

We propose to make the same amendments to this section we propose for §§1206.272 and 1206.465. Please refer to §§1206.272 and 1206.465 for an explanation of changes.

1206.473 What reporting adjustments must I make for washing allowances?

We propose to make the same amendments to this section we propose for §§1206.273 and 1206.466. Please refer to §§1206.273 and 1206.466 for an explanation of changes.

III. Procedural Matters

1. Summary Cost and Royalty Impact Data

We have summarized estimated costs and benefits the proposed rule may have on potentially affected groups: Industry, the Federal Government, Indian lessors, and State and local governments. All of the proposed amendments that have cost impacts would result in increased royalty collections. The sum of the proposed amendments that have cost benefits are due to administrative cost savings to industry, not a decrease in royalties due. The net impact of the proposed amendments is an estimated annual increase in royalty collections of between $72.9 million and $87.3 million. This net impact represents a slight increase of between 0.8 percent and 1.0 percent of the total Federal oil, gas, and coal royalties ONRR collected in 2010. We also estimate that industry would experience reduced annual administrative costs of $3.61 million.

Please note that, unless otherwise indicated, numbers in the following tables are rounded to three significant digits.

A. Industry

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

Summary of Royalty Impacts to Industry			
Rule Provision	Low	Mid	High
Gas -replace benchmarks			
Affiliate Resale	$0	$2,010,000	$4,030,000
Index	$11,300,000	$11,300,000	$11,300,000
NGLs - replace benchmarks			
Affiliate Resale	$0	$256,000	$510,000
Index	$1,200,000	$1,200,000	$1,200,000
Gas transportation limited to 50%	$4,170,000	$4,170,000	$4,170,000

Processing allowance limited to 66⅔%	$5,440,000	$5,440,000	$5,440,000
POP contracts limited to 66⅔ % processing allowance	$0	$0	$0
Extraordinary processing allowance	$18,500,000	$18,500,000	$18,500,000
BBB bond rate change for gas transportation	$1,640,000	$1,640,000	$1,640,000
Eliminate deepwater gathering	$17,400,000	$20,500,000	$23,600,000
Oil Transportation limited to 50%	$6,430,000	$6,430,000	$6,430,000
Oil and gas line losses	$4,570,000	$4,570,000	$4,570,000
Oil line fill	$978,000	$1,710,000	$2,450,000
BBB bond rate change for oil transportation	$2,380,000	$2,380,000	$2,380,000
Coal - non-arm's length netback & coop sales	($1,060,000)	$0	$1,060,000
Total	$72,900,000	$80,100,000	$87,300,000

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

ONRR identified two proposed rule changes that would benefit industry by reducing their administrative costs. The benefits industry would realize for each of these components are as follows:

Rule Provision	Benefit
Replace benchmarks - Gas & NGLs	$247,000
Eliminate deepwater gathering	$3,360,000
Total	$3,610,000

The table below lists the overall economic impact to industry from the proposed changes, based on the mid-range estimate of costs:

Description	Annual (Cost)/Benefit Amount
Cost - All Rule Provisions	($80,100,000)
Benefit - Administrative Savings	$3,610,000
Net Cost or Benefit to Industry	($76,500,000)

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

As discussed above, we propose replacing the current benchmarks in 30 CFR 1206.152(c) (unprocessed gas) and 1206.152(c) (processed gas) with a methodology that uses the gross proceeds under the lessee's affiliate's first arm's-length sale to value gas for royalty purposes. The lessee also would have the option to elect to pay royalties based on a value using the monthly high index price, less a standard deduction for transportation.

To perform this economic analysis, ONRR first extracted royalty data that we collected on residue gas, unprocessed gas, and coalbed methane (product codes 03, 04, 39, respectively) for calendar year 2010. We chose calendar year 2010 because the Royalty-in-Kind (RIK) volumes were minimal due to the 2010 termination of the RIK program. In previous years, RIK volumes were substantial. Data from RIK production is not representative of industry sales, so we excluded any remaining RIK volumes from our analysis. We excluded calendar year 2011 because lessees are still adjusting reports for that year and the data reported is still going through ONRR's edits.

We then extracted gas royalty data for non-arm's-length transactions reported with a sales type code of NARM. We also extracted gas royalty data for sales type code POOL, because royalty reporters may also use this code to report non-arm's-length transactions. Based on ONRR's experience auditing transactions that use sales type code POOL, we know that only a relatively small portion of them are non-arm's length. Therefore, we used only 10 percent of the POOL volumes in our economic analysis of the volumes of gas sold non-arm's length.

Based on ONRR's experience auditing production sold under non-arm's-length contracts, we believe industry would incur a royalty increase in the range of 0 to 5 cents per MMBtu under our proposal to use the affiliate's first arm's-length resale to value gas production for royalty purposes. ONRR created a range of potential royalty increases by assuming no royalty increase for the low estimate, 2.5 cents per MMBtu for the mid-range estimate, and 5 cents per MMBtu for the high estimate. We then multiplied the NARM volume and 10 percent of the POOL volume reported to ONRR in 2010 by the potential royalty increases.

The results provided below are an estimated cost to industry due to an annual royalty increase of between zero and approximately $8 million. We reduced this estimate by one-half to $4.03 million, assuming 50 percent of the non-arm's-length lessees would choose this option.

		Royalty Increase ($)		
	2010 MMBtu (non-rounded)	**Low (0 cents)**	**Mid (2.5 cents)**	**High (5 cents)**
NAL Volume	149,348,561	$0	$3,730,000	$7,470,000
10 % of POOL Volume	11,606,523	$0	$290,000	$580,000
Total	160,955,084	$0	$4,020,000	$8,050,000
50% of lessees choose this option		**$0**	**$2,010,000**	**$4,030,000**

Cost—Using Index Price Option to Value Non-Arm's-Length Sales of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

To estimate the royalty impact of 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 six major geographic areas with active index prices—the Green River Basin, San Juan Basin, Piceance and Uinta Basins, Powder River and Wind River Basins, Permian Basin, and Offshore Gulf of Mexico (GOM). These six areas account for approximately 95 percent of all Federal gas produced. To calculate the estimated impact, we performed the following steps:

(1) 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.

(2) Subtracted the transportation deduction we specified in the proposed rule from the highest index price that we identified in step (1).

(3) Subtracted the average monthly net royalty price reported to us for unprocessed gas from the highest index price for the same month we calculated in step (2).

(4) Multiplied the royalty volume by the monthly difference that we calculated in step (3) to calculate a monthly royalty difference for each region.

(5) Totaled the difference we calculated in step (4) for the regions.

Although the index-based methodology resulted in an annual increase in royalties due, the current average royalty prices reported to us were higher than the index-based option for 3 months in 2010.

ONRR estimates the cost to industry due to this change would be an increase in royalty collections of approximately $11.3 million annually. This estimate represents a small average increase of approximately 3.6 percent or 14 cents per MMBtu, based on an annual royalty volume of 160,955,084 MMBtu (for NARM and 10 percent POOL reported sales type codes). Because this is the first time we have offered this option, we don't know how many payors will choose it. For purposes of this analysis, we are assuming that 50 percent of lessees with non-arm's-length sales would choose this option and, therefore, have reduced this estimate by one-half. We would like to know from commenters if this 50-percent assumption is reasonable.

2010 Index Analysis	**GOM Gas**	**Other Gas**	**Total**
Current Royalties (rounded to the nearest dollar)	$ 167,291,148	$ 435,222,354	$602,513,502
Royalty under Index Option	$ 180,000,000	$ 445,000,000	$625,000,000
Difference	$ 12,700,000	$ 9,780,000	$22,500,000
Per Unit Uplift ($/MMBtu)	$0.297	$0.083	$0.140
% change	7.06%	2.20%	3.60%
50% of lessees choose this option			**$11,300,000**

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal NGLs

Like the valuation changes we discussed above, for Federal unprocessed, residue, and coalbed methane gas valuation changes, the proposed rule would value processed Federal NGLs based on the first arm's-length sale rather than the current benchmarks. The lessee would also have the option to pay royalties using an index price value derived from an NGL commercial price bulletin less a theoretical processing allowance that includes transportation and fractionation of the NGLs. We again used the 2010 NARM and POOL NGL data 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 above. 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 increase. Based on our experience, we believe that the NGLs resale margin is, similar to gas, relatively small, ranging from zero to 3 cents per gallon. Thus, our estimated royalty increase is zero for the low, 1.5 cents per gallon for the mid-range, and 3 cents per gallon for the high range. The results provided below show a mid-range royalty increase of $256,000 using these assumptions, and, again, we reduced them by one-half under the assumption that 50 percent of the lessees would choose this option. Again, we would ask for comments on the reasonableness of this 50-percent assumption.

	2010 gallons (rounded to the nearest gallon)	**Royalty Increase ($)**		
		Low (0 cents)	**Mid (1.5 cents)**	**High (3 cents)**
NAL Volume	6,170,341	$0	$92,600	$185,000
10 % of POOL Volume	27,913,486	$0	$419,000	$837,000
Total	34,083,827	$0	$512,000	$1,020,000
50% of lessees choose this option		**$0**	**$256,000**	**$510,000**

Cost—Using Index Price Option to Value Non-Arm's-Length Sales of Federal NGLs

Like the Federal unprocessed, residue, and coalbed methane gas changes we discuss above, lessees also would have the option to pay royalties on Federal NGLs using an index-based value less a theoretical processing allowance that includes transportation and fractionation. We used the same 2010 NARM and POOL transaction data for NGLs for this analysis. We were unable to compare NGLs prices reported on the Form ONRR-2014 to those in commercial price bulletins because prices lessees report on the Form ONRR-2014 are one rolled-up price for all NGLs, but the bulletins price each NGLs product (such as ethane and propane) separately. Therefore, we base our analysis on the royalty changes that would result from the theoretical processing allowance proscribed under this new option.

We chose a conservative number as a proxy for the processing allowance deduction that we would allow for this index option. To determine the cost of this option for NGLs, we calculated the difference between the average processing allowance reported on the Form ONRR-2014 and the proxy allowance we would allow under this option. That difference equaled an increase in value of approximately 7 cents per gallon. We then multiplied the total NAL volume of 34,083,827 gallons reported to us by the 7 cents per gallon, for an estimated royalty increase of $2.4 million. We reduced this number by one-half under the assumption that 50 percent of lessees would choose this option, resulting in a total cost to industry of $1.2 million. Again, we would ask for comments on the reasonableness of this 50-percent assumption.

Benefit—Using Index Price Option to Value Non-Arm's-Length Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs

ONRR expects that industry would benefit by realizing administrative savings if they choose to use the index-based option to value non-arm's-length sales of Federal unprocessed gas, residue gas, coalbed methane, and NGLs. Lessees would know the price to use to value their production, saving the time it currently takes to calculate the correct price based on the current benchmarks. They would also save time using the ONRR-specified transportation rate for gas and the ONRR-specified processing allowance for NGLs, rather than having to calculate those values themselves.

Of the lessees that we estimate would use this option, we estimate the index-based option would shorten the time burden per line reported by 50 percent to 1.5 minutes for lines industry electronically submits and 3.5 minutes for lines they manually submit. We used tables from the Bureau of Labor Statistics (*www.bls.gov/oes132011.htm*) 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 would be approximately \$50.53 per hour = \$36.09 [mean hourly wage] x 1.4 [benefits cost factor]. Using a labor cost factor of \$50.53 per hour, we estimate the annual administrative benefit to industry would be approximately \$247,000.

	Time Burden per line reported	Estimated lines reported using index option (50%)	Annual Burden Hours
Electronic Reporting (99%)	1.5 min	190,872	4,772
Manual Reporting (1%)	3.5 min	1,928	112
Industry Labor Cost / hour			\$50.53
Total Benefit to Industry			**\$247,000**

Cost—Elimination of Transportation Allowances in Excess of 50 Percent of the Value of Federal Gas

The current Federal gas valuation regulations limit lessees' transportation allowances to 50 percent of the value of the gas unless they request and receive approval to exceed that limit. The proposed rule would eliminate the lessees' ability to exceed that limit. To estimate the costs associated with this change, we first identified all calendar year 2010 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 cost to industry of \$4.17 million in additional royalties.

Cost—Elimination of Transportation Allowances in Excess of 50 Percent of the Value of Federal Oil

The current Federal oil valuation regulations limit lessees' transportation allowances to 50 percent of the value of the oil unless they request and receive approval to exceed that limit. The proposed rule would eliminate the lessees' ability to exceed that limit. To estimate the costs associated with this change, we first identified all calendar year 2010 reported oil transportation allowance 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 cost to industry of $6.43 million in additional royalties.

Cost—Elimination of Processing Allowances in Excess of 66⅔ Percent of the Value of the NGLs for Federal Gas

The current Federal gas valuation regulations limit lessees' processing allowances to 66⅔ percent of the value of the NGLs unless they request and receive approval to exceed that limit. The proposed rule would eliminate the lessees' ability to exceed that limit. To estimate the cost to industry associated with this change, we first identified all calendar year 2010 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 cost to industry of $5.44 million in additional royalties.

Cost—POP Contracts now Subject to the 66⅔ Percent Processing Allowance Limit for Federal Gas

Lessees with POP contracts currently pay royalties based on their gross proceeds as long as they pay a minimum value equal to 100 percent of the residue gas. Under the proposed rule, we also would not allow lessees with POP contracts to deduct more than the 66⅔ percent of the value of the NGLs. 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 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. Under the proposed rule, the combined value of each product the lessee gives up to the processing plant cannot exceed two-thirds of the NGLs' value.

Lessees report POP contracts to ONRR using sales type code APOP for arm's-length POP contracts and NPOP for non-arm's-length POP contracts. Because lessees report APOP 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 NPOPs. However, NPOP volumes constitute only 0.02 percent of all the natural gas royalty volumes reported to ONRR. We deemed the NPOP volume to be too low to adequately assess the impact of this provision on both APOP and NPOP contracts.

Therefore, we decided to examine all reported calendar year 2010 onshore residue gas and NGLs royalty data and assumed 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 NGLs 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 2010 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 POP contracts. We calculated 30 percent of both the value of residue gas and 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 proposed rule). The table below summarizes these calculations which we rounded to the nearest dollar:

	2010 Royalty Value	70%	30%
Residue Gas	$602,194,031	$421,535,822	$180,658,209
NGLs	$506,818,440	$354,772,908	$152,045,532
Total	$1,109,012,471	$776,308,730	$332,703,741
66.67% Limit	$337,878,960	($506,818,440 x 2/3)	

Our analysis shows that the theoretical processing deduction for 30 percent of the value of residue gas and NGLs ($333 million) under our assumed onshore POP contract allowance would not exceed the 66⅔ cap ($338 million) under the proposed rule and, thus, we estimate that this change would be revenue neutral.

