DEPARTMENT OF THE INTERIOR

Office of Natural Resources Revenue

30 CFR Parts 1202, 1205, and 1210

[Docket No. ONRR–2011–0013; DS63610300 DR2PS0000.CH7000 134D0102R2]

RIN 1012–AA02

Reporting and Paying Royalties on Federal Leases

AGENCY: Office of Natural Resources Revenue, Interior.

ACTION: Proposed rule.

SUMMARY: The Office of Natural Resources Revenue (ONRR) is proposing new regulations to implement section 6(d) of the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996. The new regulations would prescribe when a Federal lessee must report and pay royalties on the volume of oil and gas it takes from a lease or on the volume to which it is entitled based on its ownership interest in the lease.

DATES: Comments must be submitted on or before October 7, 2013.

ADDRESSES: You may submit comments to ONRR on the rulemaking by any of the following methods. Please use the Regulation Identifier Number (RIN) 1012–AA02 as an identifier in your message. See also Public Availability of Comments under Procedural Matters.

- Federal eRulemaking Portal: *http://www.regulations.gov.* In the entry titled ''Enter Keyword or ID,'' enter ONRR–2011–0013, then click search. Follow the instructions to submit public comments and view supporting and related materials available for this rulemaking. ONRR will post all comments.
- Mail comments to Armand Southall, Regulatory Specialist, ONRR, P.O. Box 25165, MS 61030A, Denver, Colorado 80225–0165.
- Hand-carry comments or use an overnight courier service. Our courier address is Building 85, Room A–614, Denver Federal Center, West 6th Ave. and Kipling St., Denver, Colorado 80225.

Information Collection Request (ICR) Comments: Submit written comments by either fax (202) 395–5806 or email (*OIRA_Docket@omb.eop.gov*) directly to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for the Department of the Interior [OMB Control Number ICR 1012–0NEW as it relates to this proposed rule, Reporting and Paying Royalties on Federal Leases]. Please also send a copy to ONRR by one of the methods above.

FOR FURTHER INFORMATION CONTACT: For comments or questions on procedural issues, contact Armand Southall, Regulatory Specialist, at (303) 231–3221. For questions on technical issues, contact one of the authors: Sarah Inderbitzin at (303) 231–3748, Roman Geissel at (303) 231–3226, or Lydia Barder at (303) 231–3570.

SUPPLEMENTARY INFORMATION:

I. Purpose of the Regulatory Action

a. The proposed rule, known as Takes vs. Entitlements, would make substantive changes to the regulations in order to implement section 6(d) of the Royalty Simplification and Fairness Act (RSFA). Section 6(d), titled ''Volume Allocation of Oil and Gas Production,'' amended section 111 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. 1721, by adding new paragraphs (k)(1) through (5), 110 Stat. 1713, 1714.

b. This rulemaking would implement FOGRMA paragraphs 111(k)(1) through (4). The new regulations would prescribe when a Federal lessee must report and pay royalties on the volume of oil and gas it takes from a lease or on the volume to which it is entitled based on its ownership interest in the lease.

II. Summary of Major Provisions of the Regulatory Action in Question

In this proposed rule, we would amend title 30 of the *Code of Federal Regulations* (CFR) part 1202, subparts C and D, relating to the volume of production on which lessees must pay royalties. We also would amend subparts D and J to clarify that lessees should report gas volumes produced from Federal and Indian leases consistent with Bureau of Land Management (BLM) or Bureau of Ocean Energy Management (BOEM) regulations and notices. Because RSFA, including the takes versus entitlements provisions in 30 U.S.C. 1721(k), applies only to Federal leases, the only portions of this rule that apply to Indian leases are those specifically noted in the preamble or the proposed regulations.

This proposed rule also would add a new 30 CFR part 1205. Subpart A would explain the general provisions of the rule, define the leases to which the rule applies, and provide definitions of terms used in the rulemaking. Subpart B would explain the basic reporting and payment requirements for each of the three classes of leases FOGRMA paragraph 111(k)(1) identifies: 100-percent Federal agreements, leases in mixed agreements, and leases not contained in agreements (stand-alone leases), as the following table shows.

If you are a lessee of a lease or portion of a lease that is . . .	Then you must report and pay royalties based on . . .
(1) Not contained in an agreement (stand-alone)	The volume of production you take from the lease or portion of a lease that is not in an agreement.
(2) In a 100-percent Federal agreement	The volume of production you take from the lease or portion of the lease in a 100-percent Federal agreement.
(3) In a mixed agreement	Your entitled share of production allocated to the lease or portion of the lease in the mixed agreement.

Subpart C would explain how lessees can propose and receive approval to use alternatives to the reporting requirements for leases in 100-percent Federal agreements. Subpart D would explain (1) How lessees can use the marginal property reporting exception for mixed agreements that meet specific criteria, (2) identify the determining criteria, and (3) explain how to report on an eligible marginal property.

III. Costs and Benefits

ONRR estimates the net cost of compliance to industry in the first year this rule is effective would be $643,378 and $7,544 in subsequent years. We base the requests for alternate reporting costs on an estimated 250 requests for alternate reporting based on entitlements rather than takes. ONRR estimates that these requests will take 10 hours each to complete, not including an additional one-quarter hour for recordkeeping. Thus, the hour burden in the first year would be 2,563 hours. We estimate the labor costs of these hours, coupled with the $2,400 fee per request for alternate reporting, would be $717,898. In subsequent years, ONRR expects requests for alternate reporting would drop to 23 per year, and requests to terminate alternate reporting would be 2 per year. Using the same calculations, ONRR expects the cost for alternate reporting in subsequent years would be $66,976.

We estimated marginal property qualification based on 3,600 producing mixed agreements, allowing one-half hour to determine average daily well production and one-quarter hour for recordkeeping. The hour burden would be 2,700 hours, and the cost would be $124,200, based on the same cost factor used in determining the costs for alternate reporting.

ONRR estimates the reduction in reporting burden would save industry 4,320 hours per year. Using the same cost factor that we used in the costs for alternate reporting and determining marginal property qualification, the benefit to industry would be $198,720 per year.

Adding the costs and subtracting the benefit accrued provides the net cost to industry of $643,378 in the first year and $7,544 in subsequent years.

ONRR believes the costs and benefits to state governments would be minimal and are not quantifiable at this time.

ONRR believes the Federal Government would benefit by a reduced burden and clearer reporting instructions for verifying production reports. ONRR also believes the Federal Government may benefit because (1) the reduced burden of reporting may extend the life on marginal properties, and (2) the diminished out-of-pocket expenses may enhance lease investment.

IV. Introduction

On August 13, 1996, the President signed into law the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (RSFA), Public Law 104–185, 110 Stat. 1700, as corrected by Public Law 104–200. Section 6(d) of RSFA amended section 111 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA). This rulemaking would implement FOGRMA paragraphs 111(k)(1) through (4), which Congress enacted to clarify and resolve the long-standing issues regarding so-called ‘‘takes versus entitlements.’’ The issues arose primarily where the amount of natural gas taken and sold from Federal leases in a unit or communitization agreement was not equal to the lessee's entitled share based on the lessee's ownership interest in its leases in the unit or communitization agreement. These imbalances led to numerous questions about who should report and pay on what volumes and for what leases.

In an earlier effort to resolve these issues, ONRR's predecessor organization, Minerals Revenue Management (MRM), a program of Minerals Management Service (MMS), published an advance notice of proposed rulemaking on June 1, 1992 (57 FR 23068), seeking comments on valuation and reporting and paying royalties on production from Federal agreements. (Hereafter, in this rulemaking, we will refer only to ONRR, although actions may have occurred before ONRR was established.) We formed the Federal Gas Valuation Negotiated Rulemaking Committee, one purpose of which was to seek ways to resolve these issues. Subsequently, we published a proposed rule on November 6, 1995 (60 FR 56007), which contained reporting and payment provisions similar to FOGRMA paragraphs 111(k)(1) through (4). However, the proposed rule was withdrawn on April 22, 1997 (62 FR 19536).

Prior to initiating this rulemaking, in order to implement FOGRMA paragraphs 111(k)(1) through (4), we sought input from interested states, oil and gas trade associations, and our own ONRR analysts. We held outreach meetings on October 30, November 19, and December 6, 1996, and obtained input on general definitions, the reporting requirements for 100-percent Federal agreements, the definition of a ‘‘marginal property,’’ and the determination of a marginal property reporting exception.

Subsequently, ONRR began drafting a proposed rule. However, during that process, several issues came up regarding how this proposed rule should apply to production that is commingled prior to the royalty measurement point. Thus, we held additional public meetings on December 14, 2005, and May 10, 2006, to solicit input on this issue. We also published advance notices of proposed rulemaking on November 29, 2005 (70 FR 71421), and April 7, 2006 (71 FR 17774), giving examples of this issue and requesting comments.

V. Explanation of Proposed Amendments

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, 1205, and 1210 and signature page in this proposed rule. This language will be codified in the CFR if this rule is finalized as written.

After you have read the rule, please return to the preamble discussion below. The preamble contains additional information about the rule, such as why we defined a term in a certain manner, why we chose a certain reporting procedure over another, and how we interpret the law this rule would implement.

A. Section-By-Section Analysis of Proposed Changes to 30 CFR Part 1202—Royalties, Subpart C—Federal and Indian Oil, Subpart D—Federal Gas, and Subpart J—Gas Production From Indian Leases

ONRR proposes to amend subparts C, D, and J relating to the Federal and Indian production volumes on which you must pay royalties.

§ 1202.100 Royalty on Oil

This rule proposes to eliminate the current requirement to trace the sale of oil production that you do not take from a Federal lease by removing the reference to Federal leases in paragraph (e) and expressly limiting its applicability to Indian leases only.

This rule also proposes to revise paragraph (f) to read as follows:

Federal oil. The regulations explaining when you must report and pay royalties on the volume of oil you take from your Federal lease, including Federal leases committed to a federally approved unitization or communitization agreement, or on the entitled share of production from or allocated to your Federal lease, are found in 30 CFR part 1205.

Existing paragraph (f) provides that lessees may request that ONRR establish a valuation method other than that required in 30 CFR part 1206, under certain conditions. We propose to revise this paragraph because the revised regulations for Federal and Indian oil in 30 CFR part 1206 now contain similar, but less proscriptive, provisions. See 30 CFR 1206.59 (Indian oil) and 30 CFR 1206.107 (Federal oil). We also propose to revise existing paragraph (f) to direct lessees of Federal oil and gas production to the regulations pertaining to the reporting and payment of royalties on Federal oil proposed under this rulemaking in a new part 1205 in 30 CFR.

Finally, because this subpart applies to both Federal and Indian oil, we propose to add headings to the paragraphs to make it clear to the reader which paragraphs apply only to Federal oil or Indian oil.

Under existing regulations, if another person takes and disposes of a portion of Federal production to which you were entitled but did not take, the actual disposition of that production by the other person controls its valuation. By removing the reference to Federal leases in this section and limiting its applicability to Indian leases only, the portion of oil production to which you were entitled but did not take from a Federal lease would be valued under 30

CFR part 1206, subpart C, as production not sold under an arm's-length contract.

§ 1202.150 Royalty on Gas

This rule proposes to separate the requirements applicable to Indian leases from those for Federal leases. Thus, the proposed rule would retain the existing requirements for Indian leases but would eliminate the current requirement to trace the sale of gas production that you do not take from a Federal lease because RSFA takes versus entitlements provisions apply only to Federal leases. This proposed rule also would remove references to 30 CFR part 1206 regarding valuation and, instead, direct lessees to 30 CFR part 1205 because proposed §§ 1205.104 and 1205.30 explain how to value volume differences under this rule. Accordingly, the proposed rule would revise paragraph § 1202.150(e) to refer lessees of Federal leases to 30 CFR part 1205 as follows:

> The regulations explaining when you must report and pay royalties on the volume of gas you take from your Federal lease, including Federal leases committed to a federally approved unitization or communitization agreement, or on the entitled share of production from or allocated to your Federal lease, are found in 30 CFR part 1205.

§ 1202.152 Standards for Reporting and Paying Royalties on Gas

The current regulations provide in the first sentence of paragraph (a)(1)(i) that persons responsible for reporting royalties or production must ''[r]eport gas volumes and British thermal unit (Btu) heating values, if applicable, under the same degree of water saturation.'' The first sentence of paragraph (a)(2) provides that ''[t]he frequency and method of Btu measurement as set forth in the lessee's contract shall be used to determine Btu heating values for reporting purposes.'' However, we believe it is more appropriate for such persons to report volumes consistent with the requirements of the agencies managing lease operations, inspections, and enforcement. Thus, this rule proposes to replace paragraphs (a)(1) and (a)(2) with a new paragraph (a) to refer lessees to BLM (for Federal and Indian leases) and BOEM (for offshore leases) regulations, orders, and notices for the requirements to report volumes. However, we are also making such reporting ''subject to ONRR verification based on third party data.'' This addition to the rule will ensure that ONRR can verify the Btus you report using data from third parties, including, but not limited to, purchaser or plant statements or receipts.

§ 1202.558 What standards do I use to report and pay royalties on gas?

