[Code of Federal Regulations]
[Title 30, Volume 2]
[Revised as of July 1, 2009]
From the U.S. Government Printing Office via GPO Access
[CITE: 30CFR203]

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TITLE 30--MINERAL RESOURCES

CHAPTER II--MINERALS MANAGEMENT SERVICE, DEPARTMENT OF THE INTERIOR

PART 203_RELIEF OR REDUCTION IN ROYALTY RATES--Table of Contents

Subpart B_OCS Oil, Gas, and Sulfur General

Source: 63 FR 2618, Jan. 16, 1998, unless otherwise noted.

Royalty Relief for Drilling Ultra-Deep Wells on Leases Not Subject to Deep Water Royalty Relief

Source: 73 FR 69506, Nov. 18, 2008, unless otherwise noted.

Sec. 203.30 Which leases are eligible for royalty relief as a result of drilling a

Your lease may receive a royalty suspension volume (RSV) under Sec. Sec. 203.31 through 203.36 if the lease meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a deep well or an ultra-deep well, except as provided in Sec. 203.31(b).

(c) If the lease is located entirely in more than 200 meters and entirely less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under Sec. Sec. 203.60 through 203.79.

Sec. 203.31 If I have a qualified phase 2 or qualified phase 3 ultra-deep well, wha

(a) Subject to the administrative requirements of Sec. 203.35 and the price conditions in Sec. 203.36, your qualified well earns your lease an RSV shown in the following table in billions of cubic feet (BCF) or in thousands of cubic feet (MCF) as prescribed in Sec. 203.33:

If you have a qualified phase 2 or qualified phase 3 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well,	35 BCF.

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(2) A sidetrack with a sidetrack measured depth of at least 20,000 feet,	35 BCF.
(3) An ultra-deep short sidetrack that is a phase 2 ultra-deep well,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.
(4) An ultra-deep short sidetrack that is a phase 3 ultra-deep well,	0 BCF.

(b)(1) This paragraph applies if your lease:

(i) Has produced gas or oil from a deep well with a perforated interval the top of which is less than 18,000 feet TVD SS;

(ii) Was issued in a lease sale held between January 1, 2004, and December 31, 2005; and

(iii) The terms of your lease expressly incorporate the provisions of Sec. Sec. 203.41 through 203.47 as they existed at the time the lease was issued.

(2) Subject to the administrative requirements of Sec. 203.35 and the price conditions in Sec. 203.36, your qualified well earns your lease an RSV shown in the following table in BCF or MCF as prescribed in Sec. 203.33:

If you have a qualified phase 2 ultra-deep well that is . .	Then your lease earns an RSV on this volume of gas production:
(i) An original well or a sidetrack with a sidetrack measured depth of at least 20,000 feet TVD SS,	10 BCF.
(ii) An ultra-deep short sidetrack,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(c) Lessees may request a refund of or recoup royalties paid on production from qualified phase 2 or phase 3 ultra-deep wells that:

(1) Occurs before December 18, 2008 and

(2) Is subject to application of an RSV under either Sec. 203.31 or Sec. 203.41.

(d) The following examples illustrate how this section applies. These examples assume that your lease is located in the GOM west of 87 degrees, 30 minutes West longitude and in water less than 400 meters deep (see Sec. 203.30(a)), has no existing deep or ultra-deep wells and that the price thresholds prescribed in Sec. 203.36 have not been exceeded.

Example 1: In 2008, you drill and begin producing from an ultra-deep well with a perforated interval the top of which is 25,000 feet TVD SS, and your lease has had no prior production from a deep or ultra-deep well. Assuming your lease has no deepwater royalty relief (see Sec. 203.30(c)), your lease is eligible (according to Sec. 203.30(b)) to earn an RSV under Sec. 203.31 because it has not yet produced from a deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing. According to Sec. 203.31(a), your 25,000 foot well qualifies your lease for this RSV because the well was drilled after the relief authorized here became effective (when the proposed version of this rule was published on May 18, 2007) and produced from an interval that meets the criteria for an ultra-deep well (i.e., is a phase 2 ultra-deep well as defined in Sec. 203.0). Then in 2014, you drill and produce from another ultra-deep well with a perforated interval the top of which is 29,000 feet TVD SS. Your lease earns no additional RSV under this section when this second ultra-deep well produces, because your lease no longer meets the condition in Sec. 203.30(b)) of no production from a deep well. However, any remaining RSV earned by the first ultra-deep well on your lease would be applied to production from both the first and the second ultra-deep wells as prescribed in Sec. 203.33(a)(2), or Sec. 203.33(b)(2) if your lease is part of a unit.

Example 2: In 2005, you spudded and began producing from an ultra-deep well with a perforated interval the top of which is 23,000 feet TVD SS. Your lease earns no RSV under this section from this phase 1 ultra-deep well (as defined in Sec. 203.0) because you spudded the well before the publication date (May 18, 2007) of the proposed rule when royalty relief under Sec. 203.31(a) became effective. However, this ultra-deep well may earn an RSV of 25 BCF for your lease under Sec. 203.41 (that became effective May 3, 2004), if the lease is located in water depths partly or entirely less than 200 meters and has not previously produced from a deep well (Sec. 203.30(b)).

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Example 3: In 2000, you began producing from a deep well with a perforated interval the top of which is 16,000 feet TVD SS and your lease is located in water 100 meters deep. Then in 2008, you drill and produce from a new ultra-deep well with a perforated interval the top of which is 24,000 feet TVD SS. Your lease earns no RSV under either this section or Sec. 203.41 because the 16,000-foot well was drilled before we offered any way to earn an RSV for producing from a deep well (see dates in the definition of qualified well in Sec. 203.0) and because the existence of the 16,000-foot well means the lease is not eligible (see Sec. 203.30(b)) to earn an RSV for the 24,000-foot well. Because the lease existed in the year 2000, it cannot be eligible for the exception to this eligibility condition provided in Sec. 203.31(b).

Example 4: In 2008, you spud and produce from an ultra-deep well with a perforated interval the top of which is 22,000 feet TVD SS, your lease is located in water 300 meters deep, and your lease has had no previous production from a deep or ultra-deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing because your lease meets the conditions in Sec. 203.30 and the well fits the definition of a phase 2 ultra-deep well (in Sec. 203.0). Then in 2010, you spud and produce from a deep well with a perforated interval the top of which is 16,000 feet TVD SS. Your 16,000-foot well earns no RSV because it is on a lease that already has a producing well at least 18,000 feet subsea (see Sec. 203.42(a)), but any remaining RSV earned by the ultra-deep well would also be applied to production from the deep well as prescribed in Sec. 203.33(a)(2), or Sec. 203.33(b)(2) if your lease is part of a unit and Sec. 203.43(a)(2), or Sec. 203.43(b)(2) if your lease is part of a unit. However, if the 16,000-foot deep well does not begin production until 2016 (or if your lease were located in water less than 200 meters deep), then the 16,000-foot well would not be a qualified deep well because this well does not begin production within the interval specified in the definition of a qualified well in Sec. 203.0, and the RSV earned by the ultra-deep well would not be applied to production from this (unqualified) deep well.

Example 5: In 2008, you spud a deep well with a perforated interval the top of which is 17,000 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under Sec. 203.41 when it begins producing. Then in 2011, you spud an ultra-deep well with a perforated interval the top of which is 26,000 feet TVD SS. Your 26,000-foot well becomes a qualified ultra-deep well because it meets the date and depth conditions in this definition under Sec. 203.0 when it begins producing, but your lease earns no additional RSV under this section or Sec. 203.41 because it is on a lease that already has production from a deep well (see Sec. 203.30(b)). Both the qualified deep well and the qualified ultra-deep well would share your lease's total RSV of 15 BCF in the manner prescribed in Sec. Sec. 203.33 and 203.43.

Example 6: In 2008, you spud a qualified ultra-deep well that is a sidetrack with a sidetrack measured depth of 21,000 feet and a perforated interval the top of which is 25,000 feet TVD SS. This well meets the definition of an ultra-deep well but is too long to be classified an ultra-deep short sidetrack in Sec. 203.0. If your lease is located in 150 meters of water and has not previously produced from a deep well, your lease earns an RSV of 35 BCF because it was drilled after the effective date for earning this RSV. Further, this RSV applies to gas production from this and any future qualified deep and qualified ultra-deep wells on your lease, as prescribed in Sec. 203.33. The absence of an expiration date for earning an RSV on an ultra-deep well means this long sidetrack well becomes a qualified well whenever it starts production. If your sidetrack has a sidetrack measured depth of 14,000 feet and begins production in March 2009, it earns an RSV of 12.4 BCF under this section because it meets the definitions of a phase 2 ultra-deep well (production begins before the expiration date for the pre-existing relief in its water depth category) and an ultra-deep short sidetrack in Sec. 203.0. However, if it does not begin production until 2010, it earns no RSV because it is too short as a phase 3 ultra-deep well to be a qualified ultra-deep well.