Cost—Termination of Policy Allowing Transportation Allowances for Deepwater Gathering Systems for Federal Oil and Gas

The Deep Water Policy we discuss above 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. The proposed rule would rescind and supersede the Deep Water Policy, and lessees would have to pay royalties under our proposed valuation regulations applicable to Federal oil and gas transportation allowances prospectively. To analyze the cost impact to industry of rescinding this policy, we used data from BSEE's Arc GIS TIMS (Technical Information Management System) database to estimate that 113 subsea pipeline segments serving 108 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. We also considered only pipeline segments that were in active status and leases in producing status for our analysis. To determine a range (shown in the tables below as low, mid, and high estimates) for the cost to 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 is available for 13 subsea gathering segments serving 15 leases covering time periods from 1999 through 2010. We used this data to determine an average initial 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 when 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 12 percent is a reasonable increase for overhead. We then decreased the total annual O&M cost per pipeline segment by 9 percent because an average of 9 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 GOM. Based on these calculations, the average annual allowance per pipeline segment is approximately $226,000. This represents the estimated amount per pipeline segment ONRR will no longer allow a lessee 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 $226,000 annual allowance per pipeline segment that we would disallow under this proposed rulemaking times the number of eligible segments. To calculate a range for the total cost, 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 disallow are $21.8 million, $25.6 million, and $29.5 million, respectively.

Of currently eligible leases, 42 out of 108, or about 40 percent, qualify for deep water royalty relief. However, due to varying lease terms, royalty relief programs, price thresholds, volume thresholds, and other factors, ONRR estimated that only half of the 42 leases eligible for royalty relief (20 percent) actually received royalty relief. Therefore, we decreased the low, mid, and high estimated annual cost 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 would no longer allow under this proposed rule.

	Low	Mid	High
Estimated Royalty Impact	$17,400,000	$20,500,000	$23,600,000

Benefit—Termination of Policy Allowing Transportation Allowances for Deepwater Gathering Systems for Offshore Federal Oil and Gas

ONRR estimates the elimination of transportation allowances for deepwater gathering systems would provide industry with an administrative benefit because they would no longer have to perform this calculation. We believe the cost to perform this calculation is significant because industry has often hired outside consultants to calculate their subsea transportation allowances. Using this information, we estimated each company with leases eligible for transportation allowances for deepwater gathering systems would allocate one full-time FTE annually to perform this calculation, if 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 [$36.09 mean hourly wage] with a multiplier of 1.4 for industry benefits to equal approximately $50.53 per hour [$36.09 x 1.4]. Using this labor cost per hour, we estimate the annual administrative benefit to industry would be approximately $3,360,000.

	Annual Burden Hours per Company	Industry Labor Cost / hour	Companies reporting eligible leases	**Estimated Benefit to Industry**
Deepwater Gathering	2,080	$50.53	32	**$3,360,000**

Cost—Elimination of Extraordinary Cost Gas Processing Allowances for Federal Gas

As we discuss above, we are proposing to eliminate the provision in our current regulations that allow a lessee to request an extraordinary processing cost allowance and to terminate any extraordinary cost processing allowances 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 lessees deducted from the value of residue gas produced from the leases. We then calculated the annual total processing allowance lessees have claimed for 2007 through 2010 for the leases at issue. We then averaged the yearly totals for those 4 years to estimate an annual cost to industry of $18.5 million in increased royalties.

Cost—Decrease Rate of Return Used to Calculate Non-Arm's Length Transportation Allowances from 1.3 to 1 Times the Standard and Poor's BBB Bond for Federal Oil and Gas

For Federal oil transportation, ONRR does not maintain or request data identifying if transportation allowances are arm's length or non-arm's length. However, based on our experience, we believe that a large portion of GOM oil is transported through lessee-owned 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 10 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. These are the same assumptions we made when analyzing changes to both the Federal oil and Federal gas valuation rules in 2004.

In 2010, the total oil transportation allowances Federal lessees deducted were approximately \$60 million from the GOM and \$11 million from everywhere else. Based on these totals and our assumptions about the allowance components, the portion of the non-arm's-length allowances attributable to the rate of return would be approximately \$10,000,000 for the GOM (\$60,000,000 x ⅓ x 50%) and \$367,000 (\$11,000,000 x ⅓ x 10%) for the rest of the country. Therefore, we estimate that decreasing the basis for the rate of return by 23 percent could result in decreased yearly oil transportation allowance deductions of approximately \$2,380,000 (\$10,367,000 x 0.23). Thus, we estimate the net cost to industry as a result of this change would be an approximately \$2,380,000 increase in royalties due.

With respect to Federal gas, like oil, ONRR does not maintain or request information on whether gas transportation allowances are arm's length or non-arm's length. However, unlike oil, we believe that 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 we made for oil above.

In 2010, the total gas transportation allowances Federal lessees deducted were approximately $214 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 would be approximately $7.13 million ($214,000,000 x 1/3 x 10%). Therefore, we estimate that decreasing the basis for the rate of return by 23 percent could result in decreased yearly gas transportation allowance deductions of approximately $1.64 million ($7.13 million x 0.23). That is, the net increased cost to industry, based on this change, would be approximately $1,640,000 in additional royalties.

Cost—Allow a Rate of Return on Reasonable Salvage Value for Federal Oil, Gas, and Coal

For Federal oil and gas, after a transportation system or a processing plant has been depreciated to its reasonable salvage value, we propose to allow a lessee a return on that reasonable salvage value of the transportation system or processing plant as long as the lessee uses that system or plant for its Federal oil or gas production. We estimate the economic impact on industry would be small because we would continue the requirements of the current regulations that a lessee must base depreciation of a system or plant upon the useful life of the equipment or the expected life of the reserves served by the system or plant. Thus, when properly established, the depreciation schedule should reflect the useful life of the system or plant, and ONRR would not expect a lessee to continue to use a system or plant for periods significantly longer than the period reflected by the depreciation schedule the lessee established for royalty purposes. This assumption is true especially if the lessee did not make additional capital expenditures that extended the life of the system or plant. In that case, the lessee should have extended the depreciation schedule to reflect the extended life of the system or plant, and, possibly, the salvage value, itself. In other words, we believe the vast majority of systems would not be depreciated to salvage value while royalty is being paid because the system still has a useful life while production occurs. Thus, we do not believe there would be any costs to industry associated with this change.

With respect to Federal coal, we believe that the royalty impact for coal would be equally small for the same reasons we mention above.

Cost—Disallow Line Loss as a Component of Arm's-Length and Non-Arm's-Length Oil and Gas Transportation

ONRR also proposes to eliminate the current regulatory provision allowing a lessee to deduct 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 also equates 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 2010, the total value of the Federal royalty volume subject to transportation allowances was $3,796,827,823 in the GOM and $1,204,177,633 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 would be $4.04 million, as we detailed in the table below. Therefore, the annual cost to industry would be approximately $4.04 million in additional royalties.

Oil Line Loss Royalty Impact		Line Loss	Royalty Increase
50% of GOM royalty value	$1,898,413,912	0.2%	$3,800,000
10% of everywhere else royalty value	$120,417,763	0.2%	$241,000
		Total	$4,040,000

For Federal gas produced in calendar year 2010, the royalty value of the Federal gas royalty volume subject to transportation allowances was $2,656,843,158. Using our previous assumption that 10 percent of Federal gas transportation allowances are non-arm's length, we estimated the value of the line loss would be $530,000. Therefore, the annual cost to industry would be approximately $530,000 in increased royalties.

Gas Line Loss Royalty Impact		Line Loss	Royalty Increase
10% of royalty value	$265,684,316	0.2%	$531,000

The total estimated royalty increase for both oil and gas due to this change would be $4.57 million [$4,040,000 (oil) plus $531,000 (gas) = $4,570,000].

Cost—Disallow Line Fill as a Component of Non-Arm's-Length Oil Transportation Allowances

We estimated that oil line fill costs ranged from a low $0.02 to a high of $0.05 per barrel, with a mid-range of $0.035. These are the same estimates we made in our 2004 oil valuation rule when we made a change to allow this component as a cost of oil transportation, and we believe these cost estimates are still valid. We restricted our analysis to only oil production from the GOM because we believe that including line fill as a component of transportation allowances is uncommon everywhere else. We then applied these estimates to the total 2010 GOM Federal oil royalty volume of 48,910,000 barrels to estimate the range of reduced transportation costs included in allowance calculations, as we detail in the table below.

Line Fill Royalty Impact Estimate			
	Low	Mid	High
2010 Federal GOM Royalty Oil Volume (barrels)	($0.02 per barrel)	($0.035 per barrel)	($0.05 per barrel)
48,910,000	$978,000	$1,710,000	$2,450,000

In other words, based on this analysis, the proposed rule would not allow lessees to include the amounts in the table above as a component of their transportation allowance.

Cost—Depreciating Oil Pipeline Assets Only Once

ONRR proposes to allow depreciation of oil pipeline assets only one time. Under our current valuation regulations for Federal oil, if an oil pipeline is sold, ONRR allows the purchasing company to include the purchase price to establish a new depreciation schedule and, in essence, depreciate the same piece of pipe twice or more if it is sold again. Under this proposed rulemaking, we would allow depreciation only once. In theory, this change could result in additional royalties. However, based on our experience monitoring the oil markets, we believe that the sale of oil pipeline assets is rare, and we are not aware of any such sales in the last 5 calendar years. We are also not aware of any planned future sales of oil pipelines that this proposed rule change would impact. Therefore, although ONRR believes that there will be a cost to industry under this proposal, we cannot quantify the cost at this time.

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal Coal and Sales of Federal Coal Between Coal Cooperatives and Coal Cooperative Members and Between Coal Cooperative Members

We discuss this cost in the next section.

Cost—Using Sales of Electricity to Value Non-Arm's-Length Sales of Federal Coal and Sales of Federal Coal Between Coal Cooperatives and Coal Cooperative Members and Between Coal Cooperative Members

In ONRR's experience, non-arm's-length sales of Federal coal that is then resold at arm's length are rare. Under the current valuation regulations, such sales result in royalty values equivalent to values that result under the proposed regulation at §1206.252(a) based on arm's-length resale prices. Thus, ONRR estimates that there will be no royalty effect for these types of sales. In other words, there is no cost to lessees who produce Federal coal due to this valuation change in the proposed rule.

The remaining non-arm's-length dispositions of Federal coal (including lessees, their affiliates, coal cooperatives, and members of coal cooperatives) are when the lessee, its affiliate, coal cooperatives, or members of coal cooperatives consume(s) the Federal coal produced to generate electricity. These dispositions typically constitute from about one to two percent of royalties paid on Federal coal produced.

Under the proposed rule, a lessee, its affiliates, a coal cooperative, and a member of a coal cooperative generally would base the royalty value of such sales on the sales value of the electricity, less costs to generate and, in some cases, transmit the electricity to the buyers, and less applicable coal washing and transportation costs. ONRR has limited experience determining lease product royalty values using the methodology under proposed §1206.252(b)(1). Therefore, to perform an economic analysis, ONRR first determined the average royalties paid to ONRR in calendar years 2009 through 2011 for these Federal coal dispositions. Based on our experience with other dispositions of Federal coal, ONRR estimated that, at most, royalty values under the proposed rule would increase or decrease by 10 percent, compared to royalty values we determined under current regulations. Using these assumptions, ONRR estimated the annual average royalty impact and, thus, the cost or benefit to industry from the proposed rule.

Our methodology is the same for estimating the royalty impact of using sales of electricity to value non-arm's-length sales of Federal coal, sales of Federal coal between coal cooperatives and coal cooperative members, and sales between coal cooperative members. Therefore, the estimated royalty impact would be a combined figure covering all such valuation of Federal coal under the proposed rule. Accordingly, ONRR estimates the combined average annual royalty impacts for these coal dispositions would range from a royalty decrease of $1.06 million (benefit) to a royalty increase of $1.06 million (cost).

ONRR requests comments on its estimates of the cost regarding valuation of these dispositions of Federal coal under the proposed rule. In particular, we seek information on the costs of electric power generation and transmission and whether the proposed rule would result in royalty increases or decreases.

Cost—Using Default Provision to Value Non-Arm's-Length Sales of Federal Coal in Lieu of Sales of Electricity

If ONRR were unable to establish royalty values of Federal coal using the sales value of electricity generated from coal produced, royalty value would be based on a method the lessee proposes under §1206.252(b)(2)(i), which ONRR approves, or on a method that ONRR determines under §1206.254. In either case, ONRR would accept or would assign a royalty value that would approximate the market value of the coal. Whether valuing under §§1206.252(b)(2)(i) or 1206.254, the lessee and ONRR would employ a valuation method that uses or approximates market value. Current coal valuation regulations also attempt to provide royalty values that would approximate the market value of this coal. Thus, given the low percentage of non-arm's-length dispositions of Federal coal and the use of market-based methods to determine royalty value under the current regulations and the proposed rule, if valuation does not follow §1206.252(a) or §1206.252(b)(1), ONRR estimates that the royalty effect of the proposed rule on lessees of Federal coal would be nominal.

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Indian Coal

Currently, lessees of Indian coal sell their entire production at arm's-length so this proposed change would have no cost impact on lessees of Indian coal.

Cost—Using Sales of Electricity to Value Non-Arm's-Length Sales of Indian Coal

Currently, lessees of Indian coal sell their entire production at arm's-length so this proposed change would have no cost impact on lessees of Indian coal.

Cost—Using First Arm's-Length Sale to Value Sales of Indian Coal Between Coal Cooperative Members

Currently, no coal cooperatives are lessees of Indian coal, so we do not expect there to be any royalty impact as a result of the proposed rule change.

Cost—DOI Use of Default Provision to Value Federal Oil, Gas, or Coal and Indian Coal

As we discussed above, we propose to add a "default provision" that addresses valuation when the Secretary cannot determine the value of production because of a variety of factors, or the Secretary determined the value is wrong for a multitude of reasons (for example, misconduct). In those cases, the Secretary would exercise his/her authority, and considerable discretion, to establish the reasonable value of production using a variety of discretionary factors and any other information the Secretary believes is appropriate. This default provision covers all products (Federal oil, gas and coal, and Indian coal) and all pertinent valuation factors (sales, transportation, processing, and washing).

Based on our experience, ONRR believes it would rarely use the default option. We also believe that assigning a royalty impact figure to any of the default provisions is speculative because (1) each instance would be case-specific, (2) we cannot anticipate when we would use the option, and (3) we cannot anticipate the value we would require companies to pay. Additionally, we believe the royalty impact would be relatively small because the default provisions would always establish a reasonable value of production using market-based transaction data, which has always been the basis for our royalty valuation rules in the first instance.