The current regulations provide in the first sentence of paragraph (a)(1) that persons responsible for reporting royalties or production must ''[r]eport gas volumes and British thermal unit (Btu) heating values, if applicable, under the same degree of water saturation. Report gas volumes and Btu heating value at a standard pressure base of 14.73 psia [pounds per square inch absolute] and a standard temperature of 60 degrees Fahrenheit. Report gas volumes in units of 1,000 cubic feet (Mcf).'' The first sentence of paragraph (a)(2) provides that ''You must use the frequency and method of Btu measurement stated in your contract to determine Btu heating values for reporting purposes.'' However, we believe it is more appropriate for such persons to report volumes consistent with the requirements of the agency managing lease operations, inspections, and enforcement. Thus, this rule proposes to replace paragraphs (a)(1) and (a)(2) with a new paragraph (a) to refer lessees to BLM regulations, orders, and notices for the requirements to report volumes. However, we are also making such reporting ''subject to ONRR verification based on third party data.'' This addition to the rule will ensure that ONRR can verify the Btus you report using data from third parties, including, but not limited to, purchaser or plant statements or receipts.

B. Section-by-Section Analysis of 30 CFR Part 1205—Reporting and Paying Royalties on Federal Leases

We propose to add a new part 1205 to our regulations in 30 CFR. This part would implement the new reporting and payment requirements in FOGRMA paragraphs 111(k)(1) through (4) for Federal oil and gas leases.

Subpart A—General Provisions

§ 1205.1 What is the purpose of this part?

This section would explain the purpose of part 1205 and emphasize that reporting and payment requirements under this new part would not alter a lessee's ultimate royalty liability and obligations for oil or gas produced from Federal leases.

§ 1205.2 What leases are subject to this part?

This section would explain that this part applies only to Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS). Because RSFA applies only to Federal oil and gas leases, this part would not apply to: (1) Federal leases for minerals other than oil and gas; (2) Indian mineral leases; or (3) Leases for which the Federal Government became the lessor when it acquired a mineral interest subject to a private mineral lease.

§ 1205.3 What definitions apply to this part?

This section defines certain terms used in part 1205. Only definitions requiring supplementary explanations are discussed below. See the proposed rule language for a complete list of terms and definitions.

100-percent Federal agreement would mean any agreement that contains only Federal leases having the same fixed royalty rate and funds distribution. A 100-percent Federal agreement would exclude any agreement that includes leases subject to the Gulf of Mexico Energy Security Act of 2006 (GOMESA).

Paragraph 111(k)(1)(A) of FOGRMA defines 100-percent Federal agreements as agreements containing ''. . . only Federal leases with the same royalty rate and funds distribution . . . .'' In the proposed rule, we added the word ''fixed'' before ''royalty rate'' in the definition because royalty rates on variable rate leases in an agreement may be different for each reporting period, based on volumes produced and the number of wells. Because there is little chance that, in any month, the royalty rates for fixed and variable rate leases in an agreement would be identical, we would restrict 100-percent Federal agreements to only those leases having the same fixed royalty rate. We believe this reflects the statutory intent.

We excluded leases subject to GOMESA because of the unique funds distribution requirements for those leases. The funds distribution formulas established by GOMESA result in a different fund distribution for every lease, regardless of a lease's inclusion in a unit or communitization area. Because the distribution formulas established by GOMESA result in a different funds distribution for every lease, 30 U.S.C. 1721(k)(1)(A) does not apply to GOMESA leases. Furthermore, unlike Outer Continental Shelf Lands Act Section 8(g) leases, 43 U.S.C. 1337(g), for which funds are disbursed to not more than two state entities by lease and production month, GOMESA funds are accumulated from all leases subject to its requirements and are then disbursed the following calendar year to the four Gulf producing states—and their political subdivisions. Thus, including GOMESA leases in the definition of 100-percent Federal agreement would prove too administratively burdensome, given their unique distribution requirements.

Barrels of oil equivalent (BOE) would mean the combined equivalent production of oil and gas stated in barrels of oil. This definition would explain that each barrel of oil production is equal to one BOE and each 6,000 cubic feet (6 Mcf) of gas production is equal to one BOE. This definition is the same as the one published in the marginal property rule (30 CFR 1204.2).

Combined equivalent production would mean the total of all oil and gas production for the marginal property, stated in BOE. This definition is the same as the one published in the marginal property rule (30 CFR 1204.2).

Commingling approval would be defined as the BLM or the Bureau of Safety and Environmental Enforcement (BSEE) approved surface mixing of production from two or more independent leases or agreements, before measurement for royalty purposes. The commingling approval identifies how the volume measured at the approved point of royalty measurement must be allocated to each lease or agreement subject to the commingling approval. Further, as discussed in § 1205.104 below, a commingling approval affects both your take volume and your entitled volume, because the sum of all the lessees' take volumes—or, as the case may be, entitled volumes—from a lease must equal the total volume allocated to the lease under the commingling approval.

Delegated State would mean a state with which ONRR has entered into a delegation agreement under 30 U.S.C. 1735.

Lessee would be defined as any person to whom the United States issues an oil and gas lease, an assignee of all or a part of the record title interest, or any person to whom operating rights in a lease have been assigned. This definition essentially follows the definition contained in section 3 of FOGRMA, 30 U.S.C. 1702, as amended by RSFA section 2(1), Public Law 104–185, 110 Stat. 1700.

Mixed agreement would mean any agreement other than a 100-percent Federal agreement. Mixed agreements contain any mixture of Federal, Indian, state, or private mineral estates; or contain all Federal leases with different royalty rates or funds distribution. A mixed agreement would include any agreement that contains leases subject to GOMESA. For example, a communitization agreement with two Federal leases—one with a fixed 12½-percent royalty rate and one with a variable royalty rate based on volume of production—would be a mixed agreement.

Take would be defined as any oil or gas volumes removed or sold from a lease or agreement, as measured at or allocated from an approved point of royalty measurement. For stand-alone leases, the take volume is the volume measured at the approved point of royalty measurement for the lease. For leases in a 100-percent Federal agreement or subject to a commingling approval, the take volume for an individual lease is the volume allocated back to the lease after measurement at an approved point of royalty measurement for the agreement or commingling approval.

Paragraphs 111(k)(1)(A) and (C) of FOGRMA, in describing situations in which lessees are to report and pay based on actual take volume, state that a lessee or its designee will report and pay royalties on stand-alone leases and leases in 100-percent Federal agreements based on the ''actual volume of production sold by or on behalf of that lessee.'' Congress did not define ''sold'' in RSFA. Therefore, we found it necessary to define ''sold'' in this rulemaking as ''take'' for the following reasons:

(1) It is plain from the context of paragraphs 111(k)(1)(A) and (C) that Congress was referring to the actual royalty-bearing volume taken by the lessee, and not just to production whose title was transferred to another party in return for money.

(2) There are other important and frequently used royalty-bearing dispositions of production other than exchanging production for money. Any production ''removed from the lease,'' and not used in lease operations, is royalty-bearing. Limiting this rule to apply only to ''sold'' volumes, as that term is commonly used, would greatly complicate royalty computations on many leases because it would require more than one reporting and payment method depending upon the type of disposition. This would defeat Congress' intent in RSFA to simplify reporting and payment.

(3) Long-standing lease terms and existing valuation regulations require royalty to be paid on any production measured at an approved point of royalty measurement, regardless of whether that production is subsequently ''sold'' in the technical sense. See 30 CFR 1206.103 for Federal oil and 30 CFR 1206.154 for Federal gas. Nothing in RSFA purports to change that requirement. For example, assume gas is removed from a lease at an approved point of royalty measurement and stored offsite in an underground gas storage reservoir without first being exchanged for money. Royalty would be due at the time the gas is measured and removed from the lease, not later when it is removed from storage and exchanged for money.

Thus, to accurately capture the paying and reporting concept we believe Congress intended in RSFA, we defined the word ''take'' to include ''sold.'' Accordingly, for purposes of this rule, ''take'' production defines the total body of production from a lease or agreement on which royalty is due during a reporting period. We believe this definition of ''take'' is the proper interpretation of the word ''sold'' in RSFA and reflects the statutory intent. We specifically request comments on this interpretation.

The following examples for stand-alone Federal leases illustrate the concept of ''takes'':

- First, assume you have a proceeds-sharing agreement in which a fellow interest owner in your Federal lease sells your portion of the lease production and shares the proceeds received from that sale with you. The other interest owner is deemed to have taken your production on your behalf, and you must report and pay royalty on the volumes for which you received proceeds.
- Second, assume you have a contract in which you and a fellow interest owner in a Federal lease take all the production from a Federal lease in alternate months. In the months in which your fellow interest owner sells all of the production, including your entitled share, your fellow interest owner is deemed to have taken all of the production and must report and pay royalties on all of the production. You would not have to report and pay royalty on any volumes for those months.

We specifically request comments on this definition of ''take'' and its relationship to total production that is ''sold'' from a lease or agreement.

Subpart B—Reporting and Paying Royalties on Federal Leases

Subpart B would describe how you must report and pay royalties each month based on the type of lease you have.

§ 1205.101 How do I report and pay royalties?

This section would explain the reporting and payment requirements for stand-alone leases, leases in a 100-percent Federal agreement, and leases in a mixed agreement. This section would use a chart to aid understanding.

Paragraph (a)(1) would explain that if you take production from a stand-alone lease (this would include a portion of a lease that is not part of an agreement), you must report and pay royalties based on the production you take. For example, assume you are a lessee for a stand-alone Federal lease under the following conditions:

Volume produced from the lease (A)	Your ownership interest in the lease (B)	Volume you take from the lease (C)	Volume on which you report and pay royalty (D) (D) = (C)
1,000 Mcf	40%	700 Mcf	700 Mcf

Thus, when you pay royalty on a stand-alone lease, your entitled volume based on your ownership interest in the lease (1,000 Mcf × 40% = 400 Mcf) is not used in the computation to determine the volumes on which you report and pay. Rather, you would report and pay royalty on the 700 Mcf you actually took.

Paragraph (a)(2) would explain that if you are a lessee taking production from a 100-percent Federal agreement, you must report and pay based on the production you take. For example, assume you are a lessee for one lease in a 100-percent Federal agreement under the following conditions:

Volume produced from the agreement (A)	Percent of volume allocated to your lease from the agreement (B)	Your ownership interest in one lease in the agreement (C)	Volume you take from the agreement (D)	Volume on which you report and pay royalty (E) (E) = (D)
1,000 Mcf	50%	10%	800 Mcf	800 Mcf

Thus, when you pay royalty on a 100-percent Federal agreement, your entitled volume (1,000 Mcf × 50% × 10% = 50 Mcf) is not used in the computation to determine the volumes on which you report and pay. Rather, you would report and pay royalty on the 800 Mcf you actually took.

Paragraph (a)(3) would explain the reporting requirements for lessees in mixed agreements. The proposed rule would require lessees to report and pay royalties based on their entitled share of the volume allocated to their lease from the agreement, regardless of the volume they take. For example, assume you are a lessee for a Federal lease in a mixed agreement under the following conditions:

Volume produced from the agreement (A)	Percent of volume allocated to your lease from the agreement (B)	Your ownership interest in one lease in the agreement (C)	Volume you take from the agreement (D)	Volume on which you report and pay royalty (E) (A) × (B) × (C)
1,000 Mcf	60%	30%	300 Mcf	1,000 Mcf × 60% × 30% = 180 Mcf

Thus, when you pay royalty on a lease in a mixed agreement, your take volume (Column D, 300 Mcf) is not used in the computation to determine the volumes on which you report and pay. Rather, you would report and pay royalty on the 180 Mcf to which you were entitled.

Paragraph (b) would explain that if you are a lessee for more than one lease in a 100-percent Federal agreement, you must allocate and report for each lease based on its allocated share. See §§ 1202.100(e) and 1202.150(e). ONRR considered allowing lessees to report on only one of their leases in a 100-percent Federal agreement but decided the adverse impact to minimum royalty obligations for all other leases in the agreement outweighed the benefits of simplified reporting for one lease. Leases must meet the minimum royalty obligation at the end of each lease year. If we were to allow lessees to report on only one of their leases in an agreement, then the other leases in the agreement might not meet their minimum royalty obligation by the end of the lease year. In that case, lessees would have to pay minimum royalty on all of their other leases in the agreement in order for the other leases to meet their minimum royalty obligation.

§ 1205.102 How do I determine my take volume?

This section would explain that your take volume is the volume you, or someone on your behalf, removed or sold from your lease or leases. In this proposed rulemaking, as discussed above, ONRR is using the term ''sold'' in the definition of ''take.'' The underlying requirement is that the sum of all take volumes reported for the lease must equal the volume upon which royalty is due.

ONRR is not a party to the decisions that determine which lessees take what volume. Those decisions are made solely between lessees, operators, purchasers, and transporters of the oil and gas. However, we routinely verify that the combined volumes reported and paid by all lessees or designees on their royalty reports are equal to the volumes removed or sold from the lease or agreement as reported on corresponding production reports submitted by operators of a lease or agreement. To minimize questions when volumes reported on the royalty report do not match volumes reported on production reports, we strongly recommend that all parties to the ''take'' decisions establish procedures to ensure that all removed or sold volumes are accounted for and paid in every reporting period. In addition, we recommend that all parties take the necessary steps to ensure that minimum royalty obligations are met for each lease in an agreement.

§ 1205.103 How do I determine my entitled volume in a mixed agreement?

This section would explain that you would determine your entitled volume by multiplying your entitled share in the lease by the volume of production allocated to your lease under the agreement allocation schedule.

The determination of entitled volumes is not based on your ownership interest in a specific well on a lease. Consider the example in which you own 100 percent of the operating rights in the only Federal lease in a mixed agreement, and you chose not to participate in the drilling of the only well drilled on the agreement (non-consent well). Depending on the terms of your operating agreement, you might not be entitled to any production until, for example, 200 percent of the development costs are paid in full. Despite the fact that you do not receive production for a period of time, you must report and pay royalties on the full volume allocated to your Federal lease under the agreement allocation schedule.