Example 7: Your lease was issued in June 2004 and expressly incorporates the provisions of Sec. Sec. 203.41 through 203.47 as they existed at that time. In January 2005, you spud a deep well (well no. 1) with a perforated interval the top of which is 16,800 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under Sec. 203.41 when it begins producing. Then in February 2008, you spud an ultra-deep well (well no. 2) with a perforated interval the top of which is 22,300 feet that begins producing in November 2008, after well no. 1 has started production. Well no. 2 earns your lease an additional RSV of 10 BCF under paragraph (b) of this section because it begins production in time to be classified as a phase 2 ultra-deep well. If, on the other hand, well no. 2 had begun producing in June 2009, it would earn no additional RSV for the lease because it would be classified as a phase 3 ultra-deep well and thus is not entitled to the exception under paragraph (b) of this section.

Sec. 203.32 What other requirements or restrictions apply to royalty relief for a q

(a) If a qualified ultra-deep well on your lease is within a unitized portion of your lease, the RSV earned by that well under this section applies only to

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your lease and not to other leases within the unit or to the unit as a whole.

(b) If your qualified ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line, then either:

(1) The lease with the perforated interval that initially produces

earns the RSV or

(2) If the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.

(c) Any RSV earned under Sec. 203.31 is in addition to any royalty suspension supplement (RSS) for your lease under Sec. 203.45 that results from a different wellbore.

(d) If your lease earns an RSV under Sec. 203.31 and later produces from a deep well that is not a qualified well, the RSV is not forfeited or terminated, but you may not apply the RSV earned under Sec. 203.31 to production from the non-qualified well.

(e) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any RSVs allowed under paragraphs (a) and (b) of Sec. 203.31.

(f) Unused RSVs transfer to a successor lessee and expire with the lease.

Sec. 203.33 To which production do I apply the RSV earned by qualified phase 2 and

(a) You must apply the RSV allowed in Sec. 203.31(a) and (b) to gas volumes produced from qualified wells on or after May 18, 2007, reported on the Oil and Gas Operations Report, Part A (OGOR-A) for your lease under Sec. 216.53. All gas production from qualified wells reported on the OGOR-A, including production not subject to royalty, counts toward the total lease RSV earned by both deep or ultra-deep wells on the lease.

(b) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well that is not within an MMS-approved unit. Subject to the price conditions of Sec. 203.36, you must apply the RSV prescribed in Sec. 203.31 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in Sec. 203.35 or Sec. 203.44.

(c) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well where all or part of the lease is within an MMS-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions of Sec. 203.36, you must apply the RSV prescribed in Sec. 203.31 as follows:

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date that the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in Sec. 203.35 or Sec. 203.44; and

(ii) Allocated to your lease under an MMS-approved unit agreement from qualified wells on unitized areas of your lease and on other leases in participating areas of the unit, regardless of their depth, for which the requirements in Sec. 203.35 or Sec. 203.44 have been met. The allocated share under paragraph (a)(2)(ii) of this section does not increase the RSV for your lease.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified phase 2 ultra-deep well on the non-unitized portion of lease A that earns lease A an RSV of 35 BCF under Sec. 203.31, one qualified deep well on the unitized portion of lease A (drilled after the ultra-deep well on the non-unitized portion of that lease) and a qualified phase 2 ultra-deep well on lease B that earns lease B a 35 BCF RSV under Sec. 203.31. The participating area percentages allocate 40 percent of production from both of the unit qualified wells to lease A and 60 percent to lease B. If the non-unitized qualified phase 2

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ultra-deep well on lease A produces 12 BCF, and the unitized qualified well on lease A produces 18 BCF, and the qualified well on lease B produces 37 BCF, then the production volume from and allocated to lease A to which the lease A RSV applies is 34 BCF [12 + (18 + 37)(0.40)]. The production volume allocated to lease B to which the lease B RSV applies is 33 BCF [(18 + 37)(0.60)]. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (b) of this section, reaches the applicable RSV allowed under Sec. 203.31 or Sec. 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production from or allocated to your lease that exceeds the RSV remaining at the beginning of that month.

Sec. 203.34 To which production may an RSV earned by qualified phase 2 and phase 3

You may not apply an RSV earned under Sec. 203.31:

(a) To production from completions less than 15,000 feet TVD SS, except in cases where the qualified well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(b) To production from a deep well or ultra-deep well on any other lease, except as provided in paragraph (c) of Sec. 203.33;

(c) To any liquid hydrocarbon (oil and condensate) volumes; or

(d) To production from a deep well or ultra-deep well that commenced drilling before:

(1) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep; or

(2) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

Sec. 203.35 What administrative steps must I take to use the RSV earned by a qualif

To use an RSV earned under Sec. 203.31:

(a) You must notify the MMS Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all your ultra-deep wells.

(b) Before beginning production, you must meet any production measurement requirements that the MMS Regional Supervisor for Production and Development has determined are necessary under 30 CFR Part 250, Subpart L.

(c)(1) Within 30 days of the beginning of production from any wells that would become qualified phase 2 or phase 3 ultra-deep wells by satisfying the requirements of this section:

(i) Provide written notification to the MMS Regional Supervisor for Production and Development that production has begun; and

(ii) Request confirmation of the size of the RSV earned by your lease.

(2) If you produced from a qualified phase 2 or phase 3 ultra-deep well before December 18, 2008, you must provide the information in paragraph (c)(1) of this section no later than January 20, 2009.

(d) If you cannot produce from a well that otherwise meets the criteria for a qualified phase 2 ultra-deep well that is an ultra-deep short sidetrack before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep, or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep, the MMS Regional Supervisor for Production and Development may extend the deadline for beginning production for up to 1 year, based on the circumstances of the particular well involved, if it meets all the following criteria.

(1) The delay occurred after drilling reached the total depth in your well.

(2) Production (other than test production) was expected to begin from the well before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep. You must provide a credible activity schedule with supporting documentation.

(3) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which MMS deems were unavoidable.

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Sec. 203.36 Do I keep royalty relief if prices rise significantly?

(a) You must pay royalties on all gas production to which an RSV otherwise would be applied under Sec. 203.33 for any calendar year in which the average daily closing New York Mercantile Exchange (NYMEX) natural gas price exceeds the applicable threshold price shown in the following table.

A price threshold in year 2007 dollars of . . .	Applies to .
(1) $10.15 per MMBtu......................	(i) The first 25 BCF of RSV earned un phase 2 ultra-deep well on a lease th partly or entirely less than 200 mete December 18, 2008; and (ii) Any RSV earned under Sec. 203.31 well.
(2) $4.55 per MMBtu.......................	(i) Any RSV earned under Sec. 203.31 well unless the lease terms prescribe threshold; (ii) The last 10 BCF of the 35 BCF of 203.31(a) by a phase 2 ultra-deep wel in water partly or entirely less than before December 18, 2008 and that is (iii) The last 15 BCF of the 35 BCF of 203.31(a) by a phase 2 ultra-deep wel (iv) Any RSV earned under Sec. 203.31

	well on a lease in water partly or en deep issued on or after December 18, prescribe a different price threshold
	(v) Any RSV earned under Sec. 203.31(well on a lease in water entirely mor entirely less than 400 meters deep.
(3) $4.08 per MMBtu........................	(i) The first 20 BCF of RSV earned by non-converted lease issued in OCS Lea
(4) $5.83 per MMBtu........................	(i) The first 20 BCF of RSV earned by non-converted lease issued in OCS Lea or 187.

(b) For purposes of paragraph (a) of this section, determine the threshold price for any calendar year after 2007 by:

(1) Determining the percentage of change during the year in the Department of Commerce's implicit price deflator for the gross domestic product; and

(2) Adjusting the threshold price for the previous year by that percentage.

(c) The following examples illustrate how this section applies.