B. State and Local Governments

This proposed rule would not impose any additional burden on local governments. ONRR estimates that the States this rule impacts would receive an overall increase in royalties as follows:

States receiving revenues for offshore Outer Continental Shelf Lands Act Section 8(g) leases would share in a portion of the increased royalties resulting from this proposed rule, as would States receiving revenues from onshore Federal lands. Based on the ratio of Federal revenues disbursed to States for section 8(g) leases and onshore States we detail in the table below, ONRR assumed the same proportion of revenue increases for each proposal that would impact those State revenues for most of the provisions.

Royalty Distributions by Lease Type			
	Onshore	Offshore	8(g)
Fed	50%	100%	73%
State	50%	0%	0%
State (8g)	0%	0%	27%

Some provisions, such as deepwater gathering allowances, affect only Federal revenues, while others, such as the extraordinary processing allowance, affect only onshore States and Federal revenues. The table summarizing the State and local government royalty increases we provide in section E details these differences.

The State distribution for offshore royalties would increase at some point in time because of the provisions of the Gulf of Mexico Energy Security Act of 2006 (GOMESA) (Pub. Law No. 109-432, 120 Stat. 2922). Section 105 of GOMESA provides Outer Continental Shelf (OCS) oil and gas revenue sharing provisions for the four Gulf producing States (Alabama, Louisiana, Mississippi, and Texas) and their eligible coastal political subdivisions. Through fiscal year 2016, the only shareable qualified revenues originate from leases issued within two small geographic areas. Beginning in fiscal year 2017, qualified revenues originating from leases issued since the passing of GOMESA located within the balance of the GOM acreage will also become shareable. The majority of these leases are not yet producing. The time necessary to start production operations and to produce royalty-bearing quantities varies from lease to lease, and these factors directly influence how the distribution of offshore royalties will change over time. None of the leases in these frontier areas have begun producing, and we believe it is speculative to anticipate when they will begin producing royalty-bearing quantities and impact the distribution of revenues to States.

C. Indian Lessors

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

D. Federal Government

The impact to the Federal Government, like the States, would be a net overall increase in royalties as a result of these proposed changes. In fact, the royalty increase anticipated by the Federal Government would be the difference between the total royalty increase from industry and the royalty increase affecting the States. The net yearly impact on the Federal Government would be approximately $61.8 million we detail in section E.

E. 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 increases, while the positive values in the other columns represent the increase in royalty receipts by each affected group. For purposes of this summary table, we assumed that the average for royalty increases is the midpoint of our range.

Rule Provision	**Industry**	**Federal**	**State**	**State 8(g)**
Gas - replace benchmarks				
Affiliate Resale	($2,010,000)	$1,390,000	$605,000	$13,500
Index	($11,300,000)	$7,820,000	$3,400,000	$75,700
NGLs - replace benchmarks				
Affiliate Resale	($256,000)	$191,000	$63,000	$1,850
Index	($1,200,000)	$896,000	$295,000	$8,650
Gas transportation limited to 50%	($4,170,000)	$2,890,000	$1,260,000	$27,900
Processing allowance limited to 66⅔ %	($5,440,000)	$4,060,000	$1,340,000	$39,200
POP contracts limited to 66⅔ %	$0	$0	$0	$0
Extraordinary processing allowance	($18,500,000)	$9,250,000	$9,250,000	$0
BBB bond rate change for gas transportation	($1,640,000)	$1,140,000	$494,000	$11,000
Eliminate deepwater gathering	($20,500,000)	$20,500,000	$0	$0
Oil Transportation limited to 50%	($6,430,000)	$5,810,000	$594,000	$27,100
Oil and gas line losses	($4,570,000)	$4,130,000	$422,000	$19,200
Oil line fill	($1,710,000)	$1,540,000	$158,000	$7,190
BBB bond rate change for oil transportation	($2,380,000)	$2,150,000	$220,000	$10,000
Coal—non-arm's length netback & coop sales	$0	$0	$0	$0
Total	($80,100,000)	$61,800,000	$18,100,000	$241,000

2. Regulatory Planning and Review (E.O. 12866)

This document is a significant rule, and the Office of Management and Budget (OMB) has reviewed this proposed rule under Executive Order 12866. We made the assessments that E.O. 12866 requires, and we provide the results below.

a. This proposed rule would not have an effect of $100 million or more on the economy. It would not adversely affect in a material way the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. The Summary of Royalty Impacts table, in item 1 above, demonstrates that the economic impact on industry, State and local governments, and the Federal Government would be well below the $100 million threshold the Federal Government uses to define a rule as having a significant impact on the economy.

b. This proposed rule would not create a serious inconsistency or otherwise interfere with an action another agency has taken or planned. ONRR is the only agency that promulgates rules for royalty valuation on Federal oil and gas leases and Federal and Indian coal leases.

c. This proposed rule would not alter the budgetary effects of entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients. The scope of this proposed rule does not have a material impact in any of these areas.

d. This proposed rule would raise novel legal or policy issues but would simplify the valuation regulations, thus reducing the possibility of impacts as a result of any novel legal and policy issues.

3. Regulatory Flexibility Act.

The Department of the Interior certifies that this proposed rule would 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 analysis.

4. Small Business Regulatory Enforcement Fairness Act

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

a. Would not have an annual effect on the economy of $100 million or more. We estimate the maximum effect would be $87,300,000. See item 1 above.

b. Would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. See item 1 above.

c. Would 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 proposed rule would be to the benefit of U.S.-based enterprises and would be a result of suggestions made through the Royalty Policy Committee made up, in part, of industry representatives.

5. Unfunded Mandates Reform Act

This proposed rule would not impose an unfunded mandate on state, local, or tribal governments, or the private sector of more than $100 million per year. This proposed rule would not have a significant or unique effect on State, local, or tribal governments, or the private sector. Therefore, we are not providing a statement containing the information that the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq*.) requires. See item 1 above.

6. Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this proposed rule would not have significant takings implications. This proposed rule would apply to Federal oil, Federal gas, Federal coal, and Indian coal leases only. This proposed rule would not be a governmental action capable of interference with constitutionally protected property rights. This proposed rule does not require a Takings Implication Assessment.

7. Federalism (E.O. 13132).

Under the criteria in E.O. 13132, this proposed rule would not have sufficient federalism implications to warrant the preparation of a Federalism Assessment. The management of Federal oil leases, Federal gas leases, and Federal and Indian coal leases is the responsibility of the Secretary of the Interior. This proposed rule would not impose administrative costs on States or local governments. Therefore, this proposed rule would not require a Federalism Assessment.

8. Civil Justice Reform (E.O. 12988).

This proposed rule would comply with the requirements of E.O. 12988, for the reasons we outline in the following paragraphs.

The proposed rule would meet the criteria of section 3(a), which requires that we write and review all regulations to eliminate errors and ambiguity in order to minimize litigation.

The proposed rule would meet the criteria of section 3(b)(2), which requires that we write all regulations in clear language with clear legal standards.

9. Consultation with Indian Tribes (E.O. 13175).

Under the criteria in E.O. 13175, we evaluated this proposed rule and determined it would have potential effects on federally recognized Indian tribes. Specifically, this rule would change the valuation methodology for coal produced from Indian leases as discussed above. Accordingly:

(a) We consulted with the affected tribes on a government-to-government basis.

(b) We will fully consider tribal views in the final rule.

10. Paperwork Reduction Act.

This proposed rule also refers to, but does not change, the information collection requirements that OMB already approved under OMB Control Numbers 1012-0004, 1012-0005, and 1012-0010. Since the proposed rule is reorganizing our current regulations, please refer to the Derivations Table in Section III for specifics. The corresponding information collection burden tables will be updated during their normal renewal cycle. See 5 CFR 1320.4(a)(2).

11. National Environmental Policy Act.

This proposed rule would not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the National Environmental Policy Act of 1969 (NEPA) is not required because this rule is categorically excluded under: "(i) Policies, directives, regulations, and guidelines: that are of an administrative, financial, legal, technical, or procedural nature." See 43 CFR 46.210(i) and the DOI Departmental Manual, part 516, section 15.4.D. We also have determined that this rule is not involved in any of the extraordinary circumstances listed in 43 CFR 46.215 that would require further analysis under NEPA. The procedural changes resulting from these amendments would have no consequences with respect to the physical environment. This proposed rule would not alter in any material way natural resource exploration, production, or transportation.

12. Data Quality Act.

In developing this proposed rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106-554), also known as the Information Quality Act. The Department of the Interior has issued guidance regarding the quality of information that it relies on for regulatory decisions. This guidance is available on DOI's website at www.doi.gov/ocio/iq.html.

13. Effects on the Energy Supply (E.O. 13211).

This proposed rule would not be a significant energy action under the definition in E.O. 13211, and, therefore, would not require a Statement of Energy Effects.

14. Clarity of this Regulation.

Executive Orders 12866 and 12988 and the Presidential Memorandum of June 1, 1998, require us to write all rules in Plain Language. This means that each rule that we publish must: (a) have logical organization; (b) use the active voice to address readers directly; (c) use clear language rather than jargon; (d) use short sections and sentences; and (e) use lists and tables wherever possible.

If you feel that we have not met these requirements, send your comments to armand.southall@onrr.gov. To better help us revise the rule, make your comments as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you think we wrote unclearly, which sections or sentences are too long, the sections where you feel lists or tables would be useful, etc.

15. Public availability of comments.

Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us, in your comment, to withhold your personal identifying information from public view, we cannot guarantee that we will be able to do so.

List of Subjects in 30 CFR Parts 1202 and 1206

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

Dated: December 18, 2014.________________

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Kris Sarri,
Principal Deputy Assistant Secretary for
Policy, Management and Budget

Authority and Issuance

For the reasons stated in the preamble, the Office of Natural Resources Revenue proposes to amend 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 définitions in §1206.20 of this chapter are applicable to subparts B, C, D, and J of this part.

Subpart F—Coal

3. Add §1202.251 to subpart F to read as follows:

§1202.251 What coal is subject to royalties?

(a) All coal (except coal unavoidably lost as determined by BLM under 43 CFR part 3400) from a Federal or Indian lease is subject to royalty. This includes coal used, sold, or otherwise disposed of by you on or off the lease.

(b) If you receive compensation for unavoidably lost coal through insurance coverage or other arrangements, you must pay royalties at the rate specified in the lease on the amount of compensation you receive for the coal. No royalty is due on insurance compensation you received for other losses.

(c) If you rework waste piles or slurry ponds to recover coal, you must pay royalty at the rate specified in the lease at the time you use, sell, or otherwise finally dispose of the recovered coal.

(1) The applicable royalty rate depends on the production method you used to initially mine the coal contained in the waste pile or slurry pond (*i.e.*, underground mining method or surface mining method).

(2) You must allocate coal in waste pits or slurry ponds you initially mined from Federal or Indian leases to those Federal or Indian leases regardless of whether it is stored on Federal or Indian lands.

(3)You must maintain accurate records demonstrating how to allocate the coal in the waste pit or slurry pond to each individual Federal or Indian coal lease.

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 to read as follows:

Subpart A—General Provisions and Definitions

Sec.

1206.10 Has the Office of Management and Budget (OMB) approved the information collection requirements in this part?

1206.20 What definitions apply to this part?

Subpart A—General Provisions

§1206.10 Has the Office of Management and Budget (OMB) approved the information collection requirements in this part?

OMB has approved the information collection requirement contained in this part under 44 U.S.C. 3501 *et seq*. See 30 CFR part 1210 for details concerning the estimated reporting burden and how to comment on the accuracy of the burden estimate.

§1206.20 What definitions apply to this part?

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.

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 to determine if 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, if a person is the greatest single owner, or if 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, 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 and/or gas field, in which oil and/or gas lease products have 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 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 an examination, conducted under the generally accepted Governmental Auditing Standards, of royalty reporting and payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases or Indian leases.

BIA means the Bureau of Indian Affairs, Department of the Interior.

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

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

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

Coal means coal of all ranks from lignite through anthracite.

Coal cooperative means an entity organized to provide coal or coal-related services to the entity's members (who may also be owners of the entity), partners, and others. The entity's members are commonly electric power generation companies, electric utilities, and electric generation and transmission cooperatives. The entity may operate as a coal lessee, operator, payor, or affiliate of these, and may or may not be organized to make a profit.

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).

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 processing. Condensate is the mixture of liquid hydrocarbons resulting from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Constraint means a reduction in, or elimination of, gas flow, deliveries or sales required by the delivery system.

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.

FERC means Federal Energy Regulatory Commission.

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.

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 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, including any movement of bulk production from the wellhead to a platform offshore.

Geographic region means, for Federal gas, an area 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 and economic characteristics.

Gross proceeds means the total monies and other consideration accruing for the disposition of any of the following:

(1) *Oil.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government;

(ii) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf;

(iii) Reimbursements for harboring or terminalling fees, royalties, and any other reimbursements;

(iv) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation;

(v) Payments made to reduce or buy down the purchase price of oil 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

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

(2) *Gas, residue gas, and gas plant products.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering that the lessee must perform at no cost to the Federal Government;

(ii) Reimbursements for royalties, fees, and any other reimbursements;

(iii) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation; and

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

(3) *Coal.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oil, and other preparation of the coal that the lessee must perform at no cost to the Federal Government or Indian lessor;

(ii) Reimbursements for royalties, fees, and any other reimbursements;

(iii) Tax reimbursements even though the Federal or Indian royalty interest may be exempt from taxation; and

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

Index means:

(1) For gas, the calculated composite price ($/MMBtu) of spot market sales a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes; or

(2) For oil, the calculated composite price ($/barrel) of spot market sales a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes.

Index pricing point means any point on a pipeline for which there is an index, which ONRR-approved publications may refer to as a trading location.

Index zone means a field or an area with an active spot market and published indices applicable to that field or an area that is acceptable to ONRR under §1206.141(d)(1).

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any minerals or interest in minerals is held in trust by the United States or that is subject to Federal restriction against alienation.

Individual Indian mineral owner means any Indian for whom minerals or an interest in minerals is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Keepwhole contract means a processing agreement under which the processor delivers to the lessee a quantity of gas after processing equivalent to the quantity of gas the processor received from the lessee prior to processing, normally based on heat content, less gas used as plant fuel and gas unaccounted for and/or lost. This includes but is not limited to agreements under which the processor retains all NGLs it recovered from the lessee's gas.

Lease means any contract, profit-sharing arrangement, joint venture, or other agreement issued or approved by the United States under any mineral leasing law, including the Indian Mineral Development Act, 25 U.S.C. 2101-2108, that authorizes exploration for, extraction of, or removal of lease products, or the geographical area covered by that authorization, whichever is required by the context.

Lease products mean any leased minerals, attributable to, originating from, or allocated to a lease or produced in association with a lease.

Lessee means any person to whom the United States, an Indian tribe, and/or individual Indian mineral owner issues a lease, and any person who has been assigned all or a part of record title, operating rights, or an obligation to make royalty or other payments required by the lease. This includes:

(1) Any person who has an interest in a lease; and

(2) In the case of leases for Indian coal or Federal coal, an operator, payor, or other person with no lease interest who makes royalty payments on the lessee's behalf.