§ 1205.104 How do I determine value for my entitled volume in a mixed agreement?

This section would explain how to value volumes you report for a mixed agreement.

Paragraph (a) would explain that if you take less than your entitled volume of production from a mixed agreement during a month, then the royalty value you must use for the difference is the volume weighted-average unit value for the total volume you take from the property during that month, as determined under part 1206 of this title.

Paragraph (b) would explain that, if you do not take any production to which you were entitled from a mixed agreement during a month, then the royalty value for your entitled share for that month is the value determined for non-arm's-length dispositions under 30 CFR 1206.103 for oil; 30 CFR 1206.152(c) for unprocessed gas; and 30 CFR 1206.153(c) for processed gas.

§ 1205.105 How does a commingling approval affect my take volume?

When BSEE or BLM approves either surface or downhole commingling of production before royalty measurement, the commingling approval identifies where the production will be measured for royalty purposes and how that measured volume will be allocated to each lease or agreement subject to the commingling approval. This section would explain that, if your lease is a stand-alone lease subject to a BLM or BSEE commingling approval, or in an agreement that is subject to a BLM or BSEE commingling approval, the volume allocated to the lease or agreement under the commingling approval is the production taken from the lease or agreement and the total volume upon which royalties must be paid. In other words, the commingling approval dictates the total volume removed or sold from the lease or agreement, and hence your takes from the lease. For example, assume two stand-alone Federal leases, each with a single lessee, are subject to a commingling approval under the following conditions:

Lease	Percent of production allocated to each lease under commingling approval (A)	Volume measured at approved point of royalty measurement under commingling approval (B)	Volume allocated to each lease under commingling approval (C) (A) × (B)	Volumes nominated and delivered (taken) by each lessee (D)	Over or <under> taken volumes for each lease (E) (D) − (C)
1	25	5,000 Mcf	1,250 Mcf	1,000 Mcf	<250 Mcf>
2	75		3,750 Mcf	4,000 Mcf	250 Mcf

Under proposed § 1205.101(a)(1), a lessee of a stand-alone Federal lease—assuming it was not subject to a commingling approval—would be required to report on the take volume, Column D. However, because of the commingling approval, this proposed § 1205.104 would require a lessee to report and pay royalties on the total volume allocated to each lease under the commingling approval—that is, Column C—whether or not that volume equals the take volume. Thus, in this example, the lessee for Lease 1 would have to report and pay royalties on 1,250 Mcf, rather than the 1,000 Mcf it actually took; and the lessee for Lease 2 would have to report and pay royalties on 3,750 Mcf, rather than the 4,000 Mcf it actually took. This example does not address the more complicated situation in which stand-alone leases have multiple owners and the total takes of the lessees of one of the leases does not equal the volume upon which royalties are due under the commingling approval. In those situations, lessees must report and pay on the full volume allocated to each lease under the commingling approval.

Note that the effect of a commingling approval would be slightly different for leases in 100-percent Federal agreements, because the commingling approval would dictate the total volume allocated to the agreement, not the individual leases. Once the volume allocated to the agreement is established by the commingling approval, you would then have to allocate that volume to your leases in the agreement and report and pay accordingly. See § 1205.101(b), discussed above. We realize that there are other alternatives to handle the commingling situation. We solicit comments on the proposed method for handling commingling and welcome suggestions for alternatives.

§ 1205.106 Are there exceptions to the reporting and payment requirements in this subpart?

This section would explain the two exceptions to the reporting and payments requirements in this subpart.

Paragraph (a) would explain that you may qualify for an alternative to the royalty reporting and payment requirements for 100-percent Federal agreements under § 1205.101(a)(2) if you meet certain requirements. Subpart C would explain the requirements for alternative reporting, which are discussed further below.

Under proposed paragraph (b), you also could qualify to report on your take volume rather than entitled volume, with appropriate adjustments after year-end, if your mixed agreement is a marginal property. Subpart D would explain the requirements for the marginal property reporting exception, which are discussed further below.

Subpart C—Reporting and Paying Royalties on Federal Leases Under an Alternative Method for a 100-Percent Federal Agreement

Subpart C would explain the requirements for requesting approval for, and using an alternative method of, reporting and paying royalties for Federal leases that participate in a 100-percent Federal agreement. This subpart implements FOGRMA paragraph 111(k)(3), which provides that, under certain conditions, lessees in an agreement may request an alternative method of reporting and paying royalties other than that prescribed under paragraphs 111(k)(1) and (2).

§ 1205.201 How do I qualify for alternative reporting and payment for a 100-percent Federal Agreement?

This section would explain that you may qualify for an alternative to the royalty reporting and payment requirements for agreements under subpart B if:

(a) You are in a 100-percent Federal agreement;

(b) You and all other lessees in the agreement concur in writing to the alternative method; and

(c) The alternative does not reduce the total monthly royalty obligation reported and paid to ONRR.

During the outreach meetings, participants discussed FOGRMA paragraph 111(k)(3) at length. Meeting participants provided input that RSFA was intended to give lessees in 100-percent Federal agreements the option to report on their entitled volume rather than on their take volume. We are proposing to restrict alternative methods to 100-percent Federal agreements, primarily because it is impracticable to fully effectuate as written since ONRR cannot require private and state lessees in a mixed agreement to use an alternative method or report in accordance with Federal regulations. Nor can we apply FOGRMA enforcement authorities to such entities even if they agree in writing to an alternative methodology because any right to enforce would derive from the contractual agreement, not FOGRMA.

We are specifically requesting comments on whether or not we should allow alternative reporting for mixed agreements. In your comments, please provide any legal authority for your position and specific examples of how it would be applied to mixed agreements.

§ 1205.202 How do I request alternative reporting and payment for a 100-percent Federal Agreement?

This section would explain the information that ONRR would need to adequately review a proposed alternative method of reporting and payment.

Paragraph (a) would explain that, to obtain approval to use an alternative method of royalty reporting and payment, you must submit one written request to ONRR on behalf of all lessees of leases in the agreement.

Paragraph (b) would explain that, in your request, you must describe the proposed alternative, identify the agreement and all the leases in the agreement, identify all lessees and their ownership interest in each Federal lease in the agreement, and include a copy of the written consent to the alternative method from all lessees in the agreement. Paragraph (b) also would explain that you must demonstrate that the proposed alternative method will not reduce the total monthly royalties due for the agreement. In addition, paragraph (b) would explain that you must submit a nonrefundable processing fee of $2,400 to ONRR, under 30 CFR 1218.51, for each agreement for which you request an alternative method of reporting and payment. If you did not submit the full fee, we would return the request unprocessed. If we returned the request unprocessed for failure to pay the fee, you could not appeal the return of the request. Finally, paragraph (b) would provide that ONRR may periodically adjust the $2,400 fee to account for increases in our actual costs due to inflation and increases in Federal employee salaries. If we adjusted the fees, we would publish a notice in the **Federal Register**.

Our rationale for collecting the fee is as follows. We would recover its costs under the Independent Offices Appropriations Act of 1952 (IOAA), 31 U.S.C. 9701 *et seq.,* for Federal offshore leases, and the Federal Land Policy and Management Act of 1976 (FLPMA), 43 U.S.C. 1701, for Federal onshore leases. As part of this proposed rule, we analyzed the proposed cost recovery fees for reasonableness according to the factors in FLPMA section 304(b). Although the IOAA does not contain the same ''reasonableness factors'' as FLPMA section 304(b), the factors we considered under FLPMA to determine reasonable fees led us to conclude that the fees for offshore leases should be the same as the fees for onshore leases.

The reasonableness factors required by FLPMA are: (a) Actual costs (exclusive of management overhead); (b) the monetary value of the rights or privileges sought by the applicant; (c) the efficiency to the Federal Government processing involved; (d) that portion of the cost incurred for the benefit of the general public interest rather than for the exclusive benefit of the applicant; (e) the public service provided; and (f) other factors relevant to determining the reasonableness of the costs.

The method used to evaluate the factors is twofold. First, ONRR estimated the actual costs and evaluated each of the remaining FLPMA reasonableness factors (b) through (f) individually to decide whether the factor might reasonably lead to an adjustment in actual costs. If so, we then weighed that factor against the remaining factors to determine whether another factor might reasonably increase, decrease, or eliminate the contemplated adjustment. On the basis of this twofold analysis, we determined what final fee is reasonable. We cannot recover an amount greater than its actual costs, so any final adjustment cannot result in a fee greater than actual costs.

Reasonableness Factors Required by FLPMA

(a) Actual Costs

Actual costs means the financial measure of resources ONRR would expend to process a request that a lessee or its designee would be allowed to report under an alternative method. Actual costs include, but are not limited to, the costs of special studies, monitoring compliance with this part, termination of relief authorized under this part, or any other relevant action. Actual costs include both direct and indirect costs, exclusive of management overhead. Management overhead costs means costs associated with the ONRR directorate, except where a member of such staff is required to perform work on a specific case. Section 304(b) of FLPMA requires that management overhead be excluded from chargeable costs.

Our direct costs include expenditures for labor, material, and equipment usage connected with processing the requests. We calculated direct costs by estimating the average time it would take ONRR personnel to complete similar existing tasks.

Our indirect costs include items such as rent and overhead (excluding management overhead). We calculated our indirect cost rate by dividing the indirect costs described above by the total direct program costs to arrive at an indirect cost percentage. Then we multiplied the direct costs to process a request for alternative reporting by the indirect cost percentage and added that figure to the direct costs to determine its total actual costs of $60.00 per hour = $40.10 per hour [2011 GS–12, Step 5] × 1.5 [benefits cost factor]. This method of calculating costs is a generally accepted practice in both the private and public sectors.

Our method of establishing actual costs involved estimating the average cost of processing an individual request. Processing requests consists of two phases. In the first phase, ONRR personnel would review and analyze the proposed alternative method and provide preliminary approval, modification, or denial. In the second phase, we would communicate the decision to the lessee.

We estimated that it would take an average of 40 hours to review and respond to a request for an alternative method of reporting and paying. We concluded that, while it might be possible to track costs and reasonableness on a case-by-case basis, it would be so inefficient and expensive as to be considered unreasonable. Using an hourly cost of $60.00 per hour for both direct and indirect costs, we determined that our average cost to process each request to use alternative reporting would be approximately $2,400.

(b) Monetary Value of the Rights and Privileges Sought

Monetary value of the rights and privileges sought means the objective worth of the alternative reporting method sought or taken, in financial terms, to the lessee or its designee. We rejected the idea of trying to calculate monetary value on a case-by-case basis as too time consuming, wasteful of resources, and subject to endless disputes. Instead, we have attempted to calculate an average or estimated figure to represent the monetary value of rights for possible alternatives under this rulemaking. In addition, we took into account equitable considerations involving the costs to process relative to the monetary value of the relief sought.

We determined that approving a proposal that would allow lessees to report and pay on their entitled share of production, rather than reporting on the required takes method, would allow the company to use only one system for reporting and would simplify the overall process for them. Approving this alternative would benefit lessees and their designees by decreasing the total number of hours they would devote manually to complete royalty reports for a portion of their Federal leases. We estimated the maximum monetary benefit of these relief options could be as high as $552 annually = 1 hour per month savings × 12 months × $46/hour. The hourly labor cost of $46 is based on the Bureau of Labor Statistics National Occupational Employment and Wage Estimates. However, we did not adjust our actual costs for this factor.

(c) Efficiency to the Federal Government Processing Involved

Efficiency to the Federal Government processing involved means the ability of the United States to process a request for an alternative method of reporting and paying royalties under § 1205.202 with a minimum of waste, expense, and effort. Implicit in this factor is the establishment of a cost recovery process that does not cost more to operate than ONRR would collect and does not unduly increase the costs to be recovered. As noted in the above section on actual costs, we determined that it would be inefficient to determine actual cost data on a case-by-case basis. Estimates based on our experience indicate that the cost of maintaining actual cost data on specific cases would be unreasonably high, and the amount potentially collectible could be relatively small. This is principally because our automated accounting system would have to be extensively reprogrammed to add a relatively few items of information. Thus, we would use cost estimates derived from previously collected data.

Because RSFA specifies that any alternative method of reporting and paying royalties may not reduce the royalty obligation, ONRR must perform sufficient review of each request to assure that this requirement would be met. We believe the actual cost estimate from factor (a) above anticipates an efficient process that would provide for the necessary technical review. The procedures we would use in processing the data would be based on standardized steps for similar ONRR transactions in order to eliminate duplication and extraneous procedures. Therefore, we believe factor (c) would be the most efficient processing method. Accordingly, because factor (c) would be an efficient processing method, we have made no adjustment to actual costs as a result of this factor.

(d) Cost Incurred for the Benefit of the General Public Interest

Cost incurred for the benefit of the general public interest (public benefit) means funds the United States would expend in connection with the processing of a request for alternative reporting under § 1205.202, for studies or data collection determined to have value or utility to the United States or the general public, separate and apart from the document processing. It is important to note that this definition addresses funds that would be expended in connection with a request. There is another level of public benefit that includes studies that we are required, by statute or regulation, to perform regardless of whether a request is received. The costs of such studies are excluded from any cost recovery calculations from the outset. Therefore, no additional reduction from costs recovered is necessary in relation to these studies.

Our analysts concluded that the processing of requests for alternative methods of reporting and paying royalties under this proposed rule did not, as a rule, produce studies or data collection that might benefit the public to any appreciable degree. Therefore, any possible benefits of such studies to the public are balanced by their possible benefits to the applicant. Accordingly, we made no adjustment to actual costs based on this factor.