Example 1: Assume that a lessee drills and begins producing from a qualified phase 2 ultra-deep well in 2008 on a lease issued in 2004 in less than 200 meters of water that earns the lease an RSV of 35 BCF. Further, assume the well produces a total of 18 BCF by the end of 2009 and in both of those years, the average daily NYMEX closing natural gas price is less than $10.15 (adjusted for inflation after 2007). The lessee does not pay royalty on the 18 BCF because the gas price threshold under paragraph (a)(1) of this section applies to the first 25 BCF of this RSV earned by this phase 2 ultra-deep well. In 2010, the well produces another 13 BCF. In that year, the average daily closing NYMEX natural gas price is greater than $4.55 per MMBtu (adjusted for inflation after 2007), but less than $10.15 per MMBtu (adjusted for inflation after 2007). The first 7 BCF produced in 2010 will exhaust the first 25 BCF (that is subject to the $10.15 threshold) of the 35 BCF RSV that the well earned. The lessee must pay royalty on the remaining 6 BCF produced in 2010, because it is subject to the $4.55 per MMBtu threshold under paragraph (a)(2)(ii) of this section which was exceeded.

Example 2: Assume that a lessee:

(1) Drills and produces from well no.1, a qualified deep well in 2008 to a depth of 15,500 feet TVD SS that earns a 15 BCF RSV for the lease under Sec. 203.41, which would be subject to a price threshold of $10.15 per MMBtu (adjusted for inflation after 2007), meaning the lease is partly or entirely in less than 200 meters of water;

(2) Later in 2008 drills and produces from well no. 2, a second qualified deep well to a depth of 17,000 feet TVD SS that earns no additional RSV (see Sec. 203.41(c)(1)); and

(3) In 2015, drills and produces from well no. 3, a qualified phase 3 ultra-deep well that earns no additional RSV since the lease already has an RSV established by prior deep well production. Further assume that in 2015, the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007). In 2015, any remaining RSV earned by well no. 1 (which would have been applied to production from well nos. 1 and 2 in the intervening years), would be applied to production from all three qualified wells. Because the price threshold applicable to that RSV was not exceeded, the production from all three qualified wells would be royalty-free until the 15 BCF RSV earned by well no. 1 is exhausted.

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Example 3: Assume the same initial facts regarding the three wells as in Example 2. Further assume that well no. 1 stopped producing in 2011 after it had produced 8 BCF, and that well no. 2 stopped producing in 2012 after it had produced 5 BCF. Two BCF of the RSV earned by well no. 1 remain. That RSV would be applied to production from well no. 3 until it is exhausted, and the lessee therefore would not pay royalty on those 2 BCF produced in 2015, because the $10.15 per MMBtu (adjusted for inflation after 2007) price threshold is not exceeded. The determination of which price threshold applies to deep gas production depends on when the first qualified well earned the RSV for the lease, not on which wells use the RSV.

Example 4: Assume that in February 2010 a lessee completes and begins producing from an ultra-deep well (at a depth of 21,500 feet TVD SS) on a lease located in 325 meters of water with no prior production from any deep well and no deep water royalty relief. The ultra-deep well would be a phase 2 ultra-deep well (see definition in Sec. 203.0), and would earn the lease an RSV of 35 BCF under Sec. Sec. 203.30 and 203.31. Further assume that the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007) during 2010. Because the lease is located in more than 200 but less than 400 meters of water, the $4.55 per MMBtu price threshold applies to the whole RSV (see paragraph (a)(2)(v) of this section), and the lessee will owe royalty on all gas produced from the ultra-deep well in 2010.

(d) You must pay any royalty due under this section no later than March 31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under Sec. 218.54 from April 1 until the date of payment.

(e) Production volumes on which you must pay royalty under this section count as part of your RSV.

Royalty Relief for Drilling Deep Gas Wells on Leases Not Subject to Deep Water Royalty Relief

Source: 69 FR 3510, Jan. 26, 2004, unless otherwise noted.

Sec. 203.40 Which leases are eligible for royalty relief as a result of drilling a

Your lease may receive an RSV under Sec. Sec. 203.41 through 203.44, and may receive an RSS under Sec. Sec. 203.45 through 203.47, if it meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper that commenced drilling either:

(1) Before March 26, 2003, on a lease that is located partly or entirely in water less than 200 meters deep; or

(2) Before May 18, 2007, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

(c) In the case of a lease located partly or entirely in water less than 200 meters deep, the lease was issued in a lease sale held either:

(1) Before January 1, 2001;

(2) On or after January 1, 2001, and before January 1, 2004, and, in

cases where the original lease terms provided for an RSV for deep gas production, the lessee has exercised the option provided for in Sec. 203.49; or

(3) On or after January 1, 2004, and the lease terms provide for royalty relief under Sec. Sec. 203.41 through 203.47 of this part. (Note: Because the original Sec. 203.41 has been divided into new Sec. Sec. 203.41 and 203.42 and subsequent sections have been redesignated as Sec. Sec. 203.43 through 203.48, royalty relief in lease terms for leases issued on or after January 1, 2004, should be read as referring to Sec. Sec. 203.41 through 203.48.)

(d) If the lease is located entirely in more than 200 meters and less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under Sec. Sec. 203.60 through 203.79.

[73 FR 69510, Nov. 18, 2008]

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Sec. 203.41 If I have a qualified deep well or a qualified phase 1 ultra-deep well,

(a) To qualify for a suspension volume under paragraphs (b) or (c) of this section, your lease must meet the requirements in Sec. 203.40 and the requirements in the following table.

If your lease has not . . .	And if it later . . .	Then your lease . . .
(1) produced gas or oil from any deep well or ultra-deep well,	has a qualified deep well or qualified phase 1 ultra-deep well,.	earns an RSV specified in paragraph (b) of this section.
(2) produced gas or oil from a well with a perforated interval whose top is 18,000 feet TVD SS or deeper,	has a qualified deep well with a perforated interval whose top is 18,000 feet TVD SS or deeper or a qualified phase 1 ultra-deep well,.	earns an RSV specified in paragraph (c) of this section.

(b) If your lease meets the requirements in paragraph (a)(1) of this section, it earns the RSV prescribed in the following table:

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	15 BCF.
(2) A sidetrack with a perforated	4 BCF plus 600 MCF times sidetrack

interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	measured depth (rounded to the nearest 100 feet) but no more than 15 BCF.
(3) An original well with a perforated interval the top of which is at least 18,000 feet TVD SS,	25 BCF.
(4) A sidetrack with a perforated interval the top of which is at least 18,000 feet TVD SS,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.

(c) If your lease meets the requirements in paragraph (a)(2) of this section, it earns the RSV prescribed in the following table. The RSV specified in this paragraph is in addition to any RSV your lease already may have earned from a qualified deep well with a perforated interval whose top is from 15,000 feet to less than 18,000 feet TVD SS.

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is . . .	Then you earn an RSV on this am
(1) An original well or a sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	0 BCF.
(2) An original well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	10 BCF.
(3) A sidetrack with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	4 BCF plus 600 MCF times sidetrack me nearest 100 feet) but no more than 1

(d) Lessees may request a refund of or recoup royalties paid on production from qualified wells on a lease that is located in water entirely deeper than 200 meters but entirely less than 400 meters deep that:

(1) Occurs before December 18, 2008; and

(2) Is subject to application of an RSV under either Sec. 203.31 or Sec. 203.41.

(e) The following examples illustrate how this section applies, assuming your lease meets the location, prior production, and lease issuance conditions in Sec. 203.40 and paragraph (a) of this section:

Example 1: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, your lease earns an RSV of 15 BCF under paragraph (b)(1) of this section. This RSV must be applied to gas production from all qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48. However, if the top of the perforated interval is 18,500 feet TVD SS, the RSV is 25 BCF according to paragraph (b)(3) of this section.

Example 2: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 6,789 feet, we round the measured depth to 6,800 feet and your lease earns an RSV of 8.08 BCF under paragraph (b)(2) of this section. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48.

Example 3: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 19,500 feet, your lease earns an RSV of 15 BCF. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48, even though 4 BCF plus 600 MCF per foot of sidetrack measured depth equals 15.7 BCF because paragraph (b)(2) of this section limits the RSV for a sidetrack at the amount an original well to the same depth would earn.

Example 4: If you have drilled and produced a deep well with a perforated interval the top of which is 16,000 feet TVD SS before March 26, 2003 (and the well therefore is not a qualified well and has earned no RSV under this section), and later drill:

(i) A deep well with a perforated interval the top of which is 17,000 feet TVD SS, your lease earns no RSV (see paragraph (c)(1) of this section);

(ii) A qualified deep well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, your lease earns an RSV of 10 BCF under paragraph (c)(2) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48; or

(iii) A qualified deep well that is a sidetrack with a perforated interval the top of which is 19,000 feet TVD SS, that has a sidetrack measured depth of 7,000 feet, your lease earns an RSV of 8.2 BCF under paragraph (c)(3) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48.