Like quality means similar chemical and physical characteristics.

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 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 for Federal oil and gas, and region for Federal and Indian coal.

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.

Misconduct means any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior, regardless of the mental state of the lessee or any individual employed by or associated with the lessee.

Net output means the quantity of:

(1) Residue gas and each gas plant product that a processing plant produces; or

(2) The quantity of washed coal that a coal wash plant produces.

Netting means reducing the reported sales value to account for an allowance instead of reporting the allowance as a separate entry on Form ONRR-2014 or Form ONRR-4430.

NGLs means natural gas liquids.

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 means the Office of Natural Resources Revenue, Department of the Interior.

ONRR-approved commercial price bulletin means a publication ONRR approves for determining NGLs prices.

ONRR-approved publication means:

(1) For oil, a publication ONRR approves for determining ANS spot prices or WTI differentials; or

(2) For gas, a publication ONRR approves for determining index pricing points.

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.

Payor means any person who reports and pays royalties under a lease, regardless of whether that person also is a lessee.

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

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. The use of a Joules-Thompson (JT) unit to remove NGLs from gas is considered processing regardless of where the JT unit is located provided that you market the NGLs as NGLs.

Processing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for processing gas.

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.

Region for coal means the eight Federal coal production regions, which the Bureau of Land Management designates as follows: Denver-Raton Mesa Region, Fort Union Region, Green River-Hams Fork Region, Powder River Region, San Juan River Region, Southern Appalachian Region, Uinta-Southwestern Utah Region, and Western Interior

Region. See 44 FR 65197 (1979).

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

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: 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 December. December was the prompt month (for year 2011) from October 21 through November 18. January was the first month following the month of production, and February was the second month following the month of production. P_0 therefore is the average of the daily NYMEX

settlement prices for deliveries during December published for each business day between October 21 and November 18. P_1 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between October 21 and November 18. P_2 is the average of the daily NYMEX settlement prices for deliveries during February published for each business day between October 21 and November 18. In this example, assume that P_0 = \$95.08 per bbl, P_1 = \$95.03 per bbl, and P_2 = \$94.93 per bbl. In this example (a declining market), Roll = .6667 × (\$95.08−\$95.03) + .3333 × (\$95.08−\$94.93) = \$0.03 + \$0.05 = \$0.08. 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 November. November was the prompt month (for year 2012) from September 21 through October 22. December was the first month following the month of production, and January was the second month following the month of production. P_0 therefore is the average of the daily NYMEX settlement prices for deliveries during November published for each business day between September 21 and October 22. P_1 is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between September 21 and October 22. P_2 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between September 21 and October 22. In this example, assume that P_0 = \$91.28 per bbl, P_1 = \$91.65 per bbl, and P_2 = \$92.10 per bbl. In this example (a rising market), Roll = .6667 × (\$91.28−\$91.65) + .3333 × (\$91.28−\$92.10) = (-\$0.25) + (-\$0.27) = (-\$0.52). 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, gas, gas plant product, or coal to the buyer and does not retain any related rights such as the right to buy back similar quantities of oil, gas, gas plant product, or coal from the buyer elsewhere;

(2) The buyer pays money or other consideration for the oil, gas, gas plant product, or coal; and

(3) The parties' intent is for a sale of the oil, gas, gas plant product, or coal to occur.

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.

Short tons means 2000 pounds.

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.

Tonnage means tons of coal measured in short tons.

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 website, 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 the lessee incurs for moving:

(1) Oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs; or

(2) 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; or

(3) Coal to a point of sale remote from both the lease and mine or wash plant.

Washing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for coal washing.

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.

6. Revise subpart C to read as follows:

Subpart C—Federal Oil

Sec.

1206.100 What is the purpose of this subpart?
1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-

length contract?
1206.102 How do I value oil that is not sold under an arm's-length contract?
1206.103 What publications does ONRR approve?
1206.104 How will ONRR determine if my royalty payments are correct?
1206.105 How will ONRR determine the value of my oil for royalty purposes?
1206.106 What records must I keep to support my calculations of value under this subpart?
1206.107 What are my responsibilities to place production into marketable condition and to market production?
1206.108 How do I request a value determination?
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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 OCS. It explains how you as a lessee must calculate the value of production for royalty purposes consistent with 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, monitor, or review and adjust all royalty payments.

§1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm’s-length contract?

(a) The value of oil under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the arm’s-length contract less applicable allowances determined under §1206.111 or §1206.112. This value does not apply if you exercise an option to use a different value provided in paragraph (c)(1) or (c)(2)(i) of this section or if ONRR decides to value your oil under §1206.105. You must use this paragraph (a) to value oil when:

(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 (c)(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)(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 §1206.101(a) or §1206.102 to value your production for royalty purposes. If you fail to make the election required under this paragraph, you may not make a retroactive election and ONRR may decide your value under §1206.105.

(i) If you use §1206.101(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 decide your value under §1206.105. 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 §1206.101(c)(1) to use §1206.101(a) or §1206.102, 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 §1206.101(a) or §1206.102 to value your production for royalty purposes.

(ii) When you elect under §1206.101(c)(2)(i) to use §1206.101(a) or §1206.102, 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.

§1206.102 How do I value oil not sold under an arm's-length contract?

This section explains how to value oil that you may not value under §1206.101 or that you elect under §1206.101(c)(1) to value under this section, unless ONRR decides to value your oil under 1206.105. First, determine if paragraph (a), (b), or (c) of this section applies to production from your lease, or if 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, calculate 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, you must average the daily high and low prices for the month in the selected publication.

(2) You must 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 §1206.111.

(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 must 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)(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 §1206.101 or that you elect under §1206.101(c)(1) to value under this section.

(1)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 affiliate's 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 affiliate's 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 affiliate's 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 §1206.113.

(4) If you demonstrate to ONRR's satisfaction that paragraphs (b)(2) through (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 §1206.113.

(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 [EFFECTIVE DATE OF THE FINAL RULE], 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 decide to value your oil under § 1206.105.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an 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 decide to value under §1206.105.

§1206.103 What publications does ONRR approve?

(a) ONRR periodically will publish to *www.onrr.gov* a list of ONRR-approved 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.

§1206.104 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may direct you to use a different measure of royalty value or decide your value under §1206.105.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter) or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the oil. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under §1206.105.

(c) ONRR may decide your value under §1206.105 if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the oil for the mutual benefit of yourself and the lessor by selling your oil at a value that is unreasonably low. ONRR may consider a sales price to be unreasonably low if it is 10 percent less than the lowest reasonable measures of market price, including but not limited to, index prices and prices reported to ONRR for like quality oil; or

(3) ONRR cannot determine if you properly valued your oil under §1206.101 or §1206.102 for any reason, including but not limited to, you or your affiliate's failure to provide documents ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include all of the consideration the buyer paid you or your affiliate, either directly or indirectly, for the oil.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract but the purchaser refuses and you or your affiliate take reasonable documented measures to force purchaser compliance, you will

not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of oil.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may determine your value under §1206.105.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§1206.105 How will ONRR determine the value of my oil for royalty purposes?

If ONRR decides that it will value your oil for royalty purposes under §1206.104, or any other provision in this subpart, then ONRR will determine value, for royalty purposes, by considering any information we deem relevant, which may include, but is not limited to:

(a) The value of like-quality oil in the same field or nearby fields or areas;

(b) The value of like-quality oil from the refinery or area;

(c) Public sources of price or market information that ONRR deems reliable;

(d) Information available and reported to ONRR, including but not limited to, on Form ONRR-2014 and Form ONRR-4054;

(e) Costs of transportation or processing if ONRR determines they are applicable; or

(f) Any information ONRR deems relevant regarding the particular lease operation or the salability of the oil.

§1206.106 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 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) You can find recordkeeping requirements in parts 1207 and 1212 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.

§1206.107 What are my responsibilities to place production into marketable condition and to market production?

(a) 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.

(b) 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.

§1206.108 How do I request a value determination?

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

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, the designee(s), and the operator(s) 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) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a valuation determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance 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 the Assistant Secretary for Policy, Management and Budget signs 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 to royalty payments that follow from the determination and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

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

(d) Guidance ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

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

(e) ONRR or the Assistant Secretary may use any of the applicable valuation criteria in this subpart to provide guidance or make a determination.

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

(g) 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 §1206.109.

§1206.109 Does ONRR protect information I provide?

(a) Certain information you or your affiliate submit(s) to ONRR regarding valuation of oil, including transportation allowances, may be exempt from disclosure.

(b) To the extent applicable laws and regulations permit, ONRR will keep confidential any data you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§1206.110 What general transportation allowance requirements apply to me?

(a) 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, §1206.111, or §1206.112, as applicable. You may not deduct transportation costs you incur to move a particular volume of production to reduce royalties you owe on production for which you did not incur those costs. This paragraph applies when:

(1) You value oil under §1206.101 based on a sale at a point off the lease, unit, or communitized area where the oil is produced;

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

(ii) For oil produced on the OCS, the movement of oil from the wellhead to the first platform is not transportation; and

(3) You do not value your oil under §1206.102(a)(3) or (b)(3).

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. If your or your affiliate's transportation contract includes more than one liquid product, you must 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 prospective cost allocation method based on the values of the liquid products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the production month following the month ONRR received your proposed procedure 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 due, plus late payment interest.

(c)(1) Where you or your affiliate transport(s) 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 you first claim the allocated deductions on Form ONRR-2014.

(d)(1) Your transportation allowance may not exceed 50 percent of the value of the oil as determined under §1206.101 of this subpart.

(2) If ONRR approved your request to take a transportation allowance in excess of the 50-percent limitation under former §1206.109(c), that approval is terminated as of [effective date of final rule].

(e) You must express transportation allowances for oil as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate are paid to a dollar-value equivalent.

(f) ONRR may determine your transportation allowance under §1206.105 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the oil for the mutual benefit of yourself and the lessor by transporting your oil at a cost that is unreasonably high. We may consider a transportation allowance to be unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs, including but not limited to, transportation allowances reported to ONRR and tariffs for gas, residue gas, or gas plant product transported through the same system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under §1206.111 or §1206.112 for any reason, including, but not limited to, your or your affiliate's failure to provide documents ONRR requests under 30 CFR part 1212, subpart B.

(g) You do not need ONRR approval before reporting a transportation allowance.

§1206.111 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) 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 §1206.110(f) and subject to the limitation in §1206.110(d).

(2) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(3) You do not need ONRR approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to the following costs to determine your transportation allowance under paragraph (a) 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 section.

(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) Fees paid to a terminal operator for loading and unloading of crude oil into or

from a vessel, vehicle, pipeline, or other conveyance.

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

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

(7) 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.

(8) 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.

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

(10) Hurricane surcharges you or your affiliate actually pay(s).

(c) You may not include the following costs to determine your transportation allowance under paragraph (a) of this section:

(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; and

(9) The cost of carrying on your books as inventory a volume of oil that you or your affiliate, as the pipeline operator, maintain(s) in the line as line fill.

(d) If you have no written contract for the arm's-length transportation of oil, then ONRR will determine your transportation allowance under §1206.105. You may not use this paragraph (d) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.108(a).

(2) You may use that method to determine your allowance until ONRR issues its determination.

§1206.112 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. You must 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 may include:

(1) Capital costs and operating and maintenance expenses under paragraphs (e), (f), and (g) of this section;

(2) Overhead under paragraph (h) of this section; and

(3)(i) Depreciation and a return on undepreciated capital investment under paragraph (i)(1) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (i)(2) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request; and

(ii) A return on the reasonable salvage value under paragraph (i)(1)(iii) of this section, after you have depreciated the transportation system to its reasonable salvage value.

(c) To the extent not included in costs identified in paragraphs (e) through (h) of this section;

(1) If you or your affiliate incur(s) the following actual costs under your or your affiliate's non-arm's-length contract, you may include these costs in your calculations under this section.

(i) 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.

(ii) 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.

(iii) 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.

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

(2) You may not include in your transportation allowance:

(i) Any of the costs identified under §1206.111(c); and

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

(d) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

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

(f) Allowable operating expenses include:

(i) Operations supervision and engineering;

(ii) Operations labor;

(iii) Fuel;

(iv) Utilities;

(v) Materials;

(vi) Ad valorem property taxes;

(vii) Rent;

(viii) Supplies; and

(ix) Any other directly allocable and attributable operating expense that you can document.

(g) 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 that you can document.

(h) 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.

(i)(1) To calculate depreciation and a return on undepreciated capital investment, you may elect to use either a straight-line depreciation method (based on the life of equipment or on the life of the reserves that the transportation system services) or a unit of production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(i) A change in ownership of a transportation system will not alter the depreciation schedule the original transporter/lessee established for purposes of the allowance calculation.

(ii) You may depreciate a transportation system, with or without a change in ownership, only once.

(iii)(A) To calculate the return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the transportation system multiplied by the rate of return you determine under paragraph (i)(3) of this section.

(B) After you have depreciated a transportation system to the reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (i)(3) of this section.

(2) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (i)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(ii) You must redetermine the rate at the beginning of each subsequent calendar year.

§1206.113 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 §1206.102. As specified in this section, you must 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 due 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 §1206.111 or §1206.112, 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, you must 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 due 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, you must 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, you must 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 must change publications, you must begin a new 2-year period.

(3) If neither paragraph (b)(1) nor (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 due 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, you also must 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. You must 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.

(i) You may request prior ONRR approval to use a different adjustment.

(ii) If ONRR approves your request to use a different quality adjustment, you may begin using that adjustment the production month following the month ONRR received your request.

(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 $86.21/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is −$2.27/bbl; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of −$0.08/bbl; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is $0.40/bbl. In this example, the royalty value of the oil is $86.21 − $2.27 − $0.08 − $0.40 = $83.46/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 $83.46/bbl, as explained in the previous example. In this example, the other 60 percent also would be valued at $83.46/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 $105.65/bbl and that the lessee's actual cost of transporting the oil from Bakersfield to Hynes Station is $0.28/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 \$0.72, 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 \$105.65 − \$0.72 − \$0.28 = \$104.65/bbl. The fact that oil was exchanged to Cushing does not change use of ANS spot prices for royalty valuation.

§1206.114 How will ONRR identify market centers?

ONRR will monitor market activity and, if necessary, add to or modify the list of market centers published to *www.onrr.gov*. 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.

§1206.115 What are my reporting requirements under an arm's-length transportation contract?

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

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.116 What are my reporting requirements under a non-arm's-length transportation contract?

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

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.118 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You may find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d) If you are authorized under §1206.112(j) to use an exception to the requirement to calculate your actual transportation costs, you must follow the reporting requirements of §1206.115.

§1206.117 What interest and penalties apply if I improperly report a transportation allowance?

(a) If you deduct a transportation allowance on Form ONRR-2014 that exceeds 50 percent of the value of the oil transported, you must pay additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter, on the excess allowance amount taken from the date that amount is taken to the date you pay the additional royalties due.