(e) Public Service Provided

Public service provided means tangible improvements or other direct benefits, such as reduced administrative costs, with significant public value, that are expected in connection with approval of an alternative method of reporting and paying royalties. The definition specifically notes that negative factors, such as an adverse impact on royalty or ONRR's audit ability, could preclude considering an improvement as a public service. The definition also notes that data collection we would need in order to monitor an alternative reporting and payment method does not constitute a public service. This definition distinguishes the factor of *public service provided* (a benefit resulting from activities associated with the underlying relief) from the factor of *cost incurred for the benefit of the general public interest* (which relates to benefits of the document processing itself).

We determined that the alternative reporting and payment options under this rule would provide the benefit of reducing our costs by decreasing the total number of hours we would devote to processing documents and correcting errors. We anticipate approving simpler reporting and payment methods under this rule. Therefore, we determined that the Federal Government would benefit under this factor to some extent.

However, we made no adjustment to actual costs based on this factor because this benefit is encompassed by our actual cost estimate under factor (a) discussed above.

(f) Other Factors

The final reasonableness factor is *other factors* relevant to determining the reasonableness of the costs. We examined some of the possible alternative reporting and payment methods that could be requested under this section to determine whether other factors warranted a reduction in the proposed fee from our actual costs.

Personnel with expertise and program management responsibilities in the particular area of the transaction reviewed the possible alternative reporting and payment methods. Our personnel weighed the proposed processing fee against their knowledge of the value of similar transactions. Our analysts concluded that factor (b) *monetary value of the rights* was clearly so far above the expected processing cost that a fee set at actual costs would be reasonable.

In our outreach sessions, industry representatives indicated that significant processing fees would likely result in industry not submitting requests for alternative reporting and payment methods. Representatives of independent oil and gas producers stated that processing fees likely would discriminate against the small producers. However, those outreach sessions were held more than 12 years ago. Our personnel concluded that currently, the value of the rights was clearly so far above the expected processing cost, that a fee set at actual costs would be appropriate. Accordingly, we did not adjust the actual costs based on other factors. As a result, we determined that a processing fee of $2,400 per request would meet the reasonableness factors of FLPMA for onshore leases, and we would apply the same rate to offshore leases. We invite comments specifically concerning the amount of the proposed processing fee.

Paragraph (c) of § 1205.202 would explain that RSFA section 4(f), 30 U.S.C. 1724(f), requires that Federal oil and gas lessees maintain records for 7 years after the royalty obligation becomes due. Since the methodology requested and approved under an alternative method of reporting and payment request applies to all periods from the date of approval until such time that the alternative method is terminated, this proposed paragraph would require lessees to keep all records pertaining to the request for an alternative method until 7 years after termination of the alternative method.

§ 1205.203 Who will approve, deny, or modify my request for alternative reporting and payment for a 100-percent Federal agreement?

Paragraph 111(k)(3) under FOGRMA requires the Secretary or the delegated state to determine whether to approve a request for alternative reporting and payment. This section would explain that ONRR would decide whether to approve your request for alternative reporting and payment. However, if there is a delegated state, we would consult with the state before making a decision.

§ 1205.204 How will I know if I am approved for alternative reporting and payment for a 100-percent Federal agreement?

This section would explain that, when ONRR receives your request for alternative reporting and payment under § 1205.202, we would notify you in writing as follows:

Paragraph (a) would provide that, if your request for alternative reporting and payment is complete, we may approve, deny, or modify your request.

Paragraph (b) would provide that if your request for alternative reporting and payment is not complete, we would notify you that your request is incomplete and identify any missing information. Under paragraph (1), you would have to submit the missing information within 60 days of your receipt of our notice that your request is incomplete. Under paragraph (2), after you submit the missing information, ONRR could approve, deny, or modify your request for alternative reporting and payment under § 1205.203.

Under paragraph (b)(3), if you do not submit the missing information within 60 days, we would return your request for alternative reporting and payment as incomplete. If we returned your request because it was incomplete, then we would not return any processing fee you submitted with your request. In addition, if we returned your request as incomplete, it would not be considered an appealable denial of your request. However, under paragraph (4), you could submit a new request for alternative reporting and payment under this subpart, including another processing fee, at any time following our return of your incomplete request.

§ 1205.205 When must I begin using the alternative method for a 100-percent Federal agreement?

This section would explain when you must begin using the alternative method.

Paragraph (a) would apply to lessees who requested the alternative method. Thus, the proposed rule would provide that, if you are a lessee for a lease in an agreement when you submit a request under § 1205.202, you would begin using the alternative method of royalty reporting and payment for the production month after you receive written approval from ONRR.

Paragraph (b) would apply to a lessee who becomes the lessee for a lease in an agreement for which there is already an approved alternative method of royalty reporting and payment. In such cases, the lessee would begin reporting under the alternative method for the production month in which it became the lessee.

§ 1205.206 What if I want to stop reporting and paying under the approved alternative method for a 100-percent Federal agreement?

This section would explain that, if you want to stop using the approved alternative method of royalty reporting and payment under paragraph (a), then you would have to obtain written concurrence from all lessees in the agreement to stop using the alternative method. Under paragraph (b), you would have to provide a copy of the written concurrence to ONRR and the delegated state.

§ 1205.207 When must I stop using the approved alternative method for a 100-percent Federal agreement?

This section would explain when the approval to use an alternative method ends.

Under paragraph (a), if you request to stop using the approved alternative method under § 1205.206, you would stop using the approved alternative method of royalty reporting and payment beginning with the production month after you receive written notice of approval from ONRR. You would then return to using the reporting and payment requirements of § 1205.101(a)(2) or (3).

Paragraph (b) would explain that you would stop using the approved alternative method of royalty reporting and payment beginning within 60 days after you receive written notice from:

(1) ONRR that your approval, under this subpart, is terminated; or

(2) BLM or BSEE that either a non-Federal tract or a tract that you

determine has a different royalty rate or funds distribution has been added to your agreement.

Paragraph (c) would explain that a change in a lessee's ownership interests after the initial approval for alternative reporting and payment would not terminate an approval.

Paragraph (d) would explain that ONRR would terminate an approval in any instance where we believed it would be in the United States' best interest.

Subpart D—Reporting and Paying Royalties on Marginal Properties

Subpart D would provide a reporting and payment exception for properties that qualify as marginal properties and would describe how the exception would work.

§ 1205.301 What is the marginal property reporting and payment exception?

This reporting option would be a reporting and payment exception to the requirements under § 1205.101(a)(3) for mixed agreements. Under FOGRMA paragraph 111(k)(4), lessees would be allowed to report royalties for their leases in mixed agreements that qualify as marginal properties based on takes rather than entitlements for a calendar year or portion thereof (if they sell or acquire an interest in the marginal property during the calendar year). We believe this provision of RSFA was intended to minimize the out-of-pocket royalty payments from smaller producers who do not take their full entitled share each month. The exception applies only to mixed agreements because 100-percent Federal agreements and stand-alone Federal leases must already pay based on takes under FOGRMA paragraphs 111(k)(1)(A) and (C), as implemented under proposed § 1205.101(a)(1) and (2). Therefore, because RSFA is silent on this point, we concluded in § 1205.101(a)(3) that this exception can apply only to mixed agreements.

§ 1205.302 What is a marginal property under this subpart?

We propose to define a ''marginal property'' based on the definition in FOGRMA paragraph 111(k)(4). Paragraph 111(k)(4) defines a ''marginal property'' as:

> . . . a *lease* that produces on average the combined equivalent of less than 15 barrels of oil per well per day or 90 thousand cubic feet of gas per well per day, or a combination thereof, determined by dividing the average daily production of crude oil and natural gas from producing wells on such *lease* by the number of such wells, unless the Secretary, together with the State concerned, determines that a different production is more appropriate. (Emphasis added.)

Thus, as discussed above, a marginal property would be defined as a mixed agreement that produces an average of less than 15 barrels of oil equivalent (BOE) per well producing day.

However, we had to consider an additional issue that the definition of ''marginal property'' in paragraph 111(k)(4) presents. Participants at our outreach meetings discussed the administrative burdens that this definition would impose on lessees and ONRR, or a delegated state, if we did not interpret the term ''lease'' to mean an ''agreement.'' For example:

- By defining a marginal property as a lease within an agreement, lessees would incur substantial cost to identify the specific lease on which each agreement well is located and the specific volumes attributable to each well for each lease each month, in order to calculate the average daily well production by lease.
- The regulations require lessees to report production from wells in agreements to ONRR on production reports at the agreement level and not on a specific lease. If ONRR were to define a marginal property as only a lease, we would not have the data to determine which wells correspond to a specific lease in an agreement. Therefore, ONRR could not verify lessee calculations of average daily well production to ensure that only marginal properties are taking advantage of the exception.

To address this issue, meeting participants provided input that a marginal property should be determined on the basis of the production level of the entire mixed agreement, not on an individual lease basis. We specifically request comments on the proposed definition of ''marginal property.''

§ 1205.303 How do I determine if my property is a marginal property?

Also discussed during the outreach meetings was the production threshold that would qualify a property for the marginal property reporting exception. Paragraph 111(k)(4) of FOGRMA provides a production threshold of less than 15 BOE per well producing day. However, it also allows the Secretary, together with the state concerned [the state that receives a portion (prescribed by statute) of the royalties from a Federal onshore or offshore lease (30 U.S.C. 1702(31)], to determine a different production threshold. After much discussion, the participants agreed to adopt the production level identified in paragraph 111(k)(4). Although we considered publishing an annual list of qualified properties, we determined that it would not be possible for ONRR to publish accurately and timely a list of qualified marginal properties. Therefore, this proposed rule would require lessees to perform the calculations necessary to identify qualified marginal properties.

To determine if your lease would meet the qualifications for a marginal property under the proposed rule for the next calendar year, you would:

(1) Calculate the total volume of oil and gas produced from your property during the period between July of the previous year and June of the current year. We propose to use a base period of July through June to allow sufficient time to adjust the production data before the following calendar year reporting period begins.

(2) Divide the total gas production (in Mcf) by 6 to convert the gas volume to BOE (see definition of BOE in § 1205.3 above) and add that total to the oil volume (in barrels).

(3) Calculate the total number of days each well actually produced during the same time period (include all producing wells in the mixed agreement, including those that are not located on a Federal tract).

(4) Divide the total produced volume by the total well producing days. If your calculated average daily well production is less than 15 BOE, your property would qualify for the marginal property exception.

§ 1205.304 When may I begin using the marginal property exception?

This section would explain that you may begin reporting under the marginal property exception in the January production month of the calendar year following the base period. It also would explain that you do not need to notify ONRR of your intent to report and pay using the exception.

§ 1205.305 How long must I use the marginal property exception?

Paragraph (a) of this section would explain that once lessees begin using the marginal property reporting exception, they must continue to use the exception through the end of the calendar year. This requirement would establish a uniform period during which royalty payments made on the takes basis can be compared to royalty payments due on an entitlement basis.

Paragraph (b) of this section would explain what happens if you sell your interest in a lease during a calendar year in which you were using the marginal property exception. In that situation, the reporting period during which you must use the marginal property exception is only the period of your ownership.

§ 1205.306 How do I report under the marginal property exception?

This section would explain how you report the take volume under the marginal property exception for your Federal leases in a mixed agreement.

§ 1205.307 What if the take volume I reported does not equal my entitled volume for one or more of my Federal leases for the calendar year?

This section would explain what to do if the total takes volume on which you report and pay during the calendar year under the marginal property exception does not equal your total entitled volume for each of your Federal leases in the agreement. In that situation, you would report the difference between your entitled share and your take volume and pay additional royalties or report a credit within 6 months of the end of that calendar year. You would report the difference (true up) on the Report of Sales and Royalty Remittance, Form MMS–2014, for each of your leases as either an underpayment or an overpayment for the entire calendar year. It would not matter whether you took more or less during each individual month, but rather, if you took more or less for the entire calendar year. Thus, if for any month your takes did not equal your entitlements but, for the calendar year they were equal, you would not have to report any adjustment.

Paragraph (a) of this section would explain that you must calculate the difference between the take volume you reported under the marginal property exception and your entitled volume for the calendar year in which you used the exception.

Paragraph (b) would explain that you report the difference calculated in paragraph (a) of this section:

(1) On Form MMS–2014, Report of Sales and Royalty Remittance;

(2) By June 30 of the calendar year immediately following the calendar year for which you used the marginal property exception;

(3) As underpaid (a positive amount on Form MMS–2014 when your total takes are less than your entitlements) or overpaid (a negative amount on Form MMS–2014 when your total takes exceed your entitlements);

(4) As a single-line entry for each lease and product from the lease;

(5) Using the correct adjustment reason code for reporting under this section; and

(6) Using the December sales month of the calendar year for which you used the marginal property exception.

Paragraph (c) would explain that you do not adjust the monthly royalty lines you reported under § 1205.306(c) if the take volume you reported was accurate.

For example, assume you own an interest in a Federal lease in a mixed agreement that qualifies for the marginal property reporting exception. Assume that the lease royalty rate is 16⅔ percent.

Total annual production from the agreement (A)	Your ownership interest in the lease (B)	Percent of production allocated to your lease from the agreement (C)	Calculation of your entitled share (volume) from the agreement (D) (A) × (B) × (C)
12,000 bbl	60%	40%	12,000 bbl × 60% × 40% = 2,880 bbl

The volume on which you report royalty would be calculated as your entitled share from the mixed agreement, or 2,880 barrels (bbl), multiplied by the lease royalty rate of 16.667 percent, which equals 480 bbl.