Example 5: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, and later drill a second qualified well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, we increase the total RSV for your lease from 15 BCF to 25 BCF under paragraph (c)(2) of this section. We will apply that RSV to gas production from all qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48. If the second well has a perforated interval the top of which is 22,000 feet TVD SS (instead of 19,000 feet), the total RSV for your lease would increase to 25 BCF only in 2 situations: (1) If the second well was a phase 1 ultra-deep well, i.e., if drilling began before May 18, 2007, or (2) the exception in Sec. 203.31(b) applies. In both situations, your lease must be partly or entirely in less than 200 meters of water and production must begin on this well before May 3, 2009. If drilling of the second well began on or after May 18, 2007, the second well would be qualified as a phase 2 or phase 3 ultra-deep well and, unless the exception in Sec. 203.31(b) applies, would not earn any additional RSV (as prescribed in Sec. 203.30), so the total RSV for your lease would remain at 15 BCF.

Example 6: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 4,000 feet, and later drill a second qualified well that is a sidetrack, with a perforated interval the top of which is 19,000 feet TVD SS and a sidetrack measured depth of 8,000 feet, we increase the total RSV for your lease from 6.4 BCF [4 + (600 * 4,000)/1,000,000] to 15.2 BCF {6.4 + [4 + (600 * 8,000)/ 1,000,000)]{time} under paragraphs (b)(2) and (c)(3) of this section. We would apply that RSV to gas production from all qualified wells on your lease, as prescribed in Sec. Sec. 203.43 and 203.48. The difference of 8.8 BCF represents the RSV earned by the second sidetrack that has a perforated interval the top of which is deeper than 18,000 feet TVD SS.

[73 FR 69510, Nov. 18, 2008]

Sec. 203.42 What conditions and limitations apply to royalty relief for deep wells

The conditions and limitations in the following table apply to royalty relief under Sec. 203.41.

If . . .	Then . . .
(a) Your lease has produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	your lease cannot earn an RSV under Sec. 203.41 as a result of drilling any subsequent deep wells or phase 1 ultra-deep wells.
(b) You determine RSV under Sec. 203.41 for the first qualified deep well or qualified phase 1 ultra-deep well on your lease (whether an original well or a sidetrack) because you drilled and produced it within the time intervals set forth in the definitions for qualified wells,	that determination establishes the total RSV available for that drilling depth interval on your lease (i.e., either 15,000-18,000 feet TVD SS, or 18,000 feet TVD SS and deeper), regardless of the number of subsequent qualified wells you drill to that depth interval.
(c) A qualified deep well or qualified phase 1 ultra-deep well on your lease is within a unitized portion of your lease,	the RSV earned by that well under Sec. 203.41 applies only to production from qualified wells on or allocated to your lease and not to other leases within the unit.

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If . . .	Then . . .
(d) Your qualified deep well or qualified phase 1 ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line,	the lease with the perforated interval that initially produces earns the RSV. However, if the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.
(e) You earn an RSV under Sec. 203.41,	that RSV is in addition to any RSS for your lease under Sec. 203.45 that results from a different wellbore.
(f) Your lease earns an RSV under Sec. 203.41 and later produces from a well that is not a qualified well,	the RSV is not forfeited or terminated, but you may not apply the RSV under Sec. 203.41 to production from the non-qualified well.
(g) You qualify for an RSV under paragraphs (b) or (c) of Sec. 203.41,	you still owe minimum royalties or rentals in accordance with your lease terms.
(h) You transfer your lease,	unused RSVs transfer to a successor lessee and expire with the lease.

Example to paragraph (b): If your first qualified deep well is a sidetrack with a perforated interval whose top is 16,000 feet TVD SS and earns an RSV of 12.5 BCF, and you later drill a qualified original deep well to 17,000 feet TVD SS, the RSV for your lease remains at 12.5 BCF and does not increase to 15 BCF. However, under paragraph (c) of Sec. 203.41, if you subsequently drill a qualified deep well to a depth of 18,000 feet or greater TVD SS, you may earn an additional RSV.

[73 FR 69512, Nov. 18, 2008]

Sec. 203.43 To which production do I apply the RSV earned from qualified deep wells

(a) You must apply the RSV prescribed in Sec. 203.41(b) and (c) to gas volumes produced from qualified wells on or after May 3, 2004, reported on the OGOR-A for your lease under Sec. 216.53, as and to the extent prescribed in Sec. Sec. 203.43 and 203.48.

(1) Except as provided in paragraph (a)(2) of this section, all gas production from qualified wells reported on the OGOR-A, including production that is not subject to royalty, counts toward the lease RSV.

(2) Production to which an RSS applies under Sec. Sec. 203.45 and 203.46 does not count toward the lease RSV.

(b) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when no part of the lease is within an MMS-approved unit. Subject to the price conditions in Sec. 203.48, you must apply the RSV prescribed in Sec. 203.41 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in Sec. 203.35 or Sec. 203.44.

Example 1: On a lease in water less than 200 meters deep, you began drilling an original deep well with a perforated interval the top of which is 18,200 feet TVD SS in September 2003, that became a qualified deep well in July 2004, when it began producing and using the RSV that it earned. You subsequently drill another original deep well with a perforated interval the top of which is 16,600 feet TVD SS, which becomes a qualified deep well when production begins in August 2008. The first well earned an RSV of 25 BCF (see Sec. 203.41(a)(1) and (b)(3)). You must apply any remaining RSV each month beginning in August 2008 to production from both wells until the 25 BCF RSV is fully utilized according to paragraph (b)(2) of this section. If the second well had begun production in August 2009, it would not be a qualified deep well because it started production after expiration in May 2009 of the ability to qualify for royalty relief in this water depth, and could not share any of the remaining RSV (see definition of a qualified deep well in Sec. 203.0).

Example 2: On a lease in water between 200 and 400 meters deep, you begin drilling an original deep well with a perforated interval the top of which is 17,100 feet TVD SS in November 2010 that becomes a qualified deep well in June 2011 when it begins producing

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and using the RSV. You subsequently drill another original deep well with a perforated interval the top of which is 15,300 feet TVD SS which becomes a qualified deep well by beginning production in October 2011 (see definition of a qualified deep well in Sec. 203.0). Only the first well earns an RSV equal to 15 BCF (see Sec. 203.41(a) and (b)). You must apply any remaining RSV each month beginning in October 2011 to production from both qualified deep wells until the 15 BCF RSV is fully utilized according to paragraph (b)(2) of this section.

(c) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when all or part of the lease is within an MMS-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions in Sec. 203.48, you must apply the RSV prescribed under Sec. 203.41 as required under the following paragraphs (c)(1) through (c)(3) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From all qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in Sec. 203.35 or Sec. 203.44; and,

(ii) Allocated to your lease under an MMS-approved unit agreement from qualified wells on unitized areas of your lease and on unitized areas of other leases in the unit, regardless of their depth, for which the requirements in Sec. 203.35 or Sec. 203.44 have been met.

(3) The allocated share under paragraph (c)(2)(ii) of this section does not increase the RSV for your lease. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified 19,000-foot TVD SS deep well on the non-unitized portion of lease A, one qualified 18,500-foot TVD SS deep well on the unitized portion of lease A, and a qualified 19,400-foot TVD SS deep well on lease B. The participating area percentages allocate 32 percent of production from both of the unit qualified deep wells to lease A and 68 percent to lease B. If the non-unitized qualified deep well on lease A produces 12 BCF and the unitized qualified deep well on lease A produces 15 BCF, and the qualified deep well on lease B produces 10 BCF, then the production volume from and allocated to lease A to which the lease an RSV applies is 20 BCF [12 + (15 + 10) * (0.32)]. The production volume allocated to lease B to which the lease B RSV applies is 17 BCF [(15 + 10) * (0.68)].

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (c) of this section, reaches the applicable RSV allowed under Sec. 203.31 or Sec. 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production that exceeds the RSV remaining at the beginning of that month.