(b) If you improperly net a transportation allowance against the oil instead of reporting the allowance as a separate entry on Form ONRR-2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.118 What reporting adjustments must I make for transportation allowances?

(a) If your 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 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 period reported on the allowance form, you are entitled to a credit plus interest.

§1206.119 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of oil as measured at the point of royalty settlement that BLM or BSEE approves for onshore leases and OCS leases, respectively.

(b) If you base the value of oil determined under this subpart on a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement that BLM or BSEE approves, you must adjust that value for the differences in quantity and/or quality.

(c) You may not make any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss that you sustain before the royalty settlement metering or measurement point is not subject to royalty if BLM or BSEE, whichever is appropriate, determines that such loss was unavoidable.

(d) You must pay royalties 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 you claim to have taken place either before or after the approved point of royalty settlement.

7. Revise subpart D to read as follows:

Subpart D—Federal Gas

Sec.

1206.140 What is the purpose and scope of this subpart?
1206.141 How do I calculate royalty value for unprocessed gas I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?
1206.142 How do I calculate royalty value for processed gas I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?
1206.143 How will ONRR determine if my royalty payments are correct?
1206.144 How will ONRR determine the value of my gas for royalty purposes?
1206.145 What records must I keep to support my calculations of royalty under this subpart?
1206.146 What are my responsibilities to place production into marketable condition and to market production?
1206.147 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?
1206.148 How do I request a valuation determination or guidance?
1206.149 Does ONRR protect information I provide?
1206.150 How do I determine royalty quantity and quality?
1206.151 How do I perform accounting for comparison?
1206.152 What general transportation allowance requirements apply to me?
1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract
1206.154 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

1206.155 What are my reporting requirements under an arm's-length transportation contract?
1206.156 What are my reporting requirements under a non-arm's-length transportation contract?
1206.157 What interest and penalties apply if I improperly report a transportation allowance?
1206.158 What reporting adjustments must I make for transportation allowances?
1206.159 What general requirements regarding processing allowances apply to me?
1206.160 How do I determine a processing allowance, if I have an arm's-length processing contract?
1206.161 How do I determine a processing allowance if I have a non-arm's-length processing contract?
1206.162 What are my reporting requirements under an arm's-length processing contract?
1206.163 What are my reporting requirements under a non-arm's-length processing contract?
1206.164 What interest and penalties apply if I improperly report a processing allowance?
1206.165 What reporting adjustments must I make for processing allowances?

Subpart D—Federal Gas

§1206.140 What is the purpose and scope of this subpart?

(a) This subpart applies to all gas 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 mineral leasing laws, other applicable laws, and lease terms.

(b) The terms "you" and "your" in this subpart refer to the lessee.

(c) 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.

(d) ONRR may audit and order you to adjust all royalty payments.

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

(a) This section applies to unprocessed gas. Unprocessed gas is:

(1) Gas that is not processed;

(2) Any gas that you are not required to value under §1206.142 or that ONRR does not value under §1206.144;

(3) Processed gas that you must value prior to processing under §1206.151 of this part; and

(4) Any gas you sell prior to processing based on a price per MMBtu or Mcf when the price is not based on the residue gas and gas plant products.

(b) The value of gas under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less an applicable transportation allowance determined under §1206.152. This value does not apply if you may exercise the option provided in paragraph (c) of this section or if ONRR decides to value your gas under §1206.144. You must use this paragraph (b) to value gas when:

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

(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 gas under an arm's-length contract, unless you exercise the option provided in paragraph (c) of this section;

(3) You, your affiliate, or another person sell(s) under multiple arm's-length contracts for gas produced from a lease that is valued under this paragraph. In that case, unless you exercise the option provided in paragraph (c) of this section, because you sold non-arm's length to your affiliate or another person, the value of the gas is the volume-weighted average of the value established under this paragraph for each contract for the sale of gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price the pipeline must pay you or your affiliate under the transportation contract. You must 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.

(c) If you do not sell under an arm's-length contract, you may elect to value your gas under this paragraph (c). You may not change your election more often than once every two years.

(1)(i) If you can only transport gas to one index pricing point published in an ONRR-approved publication, available at *www.onrr.gov*, your value, for royalty purposes, is the highest reported monthly bidweek price for that index pricing point for the production month.

(ii) If you can transport gas to more than one index pricing point published in an ONRR-approved publication, available at *www.onrr.gov*, your value, for royalty purposes, is the highest reported monthly bidweek price for the index pricing points to which your gas could be transported for the production month, whether or not there are constraints for that production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your gas enters the pipeline.

(iv) You must reduce the number calculated under paragraphs (c)(1)(i) and (c)(1)(ii) of this section by 5 percent for sales from the OCS Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

(v) After you select an ONRR-approved publication available at *www.onrr.gov*, you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-approved publication, if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish a list of excluded index pricing points available at *www.onrr.gov*.

(2) You may not take any other deductions from the value calculated under this paragraph (c).

(d) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point for the gas, then you must value your gas under paragraph (c) of this section;

(2) There is not an index pricing point for the gas, then ONRR will decide the value under §1206.144.

(i) You must propose to ONRR a method to determine the value using the procedures in §1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues its decision.

(iii) After ONRR issues its determination, you must make the adjustments under §1206.143(a)(2).

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

(a) This section applies to the valuation of processed gas, including but not limited to:

(1) Gas you or your affiliate do not sell, or otherwise dispose of, under an arm's-length contract prior to processing;

(2) Gas where your or your affiliate's arm's-length contract for the sale of gas prior to processing provides for payment to be determined on the basis of the value of any products resulting from processing, including residue gas or natural gas liquids;

(3) Gas you or your affiliate process under an arm's-length keepwhole contract; and

(4) Gas where your or your affiliate's arm's-length contract includes a reservation of the right to process the gas and you or your affiliate exercise(s) that right.

(b) The value of gas subject to this section, for royalty purposes, is:

(1) The combined value of the residue gas and all gas plant products you determine under this section;

(2) Plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing you determine under §1206.141 of this part;

(3) Less applicable transportation and processing allowances you determine under this subpart, unless you exercise the option provided in paragraph (d) of this section.

(c) The value of residue gas or any gas plant product under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract. This value does not apply if you exercise the option provided in paragraph (d) of this section, or if ONRR decides to value your residue gas or any gas plant product under §1206.144. You must use this paragraph (c) to value residue gas or any gas plant product when:

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

(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 residue gas or any gas plant product under an arm's-length contract, unless you exercise the option provided in paragraph (d) of this section;

(3) You, your affiliate, or another person sell(s) under multiple arm's-length contracts for residue gas or any gas plant products recovered from gas produced from a lease that you value under this paragraph. In that case, unless you exercise the option provided in paragraph (d) of this section, because you sold non-arm's-length to your affiliate or another person, the value of the residue gas or any gas plant product is the volume-weighted average of the gross proceeds established under this paragraph for each arm's-length contract for the sale of residue gas or any gas plant products recovered from gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price the pipeline must pay you or your affiliate under the transportation contract. You must 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.

(d) If you do not sell under an arm's-length contract, you may elect to value your residue gas and natural gas liquids (NGLS) under this paragraph (d). You may not change your election more often than once every two years.

(1)(i) If you can only transport residue gas to one index pricing point published in an ONRR-approved publication, available at *www.onrr.gov*, your value, for royalty purposes, is the highest reported monthly bidweek price for that index pricing point for the production month.

(ii) If you can transport residue gas to more than one index pricing point published in an ONRR-approved publication, available at *www.onrr.gov*, your value, for royalty purposes, is the highest reported monthly bidweek price for the index pricing points to which your gas could be transported for the production month, whether or not there are constraints, for the production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your residue gas enters the pipeline.

(iv) You must reduce the number calculated under paragraphs (d)(1)(i) and (ii) of this section by 5 percent for sales from the OCS Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

(v) After you select an ONRR-approved publication available at *www.onrr.gov*, you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-approved publication, if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish a list of excluded index pricing points available at *www.onrr.gov*.

(2)(i) If you sell NGLs in an area with one or more ONRR-approved commercial price bulletins available at *www.onrr.gov*, you must choose one bulletin and your value, for royalty purposes, is the monthly average price for that bulletin for the production month.

(ii) You must reduce the number calculated under paragraph (d)(2)(i) of this section by the amounts ONRR posts at *www.onrr.gov* for the geographic location of your lease. The methodology ONRR will use to calculate the amounts is set forth in the preamble to this regulation. This methodology is binding on you and ONRR. ONRR will update the amounts periodically using this methodology.

(iii) After you select an ONRR-approved commercial price bulletin available at *www.onrr.gov*, you may not select a different commercial price bulletin more often than once every 2 years.

(3) You may not take any other deductions from the value calculated under this paragraph (d).

(4) ONRR will post changes to any of the rates in this paragraph (d) on its website.

(e) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point or commercial price bulletin for the gas, then you must value your gas under paragraph (d) of this section.

(2) There is not an index pricing point or commercial price bulletin for the gas, then ONRR will determine the value under §1206.144.

(i) You must propose to ONRR a method to determine the value using the procedures in §1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues its decision.

(iii) After ONRR issues its determination, you must make the adjustments under §1206.143(a)(2).

§1206.143 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value or decide your value under §1206.144.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the gas, residue gas, or gas plant products. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under §1206.144.

(c) ONRR may decide your value under §1206.144, if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor by selling your gas, residue gas, or gas plant products at a value that is unreasonably low. ONRR may consider a sales price unreasonably low, if it is 10 percent less than the lowest reasonable measures of market price, including but not limited to, index prices and prices reported to ONRR for like-quality gas, residue gas, or gas plant products; or

(3) ONRR cannot determine if you properly valued your gas, residue gas, or gas plant products under §1206.141 or §1206.142 for any reason, including but not limited to, your or your affiliate's failure to provide documents ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration the buyer paid you or your affiliate, either directly or indirectly, for the gas, residue gas, or gas plant products.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of gas, residue gas, or gas plant products.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide your value under §1206.144.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§1206.144 How will ONRR determine the value of my gas for royalty purposes?

If ONRR decides to value your gas, residue gas, or gas plant products for royalty purposes under §1206.143, or any other provision in this subpart, then ONRR will determine the value, for royalty purposes, by considering any information we deem relevant, which may include, but is not limited to:

(a) The value of like-quality gas in the same field or nearby fields or areas;

(b) The value of like-quality residue gas or gas plant products from the same plant or area;

(c) Public sources of price or market information that ONRR deems reliable;

(d) Information available or reported to ONRR, including but not limited to, on Form ONRR-2014 and Form ONRR-4054;

(e) Costs of transportation or processing, if ONRR determines they are applicable; or

(f) Any information ONRR deems relevant regarding the particular lease operation or the salability of the gas.

§1206.145 What records must I keep to support my calculations of royalty under this subpart?

If you value your gas under this subpart, you must retain all data relevant to the determination of the royalty you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR. You must comply with any such requirement within the time ONRR specifies.

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

(a) You must place gas, residue gas, and gas plant products in marketable condition and market the gas, residue gas, and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.

(b) If you use gross proceeds under an arm's-length contract to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform to place the gas, residue gas, and gas plant products in marketable condition or to market the gas.

§1206.147 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR does not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR redetermining royalty due, under this subpart, final or binding as against the Federal Government or its beneficiaries unless ONRR chooses to formally close the audit period in writing.

§1206.148 How do I request a valuation determination or guidance?

(a) You may request a valuation determination or guidance from ONRR regarding any gas produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, the designee(s), and the operator(s) 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) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination; or

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance 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 determination the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments to royalty payments that follow from the determination and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

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

(d) Guidance ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

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

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or make a determination.

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

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under §1206.149.

§1206.149 Does ONRR protect information I provide?

(a) Certain information you or your affiliate submit(s) to ONRR regarding royalties on gas, including deductions and allowances, may be exempt from disclosure.

(b) To the extent applicable laws and regulations permit, ONRR will keep confidential any data you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§1206.150 How do I determine royalty quantity and quality?

(a)(1) You must calculate royalties based on the quantity and quality of unprocessed gas as measured at the point of royalty settlement that BLM or BSEE approves for onshore leases and OCS leases, respectively.

(2) If you base the value of gas determined under this subpart on a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement that BLM or BSEE approves, you must adjust that value 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 you value residue gas and/or gas plant products determined under this subpart on 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 under paragraph (c) of this section, you must adjust that value for the differences in quantity and/or quality.

(c) You must determine the quantity of the residue gas and gas plant products attributable to a lease based on the following procedure:

(1) When you derive the net output of the processing plant from gas obtained from only one lease, you must base the quantity of the residue gas and gas plant products for royalty computation on the net output of the plant.

(2) When you derive the net output of a processing plant from gas obtained from more than one lease producing gas of uniform content, you must base the quantity of the residue gas and gas plant products allocable to each lease on 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 non-uniform content:

(i) You must determine the quantity of the residue gas allocable to each lease by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing that arithmetical product 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.

(ii) You must determine the net output of gas plant products allocable to each lease by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing that arithmetical product 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) You may request prior ONRR approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, you must apply that method to all gas production from Federal leases that is processed in the same plant beginning with the production month following the month ONRR received your request to use another method.

(d)(1) You may not make any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that you sustain before the royalty settlement meter or measurement point is not subject to royalty; if BLM or BSEE, whichever is appropriate, determines that such loss was unavoidable.

(2) Except as provided in paragraph (d)(1) of this section and §1202.151(c), you must pay royalties due on 100 percent of the volume determined under paragraphs (a) through (c) of this section. You may not reduce that determined volume for actual losses after you have determined the quantity basis, or for theoretical losses that you claim 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. You may not take any deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after you have determined the quantity basis or for theoretical losses that you claim to have taken place.

§1206.151 How do I perform accounting for comparison?

(a) Except as provided in paragraph (b) of this section, if you or your affiliate (or a person to whom you have transferred gas under a non-arm's-length contract or without a contract) processes your or your affiliate's gas and after processing the gas, you or your affiliate do not sell the residue gas under an arm's-length contract, the value, for royalty purposes, will 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 under §1206.142 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 under §1206.102 of this subpart; or

(2) The value, for royalty purposes, of the gas prior to processing as determined under §1206.141 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases will govern as provided in §1206.142(a)(2) of this subpart.

(c) When lease terms require accounting for comparison, you must perform accounting for comparison under paragraph (a) of this section.

§1206.152 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport residue gas, gas plant products, or unprocessed gas from the lease to the point off the lease under §1206.153 or §1206.154, as applicable. You may not deduct transportation costs you incur to move a particular volume of production to reduce royalties you owe on production for which you did not incur those costs. This paragraph applies when:

(1) You value unprocessed gas under §1206.141(b) or residue gas and gas plant products under §1206.142(b) based on a sale at a point off the lease, unit, or communitized area where the residue gas, gas plant products, or unprocessed gas is produced; and

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

(ii) For gas produced on the OCS, the movement of gas from the wellhead to the first platform is not transportation.