Further, assume that you would report based on your takes from the mixed agreement for the year under the marginal property exception. You reported a take volume of 3,500 bbl. The volume on which you report royalty would be your take volume from the mixed agreement (3,500 bbl × 16.667% [lease royalty rate] = 583 bbl). You would calculate your annual adjustment to entitlements as follows:

Your entitled volume from the mixed agreement for royalty purposes (A)	Your take volume from the mixed agreement for royalty purposes (B)	Calculation of annual adjustment to entitlements (C) (A) − (B)
480 bbl	583 bbl	480 bbl − 583 bbl = −103 bbl

The volume for royalty purposes of a negative 103 barrels means you overpaid the royalties for this lease for the calendar year. Thus, you would report the royalties associated with the negative 103 barrels on your Form MMS–2014 following current reporting instructions.

This section also would explain that you would not have to adjust each line you reported during the calendar year (unless you originally reported those lines incorrectly). For example, based on your lease ownership percentage and your lease participation in the mixed agreement, assume you were entitled to take 500 bbl of oil and 10,000 Mcf of gas for the year. However, you actually took 600 bbl of oil and 9,000 Mcf of gas. You would be required to report an adjustment line for each product for your lease for the year. Therefore, you would report one net line for oil showing a negative 100 bbl and one net line for gas showing a positive 1,000 Mcf.

You would not be required to back out all previously reported lines when you report your annual adjustment from takes to entitlements. However, if you made an error when reporting your take volume during the calendar year, then you would be required to submit amended royalty reports correcting the lines originally submitted.

You would report a single line for adjustments to your transportation and processing allowances. A positive value on your adjustment would show that you overclaimed an allowance based on your take volume under the marginal property exception.

§ 1205.308 How do I determine the royalty value for the difference between my take volume and entitled volume?

This section would explain how to value any volumes you report under § 1205.307.

Paragraph (a) would explain how to value production that you take from a qualifying marginal property during the calendar year when you report a difference between your take and entitled volume under § 1205.307. In that instance, the royalty value you use for the difference would be based on the volume weighted-average unit value as determined under part 1206 of this title for the total volume you take from the property during that calendar year.

Paragraph (b) would explain what you must do if you do not take production from a marginal property during the calendar year but you report a difference under § 1205.307. In that instance, the royalty value for the difference would be the value for non-arm's-length dispositions determined under part 1206 of this title.

§ 1205.309 What must I do if I underpay royalties under this subpart?

This section would explain that you must pay any additional royalty due under paragraph (a) based on your entitled share plus accrued interest, if the difference you reported under § 1205.307 is positive, indicating that you underpaid royalties. Paragraph (b) would explain that you would owe interest on your underpaid royalties. As prescribed under 30 CFR part 1218, you would owe interest from the beginning of the calendar year following the calendar year you used the marginal property exception until the date you pay the additional royalties. For example, if you paid the additional royalties on January 1 of the following calendar year, you would owe no interest. If you paid the additional royalties on February 28, you would owe interest from January 1 until February 28.

§ 1205.310 What must I do if I overpay royalties under this subpart?

Paragraph (a) would explain that if you reported a negative difference under § 1205.307, then you are entitled to a credit for the amount of overpaid royalties.

Paragraph (b) would explain that you are entitled to a credit for the overpaid amount from January 1 of the calendar year following the calendar year for which you used the marginal property exception until the earlier of:

(1) The date you reported the negative difference under § 1205.307; or

(2) June 30 of the calendar year immediately following the year you used the marginal property exception.

Paragraph (c) would explain that ONRR will pay interest on the overpayment after you take the credit.

§ 1205.311 What must I do if I erroneously report using the marginal property exception?

This section would explain that if you have reported royalties using the marginal property exception for a property that is not a qualified marginal property, you must amend your Form MMS–2014. You also would owe (or receive) interest as determined under part 1218 of this title and, depending on the circumstance, you could be subject to civil penalty procedures under part 1241 of this title.

§ 1205.312 What must I do if my property no longer qualifies as a marginal property under this subpart?

This section would explain that if your property ceases to qualify for the marginal property exception, you must return to reporting under the requirements of § 1205.101(a)(3) beginning the next calendar year.

C. Proposed Changes to 30 CFR Part 1210—Forms and Reports

We would make a technical amendment to the table at 30 CFR 1210.10 by adding the OMB control number for the new ICR.

VI. Procedural Matters

1. Summary Cost and Royalty Impact Data

We summarized below the estimated costs and benefits of this proposed rule for the three affected groups—industry, state and local governments, and the Federal Government. We segregated the costs into two categories—those costs that would be incurred in the first year after this rule is effective; and those costs that would be incurred on a continuing basis each year thereafter.

The cost and benefit information in Item 1 of the Procedural Matters is used as the basis for Departmental certifications in Items 2 through 10.

A. Industry

Description (see corresponding narrative below)	<Cost>/Benefit Amount	
	First year	Subsequent years
Cost—Requests for Alternative Reporting	$<717,898>	$<66,976>
Cost—Determining Marginal Property Qualification	<124,200>	<124,200>
Benefit—Simplified Reporting for Marginal Properties	198,720	198,720
Net Cost or Benefit to Industry	<643,378>	7,544

Cost—Requests for Alternative Reporting. We estimate alternative reporting requests would cost industry $717,898 in the first year and $66,976 each year thereafter. We estimate that industry would submit 250 requests in the first year for an alternative method of reporting and payment. There are about 200 offshore and 50 onshore 100-percent Federal agreements on which ONRR expects submission of requests to allow lessees to continue to report on an entitlements basis rather than change to a takes reporting basis as required by RSFA. We estimate that each request would take approximately 10 hours to complete, for a total of 2,500 hours. We estimate the recordkeeping associated with each request would be one-quarter hour. We estimate the total burden in the first year would be 2,563 hours = 2,500 reporting hours + 63 recordkeeping hours. We used tables from the Bureau of Labor Statistics 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 $46 per hour = $32.83 [mean hourly wage] × 1.4 [benefits cost factor]. Using a labor cost factor of $46 per hour, we estimate the total first-year cost to industry would be $117,898 = 2,563 reporting hours × $46/hour. Industry must also submit processing fees for each of the 250 requests amounting to $600,000 = 250 requests × $2,400 fee. Thus, the estimated total industry costs for alternative reporting requests in the first year would be $717,898 = $117,898 + $600,000.

In subsequent years, we estimate the number of alternative reporting requests would decrease from 250 to 23 annually, thus lowering the cost to industry. We also estimate that industry would file two termination requests for their respective alternative method, which would result in an annual estimate of 256 hours (25 requests [23 alternative reporting requests + 2 termination requests] × 10 reporting hours) + 6 hours (25 requests × 0.25 recordkeeping hours). Based on the labor cost factor of $46 per hour, we estimate the total annual cost would be $11,776 = 256 hours × $46 per hour. Industry also would submit the $2,400 processing fee for the 23 new alternative reporting requests, which would cost $55,200 = 23 requests × $2,400 processing fee. Thus the estimated total costs, in subsequent years, for alternative requests would be $66,976 = $11,776 + $55,200.

Cost—Determining Marginal Property Qualification. We estimate approximately 3,600 producing mixed agreements would qualify for the marginal property reporting and payment exception, and 1,000 lessees reporting royalties for these mixed agreements would try to avail themselves of the marginal property reporting exception. Industry would be required to determine whether or not their mixed agreements qualify as a marginal property on a yearly basis by calculating the average daily well production for the agreement, resulting in an annual estimate of 2,700 hours = (3,600 mixed agreements × 0.5 hours) + (3,600 mixed agreements × 0.25 recordkeeping hours). Based on the labor cost factor of $46 per hour, we estimate the total annual cost would be $124,200 = 2,700 hours × $46/hour.

Benefit—Simplified Reporting for Marginal Properties. ONRR estimates that simplified reporting for marginal properties would save industry $198,720 per year. We estimate that approximately 3,600 producing mixed agreements would qualify for the marginal property exception on an annual basis. For each marginal property, we estimate that there would be an average of two leases with two payors and one line each for oil and gas products reported on each payor and lease on Form MMS–2014 each month. We estimate eight lines would be reported monthly on Form MMS–2014 per marginal property. Therefore, for these qualifying marginal properties, a total of 28,800 lines would be reported on Form MMS–2014 monthly or 345,600 lines annually calculated as follows:

3,600 agreements × 2 payors per marginal property × 2 leases per marginal property × 2 reported lines per lease × 12 months.

Due to the reporting relief provided by this proposed rulemaking, we estimate that the reporting burden for Form MMS–2014 would be reduced by 25 percent for qualifying marginal properties, from 345,600 lines annually to 259,200 lines annually, a reduction of 86,400 lines. We estimate that the total annual burden reduction for this information collection would be 4,320 hours calculated as follows:

(86,400 lines × 20% manually submitted × 7/60 hours per manual line) + (86,400 lines × 80% electronically submitted × 2/60 hours per electronic line).

The estimated annual savings to industry would be $198,720 = 4,320 hours × $46 per hour.

B. State and Local Governments

State revenues may be negatively impacted by the marginal property reporting exception because royalty payments may be deferred for up to 18 months. We believe the impact would be minimal because small producers would be more likely to use the marginal property exception than large producers. We are specifically requesting comments from both states and industry on what impact states may incur due to the marginal property reporting exception.

States may realize additional royalty revenues in future years if RSFA has the desired effect of extending the life of marginal properties. These benefits are not quantifiable at this time.

C. Federal Government

Benefit—Reduced Operating Costs for Fewer Reported Lines. We estimate that the Federal Government may benefit from clearer takes versus entitlement reporting procedures. More accurate reporting based on clearer reporting instructions would reduce ONRR resources needed to identify, notify, and resolve which parties are responsible for the reporting and payment of royalties on Federal oil and gas leases. However, these savings are not quantifiable at this time.

Further, the Federal Government may realize additional royalty revenues in future years if: (a) the savings to lessees and designees from the marginal property reporting exception has the desired outcome of extending the production life of marginal properties; and (b) reduced out-of-pocket expenses motivates lessees to invest in further lease development. However, these additional revenues are not quantifiable at this time.

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 have made the assessments required by E.O. 12866, and the results are given below.

a. This proposed rule would not have an effect of $100 million or more per year 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 Costs and Benefits table, in Item 1 above, demonstrates that the economic impact on industry would be well below the $100 million threshold used to define a rulemaking as having a significant impact on the economy.

b. This proposed rule would not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency. ONRR is the only agency that promulgates rules for reporting royalties on Federal oil and gas leases. Because this proposed rule would address only reporting and payment issues, it would not affect inspections and other actions that BLM, BSEE, or states perform.

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.

d. This proposed rule could raise novel legal or policy issues. This proposed rule would codify Interior Board of Land Appeals decisions and provide additional details about the reporting and payment methods mandated by RSFA.

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.*). Approximately 2,500 different companies submit royalty and production reports to ONRR each month. In addition, approximately 200 of these 2,500 companies are large businesses under the U.S. Small Business Administration definition because they have over 500 employees.

The remaining 2,300 companies are considered to be small businesses.

As documented in Item 1A Industry (costs and benefits) in the Procedural Matters section, we believe industry would indeed have net savings after the first year as a result of the provisions in this proposed rule. The most significant costs in the first year after this rule became effective would be the initial programming costs necessary to incorporate rule provisions into each company's automated reporting system. As stated earlier, we believe most of these costs would be incurred by very large companies with complex automated reporting systems. Consequently, we believe this proposed rule would have an overall positive economic effect on small businesses. In addition to the monetary benefits discussed in Item 1A, this proposed rule would have other beneficial effects unique to small businesses.

Small businesses would be better able to match royalty payments with the cash flow from the sale of production. This proposed rule would require lessees to pay royalties on stand-alone leases and 100-percent Federal agreements on a takes basis; that is, only when the lessee sells or removes production. This procedure would be substantially different from current requirements that lessees pay on their entitled share regardless of who took production. This proposed rule also would allow lessees to pay on a takes basis for mixed agreements if the agreement qualifies as a marginal property. Typically, as properties near the end of their productive life, larger companies with higher overhead divest their marginal properties to smaller companies who can operate the properties more profitably. Consequently, we anticipate that most reporting relief granted under the marginal property reporting exception would be for small entities. Paying on a takes basis would reduce the number of out-of-pocket royalty payments that would otherwise occur under entitlement reporting.

The marginal property exception would also benefit small businesses reporting on a takes basis because it would allow lessees to ''true up'' to their entitled share up to 6 months after the calendar year. The lessee's decision to defer the true-up adjustment and associated royalty payment would be strictly discretionary. For example, the lessee could choose to true up by January 1 of the next calendar year and avoid any interest charges. On the other hand, the lessee could make a conscious decision to defer out-of-pocket royalty payments and use the funds for other purposes for up to 6 months. For example, lessees could choose to invest the money if the return on investment is higher than the interest that will be due to the Government at the end of the time period, or use the funds temporarily to capitalize development of their oil and gas properties while awaiting a more permanent source of funds. An important benefit of this proposed rule would provide greater flexibility for small businesses to meet their unique cash management needs.

4. Small Business Regulatory Enforcement Fairness Act (SBREFA)

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. The effect would be limited to a maximum estimated at $3,534,730 = $3,842,098 × (2,300 small businesses/ 2,500 companies). 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 rulemaking would benefit U.S.-based enterprises if finalized as written.

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, a statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

6. Takings (E.O. 12630)

Under the criteria in Executive Order 12630, this proposed rule would not have any significant takings implications. This proposed rule would not impose conditions or limitations on the use of any private property. Therefore, a takings implication assessment is not required.