(e) You may not apply the RSV allowed under Sec. 203.41 to:

(1) Production from completions less than 15,000 feet TVD SS, except in cases where the qualified deep well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(2) Production from a deep well or phase 1 ultra-deep well on any other lease, except as provided in paragraph (c) of this section;

(3) Any liquid hydrocarbon (oil and condensate) volumes; or

(4) Production from a deep well or phase 1 ultra-deep well that commenced drilling before:

(i) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep, or

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(ii) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

[73 FR 69512, Nov. 18, 2008]

Sec. 203.44 What administrative steps must I take to use the royalty suspension vol

(a) You must notify the MMS Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all deep wells and phase 1 ultra-deep wells; and

(b) Within 30 days of the beginning of production from all wells that would become qualified wells by satisfying the requirements of this section, you must:

(1) Provide written notification to the MMS Regional Supervisor for Production and Development that production has begun; and

(2) Request confirmation of the size of the royalty suspension volume earned by your lease.

(c) Before beginning production, you must meet any production measurement requirements that the MMS Regional Supervisor for Production and Development has determined are necessary under 30 CFR part 250, subpart L.

(d) You must provide the information in paragraph (b) of this section by January 20, 2009 if you produced before December 18, 2008 from a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely in water more than 200 meters and less than 400 meters deep.

(e) The MMS Regional Supervisor for Production and Development may extend the deadline for beginning production for up to one year for a well that cannot begin production before the applicable date prescribed in the definition of ``qualified deep well'' in Sec. 203.0 if it meets all of the following criteria.

(1) The well otherwise meets the criteria in the definition of a qualified deep well in Sec. 203.0.

(2) The delay in production occurred after reaching total depth in the well.

(3) Production (other than test production) was expected to begin from the well before the applicable deadline in the definition of a qualified deep well in Sec. 203.0. You must provide a credible activity schedule with supporting documentation.

(4) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which MMS deems were

unavoidable.

[69 FR 3510, Jan. 26, 2004, as amended at 69 FR 24054, Apr. 30, 2004. Redesignated and amended at 73 FR 69512, 69513, Nov. 18, 2008]

Sec. 203.45 If I drill a certified unsuccessful well, what royalty relief will my l

Your lease may earn a royalty suspension supplement. Subject to paragraph (d) of this section, the royalty suspension supplement is in addition to any royalty suspension volume your lease may earn under Sec. 203.41.

(a) If you drill a certified unsuccessful well and you satisfy the administrative requirements of Sec. 203.47, subject to the price conditions in Sec. 203.48, your lease earns an RSS shown in the following table. The RSS is shown in billions of cubic feet of gas equivalent (BCFE) or in thousands of cubic feet of gas equivalent (MCFE) and is applicable to oil and gas production as prescribed in Sec. 204.46.

If you have a certified unsuccessful well that is:	Then your lease earns an RSS on t production as prescribed in this s
(1) An original well and your lease has not produced gas or oil from a deep well or an ultra-deep well,	5 BCFE.
(2) A sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has not produced gas or oil from a deep well or an ultra-deep well,	0.8 BCFE plus 120 MCFE times sidetrac the nearest 100 feet) but no more th
(3) An original well or a sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	2 BCFE.

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(b) This paragraph applies to oil and gas volumes you report on the OGOR-A for your lease under Sec. 216.53.

(1) You must apply the RSS prescribed in paragraph (a) of this section, in accordance with the requirements in Sec. 203.46, to all oil and gas produced from the lease:

(i) On or after December 18, 2008, if your lease is located in water more than 200 meters but less than 400 meters deep; or

(ii) On or after May 3, 2004, if your lease is located in water partly or entirely less than 200 meters deep.

(2) Production to which an RSV applies under Sec. Sec. 203.31 through 203.33 and Sec. Sec. 203.41 through 203.43 does not count toward the lease RSS. All other production, including production that is not subject to royalty, counts toward the lease RSS.

Example 1: If you drill a certified unsuccessful well that is an original well to a target 19,000 feet TVD SS, your lease earns an RSS of 5 BCFE that would be applied to gas and oil production if your lease has not previously produced from a deep well or an ultra-deep well, or you earn an RSS of 2 BCFE of gas and oil production if your lease has previously produced from a deep well with a perforated interval from 15,000 to less than 18,000 feet TVD SS, as prescribed in Sec. 203.46.

Example 2: If you drill a certified unsuccessful well that is a sidetrack that reaches a target 19,000 feet TVD SS, that has a sidetrack measured depth of 12,545 feet, and your lease has not produced gas or oil from any deep well or ultra-deep well, MMS rounds the sidetrack measured depth to 12,500 feet and your lease earns an RSS of 2.3 BCFE of gas and oil production as prescribed in Sec. 203.45.

(c) The conversion from oil to gas for using the royalty suspension supplement is specified in Sec. 203.73.

(d) Each lease is eligible for up to two royalty suspension supplements. Therefore, the total royalty suspension supplement for a lease cannot exceed 10 BCFE.

(1) You may not earn more than one royalty suspension supplement from a single wellbore.

(2) If you begin drilling a certified unsuccessful well on one lease but the completion target is on a second lease, the entire royalty suspension supplement belongs to the second lease. However, if the target straddles a lease line, the lease where the surface of the well is located earns the royalty suspension supplement.

(e) If the same wellbore that earns a royalty suspension supplement as a certified unsuccessful well later produces from a perforated interval the top of which is 15,000 feet TVD SS or deeper before May 3, 2009, it will become a qualified well subject to the following conditions:

(1) Beginning on the date production starts, you must stop applying the royalty suspension supplement earned by that wellbore to your lease production.

(2) If the completion of this qualified well is on your lease or, in the case of a directional well, is on another lease, then you must subtract from the royalty suspension volume earned by that qualified well the royalty suspension supplement amounts earned by that wellbore that have already been applied either on your lease or any other lease. The difference represents the royalty suspension volume earned by the qualified well.

(f) If the same wellbore that earned a royalty suspension supplement later has a sidetrack drilled from that wellbore, you are not required to subtract any royalty suspension supplement earned by that wellbore from the royalty suspension volume that may be earned by the sidetrack.

(g) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any royalty suspension supplements under this section.

[69 FR 3510, Jan. 26, 2004, as amended at 69 FR 24054, Apr. 30, 2004; 72 FR 25198, May 4, 2007; 73 FR 15890, Mar. 26, 2008. Redesignated and amended at 73 FR 69512, 69513, Nov. 18, 2008]

Editorial Note: At 73 FR 69513, Nov. 18, 2008, Sec. 203.45 was amended by revising paragraph (e); however, the amendment could not be incorporated because of inaccurate amendatory language.

Sec. 203.46 To which production do I apply the royalty suspension supplements from

(a) Subject to the requirements of Sec. Sec. 203.40, 203.43, 203.45, 203.47, and 203.48, you must apply an RSS in Sec. 203.45 to the earliest oil and gas production:

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(1) Occurring on and after the day you file the information under Sec. 204.47(b),

(2) From, or allocated under an MMS-approved unit agreement to, the lease on which the certified unsuccessful well was drilled, without regard to the drilling depth of the well producing the gas or oil.

(b) If you have a royalty suspension volume for the lease under Sec. 203.41, you must use the royalty suspension volumes for gas produced from qualified wells on the lease before using royalty suspension supplements for gas produced from qualified wells.

Example to paragraph (b): You have two shallow oil wells on your lease. Then you drill a certified unsuccessful well and earn a royalty suspension supplement of 5 BCFE. Thereafter, you begin production from an original well that is a qualified well that earns a royalty suspension volume of 15 BCF. You use only 2 BCFE of the royalty suspension supplement before the oil wells deplete. You must use up the 15 BCF of royalty suspension volume before you use the remaining 3 BCFE of the royalty suspension supplement for gas produced from the qualified well.

(c) If you have no current production on which to apply the RSS allowed under Sec. 203.45, your RSS applies to the earliest subsequent production of gas and oil from, or allocated under an MMS-approved unit agreement to, your lease.

(d) Unused royalty suspension supplements transfer to a successor lessee and expire with the lease.

(e) You may not apply the RSS allowed under Sec. 203.45 to production from any other lease, except for production allocated to your lease from an MMS-approved unit agreement. If your certified unsuccessful well is on a lease subject to an MMS-approved unit agreement, the lessees of other leases in the unit may not apply any portion of the RSS for your lease to production from the other leases in the unit.

(f) You must begin or resume paying royalties when cumulative gas and oil production from, or allocated under an MMS-approved unit agreement to, your lease (excluding any gas produced from qualified wells subject to a royalty suspension volume allowed under Sec. 203.41) reaches the applicable royalty suspension supplement. For the month in which the cumulative production reaches this royalty suspension supplement, you owe royalties on the portion of gas or oil production that exceeds the amount of the royalty suspension supplement remaining at the beginning of that month.