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. If your or your affiliate's transportation contract includes more than one product in a gaseous phase, you must allocate costs consistently and equitably to each of the products transported. 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 products in the gaseous phase (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 prospective cost allocation method based on the values of the products transported. ONRR will approve the method, if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the production month following the month ONRR received your proposed procedure 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

(c)(1) Where you or your affiliate transport(s) 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

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

(d) If you value unprocessed gas under §1206.141(c) or residue gas and gas plant products under §1206.142 (d), you may not take a transportation allowance.

(e)(1) Your transportation allowance may not exceed 50 percent of the value of the residue gas, gas plant products, or unprocessed gas as determined under §1206.141 or §1206.142 of this subpart.

(2) If ONRR approved your request to take a transportation allowance in excess of the 50-percent limitation under former §1206.156(c)(3), that approval is terminated as of the effective date of the final rule.

(f) You must express transportation allowances for residue gas, gas plant products, or unprocessed gas as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate are paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under §1206.144 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor by transporting your gas, residue gas, or gas plant products at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10-percent higher than the highest reasonable measures of transportation costs including, but not limited to, transportation

allowances reported to ONRR and tariffs for gas, residue gas, or gas plant products transported through the same system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under §1206.153 or §1206.154 for any reason, including but not limited to, you or your affiliate's failure to provide documents ONRR requests under 30 CFR part 1212, subpart B.

(h) You do not need ONRR approval before reporting a transportation allowance.

§1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) 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 §1206.152(g) and subject to the limitation in §1206.152(e).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to, the following costs to determine your transportation allowance under paragraph (a) 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 section.

(1) *Firm demand charges paid to pipelines.* You may deduct firm demand charges or capacity reservation fees you or your affiliate paid to a pipeline, including charges or fees for unused firm capacity you or your affiliate have not sold before you report your allowance. If you or your affiliate receive(s) 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 or your affiliate receive(s) 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter;

(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 transportation arrangements unless the transportation allowance is based on arm's-length transportation rates charged under a FERC- or State regulatory-approved tariff, or ONRR approves your use of a FERC or State regulatory-approved tariff as an exception from the requirement to calculate actual costs under §1206.154(l) of this subpart. If you or your affiliate receive(s) volumes or credit for line gain, you must reduce your transportation allowance accordingly and pay any resulting royalties, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter;

(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;

(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 §1206.146 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 or your affiliate as a shipper to maintain under a transportation contract; and

(11) *Hurricane Surcharges.* You may deduct hurricane surcharges you or your affiliate actually pay(s).

(c) You may not include the following costs to determine your transportation allowance under paragraph (a) 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 or your affiliate pay(s) 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 or your affiliate incur(s) 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 or your affiliate for over-delivered volumes outside the tolerances and the price you or your affiliate receive(s) for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you or your affiliate incur(s) 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 or your affiliate incur(s) (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 or your affiliate incur(s) 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 or your affiliate pay(s) 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 you or your affiliate pay(s) 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 you or your affiliate pay(s) 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 or your affiliate incur(s) for services you are required to provide at no cost to the lessor, including but not limited to, costs to place your gas, residue gas, or gas plant products into marketable condition disallowed under §1206.146 and costs of boosting residue gas disallowed under 30 CFR 1202.151(b).

(d) If you have no written contract for the transportation of gas, then ONRR will determine your transportation allowance under §1206.144. You may not use this paragraph (d), if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.148(a).

(2) You may use that method to determine your allowance until ONRR issues its determination.

§1206.154 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. You must 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 may include:

(1) Capital costs and operating and maintenance expenses under paragraphs (e), (f), and (g) of this section;

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

(3) Depreciation and a return on undepreciated capital investment under paragraph (i)(1) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (i)(2) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request; and

(4) A return on the reasonable salvage value under paragraph (i)(1)(iii) of this section, after you have depreciated the transportation system to its reasonable salvage value.

(c)(1) To the extent not included in costs identified in paragraphs (e) through (g) of this section, if you or your affiliate incur(s) the actual transportation costs listed under §1206.153(b)(2), (5), and (6) of this subpart under your or your affiliate's non-arm's-length contract, you may include those costs in your calculations under this section. You may not include any of the other costs identified under §1206.153 (b); and

(2) You may not include in your calculations under this section any of the nonallowable costs listed under §1206.153(c).

(d) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

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

(f) 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 that you can document.

(g) Allowable maintenance expenses include:

(i) Maintenance of the transportation system;

(ii) Maintenance of equipment;

(iii) Maintenance labor; and

(iv) Other directly allocable and attributable maintenance expenses that you can document.

(h) 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.

(i)(1) To calculate depreciation and a return on undepreciated capital investment, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves that the transportation system services, or a unit of production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(i) A change in ownership of a transportation system will not alter the depreciation schedule the original transporter/lessee established for purposes of the allowance calculation.

(ii) You may depreciate a transportation system only once with or without a change in ownership.

(iii)(A) To calculate the return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the transportation system multiplied by the rate of return you determine under paragraph (i)(3) of this section.

(B) After you have depreciated a transportation system to the reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (i)(3) of this section.

(2) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (i)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average that BBB rate Standard & Poor's publishes for the first month for which the allowance is applicable.

(ii) You must redetermine the rate at the beginning of each subsequent calendar year.

§1206.155 What are my reporting requirements under an arm's-length transportation contract?

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

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.156 What are my reporting requirements under a non-arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on non-arm's-length transportation costs you or your affiliate incur(s).

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.158 applies 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. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d) If you are authorized under §1206.154(j) to use an exception to the requirement to calculate your actual transportation costs, you must follow the reporting requirements of §1206.155.

§1206.157 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit with interest.

(b) If you deduct a transportation allowance on Form ONRR-2014 that exceeds 50 percent of the value of the gas, residue gas, or gas plant products transported, you must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties due.

(c) If you improperly net a transportation allowance against the sales value of the residue gas, gas plant products, or unprocessed gas instead of reporting the allowance as a separate entry on Form ONRR-2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.158 What reporting adjustments must I make for transportation allowances?

(a) If your 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 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 period reported on the allowance form, you are entitled to a credit plus interest.

§1206.159 What general processing allowances requirements apply to me?

(a)(1) When you value any gas plant product under §1206.142(c) of this subpart, you may deduct from value the reasonable actual costs of processing.

(2) You do not need ONRR approval before reporting a processing allowance.

(b) You must allocate processing costs among the gas plant products. You must determine a separate processing allowance for each gas plant product and processing plant relationship. ONRR considers NGLs one product.

(c)(1) You may not apply the processing allowance against the value of the residue gas.

(2) The processing allowance deduction on the basis of an individual product may not exceed 66⅔ percent of the value of each gas plant product determined under §1206.142(c). Before you calculate the 66⅔ percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under §1206.152.

(3) If ONRR approved your request to take a processing allowance in excess of the limitation in paragraph (c)(2) of this section under former §1206.158(c)(3), that approval is terminated as of [EFFECTIVE DATE OF FINAL RULE].

(4) If ONRR approved your request to take an extraordinary cost processing allowance under former §1206.158(d), ONRR terminates that approval as of [EFFECTIVE DATE OF FINAL RULE].

(d)(1) ONRR will not allow a processing cost deduction 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.

(2) Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," ONRR will not allow processing cost deductions for such costs unless the acid gases removed are further processed into a gas plant product.

(A) In such event, you are eligible for a processing allowance determined under this subpart.

(B) ONRR will not grant any processing allowance for processing lease production that is not royalty bearing.

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

(a)(1) If you or your affiliate incur processing costs under an arm's-length processing contract, you may claim a processing allowance for the reasonable, actual costs incurred as more fully explained in paragraph (b) of this section, except as provided in paragraphs (a)(3)(1) and (a)(3)(ii) of this section and subject to the limitation in §1206.159(c)(2).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's length.

(3) ONRR may determine your processing allowance under §1206.144, if:

(i) ONRR determines that your or your affiliate's contract reflects more than the consideration actually transferred either directly or indirectly from you or your affiliate to the processor for processing; or

(ii) ONRR determines that the consideration you or your affiliate paid under an arm's-length processing contract does not reflect the reasonable cost of the processing because you breached your duty to market the gas for the mutual benefit of yourself and the lessor by processing your gas at a cost that is unreasonably high. We may consider a processing allowance unreasonably high, if it is 10-percent higher than the highest reasonable measures of processing costs, including but not limited to processing allowances reported to ONRR for gas processed in the same plant or area.

(b)(1) If your or your affiliate's arm's-length processing contract includes more than one gas plant product and you can determine the processing costs for each product based on the contract, then you must determine the processing costs for each gas plant product under the contract.

(2) If your or your affiliate's arm's-length processing contract includes more than one gas plant product and you cannot determine the processing costs attributable to each product from the contract, you must propose an allocation procedure to ONRR.

(i) You may use your proposed allocation procedure until ONRR issues its determination.

(ii) You must submit all relevant data to support your proposal.

(iii) ONRR will determine the processing allowance based upon your proposal and any additional information ONRR deems necessary.

(iv) You must submit the allocation proposal within 3 months of claiming the allocated deduction on Form ONRR-2014.

(3) You may not take an allowance for the costs of processing lease production that is not royalty-bearing.

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

(c) If you have no written contract for the arm's-length processing of gas, then ONRR will determine your processing allowance under §1206.144. You may not use this paragraph (c) if you or your affiliate perform(s) your own processing.

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.148(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§1206.161 How do I determine a processing allowance if I have a non-arm's-length processing contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length processing contract, including situations where you or your affiliate provide your own processing services. You must calculate your processing allowance based on you or your affiliate's reasonable, actual costs for processing during the reporting period using the procedures prescribed in this section.

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section;

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

(3) Depreciation and a return on undepreciated capital investment in accordance with paragraph (h)(1) of this section, or you may elect to use a cost equal to the initial depreciable capital investment in the processing plant under paragraph (h)(2) of this section. After you have elected to use either method for a processing plant, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request; and

(4) A return on the reasonable salvage value under paragraph (h)(1)(iii) of this section, after you have depreciated the processing plant to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the processing plant.

(e) 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 that you can document.

(f) Allowable maintenance expenses include:

(1) Maintenance of the processing plant;

(2) Maintenance of equipment;

(3) Maintenance labor; and

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

(g) 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 and other fees, including royalties, are not allowable expenses.

(h)(1) To calculate depreciation and a return on undepreciated capital investment, 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 processing plant services, or a unit-of-production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(i) A change in ownership of a processing plant will not alter the depreciation schedule that the original processor/lessee established for purposes of the allowance calculation.

(ii) You may depreciate a processing plant only once with or without a change in ownership.

(iii)(A) To calculate a return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the processing plant multiplied by the rate of return you determine under paragraph (h)(3) of this section.

(B) After you have depreciated a processing plant to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (h)(3) of this section.

(2) You may use as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied by the rate of return determined under paragraph (h)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average that BBB rate Standard & Poor's publishes for the first month for which the allowance is applicable.

(ii) You must redetermine the rate at the beginning of each subsequent calendar year.

(i)(1) You must determine the processing allowance for each gas plant product based on your or your affiliate's reasonable and actual cost of processing the gas. You must base your allocation of costs to each gas plant product upon generally accepted accounting principles.

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

(j) You may apply for an exception from the requirement to calculate actual costs under paragraphs (a) and (b) of this section.

(1) ONRR will grant the exception, if:

(i) You have or your affiliate 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 under arm's-length processing contracts.

(2) If ONRR grants the exception, you must use as your processing allowance the volume-weighted average prices charged other persons under arm's-length contracts for processing at the same plant.

§1206.162 What are my reporting requirements under an arm's-length processing contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on arm's-length processing costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length processing contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.163 What are my reporting requirements under a non-arm's-length processing contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on non-arm's-length processing costs you or your affiliate incur(s).

(b)(1) For new non-arm's-length processing facilities or arrangements, you must base your initial deduction on estimates of allowable gas processing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the processing plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar processing plants.

(3) Section 1206.165 will applies 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. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d) If you are authorized under §1206.161(j) to use an exception to the requirement to calculate your actual processing costs, you must follow the reporting requirements of §1206.162.

§1206.164 What interest and penalties apply if I improperly report a processing allowance?

(a)(1) If ONRR determines that you took an unauthorized processing allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter.

(2) If you understated your processing allowance, you may be entitled to a credit with interest.

(b) If you deduct a processing allowance on Form ONRR-2014 that exceeds 66⅔ percent of the value of a gas plant product, you must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties due.

(c) If you improperly net a processing allowance against the sales value of a gas plant product instead of reporting the allowance as a separate entry on Form ONRR-2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.165 What reporting adjustments must I make for processing allowances?

(a) If your actual processing 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 due, plus late payment interest calculated under §§1218.54 and 1218.102 of this chapter from the date you took the deduction to the date you repay the difference.

(b) If the actual processing allowance is greater than the amount you claimed on Form ONRR-2014 for any month during the period reported on the allowance form, you are entitled to a credit plus interest.

8. Revise subpart F to read as follows:

Subpart F—Federal Coal

Sec.

1206.250 What is the purpose and scope of this subpart?
1206.251 How do I determine royalty quantity and quality?
1206.252 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?
1206.253 How will ONRR determine if my royalty payments are correct?
1206.254 How will ONRR determine the value of my coal for royalty purposes?
1206.255 What records must I keep to support my calculations of royalty under this subpart?
1206.256 What are my responsibilities to place production into marketable condition and to market production?
1206.257 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?
1206.258 How do I request a valuation determination or guidance?
1206.259 Does ONRR protect information I provide?
1206.260 What general transportation allowance requirements apply to me?
1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?
1206.262 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?
1206.263 What are my reporting requirements under an arm's-length transportation contract?
1206.264 What are my reporting requirements under a non-arm's-length transportation contract?
1206.265 What interest and penalties apply if I improperly report a transportation allowance?
1206.266 What reporting adjustments must I make for transportation allowances?
1206.267 What general washing allowance requirements apply to me?
1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?
1206.269 How do I determine washing allowances if I have a non-arm's-length washing contract?
1206.270 What are my reporting requirements under an arm's-length washing contract?
1206.271 What are my reporting requirements under a non-arm's-length washing contract?
1206.272 What interest and penalties apply if I improperly report a washing allowance?
1206.273 What reporting adjustments must I make for washing allowances?

Subpart F—Federal Coal

§1206.250 What is the purpose and scope of this subpart?

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

(b) The terms “you” and “your” in this subpart refer to the lessee.

(c) 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 a coal lease subject to this subpart,

then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR may audit and order you to adjust all royalty payments.

§1206.251 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of coal at the royalty measurement point that ONRR and BLM jointly determine.