7. Federalism (E.O. 13132)

Under the criteria in Executive Order 13132, this proposed rule would not have sufficient federalism implications to warrant the preparation of a Federalism Assessment. This proposed rule would affect the timing of royalty reports to the Federal Government but not the amount paid and, ultimately, distributed to the states. Consequently, this proposed rule would not substantially and directly affect the relationship between Federal and state governments or impose costs on states or localities. Therefore, a Federalism Assessment is not required.

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

This proposed rule would comply with the requirements of Executive Order 12988. Specifically, this proposed rule:

a. Would meet the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation.

b. Would meet the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

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

Under the criteria in Executive Order 13175, we have evaluated this proposed rule and determined that it would have no potential effects on federally recognized Indian tribes. This proposed rule would have no tribal implications that impose substantial direct compliance costs on Indian tribal governments.

10. Paperwork Reduction Act of 1995

This proposed rule would create a new part 1205 containing new information collection requirements. The title of the new information collection request (ICR) is ''30 CFR Part 1205, Takes vs. Entitlements.'' ONRR is submitting this ICR to OMB for review and approval, as required under the Paperwork Reduction Act of 1995 (PRA), 44 U.S.C. 3501 *et seq.* This proposed rule also would amend paragraphs in part 1202 but would not change the information collection requirements already approved for that part under OMB Control Number 1012–0004. In addition, the proposed rule would make a technical amendment to the table at § 1210.10 by adding the OMB control number for the new ICR.

As part of our continuing effort to reduce paperwork and respondent burden, we invite the public and other Federal agencies to comment on any aspect of the reporting burden through the information collection process. Please see *ICR Comments* under the **ADDRESSES** section to submit comments.

The OMB has up to 60 days to approve or disapprove this collection of information but may respond after 30 days. Therefore, submit public comments to OMB within 30 days in order to ensure their maximum consideration. However, we will consider all comments received during the comment period for this notice of proposed rulemaking.

The intent of this rulemaking is to implement provisions of RSFA governing when a Federal lessee must report and pay on the oil and gas volumes it takes from a lease, or on the volume it is entitled to, based on its ownership interest in the lease. We collect this information to ensure that lessees accurately value and properly pay royalties. In the first year, we expect that ONRR would receive approximately 250 requests for an alternative method of royalty reporting and payment for agreements.

If a lessee of a Federal agreement, with concurrence of all lessees, wants to begin or end an alternative method of royalty reporting and payment, the lessee must submit a written request to ONRR. The lessee must submit the company's name, address, phone number, and a contact name; the agreement number and a list of leases in the agreement for the property being considered for beginning or ending the alternative method of royalty reporting and payment; a list of all lessees and their ownership interest in the leases in the agreement; and documentation that will support the concurrence of all lessees to beginning or terminating such alternative method of reporting. If the request is to begin an alternative reporting method, the lessee also must submit a description of the alternative method and documentation that will prove that such an alternative method does not reduce the amount of royalty obligation.

We estimate that ONRR would receive approximately 250 requests in the first year for an alternative method of royalty reporting and payment on 100-percent Federal agreements from the lessees. We expect 200 offshore and 50 onshore submitted requests, allowing lessees to continue to report on an entitlements basis instead of changing to a takes-reporting basis as required by RSFA. Each request for alternative reporting would be subject to a non-refundable processing fee of $2,400. Lessees would take approximately 10 hours to complete submission of each request and an additional one-quarter hour for recordkeeping. We estimate the total annual burden would be 2,563 hours = (250 requests × 10 reporting hours) + (250 requests × 0.25 recordkeeping hours). In subsequent years, we expect the number of requests to decrease, thus lowering the cost to industry. We also estimate that industry would file annually two termination requests of their respective alternative method, resulting in an annual estimate of 21 hours = (2 termination requests × 10 reporting hours) + (2 termination requests × 0.25 recordkeeping hour).

We estimate a total of 2,584 burden hours for the new requirements. The following table shows the proposed requirements and burden hours for this rule and new ICR, by CFR citation.

BURDEN BREAKDOWN

30 CFR	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
PART 1205—REPORTING AND PAYING ROYALTIES ON FEDERAL LEASES				
Subpart B—Reporting and Paying Royalties on Federal Leases				
1205.101 (a)(1), (a)(2), and (a)(3).	(a) Unless you qualify for the exceptions in subparts C and D of this part, you must report and pay royalties. * * *	Hour burden covered under OMB Control No. 1012–0004 (formerly 1010–0139).		
1205.105 (a)	The volume allocated to a lease or agreement under a BLM or BSEE commingling approval is the volume on which you and all other lessees must report and pay under §1205.101(a)(1) through (3).			
1205.106 (a) and (b).	There are two exceptions to the reporting and payment requirements in this subpart: (a) You may qualify for an alternative to the royalty reporting and payment requirements for 100-percent Federal agreements under § 1205.101(a)(2) if you meet certain requirements. The requirements for alternative reporting are explained in subpart C; or (b) You may qualify to report on your take volume rather than entitled volume, with appropriate adjustments after year-end, if your mixed agreement is a marginal property. Requirements for the marginal property reporting exception are explained in subpart D.	AUDIT PROCESS. See note.		
Subpart C—Reporting and Paying Royalties on Federal Leases Under an Alternative Method for a 100-percent Federal Agreement				
1205.201 (a)	You may qualify for an alternative to the royalty reporting and payment requirements for agreements under subpart B if: (a) You are in a 100-percent Federal agreement;	AUDIT PROCESS. See note.		
1205.201 (b)	(b) You and all other lessees in the agreement concur in writing to the alternative method; and	Hour burden covered under 30 CFR 1205.202.		
1205.201 (c)	(c) The alternative does not reduce the total monthly royalty obligation reported and paid to ONRR.	AUDIT PROCESS. See note.		
1205.202 (a), (b), and (c).	(a) To obtain approval to use an alternative method of royalty reporting and payment, you must submit one written request to ONRR on behalf of all lessees of leases in the agreement.	10.25	250	2,563

BURDEN BREAKDOWN—Continued

30 CFR	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
	(b) The request you submit under paragraph (a) of this section must contain the following documents and information: (1) A description of the proposed alternative reporting and payment method. (2) The agreement number and a list of the leases in the agreement. (3) A list of all lessees and their ownership interest in the leases in the agreement. (4) A copy of the lessees' written concurrence to the alternative method required under § 1205.201(b). (5) Documentation showing that the proposed alternative method does not reduce the total monthly royalty obligation reported and paid to ONRR for the leases in the agreement. (6) A non-refundable processing fee of $2,400 for each request you make for an agreement under this section: (i) You must pay the processing fee to ONRR following the requirements for making payments found in 30 CFR 1218.51. You are not required to use Electronic Funds Transfer (EFT) for these payments. (ii) If you do not remit the full amount of the processing fee with your request, ONRR will return your request unprocessed. If ONRR returns your unprocessed request for failure to pay the fee, you may not appeal the return of your request. (iii) ONRR may adjust the processing fee by providing notice in the **Federal Register**. (c) You must retain all records pertaining to your request for an alternative method for 7 years after termination of the alternative method.			
1205.204 (a)	When ONRR receives your request for alternative reporting and payment under § 1205.202, ONRR will notify you in writing as follows: (a) If your request for alternative reporting and payment is complete, ONRR may approve, deny, or modify your request in writing. * * *.	AUDIT PROCESS. See note.		
1205.204 (b)(1) and (4).	(b) If your request for alternative reporting and payment is not complete, ONRR will notify you in writing that your request is incomplete and identify any missing information. (1) You must submit the missing information within 60 days of your receipt of ONRR's notice. * * *. (4) You may submit a new request. * * *	Hour burden covered under 30 CFR 1205.202.		
1205.205 (a) and (b).	(a) If you are a lessee for a lease in an agreement when you submit a request under § 1205.202, you must begin using the alternative method of royalty reporting and payment for the production month after you receive written approval from ONRR. (b) If you become a lessee for a lease in an agreement for which there is an approved alternative method of royalty reporting and payment, you must begin reporting under the alternative method for the production month in which you become a lessee.	Hour burden covered under OMB Control No. 1012–0004.		
1205.206 (a) and (b). 1205.207 (a) and (b).	If you want to stop using the approved alternative method of royalty reporting and payment, you must: (a) Obtain written concurrence from all lessees in the agreement to stop using the alternative method; and (b) Provide a copy of the written concurrence to ONRR and the delegated state, if applicable. (a) If you request to stop using the approved alternative method under § 1205.206, then you must stop using the approved alternative method of royalty reporting and payment beginning with the production month after you provide a copy of the written concurrence to ONRR and the delegated state, if applicable. (b) You must stop using the approved alternative method of royalty reporting and payment within 60 days after you receive written notice from BLM or BSEE notifying you that a non-Federal tract or a tract with a different royalty rate or funds distribution has been added to your agreement.	10.25	2	21

BURDEN BREAKDOWN—Continued

30 CFR	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
Subpart D—Reporting and Paying Royalties on Marginal Properties				
1205.301 (a), (b), and (c).	(a) The marginal property exception allows you to report and pay on your take volume each month and adjust to your entitled volume after the end of the calendar year rather than reporting and paying based on your entitled volume each month as required under § 1205.101(a)(3). (b) You may use the marginal property exception if: .... (1) Your lease is in a mixed agreement; and .... (2) The mixed agreement qualifies as a marginal property under this subpart. (c) You may report and pay using the marginal property exception regardless of whether any other lessee or designee who pays royalties for that marginal property uses the exception.	Hour burden covered under OMB Control No. 1012–0004.		
1205.305 (a)	(a) If you start using the marginal property exception . . . then you must report and pay. * * *	Hour burden covered under OMB Control No. 1012–0004.		
1205.306 (a) and (b).	If you want to report and pay under the marginal property exception, you must: (a) First, determine your take volume from the qualifying marginal property under § 1205.102. (b) Second, report and pay for each of your Federal leases in the qualifying marginal property by allocating the take volume determined in paragraph (a) of this section to all of your leases in the agreement based on the approved agreement allocation schedule.			
1205.307 (a), (b), and (c).	If the take volume you reported under § 1205.306(b) does not equal your entitled volume for the calendar year, for each of your Federal leases in the qualifying marginal property, you must: (a) Calculate the difference between the take volume you reported under the marginal property exception and your entitled volume for the calendar year in which you used the exception; and (b) Report the difference calculated in paragraph (a) of this section: (1) On Form MMS–2014, Report of Sales and Royalty Remittance (2) By June 30 of the calendar year immediately following the calendar year for which you used the marginal property exception. (3) As a positive amount on Form MMS–2014 when your total takes are less than your entitlements, or a negative amount on Form MMS–2014 when your total takes exceed your entitlements. (4) As a single-line entry for each lease and product from the lease. (5) Using the correct adjustment reason code for reporting under this section. (6) Using the December sales month of the calendar year for which you used the marginal property exception. (c) Do not adjust the monthly royalty lines you reported under § 1205.306(b) if the take volumes you reported were accurate.			
1205.309 (a) and (b).	If the difference you report under § 1205.307 is positive and you underpaid royalties for the qualifying marginal property, then you: (a) Must pay the additional royalty owed when you report the difference under § 1205.307; and (b) Will owe interest on the additional royalty you reported and paid under paragraph (a) of this section at the rate prescribed under part 1218 of this title. You will owe interest beginning January 1 of the calendar year following the calendar year for which you used the marginal property exception until the date you paid the additional royalties due.	Hour burden covered under OMB Control No. 1012–0004.		

BURDEN BREAKDOWN—Continued

30 CFR	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
1205.311 (a), (b), and (c).	If you erroneously report using the marginal property exception on a property that is not a qualified marginal property, you: (a) Must amend all erroneously submitted Form MMS–2014s to report your entitled volume for each calendar month; (b) Will owe any associated interest calculated under part 1218 of this title; and (c) May be subject to civil penalties under part 1241 of this title			
1205.312 (a), (b), and (c).	(a) Your property must qualify for the marginal property exception under this subpart for each calendar year based on production during the base period. (b) If you find that your property is no longer eligible for the marginal property exception because production increased in the most recent base period, you must stop using the exception as of December 31 of the year in which the most recent base period ends. (c) If you do not stop using the marginal property exception as required under paragraph (b) of this section, then you: (1) Will owe late payment interest determined under part 1218 of this title from the date you were required to stop using the exception under paragraph (b). (2) May be subject to civil penalties under part 1241 of this title	AUDIT PROCESS. See note.		
	Burden Hour Total	....	252	2,584

Note: AUDIT PROCESS—The Office of Regulatory Affairs determined that the audit process is exempt from the Paperwork Reduction Act of 1995 because ONRR staff asks non-standard questions to resolve exceptions. 5 CFR 1320.4(a)(2).

Public Comment Policy: The PRA (44 U.S.C. 3501 *et seq.*) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Before submitting an ICR to OMB, PRA section 3506(c)(2)(A) requires each agency to '' . . . consult with members of the public and affected agencies concerning each proposed collection of information. . . .'' ONRR is specifically soliciting comments on the following aspects of this collection: (a) Evaluate whether the proposed collection of information is necessary for the agency to perform its duties, including whether the information is useful; (b) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) enhance the quality, usefulness, and clarity of the information to be collected; and (d) minimize the burden on the respondents, including the use of automated collection techniques or other forms of information technology.