[69 FR 3510, Jan. 26, 2004. Redesignated and amended at 73 FR 69512, 69514, Nov. 18, 2008]

Sec. 203.47 What administrative steps do I take to obtain and use the royalty suspe

(a) Before you start drilling a well on your lease targeted to a reservoir at least 18,000 feet TVD SS, you must notify, in writing, the MMS Regional Supervisor for Production and Development of your intent to begin drilling operations and the depth of the target.

(b) After drilling the well, you must provide the MMS Regional Supervisor for Production and Development within 60 days after reaching the total depth in your well:

(1) Information that allows MMS to confirm that you drilled a certified unsuccessful well as defined under Sec. 203.0, including:

(i) Well log data, if your original well or sidetrack does not meet the producibility requirements of 30 CFR part 250, subpart A; or

(ii) Well log, well test, seismic, and economic data, if your well does meet the producibility requirements of 30 CFR part 250, subpart A; and

(2) Information that allows MMS to confirm the size of the royalty suspension supplement for a sidetrack, including sidetrack measured depth and supporting documentation.

(c) If you commenced drilling a well that otherwise meets the criteria for a certified unsuccessful well on a lease located entirely in more than 200 meters and entirely less than 400 meters of water on or after May 18, 2007, and finished it before December 18, 2008, you must provide the information in paragraph (b) of this section no later than February 17, 2009.

[69 FR 3510, Jan. 26, 2004, as amended at 69 FR 24054, Apr. 30, 2004. Redesignated and amended at 69512, 69514, Nov. 18, 2008]

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Sec. 203.48 Do I keep royalty relief if prices rise significantly?

(a) You must pay royalties on all gas and oil production for which an RSV or an RSS otherwise would be allowed under Sec. Sec. 203.40 through 203.47 for any calendar year when the average daily closing NYMEX natural gas price exceeds the applicable threshold price shown in the following table.

For a lease located in water . . .	And issued . . .	
(1) Partly or entirely less than 200 meters deep,	before December 18, 2008,.................	$
(2) Partly or entirely less than 200 meters deep,	after December 18, 2008,	$
(3) Entirely more than 200 meters and entirely less than 400 meters deep,	on any date,	$

(b) Determine the threshold price for any calendar year after 2007 by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product, as published by the Department of Commerce, changed during the calendar year.

(c) You must pay any royalty due under this section no later than March 31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under Sec. 218.54 from April 1 until the date of payment.

(d) Production volumes on which you must pay royalty under this section count as part of your RSV and RSS.

[73 FR 69514, Nov. 18, 2008]

Sec. 203.49 May I substitute the deep gas drilling provisions in Sec. 203.0 and Sec my lease terms?

(a) You may exercise an option to replace the applicable lease terms for royalty relief related to deep-well drilling with those in Sec. 203.0 and Sec. Sec. 203.40 through 203.48 if you have a lease issued with royalty relief provisions for deep-well drilling. Such leases:

(1) Must be issued as part of an OCS lease sale held after January 1, 2001, and before April 1, 2004; and

(2) Must be located wholly west of 87 degrees, 30 minutes West longitude in the GOM entirely or partly in water less than 200 meters deep.

(b) To exercise the option under paragraph (a) of this section, you must notify, in writing, the MMS Regional Supervisor for Production and Development of your decision before September 1, 2004 or 180 days after your lease is issued, whichever is later, and specify the lease and block number.

(c) Once you exercise the option under paragraph (a) of this section, you are subject to all the activity, timing, and administrative requirements pertaining to deep gas royalty relief as specified in Sec. Sec. 203.40 through 203.48.

(d) Exercising the option under paragraph (a) of this section is irrevocable. If you do not exercise this option, then the terms of your lease apply.

[69 FR 3510, Jan. 26, 2004. Redesignated and amended at 73 FR 69512, 69515, Nov. 18, 2008]

Royalty Relief for End-of-life Leases

Sec. 203.50 Who may apply for end-of-life royalty relief?

You may apply for royalty relief in two situations.

(a) Your end-of-life lease (as defined in Sec. 203.2) is an oil and gas lease and has average daily production of at least 100 barrels of oil equivalent (BOE) per month (as calculated in Sec. 203.73) in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months. These 12 months should reflect the basic operation you intend to use until your resources are depleted. If you changed your operation significantly (e.g., begin re-injecting rather than recovering gas) during the qualifying months, or if you do so while we are

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processing your application, we may defer action on your application until you revise it to show the new circumstances.

(b) Your end-of-life lease is other than an oil and gas lease (e.g., sulphur) and has production in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months.

[63 FR 2618, Jan. 16, 1998, as amended at 63 FR 57249, Oct. 27, 1998]

Sec. 203.51 How do I apply for end-of-life royalty relief?

You must submit a complete application and the required fee to the appropriate MMS Regional Director. Your MMS regional office will provide specific guidance on the report formats. A complete application for relief includes:

(a) An administrative information report (specified in Sec. 203.83) and

(b) A net revenue and relief justification report (specified in Sec. 203.84).

Sec. 203.52 What criteria must I meet to get relief?

(a) To qualify for relief, you must demonstrate that the sum of royalty payments over the 12 qualifying months exceeds 75 percent of the sum of net revenues (before-royalty revenues minus allowable costs, as defined in Sec. 203.84).

(b) To re-qualify for relief, e.g., either applying for additional relief on top of relief already granted, or applying for relief sometime after your earlier agreement terminated, you must demonstrate that:

(1) You have met the criterion listed in paragraph (a) of this section, and

(2) The 12 required qualifying months of operation have occurred under the current royalty arrangement.

Sec. 203.53 What relief will MMS grant?

(a) If we approve your application and you meet certain conditions, we will reduce the pre-application effective royalty rate by one-half on production up to the relief volume amount. If you produce more than the relief volume amount:

(1) We will impose a royalty rate equal to 1.5 times the effective royalty rate on your additional production up to twice the relief volume amount; and

(2) We will impose a royalty rate equal to the effective rate on all production greater than twice the relief volume amount.

(b) Regardless of the level of production or prices (see Sec. 203.54), royalty payments due under end-of-life relief will not exceed the royalty obligations that would have been due at the effective royalty rate.

(1) The effective royalty rate is the average lease rate paid on production during the 12 qualifying months.

(2) The relief volume amount is the average monthly BOE production for the 12 qualifying months.

Sec. 203.54 How does my relief arrangement for an oil and gas lease operate if pric

In those months when your current reference price rises by at least 25 percent above your base reference price, you must pay the effective royalty rate on all monthly production.

(a) Your current reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas over the most recent full 12 calendar months;

(b) Your base reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas during the qualifying months; and

(c) Your weighting factors are the proportions of your total production volume (in BOE) provided by oil and gas during the qualifying months.

Sec. 203.55 Under what conditions can my end-of-life royalty relief arrangement for

(a) If you have an end-of-life royalty relief arrangement, you may renounce it at any time. The lease rate will return to the effective rate during the qualifying period in the first full month following our receipt of your renouncement of the relief arrangement.
(b) If you pay the effective lease rate for 12 consecutive months, we will terminate your relief. The lease rate will return to the effective rate in the first full month following this termination.

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(c) We may stipulate in the letter of approval for individual cases certain events that would cause us to terminate relief because they are inconsistent with an end-of-life situation.

Sec. 203.56 Does relief transfer when a lease is assigned?

Yes. Royalty relief is based on the lease circumstances, not ownership. It transfers upon lease assignment.

Royalty Relief for Pre-Act Deep Water Leases and for Development and Expansion Projects

Sec. 203.60 Who may apply for royalty relief on a case-by-case basis in deep water

You may apply for royalty relief under Sec. Sec. 203.61(b) and 203.62 for an individual lease, unit or project if you:
(a) Hold a pre-Act lease (as defined in Sec. 203.0) that we have assigned to an authorized field (as defined in Sec. 203.0);
(b) Propose an expansion project (as defined in Sec. 203.0); or
(c) Propose a development project (as defined in Sec. 203.0).

[73 FR 69515, Nov. 18, 2008]

Sec. 203.61 How do I assess my chances for getting relief?