(b) You must measure coal in short tons using the methods BLM prescribes for Federal coal leases under 43 CFR part 3000. You must report coal quantity on appropriate forms required in 30 CFR Part 1210—Forms and Reports.

(c)(1) You are not required to pay royalties on coal you produce and add to stockpiles or inventory until you use, sell, or otherwise finally dispose of such coal.

(2) ONRR may request BLM to require you to increase your lease bond if BLM determines that stockpiles or inventory are excessive such that they increase the risk of resource degradation.

(d) You must pay royalty at the rate specified in your lease at the time you use, sell, or otherwise finally dispose of the coal.

(e) You must allocate washed coal by attributing the washed coal to the leases from which it was extracted.

(1) If the wash plant washes coal from only one lease, the quantity of washed coal allocable to the lease is the total output of washed coal from the plant.

(2) If the wash plant washes coal from more than one lease, you must determine the tonnage of washed coal attributable to each lease by:

(i) First, calculating the input ratio of washed coal allocable to each lease by dividing the tonnage of coal you input to the wash plant from each lease by the total tonnage of coal input to the wash plant from all leases; and

(ii) Then multiplying the input ratio derived under paragraph (e)(2)(i) of this section by the tonnage of total output of washed coal from the plant.

§1206.252 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less an applicable transportation allowance determined under §§1206.260 through 1206.262 and washing allowance under §§1206.267 through 1206.269. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length 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 coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant you or your affiliate own(s) for the generation and sale of electricity and;

(1) You or your affiliate sell(s) the electricity, then the value of the coal subject to this section, for royalty purposes, is the gross proceeds accruing to you for the power plant's arm's-length sales of the electricity less applicable transportation and washing deductions determined under §§1206.260 through 1206.262 and §§1206.267 through 1206.269 of this subpart and, if applicable, transmission and generation deductions determined under §§1206.353 and 1206.352 of subpart H;

(2) You or your affiliate do(es) not sell the electricity at arm's length (i.e. you or your affiliate deliver(s) the electricity directly to the grid), then ONRR will determine the value of the coal under §1206.254.

(i) You must propose to ONRR a method to determine the value using the procedures in §1206.258(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments under §1206.253(a)(2).

(c) If you are a coal cooperative, or a member of a coal cooperative, and:

(1) You sell or transfer coal to another member of the coal cooperative, and that member of the coal cooperative then sells the coal under an arm's-length contract, then you must value the coal under paragraph (a) of this section; or

(2) You sell or transfer coal to another member of the coal cooperative and the coal is used by you, the coal cooperative, or another member of the coal cooperative in a power plant for the generation and sale of electricity, then you must value the coal under paragraph (b) of this section.

(d) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

(e) The values in this section do not apply, if ONRR decides to value your coal under §1206.254.

§1206.253 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value, or decide your value, under §1206.254.

(2) If ONRR directs you to use a different royalty value, you must either pay any underpaid royalties due, plus late payment interest calculated under §1218.202 of this chapter or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the coal. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under §1206.254.

(c) ONRR may decide to value your coal under §1206.254 if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor by selling your coal at a value that is unreasonably low. ONRR may consider a sales price unreasonably low if it is 10-percent less than the lowest other reasonable measures of market price, including but not limited to, prices reported to ONRR for like-quality coal; or

(3) ONRR cannot determine if you properly valued your coal under §1206.252 for any reason, including but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration the buyer paid you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit

allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide to value your coal under §1206.254.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§1206.254 How will ONRR determine the value of my coal for royalty purposes?

If ONRR decides to value your coal for royalty purposes under §1206.254, or any other provision in this subpart, then ONRR will determine value by considering any information we deem relevant, which may include, but is not limited to:

(a) The value of like-quality coal from the same mine, nearby mines, same region, or other regions, or washed in the same or nearby wash plant;

(b) Public sources of price or market information that ONRR deems reliable, including but not limited to, the price of electricity;

(c) Information available to ONRR and information reported to it, including but not limited to, on Form ONRR-4430;

(d) Costs of transportation or washing, if ONRR determines they are applicable; or

(e) Any other information ONRR deems relevant regarding the particular lease operation or the salability of the coal.

§1206.255 What records must I keep to support my calculations of royalty under this subpart?

If you value your coal under this subpart, you must retain all data relevant to the determination of the royalty you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR. You must comply with any such requirement within the time ONRR specifies.

§1206.256 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place coal in marketable condition and market the coal for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.

(b) If you use gross proceeds under an arm's-length contract to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform to place the coal in marketable condition or to market the coal.

§1206.257 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR will not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR redetermining royalty due, under this subpart, final or binding as against the Federal Government or its beneficiaries unless ONRR chooses to formally close the audit period in writing.

§1206.258 How do I request a valuation determination or guidance?

(a) You may request a valuation determination or guidance from ONRR regarding any coal produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) 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 a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination; or

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance

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 determination the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

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

(d) Guidance ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

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

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or make a determination.

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

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under §1206.259.

§1206.259 Does ONRR protect information I provide?

(a) Certain information you or your affiliate submit(s) to ONRR regarding royalties on coal, including deductions and allowances, may be exempt from disclosure.

(b) To the extent applicable laws and regulations permit, ONRR will keep confidential any data you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§1206.260 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off the lease or mine as determined under §1206.261 or §1206.262, as applicable.

(2) You do not need ONRR approval before reporting a transportation allowance for costs incurred.

(b) You may take a transportation allowance when:

(1) You value coal under §1206.252 of this part;

(2) You transport the coal from a Federal lease to a sales point, which is remote from both the lease and mine; or

(3) You 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.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You only may claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Federal and non-Federal leases, you may not disproportionately allocate transportation costs to Federal lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Federal lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Federal lease, you must allocate transportation costs to each Federal lease as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Federal lease production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal

transported.

(5)(i) You must report your transportation costs on Form ONRR-4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per-short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per-short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under §1206.254 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10-percent higher than the highest reasonable measures of transportation costs including, but not limited to, transportation allowances reported to ONRR and the cost to transport coal through the same transportation system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance

under §1206.261 or §1206.262 for any reason including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

§1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's length.

(c) If you have no written contract for the arm's-length transportation of coal, then ONRR will determine your transportation allowance under §1206.254. You may not use this paragraph (c) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.258(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§1206.262 How do I determine a transportation allowance for a non-arm's-length transportation contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. You must 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 may include:

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section;

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

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (j) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request; and

(4) A return on the reasonable salvage value, under paragraph (i) of this section, after you have depreciated the transportation system to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment 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.

(e) 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 expenses that you can document.

(f) 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 that you can document.

(g) 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.

(h)(1) To calculate depreciation, you may elect to use either (i) a straight-line depreciation method based on the life of the transportation system or the life of the reserves which the transportation system services, or (ii) a unit-of-production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(2) A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for purposes of the allowance calculation.

(3) You may depreciate a transportation system only once with or without a change in ownership.

(i)(1) To calculate a return on undepreciated capital investment, you must 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 (k) of this section.

(2) After you have depreciated a transportation system to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return determined under paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (k) of this section. You may not include depreciation in your allowance

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must redetermine the rate at the beginning of each subsequent calendar year.

(3) After ONRR issues a determination, you must make the adjustments under §1206.266.

§1206.263 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on transportation costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.264 What are my reporting requirements under a non-arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length transportation costs you or your affiliate incur(s).

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.266 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.265 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit without interest.

(b) If you improperly net a transportation allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.266 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §1218.202 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-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

§1206.267 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under §1206.252 of this subpart, you may take a washing allowance for the reasonable, actual costs to wash coal. The allowance is a deduction when determining coal royalty value for the costs you incur to wash coal.

(2) You do not need ONRR approval before reporting a washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing;

(2) Disproportionately allocate washing costs to Federal leases. You must allocate washing costs to washed coal attributable to each Federal lease by multiplying the input ratio determined under §1206.251(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate paid to a dollar-value equivalent.

(d) ONRR may determine your washing allowance under §1206.254 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length washing contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high. We may consider a washing allowance unreasonably high if it is 10-percent higher than the highest other reasonable measures of washing, including but not limited to, washing allowances

reported to ONRR and costs for coal washed in the same plant or other plants in the region; or

(3) ONRR cannot determine if you properly calculated a washing allowance under §§1206.267 through 1206.269 for any reason, including but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You only may claim a washing allowance, when you sell the washed coal and report and pay royalties.

§1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's contract is arm's length.

(c) If you have no written contract for the arm's-length washing of coal, then ONRR will determine your washing allowance under §1206.254. You may not use this paragraph (c) if you or your affiliate perform(s) your own washing. If you or your affiliate perform(s) the washing, then:

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.258(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§1206.269 How do I determine washing allowances if I have a non-arm's-length

washing contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length washing contract, including situations where you or your affiliate provides your own washing services. You must calculate your washing allowance based on your or your affiliate's reasonable, actual costs for washing during the reporting period using the procedures prescribed in this section.

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section;

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

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the wash plant under paragraph (j) of this section. After you have elected to use either method for a wash plant, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request; and

(4) A return on the reasonable salvage value, under paragraph (i) of this section, after you have depreciated the wash plant to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment 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.

(e) 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 expenses that you can document.

(f) Allowable maintenance expenses include:

(1) Maintenance of the wash plant;

(2) Maintenance of equipment; and

(3) Maintenance labor.

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

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

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of the wash plant or the life of the reserves which the wash plant services, or a unit-of-production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(2) A change in ownership of a wash plant will not alter the depreciation schedule that the original washer/lessee established for purposes of the allowance calculation.

(3) With or without a change in ownership, you may depreciate a wash plant only once.

(i)(1) To calculate a return on undepreciated capital investment, you must multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the washing allowance by the rate of return provided in paragraph (k) of this section.

(2) After you have depreciated a wash plant to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the salvage value multiplied by a rate of return determined under paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the wash plant multiplied by the rate of return as determined under paragraph (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for

the first month for which the allowance is applicable.

(2) You must redetermine the rate at the beginning of each subsequent calendar year.

(3) After ONRR issues its determination, you must make the adjustments under §1206.273.

§1206.270 What are my reporting requirements under an arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on washing costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length washing contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.271 What are my reporting requirements under a non-arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length washing costs you or your affiliate incur(s).

(b)(1) For new non-arm's-length washing facilities or arrangements, you must base your initial deduction on estimates of allowable washing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the wash plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar wash plants.

(3) Section 1206.273 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§1206.272 What interest and penalties apply if I improperly report a washing allowance?

(a)(1) If ONRR determines that you took an unauthorized washing allowance, then you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

(2) If you understated your washing allowance, you may be entitled to a credit without interest.

(b) If you improperly net a washing allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.273 What reporting adjustments must I make for washing allowances?

(a) If your actual washing allowance is less than the amount you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §1218.202 of this chapter from the date you took the deduction to the date you repay the difference.

(b) If the actual washing allowance is greater than the amount you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

9. Revise subpart J to read as follows:

Subpart J—Indian Coal

Sec.

1206.450 What is the purpose and scope of this subpart?
1206.451 How do I determine royalty quantity and quality?
1206.452 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?
1206.453 How will ONRR determine if my royalty payments are correct?
1206.454 How will ONRR determine the value of my coal for royalty purposes?
1206.455 What records must I keep to support my calculations of royalty under this subpart?
1206.456 What are my responsibilities to place production into marketable condition and to market production?
1206.457 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?
1206.458 How do I request a valuation determination or guidance?
1206.459 Does ONRR protect information I provide?
1206.460 What general transportation allowance requirements apply to me?
1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?
1206.462 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?
1206.463 What are my reporting requirements under an arm's-length transportation contract?
1206.464 What are my reporting requirements under a non-arm's-length transportation contract or no written arm's-length contract?
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1206.467 What general washing allowance requirements regarding apply to me?
1206.468 How do I determine a washing allowance if I have an arm's-length washing contract or no written arm's-length contract?
1206.469 How do I determine a washing allowance if I have a non-arm's-length washing contract?
1206.470 What are my reporting requirements under an arm's-length washing contract?
1206.471 What are my reporting requirements under a non-arm's-length washing contract or no written arm's-length contract?
1206.472 What interest and penalties apply if I improperly report a washing allowance?
1206.473 What reporting adjustments must I make for washing allowances?

Subpart J—Indian Coal

§1206.450 What is the purpose and scope of this subpart?

(a) This subpart applies to all coal produced from Indian tribal coal leases and coal leases on land held by individual Indian mineral owners. It explains how you, as the lessee, must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms (except leases on the Osage Indian Reservation, Osage County, Oklahoma).

(b) The terms “you” and “your” in this subpart refer to the lessee.

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

(1) A Federal statute or treaty;

(2) A settlement agreement;

(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 a coal lease subject to this subpart,

then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR may audit and order you to adjust all royalty payments.

(e) The regulations in this subpart, intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian coal leases, are discharged under the requirements of the governing mineral leasing laws, treaties, and lease terms.

§1206.451 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of coal at the royalty measurement point that ONRR and BLM jointly determine.

(b) You must measure coal in short tons using the methods BLM prescribes for Indian coal leases. You must report coal quantity on appropriate forms required in 30 CFR part 1210.

(c)(1) You are not required to pay royalties on coal you produce and add to stockpiles or inventory until you use, sell, or otherwise finally dispose of such coal.

(2) ONRR may request BLM to require you to increase your lease bond if BLM determines that stockpiles or inventory are excessive such that they increase the risk of resource degradation.

(d) You must pay royalty at the rate specified in your lease at the time you use, sell, or otherwise finally dispose of the coal.

(e) You must allocate washed coal by attributing the washed coal to the leases from which it was extracted.

(1) If the wash plant washes coal from only one lease, the quantity of washed coal allocable to the lease is the total output of washed coal from the plant.

(2) If the wash plant washes coal from more than one lease, you must determine the tonnage of washed coal attributable to each lease by:

(i) First, calculating the input ratio of washed coal allocable to each lease by dividing the tonnage of coal you input to the wash plant from each lease by the total tonnage of coal input to the wash plant from all leases; and

(ii) Then multiplying the input ratio derived under paragraph (e)(2)(i) of this section by the tonnage of total output of washed coal from the plant.

§1206.452 How do I calculate royalty value for coal I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less an applicable transportation allowance determined under §§1206.460 through 1206.462 and washing allowance under §§1206.467 through 1206.469. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length 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 coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant you or your affiliate own(s) for the generation and sale of electricity and;

(1) You or your affiliate sell(s) the electricity, then the value of the coal subject to this section, for royalty purposes, is the gross proceeds accruing to you for the power plant's arm's-length sales of the electricity less applicable transportation and washing deductions determined under §§1206.460 through 1206.462 and §§1206.467 through 1206.469 of this subpart and, if applicable, transmission and generation deductions determined under §§1206.353 and 1206.352 of subpart H;

(2) You or your affiliate do(es) not sell the electricity at arm's length (i.e. you or your affiliate deliver(s) the electricity directly to the grid), then ONRR will determine the value of the coal under §1206.454.