The PRA also requires agencies to estimate the total annual reporting ''non-hour cost'' burden to respondents or recordkeepers resulting from the collection of information. Other than the $2,400 fee for each alternative reporting request (§ 1205.202(b)(6)), we have not identified any other costs. Therefore, if you have costs to generate, maintain, and disclose this information, you should comment and provide your total capital and startup cost components or annual operation, maintenance, and purchase of service components. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and startup costs include, among other items, software you purchase to prepare for collecting information; monitoring, sampling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: (i) Before October 1, 1995; (ii) to comply with requirements not associated with the information collection; (iii) for reasons other than to provide information or keep records for the Federal Government; or (iv) as part of customary and usual business or private practices.

ONRR will summarize written responses to this proposed information collection and address them in our final rule. We will provide a copy of the ICR to you, without charge upon request, and also post the ICR at *http://www.onrr.gov/Laws_R_D/FRNotices/FRInfColl.htm.* We will post all comments in response to this proposed information collection at *http://www.regulations.gov.*

11. National Environmental Policy Act

This rule does 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 have also 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 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 Web site at *http://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 Executive Order 13211. A Statement of Energy Effects is not required.

14. Clarity of This Regulation

We are required by Executive Orders 12866 and 12988 and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must: (a) Be logically organized; (b) use the active voice to address readers directly; (c) use clear language rather than jargon; (d) be divided into short sections and sentences; and (e) use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the "ADDRESSES" section. To better help us revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that are unclearly written, 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, email 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, 1205, and 1210

Indian leases, Actual disposition, Royalty purposes, Outer Continental shelf, Indian lands, Mineral resources, Mineral royalties, Natural gas, Oil, Public lands—mineral resources, Reporting and recordkeeping requirements.

Dated: August 1, 2013.

Rhea Suh,

Assistant Secretary, Policy, Management and Budget.

For the reasons stated in the preamble, the Office of Natural Resources Revenue proposes to amend 30 CFR parts 1202 and 1210, and add 30 CFR part 1205 as set forth below:

PART 1202—ROYALTIES

■ 1. The authority 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 C—Federal and Indian Oil

§ 1202.100 Royalty on oil.

■ 2. Amend § 1202.100 by revising paragraphs (e)(1), (e)(2), (e)(3), and (f) to read as follows:

* * * * *

(e)(1) *Indian oil.* This paragraph (e) applies only to Indian leases. In those instances where the lessees of any Indian lease committed to a federally approved unitization or communitization agreement do not actually take the proportionate share of the agreement production attributable to their lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value, for royalty purposes, of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 1206. In applying the requirements of 30 CFR part 1206 to Indian leases, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take, will be considered as controlling in arriving at the value, for royalty purposes, of that portion, as if the person actually selling or disposing of the production were the lessee of the Indian lease.

(e)(2) If an Indian lessee takes less than its proportionate share of agreement production, upon request of the lessee, ONRR may authorize a royalty valuation method different from that required by paragraph (e)(1) of this section, but consistent with the purposes of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(e)(3) For purposes of this section, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken ratably from all persons actually taking less than their proportionate share of the agreement production for that month.

* * * * *

(f) *Federal oil.* The regulations explaining when you must report and pay royalties on the volume of oil you take from your Federal lease, including Federal leases committed to a federally approved unitization or communitization agreement, or on the entitled share of production from or allocated to your Federal lease, are found in 30 CFR part 1205.

* * * * *

Subpart D—Federal Gas

§ 1202.150 Royalty on gas.

■ 3. Amend § 1202.150 by revising paragraph (e) to read as follows:

* * * * *

(e) The regulations explaining when you must report and pay royalties on the volume of gas you take from your Federal lease, including Federal leases committed to a federally approved unitization or communitization agreement, or on the entitled share of production from or allocated to your Federal lease, are found in 30 CFR part 1205.

§ 1202.152 Standards for reporting and paying royalties on gas.

■ 4. Amend § 1202.152 by revising paragraphs (a)(1) and (a)(2) to read as follows:

(a) You must report gas volumes and British thermal unit (Btu) heating values using the frequencies and methods required under BLM and Bureau of Ocean Energy Management (BOEM) regulations, orders, and notices subject to ONRR verification based on third party data.

* * * * *

Subpart J—Gas Production From Indian Leases

§ 1202.558 What standards do I use to report and pay royalties on gas?

■ 5. Amend § 1202.558 by revising paragraphs (a)(1) and (a)(2) to read as follows:

(a) You must report gas volumes and Btu heating values using the frequencies and methods required under BLM regulations, orders and notices, subject to ONRR verification based on third party data.

* * * * *

■ 6. Add part 1205 to read as follows:

PART 1205—REPORTING AND PAYING ROYALTIES ON FEDERAL LEASES

Subpart A—General Provisions

Authority: 5 U.S.C. 301 *et seq.,* 30 U.S.C. 181 *et seq.,* 351 *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 A—General Provisions

§ 1205.1 What is the purpose of this part?

(a) This part explains when you must report and pay royalties on:

(1) The volume of oil and gas you take from your Federal lease; or

(2) The entitled share of production from or allocated to your Federal lease.

(b) The requirements of this part do not alter a lessee's liability to pay royalty on the percentage of lease production equal to the lessee's working interest percentage, record title interest, or operating rights ownership in a lease.

(c) The requirements of this part do not alter a lessee's responsibility to timely pay annual obligations specified in lease terms such as minimum royalty payments.

§ 1205.2 What leases are subject to this part?

(a) This part applies to all Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS).

(b) This part does not apply to:

(1) Federal leases for minerals other than oil and gas;

(2) Indian mineral leases; or

(3) Leases for which the Federal Government became the lessor when it acquired a mineral interest subject to a private mineral lease.

§ 1205.3 What definitions apply to this part?

The following definitions apply to this part:

100-percent Federal agreement means any agreement that contains only Federal leases having the same fixed royalty rate and funds distribution. A 100-percent Federal agreement excludes any agreement that includes leases subject to the Gulf of Mexico Energy Security Act of 2006 (GOMESA).

Agreement means an agreement for exploration or development of mineral resources from identified tracts of properties described in 30 CFR chapters II or V (offshore) or 43 CFR part 3000 (onshore) that is approved by the Bureau of Safety and Environmental Enforcement (BSEE) or the Bureau of Land Management (BLM), as applicable. The most common agreements are enhanced recovery units, unit participating areas, unitization agreements, and communitization agreements. For purposes of this part, agreements fall into two categories: 100-percent Federal agreements and mixed agreements.

Approved point of royalty measurement means the point where BLM or BSEE determines the volume of oil or gas is removed from a lease or agreement. The BLM designates this point under 43 CFR 3162.7 for onshore leases, and BSEE designates this point under 30 CFR part 250, subpart L, for OCS leases. When production from different leases or agreements is commingled before the approved point of royalty measurement, the commingling approval defines how the total volume measured at the approved point of royalty measurement is allocated to each lease or agreement subject to the commingling approval.

Barrels of oil equivalent (BOE) means the combined equivalent production of oil and gas stated in barrels of oil. Each barrel of oil production is equal to one BOE. Also, each 6,000 cubic feet (6 Mcf) of gas production is equal to one BOE.

Base period means the 12-month period from July 1 through June 30 immediately preceding the calendar year for which you elect to report and pay using the marginal property reporting exception in subpart D.

Calendar year means the January through December production months.

Combined equivalent production means the total of all oil and gas production for the marginal property, stated in BOE.

Commingling approval means the BLM- or BSEE-approved surface mixing of production from two or more independent leases or agreements, before measurement for royalty purposes.

Delegated state means a state with which ONRR has entered into a delegation agreement under 30 U.S.C. 1735.

Designee means the person designated by a lessee under 30 CFR 1218.52 to make all or part of the royalty or other payments due on a lease on the lessee's behalf.

Entitled share means the percentage of the volume of production equal to your working interest percentage or operating rights ownership in a lease.

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

Mixed agreement means any agreement other than a 100-percent Federal agreement. Mixed agreements contain any mixture of Federal, Indian, state or private mineral estates, or contain all Federal leases with different royalty rates or funds distribution. A mixed agreement includes any agreement that contains leases subject to GOMESA.

Operator means any person, including the lessee, who has control of, or who manages operations affecting any Federal oil and gas lease. ''Operator'' also means any entity engaged in the business of developing, drilling for, or producing oil or gas or that has the responsibility for reporting production from a lease or portion thereof.

Producing wells means only those producing oil or gas wells that contribute to the sum of BOE used in the calculation under §§ 1205.302 and 1205.303. Producing wells do not include injection wells, disposal wells and water source wells. Wells with multiple zones commingled downhole are considered a single well.

Take means any oil or gas volumes removed or sold from a lease or agreement, as measured at or allocated from an approved point of royalty measurement. For stand-alone leases, the take volume is the volume measured at the approved point of royalty measurement for the lease. For leases in a 100-percent Federal agreement or subject to a commingling approval, the take volume for an individual lease is the volume allocated back to the lease after measurement at an approved point of royalty measurement for the agreement or commingling approval.

You and your means the lessee or its designee for a lease.

Subpart B—Reporting and Paying Royalties on Federal Leases

§ 1205.101 How do I report and pay royalties?

(a) Unless you qualify for the exceptions in subparts C and D of this part, you must report and pay royalties as stated in the table below:

If you are a lessee of a lease or portion of a lease that is . . .	Then you must report and pay royalties based on . . .
(1) Not contained in an agreement (stand-alone)	The volume of production you take from the lease or portion of a lease that is not in an agreement.
(2) In a 100-percent Federal agreement	The volume of production you take from the lease or portion of the lease in a 100-percent Federal agreement.
(3) In a mixed agreement	Your entitled share of production allocated to the lease or portion of the lease in the mixed agreement.

(b) If you report and pay royalties under paragraph (a)(2) of this section for more than one lease in a 100-percent Federal agreement, you must allocate the volume to each lease in the agreement according to the agreement allocation schedule.

§ 1205.102 How do I determine my take volume?

The volume of production you take is the volume you, or someone on your behalf, sold from your lease or leases. See § 1205.105 to determine how a commingling approval may affect your take volume.

§ 1205.103 How do I determine my entitled volume in a mixed agreement?

Your entitled volume is your entitled share in a lease or portion of a lease multiplied by the volume of production allocated to your lease under the agreement allocation schedule. See § 1205.105 to determine how a commingling approval may affect your entitled volume.

§ 1205.104 How do I determine value for my entitled volume in a mixed agreement?

(a) If you take less than your entitled volume of production from a mixed agreement during a month, then the royalty value you must use for the difference is the volume weighted-average unit value for the total volume you take from the property during that month, as determined under part 1206 of this title.

(b) If you do not take any production to which you were entitled from a mixed agreement during a month, then the royalty value for your entitled share for that month is the value determined for non-arm's-length dispositions under 30 CFR 1206.103 for oil; 30 CFR 1206.152(c) for unprocessed gas; and 30 CFR 1206.153(c) for processed gas.

§ 1205.105 How does a commingling approval affect my take volume?

(a) The volume allocated to a lease or agreement under a BLM or BSEE commingling approval is the volume on which you and all other lessees must report and pay under § 1205.101(a)(1) through (3).

(b) The sum of the volumes all lessees report under paragraph (a) of this section must equal the total volume allocated to the lease or agreement under the commingling approval.

§ 1205.106 Are there exceptions to the reporting and payment requirements in this subpart?

There are two exceptions to the reporting and payment requirements in this subpart:

(a) You may qualify for an alternative to the royalty reporting and payment requirements for 100-percent Federal agreements under § 1205.101(a)(2) if you meet certain requirements. The requirements for alternative reporting are explained in subpart C; or

(b) You may qualify to report on your take volume rather than entitled volume, with appropriate adjustments after year-end, if your mixed agreement is a marginal property. Requirements for the marginal property reporting exception are explained in subpart D.

Subpart C—Reporting and Paying Royalties on Federal Leases Under an Alternative Method for a 100-Percent Federal Agreement

§ 1205.201 How do I qualify for alternative reporting and payment for a 100-percent Federal agreement?

You may qualify for an alternative to the royalty reporting and payment requirements for agreements under subpart B if:

(a) You are in a 100-percent Federal agreement;

(b) You and all other lessees in the agreement concur in writing to the alternative method; and

(c) The alternative does not reduce the total monthly royalty obligation reported and paid to ONRR.

§ 1205.202 How do I request alternative reporting and payment for a 100-percent Federal agreement?

(a) To obtain approval to use an alternative method of royalty reporting and payment, you must submit one written request to ONRR on behalf of all lessees of leases in the agreement.

(b) The request you submit under paragraph (a) of this section must contain the following documents and information:

(1) A description of the proposed alternative reporting and payment method.

(2) The agreement number and a list of the leases in the agreement.

(3) A list of all lessees and their ownership interest in the leases in the agreement.

(4) A copy of the lessees' written concurrence to the alternative method required under § 1205.201(b).

(5) Documentation showing that the proposed alternative method does not reduce the total monthly royalty obligation reported and paid to ONRR for the leases in the agreement.

(6) A non-refundable processing fee of $2,400 for each request you make for an agreement under this section.

(i) You must pay the processing fee to ONRR following the requirements for making payments found in 30 CFR 1218.51. You are not required to use Electronic Funds Transfer (EFT) for these payments.

(ii) If you do not remit the full amount of the processing fee with your request, ONRR will return your request unprocessed. If ONRR returns your unprocessed request for failure to pay the fee, you may not appeal the return of your request.

(iii) ONRR may adjust the processing fee by providing notice in the **Federal Register**.

(c) You must retain all records pertaining to your request for an alternative method for 7 years after termination of the alternative method.

§ 1205.203 Who will approve, deny, or modify my request for alternative reporting and payment for a 100-percent Federal agreement?