You may ask for a nonbinding assessment (a formal opinion on whether a field would qualify for royalty relief) before turning in your first complete application on an authorized field. This field must have a qualifying well under 30 CFR part 250, subpart A, or be on a lease that has allocated production under an approved unit agreement.
(a) To request a nonbinding assessment, you must:
(1) Submit a draft application in the format and detail specified in guidance from the MMS regional office for the GOM;
(2) Propose to drill at least one more appraisal well if you get a favorable assessment; and
(3) Pay a fee under Sec. 203.3.
(b) You must wait at least 90 days after receiving our assessment to apply for relief under Sec. 203.62.
(c) This assessment is not binding because a complete application may contain more accurate information that does not support our original assessment. It will help you decide whether your proposed inputs for evaluating economic viability and your supporting data and assumptions are adequate.

Effective Date Note: At 63 FR 2619, Jan. 16, 1998, Sec. 203.61 was revised. This section contains information collection and recordkeeping requirements and will not become effective until approval has been given by the Office of Management and Budget.

Sec. 203.62 How do I apply for relief?

(a) You must send a complete application and the required fee to the MMS Regional Director for your region.
(b) Your application for royalty relief offshore Alaska or in deep water in the GOM must include an original and two copies (one set of digital information) of:
(1) Administrative information report;
(2) Economic Viability and relief justification report;
(3) G&G report;
(4) Engineering report;
(5) Production report; and
(6) Cost report.
(c) Section 203.82 explains why we are authorized to require these reports.
(d) Sections 203.81, 203.83, and 203.85 through 203.89 describe what these reports must include. The MMS regional office for your region will guide you on the format for the required reports, and we encourage you to contact this office before preparing your application for this guidance.

[73 FR 69515, Nov. 18, 2008]

Sec. 203.63 Does my application have to include all leases in the field?

(a) For authorized fields, we will accept only one joint application for all leases that are part of the designated field on the date of application, except as provided in paragraph (a)(3) of this section and Sec. 203.64. However, we will evaluate all acreage that may eventually become part of the authorized field. Therefore, if you have any other leases that you believe may eventually be part of the authorized field, you must submit data for these leases according to Sec. 203.81.

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(1) The Regional Director maintains a Field Names Master List with updates of all leases in each designated field.
(2) To avoid sharing proprietary data with other lessees on the field, you may submit your proprietary G&G report separately from the rest of your application. Your application is not complete until we receive all the required information for each lease on the field. We will not disclose proprietary data when explaining our assumptions and reasons for our determinations under Sec. 203.67.
(3) We will not require a joint application if you show good cause and honest effort to get all lessees in the field to participate. If you must exclude a lease from your application because its lessee will not participate, that lease is ineligible for the royalty relief for the designated field.
(b) If your application seeks only relief for a development project or an expansion project, your application does not have to include all leases in the field.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1875, Jan. 15, 2002]

Sec. 203.64 How many applications may I file on a field or a development project?

You may file one complete application for royalty relief during the life of the field or for a development project or an expansion project designed to produce a reservoir or set of reservoirs. However, you may send another application if:

(a) You are eligible to apply for a redetermination under Sec. 203.74;

(b) You apply for royalty relief for an expansion project;

(c) You withdraw the application before we make a determination; or

(d) You apply for end-of-life royalty relief.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1875, Jan. 15, 2002]

Sec. 203.65 How long will MMS take to evaluate my application?

(a) We will determine within 20 working days if your application for royalty relief is complete. If your application is incomplete, we will explain in writing what it needs. If you withdraw a complete application, you may reapply.

(b) We will evaluate your first application on a field within 180 days, evaluate your first application on a development project or an expansion project within 150 days and evaluate a redetermination under Sec. 203.75 within 120 days after we determine that it is complete.

(c) We may ask to extend the review period for your application under the conditions in the following table.

If--	Then we may--
We need more records to audit sunk costs.	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request for records and the day we receive the records.
We cannot evaluate your application for a valid reason, such as missing vital information or inconsistent or inconclusive supporting data.	Add another 30 days. We may add more than 30 days, but only if you agree.
We need more data, explanations, or revision.	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request and the day we receive the information.

(d) We may change your assumptions under Sec. 203.62 if our technical evaluation reveals others that are more appropriate. We may consult with you before a final decision and will explain any changes.

(e) We will notify all designated lease operators within a field when royalty relief is granted.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1875, Jan. 15, 2002]

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Sec. 203.66 What happens if MMS does not act in the time allowed?

If we do not act within the timeframes established under Sec. 203.65, you get royalty relief according to the following table.

If you apply for royalty relief for	And we do not decide within the time specified	As long as you
(a) An authorized field.........	You get the minimum suspension volumes specified in Sec. 203.69.	Abide by Sec. Sec. 203.70 and 203.76.
(b) An expansion project........	You get a royalty suspension for the first year of production.	Abide by Sec. Sec. 203.70 and 203.76.
(c) A development project.......	You get a royalty suspension for initial production for the number of months that a decision is delayed beyond the stipulated timeframes set by Sec. 203.65, plus all the royalty suspension volume for which you qualify.	Abide by Sec. Sec. 203.70 and 203.76.

[67 FR 1875, Jan. 15, 2002]

Sec. 203.67 What economic criteria must I meet to get royalty relief on an authoriz

We will not approve applications if we determine that royalty relief cannot make the field, development project, or expansion project economically viable. Your field or project must be uneconomic while you are paying royalties and must become economic with royalty relief.

[67 FR 1876, Jan. 15, 2002]

Sec. 203.68 What pre-application costs will MMS consider in determining economic vi

(a) We will not consider ineligible costs as set forth in Sec. 203.89(h) in determining economic viability for purposes of royalty relief.

(b) We will consider sunk costs according to the following table.

We will	When determining
(1) Include sunk costs................	Whether a field that includes a pre-Act lease which has not produced, other than test production, before the application or redetermination submission date needs relief to become economic.
(2) Not include sunk costs............	Whether an authorized field, a development project, or an expansion project can become economic with full relief (see Sec. 203.67).
(3) Not include sunk costs............	How much suspension volume is necessary to make the field, a development project, or an expansion project economic (see Sec. 203.69(c)).
(4) Include sunk costs for the project discovery well on each lease.	Whether a development project or an expansion project needs relief to become economic.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1876, Jan. 15, 2002]

Sec. 203.69 If my application is approved, what royalty relief will I receive?

If we approve your application, subject to certain conditions, we will not collect royalties on a specified suspension volume for your field, development project, or expansion project. Suspension volumes include volumes allocated to a lease under an approved unit agreement, but exclude any volumes of production that are not normally royalty-bearing under the lease or the regulations of this chapter (e.g., fuel gas).

(a) For authorized fields, the minimum royalty-suspension volumes are:

(1) 17.5 million barrels of oil equivalent (MMBOE) for fields in 200 to 400 meters of water;

(2) 52.5 MMBOE for fields in 400 to 800 meters of water; and

(3) 87.5 MMBOE for fields in more than 800 meters of water.

(b) For development projects, any relief we grant applies only to project

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wells and replaces the royalty relief, if any, with which we issued your lease.

(c) If your project is economic given the royalty relief with which we issued your lease, we will reject the application.

(d) If the lease has earned or may earn deep gas royalty relief under Sec. Sec. 203.40 through 203.49 or ultra-deep gas royalty relief under Sec. Sec. 203.30 through 203.36, we will take the deep gas royalty relief or ultra-deep gas royalty relief into account in determining whether further royalty relief for a development project is necessary for production to be economic.

(e) If neither paragraph (c) nor (d) of this section apply, the minimum royalty suspension volumes are as shown in the following table:

For . . .	The minimum royalty suspension volume is . . .	Plus . . .
(1) RS leases in the GOM or leases offshore Alaska,	A volume equal to the combined royalty suspension volumes (or the volume equivalent based on the data in your approved application for other forms of royalty suspension) with which MMS issued the leases participating in the application that have or plan a well into a reservoir identified in the application,	10 percent of the median of the distribution of known recoverable resources upon which MMS based approval of your application from all reservoirs included in the project.
(2) Leases offshore Alaska or other deep water GOM leases issued in sales after November 28, 2000,	A volume equal to 10 percent of the median of the distribution of known recoverable resources upon which MMS based approval of your application from all reservoirs included in the project.	

(f) If your application includes pre-Act leases in different categories of water depth, we apply the minimum royalty suspension volume for the deepest such lease then assigned to the field. We base the water depth and makeup of a field on the water-depth delineations in the ``Lease Terms and Economic Conditions'' map and the ``Fields Directory'' documents and updates in effect at the time your application is deemed complete. These publications are available from the MMS Gulf of Mexico Regional Office.