(i) You must propose to ONRR a method to determine the value using the procedures in §1206.458(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments under

§1206.453(a)(2).

(c) If you are a coal cooperative, or a member of a coal cooperative, and;

(1) You sell or transfer coal to another member of the coal cooperative, and that member of the coal cooperative then sells the coal under an arm's-length contract, then you must value the coal under paragraph (a) of this section; or

(2) You sell or transfer coal to another member of the coal cooperative, and the coal is used by you, the coal cooperative, or another member of the coal cooperative, in a power plant for the generation and sale of electricity, then you must value the coal under paragraph (b) of this section.

(d) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

(e) The values in this section do not apply, if ONRR decides to value your coal under §1206.454.

§1206.453 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value, or decide your value, under §1206.454.

(2) If ONRR directs you to use a different royalty value, you must either pay any underpaid royalties plus late payment interest calculated under §1218.202 of this chapter or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the coal. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under §1206.454.

(c) ONRR may decide to value your coal under §1206.454, if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor by selling your coal at a value that is unreasonably low. ONRR may consider a sales price unreasonably low, if it is 10-percent less than the lowest other reasonable measures of market price, including but not limited to, prices reported to ONRR for like-quality coal; or

(3) ONRR cannot determine if you properly valued your coal under §1206.452 for any reason, including but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration the buyer paid you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide to value your coal under §1206.454.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§1206.454 How will ONRR determine the value of my coal for royalty purposes?

If ONRR decides to value your coal for royalty purposes under §1206.454, or any other provision in this subpart, then ONRR will determine value by considering any information we deem relevant, which may include, but is not limited to:

(a) The value of like-quality coal from the same mine, nearby mines, same region, or other regions, or washed in the same or nearby wash plant;

(b) Public sources of price or market information that ONRR deems reliable, including but not limited to, the price of electricity;

(c) Information available to ONRR and information reported to it, including but not limited to, on Form ONRR-4430;

(d) Costs of transportation or washing, if ONRR determines they are applicable; or

(e) Any other information ONRR deems relevant regarding the particular lease operation or the salability of the coal.

§1206.455 What records must I keep to support my calculations of royalty under this subpart?

If you value your coal under this subpart, you must retain all data relevant to the determination of the royalty you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR or the representative of the Indian lessor, or to the Inspector General of the Department of the Interior or other persons authorized to receive such information. Such data may include arm's-length sales and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by you or your affiliate from the same mine, nearby mines, same region, or other regions. You must comply with any such requirement within the time ONRR specifies.

§1206.456 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place coal in marketable condition and market the coal for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor.

(b) If you use gross proceeds under an arm's-length contract to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform to place the coal in marketable condition or to market the coal.

§1206.457 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR will not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR redetermining royalty due, under this subpart, final or binding as against the Federal Government or its beneficiaries unless ONRR chooses to formally close the audit period in writing.

§1206.458 How do I request a valuation determination or guidance?

(a) You may request a valuation determination or guidance from ONRR regarding any coal produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) 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 a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination; or

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance 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 determination the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

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

(d) Guidance ONRR issues is not binding on ONRR, Tribes, individual Indian mineral owners, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR’s decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

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

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or make a determination.

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

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under §1206.459.

§1206.459 Does ONRR protect information I provide?

(a) Certain information you or your affiliate submit(s) to ONRR regarding royalties on coal, including deductions and allowances, may be exempt from disclosure.

(b) To the extent applicable laws and regulations permit, ONRR will keep confidential any data you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§1206.460 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off the lease or mine as determined under §1206.461 or §1206.462, as applicable.

(2) Before you may take any transportation allowance, you must submit a completed page 1 of Form ONRR-4293, Coal Transportation Allowance Report, under sections §1206.463 and §1206.464 of this subpart. You may claim a transportation allowance retroactively for a period of not more than 3 months prior to the first day of the month that ONRR receives your Form ONRR-4293.

(3) You may not use a transportation allowance that was in effect before [**EFFECTIVE DATE OF THE FINAL RULE**]. You must use the provisions of this subpart to determine your transportation allowance.

(b) You may take a transportation allowance when:

(1) You value coal under §1206.452 of this part;

(2) You transport the coal from an Indian lease to a sales point which, is remote from both the lease and mine; or

(3) You 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.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You only may claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Indian and non-Indian leases, you may not disproportionately allocate transportation costs to Indian lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Indian lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Indian lease, you must allocate transportation costs to each Indian lease as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Indian leases production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal transported.

(5)(i) You must report your transportation costs on Form ONRR-4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under §1206.454 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10-percent higher than the highest reasonable measures of transportation costs including, but not limited to, transportation allowances reported to ONRR and the cost to transport coal through the same transportation system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under §1206.461 or §1206.462 for any reason including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

§1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's length.

(c) If you have no written contract for the arm's-length transportation of coal, then

ONRR will determine your transportation allowance under §1206.454. You may not use this paragraph (c) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.458(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§1206.462 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

(a) This section applies if you or your affiliate do(es) 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 may include:

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section;

(2) Overhead under paragraph (g) of this section; and

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (j) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your

changed method beginning with the production month following the month ONRR received your change request.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment 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.

(e) 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 that you can document.

(f) 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 that you can

document.

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

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of the transportation system or 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. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(2) A change in ownership of a transportation system will not alter the depreciation schedule the original transporter/lessee established for purposes of the allowance calculation.

(3) You may depreciate a transportation system only once with or without a change in ownership.

(i) 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 (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must redetermine the rate at the beginning of each subsequent calendar year.

(3) After ONRR issues a determination, you must make the adjustments under §1206.466.

§1206.463 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on transportation costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d)(1) You must submit page 1 of the initial Form ONRR-4293 prior to, or at the same time as, you report the transportation allowance determined under an arm's-length contract on Form ONRR-4430.

(2) The initial Form ONRR-4293 is effective beginning with the production month that you are first authorized to deduct a transportation allowance and continues until the end of the calendar year, or until the termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3) After the initial period that ONRR first authorized you to deduct a transportation allowance and for succeeding periods, you must submit the entire Form ONRR-4293 by the earlier of:

(i) Within 3 months after the end of the calendar year; or

(ii) After the termination, modification, or amendment of the applicable contract or rate.

(4) You may request to use an allowance for a longer period than that required under paragraph (d)(2) of this section.

(i) You may use that allowance beginning with the production month following the month ONRR received your request to use the allowance for a longer period until ONRR decides whether to approve the longer period.

(ii) ONRR's decision whether or not to approve a longer period is not appealable under 30 CFR part 1290.

(iii) If ONRR does not approve the longer period, you must adjust your transportation allowance under §1206.466.

§1206.464 What are my reporting requirements under a non-arm's-length transportation contract or no written arm's-length contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length transportation costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(c)(1) You must submit an initial Form ONRR-4293 prior to, or at the same time as, the transportation allowance determined under a non-arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4293 by the end of the month that the Form ONRR-4430 is due, ONRR will consider the form timely received. You may base the initial form on estimated costs.

(2) The initial Form ONRR-4293 is effective beginning with the production month that you are first authorized to deduct a transportation allowance and continues until the end of the calendar year or termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3)(i) At the end of the calendar-year for which you submitted a Form ONRR-4293 based on estimates, you must submit another completed Form ONRR-4293 containing the actual costs for that calendar year.

(ii) If the transportation continues, you must include on Form ONRR-4293 your estimated costs for the next calendar year.

(A) You must base the estimated transportation allowance on the actual costs for the previous reporting period plus or minus any adjustments based on your knowledge of decreases or increases that will affect the allowance.

(B) ONRR must receive Form ONRR-4293 within 3 months after the end of the previous calendar year.

(d)(1) For new non-arm's-length transportation facilities or arrangements, on your initial Form ONRR-4293, you must include estimates of the allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you

must use estimates based on data for similar transportation systems.

(e) Upon ONRR's request, you must submit all data used to prepare your Form ONRR-4293. You must provide the data within a reasonable period of time, as ONRR determines.

(f) Section 1206.466 applies when you amend your Form ONRR-4293 based on the actual costs.

§1206.465 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit without interest.

(b) If you improperly net a transportation allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.466 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §1218.202 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-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

§1206.467 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under §1206.452 of this subpart, you may take a washing allowance for the reasonable, actual costs to wash coal. The allowance is a deduction when determining coal royalty value for the costs you incur to wash coal.

(2) Before you may take any deduction, you must submit a completed page one of Form ONRR-4292, Coal Washing Allowance Report, under §§1206.470 and 1206.471 of this subpart. You may claim a washing allowance retroactively for a period of not more than 3 months prior to the first day of the month that you have filed Form ONRR-4292 with ONRR.

(3) You may not use a washing allowance that was in effect before the effective date of the final rule. You must use the provisions of this subpart to determine your washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing;

(2) Disproportionately allocate washing costs to Indian leases. You must allocate washing costs to washed coal attributable to each Indian lease by multiplying the input ratio determined under §1206.451(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate paid to a dollar-value equivalent.

(d) ONRR may determine your washing allowance under §1206.454 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration you or your affiliate paid under an arm's-length washing contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high. We may consider a washing allowance unreasonably high if it is 10-percent higher than the highest other reasonable measures of washing, including but not limited to, washing allowances reported to ONRR and costs for coal washed in the same plant or other plants in the region; or

(3) ONRR cannot determine if you properly calculated a washing allowance under §§1206.467 through 1206.469 for any reason, including but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You only may claim a washing allowance, if you sell the washed coal and report and pay royalties.

§1206.468 How do I determine a washing allowance if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's contract is arm's length.

(c) If you have no contract for the washing of coal, then ONRR will determine your transportation allowance under §1206.454. You may not use this paragraph (c), if you or your affiliate perform(s) your own washing. If you or your affiliate perform(s) the washing, then:

(1) You must propose to ONRR a method to determine the allowance using the procedures in §1206.458(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§1206.469 How do I determine a washing allowance if I have a non-arm's-length washing contract?

(a) This section applies if you or your affiliate do(es) not have an arm's-length washing contract, including situations where you or your affiliate provides your own washing services. Calculate your washing allowance based on your or your affiliate's reasonable, actual costs for washing during the reporting period using the procedures prescribed in this section.

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section;

(2) Overhead under paragraph (g) of this section; and

(3) Depreciation under paragraph (h) of this section and a return on undepreciated

capital investment under paragraph (i) of this section, or a cost equal to a return on the initial depreciable capital investment in the wash plant under paragraph (j) of this section. After you have elected to use either method for a wash plant, you may not later elect to change to the other alternative without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment 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.

(e) 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 expenses that you can document.

(f) Allowable maintenance expenses include:

(1) Maintenance of the wash plant;

(2) Maintenance of equipment;

(3) Maintenance labor; and

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

(g) Overhead, directly attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and Indian tribal severance taxes and other fees, including royalties, are not allowable expenses.

(h)(1) To calculate depreciation, you may elect to use either (i) a straight-line depreciation method based on the life of the wash plant or the life of the reserves which the wash plant services, or (ii) a unit-of-production method. After you make an election, you may not change methods without ONRR approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month ONRR received your change request.

(2) A change in ownership of a wash plant will not alter the depreciation schedule the original washer/lessee established for purposes of the allowance calculation.

(3) With or without a change in ownership, you may depreciate a wash plant only once.

(i) 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 washing allowance by the rate of return provided in paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the wash plant multiplied by the rate of return as determined under paragraph (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must redetermine the rate at the beginning of each subsequent calendar year.

(3) After ONRR issues its determination, you must make the adjustments under §1206.473.

§1206.470 What are my reporting requirements under an arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on washing costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length washing contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d)(1) You must file an initial Form ONRR-4292 prior to, or at the same time, as the washing allowance determined under an arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4292 by the end of the month that the Form ONRR-4430 is due, ONRR will consider the form timely received.

(2) The initial Form ONRR-4292 is effective beginning with the production month that you are first authorized to deduct a washing allowance and continues until the end of the calendar year, or until the termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3) After the initial period that ONRR first authorized you to deduct a washing allowance, and for succeeding periods, you must submit the entire Form ONRR-4292 by the earlier of:

(i) Within 3 months after the end of the calendar year; or

(ii) After the termination, modification, or amendment of the applicable contract or rate.

(4) You may request to use an allowance for a longer period than that required under paragraph (d)(2) of this section.

(i) You may use that allowance beginning with the production month following the month ONRR received your request to use the allowance for a longer period until ONRR decides whether to approve the longer period.

(ii) ONRR's decision whether or not to approve a longer period is not appealable under 30 CFR part 1290.

(iii) If ONRR does not approve the longer period, you must adjust your transportation allowance under §1206.466.

§1206.471 What are my reporting requirements under a non-arm's-length washing contract or no written arm's-length contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length washing costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(c)(1) You must submit an initial Form ONRR-4292 prior to, or at the same time as, the washing allowance determined under a non-arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4292 by the end of the month that the Form ONRR-4430 is due, ONRR will consider the form received timely. You may base the initial reporting on estimated costs.

(2) The initial Form ONRR-4292 is effective beginning with the production month that you are first authorized to deduct a washing allowance and continues until the end of the calendar year or termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3)(i) At the end of the calendar year for which you submitted a Form ONRR-4292, you must submit another completed Form ONRR-4292 containing the actual costs for that calendar year.

(ii) If coal washing continues, you must include on Form ONRR-4292 your estimated costs for the next calendar year.

(A) You must base the estimated coal washing allowance on the actual costs for the previous period plus or minus any adjustments based on your knowledge of decreases or increases that will affect the allowance.

(B) ONRR must receive Form ONRR-4292 within 3 months after the end of the previous calendar year.

(d)(1) For new non-arm's-length washing facilities or arrangements on your initial Form ONRR-4292, you must include estimates of allowable washing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the wash plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar wash plants.

(e) Upon ONRR's request, you must submit all data you used to prepare your Forms ONRR-4293. You must provide the data within a reasonable period of time, as ONRR determines.

(f) Section 1206.472 applies when you amend your Form ONRR-4292 based on the actual costs.

§1206.472 What interest and penalties apply if I improperly report a washing allowance?

(a)(1) If ONRR determines that you took an unauthorized washing allowance, then you must pay any additional royalties due, plus late payment interest calculated under §1218.202 of this chapter.

(2) If you understated your washing allowance, you may be entitled to a credit without interest.

(b) If you improperly net a washing allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§1206.473 What reporting adjustments must I make for washing allowances?

(a) If your actual washing allowance is less than the amount you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §1218.202 of this chapter from the date you took the deduction to the date you repay the difference.

(b) If the actual washing allowance is greater than the amount you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

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