(a) If there is not a delegated state for your lease in a 100-percent Federal agreement, only ONRR will decide whether to approve, deny, or modify your request for alternative reporting and payment.

(b) If there is a delegated state for your lease in a 100-percent Federal agreement, ONRR will decide whether to approve, deny, or modify your request for alternative reporting and payment after consulting with the delegated state.

§ 1205.204 How will I know if I am approved for alternative reporting and payment for a 100-percent Federal agreement?

When ONRR receives your request for alternative reporting and payment under § 1205.202, we will notify you in writing as follows:

(a) If your request for alternative reporting and payment is complete, ONRR may approve, deny, or modify your request in writing.

(1) If ONRR approves your request for alternative reporting and payment, ONRR will notify you with specifics of the approval.

(2) If ONRR denies your request for alternative reporting and payment, ONRR will notify you of the reasons for denial and your appeal rights under part 1290, subpart B, of this chapter.

(3) If ONRR modifies your request for alternative reporting and payment, ONRR will notify you of the modifications.

(i) You have 60 days from your receipt of the notice to either accept or reject any modification(s) in writing.

(ii) If you reject the modification(s) or fail to respond to the notice, ONRR will deny your request. ONRR will notify you in writing of the reasons for denial and your appeal rights under part 1290, subpart B, of this chapter.

(b) If your request for alternative reporting and payment is not complete, ONRR will notify you in writing that your request is incomplete and identify any missing information.

(1) You must submit the missing information within 60 days of your receipt of ONRR's notice that your request is incomplete.

(2) After you submit all required information, ONRR may approve, deny, or modify your request for alternative reporting and payment under paragraph (a) of this section.

(3) If you do not submit all required information within 60 days of your receipt of ONRR's notice that your request is incomplete, we will return your request as incomplete. If ONRR returns your unprocessed request because it is incomplete:

(i) ONRR will not return the processing fee you paid under § 1205.202; and

(ii) You may not appeal the return of your request.

(4) You may submit a new request including another processing fee for alternative reporting and payment under this subpart at any time after ONRR returns your incomplete request.

§ 1205.205 When must I begin using the alternative method for a 100-percent Federal agreement?

(a) If you are a lessee for a lease in an agreement when you submit a request under § 1205.202, you must begin using the alternative method of royalty reporting and payment for the production month after you receive written approval from ONRR.

(b) If you become a lessee for a lease in an agreement for which there is an approved alternative method of royalty reporting and payment, you must begin reporting under the alternative method for the production month in which you become a lessee.

§ 1205.206 What if I want to stop reporting and paying under the approved alternative method for a 100-percent Federal agreement?

If you want to stop using the approved alternative method of royalty reporting and payment, you must:

(a) Obtain written concurrence from all lessees in the agreement to stop using the alternative method.

(b) Provide a copy of the written concurrence to ONRR and the delegated state, if applicable.

§ 1205.207 When must I stop using the approved alternative method for a 100-percent Federal agreement?

(a) If you request to stop using the approved alternative method under § 1205.206, then you must stop using the approved alternative method of royalty reporting and payment beginning with the production month after you provide a copy of the written concurrence to ONRR and the delegated state, if applicable.

(b) You must stop using the approved alternative method of royalty reporting and payment within 60 days after you receive written notice from BLM or BSEE notifying you that a non-Federal tract or a tract with a different royalty rate or funds distribution has been added to your agreement.

(c) A change in a lessee's ownership interests after the initial approval for alternative reporting and payment will not terminate the approval.

(d) ONRR will terminate an approval in any instance when it believes it is in the best interest of the United States.

Subpart D—Reporting and Paying Royalties on Marginal Properties

§ 1205.301 What is the marginal property reporting and payment exception?

(a) The marginal property exception allows you to report and pay on your take volume each month and adjust to your entitled volume after the end of the calendar year rather than reporting and paying based on your entitled volume each month as required under § 1205.101(a)(3).

(b) You may use the marginal property exception if:

(1) Your lease is in a mixed agreement; and

(2) The mixed agreement qualifies as a marginal property under this subpart.

(c) You may report and pay using the marginal property exception regardless of whether any other lessee or designee who pays royalties for that marginal property uses the exception.

§ 1205.302 What is a marginal property under this subpart?

A marginal property is an agreement that, during the base period, has a combined equivalent production averaging less than 15 barrels of oil equivalent (BOE) per well producing day, as calculated under § 1205.303.

§ 1205.303 How do I determine if my property is a marginal property?

To determine if your property meets the marginal property qualifications for the next calendar year, you must:

(a) Calculate the total volume of oil and gas produced from your property during the base period (starting July of the previous year through June of the current year).

(b) Divide the total gas production (in Mcf) by 6 and add that total to the oil volume (in barrels) to arrive at the total BOE.

(c) Calculate the total number of days each well actually produced during the same time period (include all producing wells in the mixed agreement, including those that are not located on a Federal tract).

(d) Divide the total produced volume by the total well producing days.

If your calculated average daily well production is less than 15 BOE, your property qualifies for the marginal property exception.

§ 1205.304 When may I begin using the marginal property exception?

(a) After determining your property qualifies as a marginal property during the base period, you may begin using the marginal property reporting exception in the January production month of the calendar year following the base period.

(b) If you become a lessee of a qualifying marginal property during the calendar year, you may begin using the marginal property exception in the production month in which you became a lessee.

(c) You do not need to notify ONRR of your intent to use the marginal property reporting exception.

§ 1205.305 How long must I use the marginal property exception?

(a) If you start using the marginal property exception during any part of the calendar year and you do not dispose of your interest in the property during that calendar year, then you must report and pay under the exception through the December production month of that calendar year.

(b) If you dispose of your interest in a qualified marginal property during the calendar year, then you must use the exception through the last production month in which you had an ownership interest in the property. If the take volume you reported during your period of ownership does not equal your entitled volume, you must adjust your payments under §§ 1205.307 through 1205.310, except that:

(1) You must use as the sales month the last month you had an ownership interest rather than the December sales month required under § 1205.307(b)(6).

(2) Interest will be calculated from the first day of the month following the month you disposed of your ownership interest rather than January 1 of the calendar year following the calendar year for which you used the marginal property exception as prescribed under § 1205.309(b).

§ 1205.306 How do I report under the marginal property exception?

If you want to report and pay under the marginal property exception you must:

(a) First, determine your take volume from the qualifying marginal property under § 1205.102.

(b) Second, report and pay for each of your Federal leases in the qualifying marginal property by allocating the take volume determined in paragraph (a) of this section to all of your leases in the agreement based on the approved agreement allocation schedule.

§ 1205.307 What if the take volume I reported does not equal my entitled volume for one or more of my Federal leases for the calendar year?

If the take volume you reported under § 1205.306(b) does not equal your entitled volume for the calendar year, for each of your Federal leases in the qualifying marginal property, you must:

(a) Calculate the difference between the take volume you reported under the marginal property exception and your entitled volume for the calendar year in which you used the exception.

(b) Report the difference calculated in paragraph (a) of this section:

(1) On Form MMS–2014, Report of Sales and Royalty Remittance.

(2) By June 30 of the calendar year immediately following the calendar year for which you used the marginal property exception.

(3) As a positive amount on Form MMS–2014 when your total takes are less than your entitlements, or as a negative amount on Form MMS–2014 when your total takes exceed your entitlements.

(4) As a single-line entry for each lease and product from the lease.

(5) Using the correct adjustment reason code for reporting under this section.

(6) Using the December sales month of the calendar year for which you used the marginal property exception.

(c) Do not adjust the monthly royalty lines you reported under § 1205.306(b) if the take volume you reported was accurate.

§ 1205.308 How do I determine the royalty value for the difference between my take volume and entitled volume?

(a) If you take production from a qualifying marginal property during the calendar year and you report a difference between your take volume and entitled volume under § 1205.307, the royalty value you must use for the difference is based on the volume weighted-average unit value for the total volume you take from the property during that calendar year, as determined under part 1206 of this title.

(b) If you do not take production from a marginal property during the calendar year but you report a difference under § 1205.307, the royalty value for the difference is the value determined for non-arm's-length dispositions under 30 CFR 1206.103 for oil; 30 CFR 1206.152(c) for unprocessed gas; and 30 CFR 1206.153(c) for processed gas.

§ 1205.309 What must I do if I underpay royalties under this subpart?

If the difference you report under § 1205.307 is positive and you underpaid royalties for the qualifying marginal property, then you:

(a) Must pay the additional royalty owed when you report the difference under § 1205.307; and

(b) Will owe interest on the additional royalty you reported and paid under paragraph (a) of this section at the rate prescribed under part 1218 of this title. You will owe interest beginning January 1 of the calendar year following the calendar year for which you used the marginal property exception until the date you paid the additional royalties due.

§ 1205.310 What must I do if I overpay royalties under this subpart?

If the difference you report under § 1205.307 is negative and you overpaid royalties for the qualifying marginal property, then:

(a) You are entitled to a credit for the royalty you overpaid;

(b) You are entitled to a credit for the overpaid amount only for the period beginning January 1 of the calendar year following the calendar year for which you used the marginal property exception until the earlier of:

(1) The date you report the negative adjustment for the overpaid amount under § 1205.307; or

(2) June 30 of the calendar year immediately following the calendar year for which you used the marginal property exception; and

(c) ONRR will pay interest on the overpayment after you take the credit.

§ 1205.311 What must I do if I erroneously report using the marginal property exception?

If you erroneously report using the marginal property exception on a property that is not a qualified marginal property, you:

(a) Must amend all erroneously submitted Form MMS–2014s to report your entitled volume for each calendar month;

(b) Will owe any associated interest calculated under part 1218 of this title; and

(c) May be subject to civil penalties under part 1241 of this title.

§ 1205.312 What must I do if my property no longer qualifies as a marginal property under this subpart?

(a) Your property must qualify for the marginal property exception under this subpart for each calendar year based on production during the base period.

(b) If you find that your property is no longer eligible for the marginal property exception in the most recent base period, you must stop using the exception as of December 31 of the year in which the most recent base period ends.

(c) If you do not stop using the marginal property exception as required under paragraph (b) of this section, then you:

(1) Will owe late payment interest determined under part 1218 of this title from the date you were required to stop using the exception under paragraph (b).

(2) May be subject to civil penalties under part 1241 of this title.

PART 1210—FORMS AND REPORTS

■ 7. The authority for part 1210 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.;* 25 U.S.C. 396, 2107; 30 U.S.C. 189, 190, 359, 1023, 1751(a); 31 U.S.C. 3716, 9701; 43 U.S.C. 1334, 1801 *et seq.;* and 44 U.S.C. 3506(a).

Subpart A—General Provisions

§ 1210.10 What are the OMB-approved information collections?

■ 8. Amend § 1210.10 by adding a new OMB control number as the last entry to the table as follows:

* * * * *

OMB control number and short title	Form or information collected
* * *	* * * *
1012–XXXX, 30 CFR Part 1205, Takes vs. Entitlements	No forms for the following collections: • Request to use an alternative method of royalty reporting and payment. • Request to stop using the approved alternative method of royalty reporting and payment.

[FR Doc. 2013–19165 Filed 8–7–13; 8:45 am]

BILLING CODE 4310–T2–P

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 199

[DOD–2011–HA–0136]

RIN 0720–AB56

Civilian Health and Medical Program of the Uniformed Services (CHAMPUS); TRICARE Uniform Health Maintenance Organization (HMO) Benefit—Prime Enrollment Fee Exemption for Survivors of Active Duty Deceased Sponsors and Medically Retired Uniformed Services Members and Their Dependents

AGENCY: Office of the Secretary, DoD.

ACTION: Proposed rule.

SUMMARY: This proposed rule would establish an exception to the usual rule that TRICARE Prime enrollment fees are uniform for the group of retirees and their dependents. Survivors and medically retired members are part of the retiree group under TRICARE rules. This exception would allow Survivors of Active Duty Deceased Sponsors and Medically Retired Uniformed Services Members and their Dependents enrolled in Prime to be exempt from future increases in TRICARE Prime enrollment fees. The Prime beneficiaries in these categories prior to 10/1/2013 would have their annual enrollment fee frozen at their current annual rate (FY 2011 rate $230 per single or $460 per family, FY 2012 rate $260 or $520, or the FY 2013 rate $269.38 or $538.56). The beneficiaries added to these categories on or after 10/1/2013 would have their fee frozen at the rate in effect at the time they are classified in either category and enroll in Prime or, if not enrolling, at the rate in effect at the time of enrollment. The fee remains frozen as long as at least one family member remains enrolled in Prime and there is not a break in enrollment. The fee charged for the dependent(s) of a Medically Retired Uniformed Services Member would not change if the dependent(s) was later re-classified a Survivor.

DATES: Written comments received at the address indicated below by October 7, 2013 will be considered and addressed in the final rule.

ADDRESSES: You may submit comments, identified by docket number and or RIN number and title, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Federal Docket Management System Office, 1160 Defense Pentagon, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this **Federal Register** document. The general policy for comments and other submissions from dependents of the public is to make these submissions available for public viewing on the Internet at *http://regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ralph (Doug) McBroom, (703) 681–0039, TRICARE Management Activity, TRICARE Policy and Operations Directorate. Questions regarding payment of specific claims under the TRICARE allowable charge method should be addressed to the appropriate TRICARE contractor.

SUPPLEMENTARY INFORMATION: With respect to TRICARE Prime enrollment fees, the regulation (32 CFR 199.18(c)) currently includes the following provision: ‘‘The specific enrollment fee requirements shall be published annually by the Assistant Secretary of Defense (Health Affairs), and shall be uniform within the following groups: dependents of active duty members in