(g) You will get a royalty suspension volume above the minimum if we determine that you need more to make the field or development project economic.

(h) For expansion projects, the minimum royalty suspension volume equals 10 percent of the median of the distribution of known recoverable resources upon which we based approval of your application from all reservoirs included in your project plus any suspension volumes required under Sec. 203.66. If we determine that your expansion project may be economic only with more relief, we will determine and grant you the royalty suspension volume necessary to make the project economic.

(i) The royalty suspension volume applicable to specific leases will continue through the end of the month in which cumulative production reaches that volume. You must calculate cumulative production from all the leases in the authorized field or project that are entitled to share the royalty suspension volume.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1876, Jan. 15, 2002; 73 FR 58472, Oct. 7, 2008; 73 FR 69515, Nov. 18, 2008]

Sec. 203.70 What information must I provide after MMS approves relief?

You must submit reports to us as indicated in the following table. Sections 203.81, 203.90, and 203.91 describe what these reports must include. The MMS Regional Office for your region will prescribe the formats.

Required report	When due to MMS	Due date extensions
(a) Fabricator's confirmation report.	Within 18 months after approval of relief.	MMS Director may grant you an extension under Sec. 203.79(c) for up to 6 months.
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(b) Post-production report......	Within 120 days after the start of production that is subject to the approved royalty suspension volume.	With acceptable justification from you, the MMS Regional Director for your region may extend the due date up to 30 days.

[67 FR 1876, Jan. 15, 2002, as amended at 73 FR 69515, Nov. 18, 2008]

Sec. 203.71 How does MMS allocate a field's suspension volume between my lease and

The allocation depends on when production occurs, when we issued the lease, when we assigned it to the field, and whether we award the volume suspension by an approved application or establish it in the lease terms, as prescribed in this section.

(a) If your authorized field has an approved royalty suspension volume under Sec. Sec. 203.67 and 203.69, we will suspend payment of royalties on production from all leases in the field that participate in the application until their cumulative production equals the approved volume. The following conditions also apply:

If . . .	Then . . .	And . . .

(1) We assign an eligible lease to your authorized field after we approve relief.	We will not change your authorized field's royalty suspension volume determined under Sec. 203.69.	Production from the assigned eligible lease(s) counts toward the royalty suspension volume for the authorized field, but the eligible lease will not share any remaining royalty suspension volume for the authorized field after the eligible lease has produced the volume applicable under Sec. 260.114 of this chapter.
(2) We assign a pre-Act or post-November 2000 deep water lease to your field after we approve your application.	We will not change your field's royalty suspension volume.	The assigned lease(s) may share in any remaining royalty relief by filing the short-form application specified in Sec. 203.83 and authorized in Sec. 203.82. An assigned RS lease also gets any portion of its royalty suspension volume remaining even after the field has produced the approved relief volume.
(3) We assign another lease that you operate to your field while we are evaluating your application.	In our evaluation of your authorized field, we will take into account the value of any royalty relief the added lease already has under Sec. 260.114 or its lease document. If we find your authorized field still needs additional royalty	(i) You toll the time period for evaluation until you modify your application to be consistent with the newly constituted field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned pre-Act lease or

	suspension volume, that volume will be at least the combined royalty suspension volume to which all added leases on the field are entitled, or the minimum suspension volume of the authorized field, whichever is greater.	royalty suspension lease shares the royalty suspension we grant to the newly constituted field. An eligible lease does not share the royalty suspension we grant to the new field. If you do not agree to toll, we will have to reject your application due to incomplete information. Production from an assigned eligible lease counts toward the royalty suspension volume that we grant under Sec. 203.69 for your authorized field, but you will not owe royalty on production from the eligible lease until it has produced the volume applicable under Sec. 260.114 of this chapter.

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(4) We assign another operator's lease to your field while we are evaluating your application.	We will change your field's minimum suspension volume provided the assigned lease joins the application and is entitled to a larger minimum suspension volume.	(i) You both toll the time period for evaluation until both of you modify your application to be consistent with the new field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned lease(s) shares the royalty

		suspension we grant to the new field. If you (the original applicant) do not agree to toll, the other operator's lease retains any suspension volume it has or may share in any relief that we grant by filing the short form application specified in Sec. 203.83 and authorized in Sec. 203.82.
(5) We reassign a well on a pre-Act, eligible, or royalty suspension lease from field A to field B.	The past production from the well counts toward the royalty suspension volume that we grant under Sec. 203.69 to field B.	For any field based relief, the past production for that well will not count toward any royalty suspension volume that we grant under Sec. 203.69 to field A. Moreover, past production from that well will count toward the royalty suspension volume applicable for the lease under Sec. 260.114 if the well is on an eligible lease or under Sec. 260.124 if the well is on a royalty suspension lease.

(b) When a project has more than one lease, the royalty suspension volume for each lease equals that lease's actual production from the project (or production allocated under an approved unit agreement) until total production for all leases in the project equals the project's approved royalty suspension volume.

(c) You may receive a royalty-suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. If the field lies on both sides of this meridian, only leases located entirely west of the meridian will receive a royalty-suspension volume.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1877, Jan. 15, 2002; 73

FR 58472, Oct. 7, 2008]

Sec. 203.72 Can my lease receive more than one suspension volume?

Yes. You may apply for royalty relief that involves more than one suspension volume under Sec. 203.62 in two circumstances.

(a) Each field that includes your lease may receive a separate royalty-suspension volume, if it meets the evaluation criteria of Sec. 203.67.

(b) An expansion project on your lease may receive a separate royalty-suspension volume, even if we have already granted a royalty-suspension volume to the field that encompasses the project. But the reserves associated with the project must not have been part of our original determination, and the project must meet the evaluation criteria of Sec. 203.67.

Sec. 203.73 How do suspension volumes apply to natural gas?

You must measure natural gas production under the royalty-suspension volume as follows: 5.62 thousand cubic feet of natural gas, measured in accordance with 30 CFR part 250, subpart L, equals one barrel of oil equivalent.

Sec. 203.74 When will MMS reconsider its determination?

You may request a redetermination after we withdraw approval or after you renounce royalty relief, unless we withdraw approval due to your providing false or intentionally inaccurate information. Under certain conditions you may also request a redetermination if we deny your application or if you want your approved royalty suspension volume to change. In these instances, to be eligible for a redetermination, at least one of the following four conditions must occur.

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(a) You have significant new G&G data and you previously have not either requested a redetermination or reapplied for relief after we withdrew approval or you relinquished royalty relief. ``Significant'' means that the new G&G data:

(1) Results from drilling new wells or getting new three-dimensional seismic data and information (but not reinterpreting old data);

(2) Did not exist at the time of the earlier application; and

(3) Changes your estimates of gross resource size, quality, or projected flow rates enough to materially affect the results of our earlier determination.

(b) You demonstrate in your new application that the technology that most efficiently develops this field or lease was not considered or deemed feasible in the original application. Your newly proposed technology must improve the profitability, under equivalent market conditions, of the field or lease relative to the development system proposed in the prior application.

(c) Your current reference price decreases by more than 25 percent from your base reference price as calculated under this paragraph.

(1) Your current reference price is a weighted-average of daily closing prices on the NYMEX for light sweet crude oil and natural gas over the most recent full 12 calendar months;

(2) Your base reference price is a weighted average of daily closing

prices on the NYMEX for light sweet crude oil and natural gas for the full 12 calendar months preceding the date of your most recently approved application for this royalty relief; and

(3) The weighting factors are the proportions of the total production volume (in BOE) for oil and gas associated with the most likely scenario (identified in Sec. Sec. 203.85 and 203.88) from your most recently approved application for this royalty relief.

(d) Before starting to build your development and production system, you have revised your estimated development costs, and they are more than 120 percent of the eligible development costs associated with the most likely scenario from your most recently approved application for this royalty relief.

[63 FR 2618, Jan. 16, 1998; 63 FR 24747, May 5, 1998, as amended at 67 FR 1878, Jan. 15, 2002]

Sec. 203.75 What risk do I run if I request a redetermination?

If you request a redetermination after we have granted you a suspension volume, you could lose some or all of the previously granted relief. This can happen because you must file a new complete application and pay the required fee, as discussed in Sec. 203.62. We will evaluate your application under Sec. 203.67 using the conditions prevailing at the time of your redetermination request. In our evaluation, we may find that you should receive a larger, equivalent, smaller, or no suspension volume. This means we could find that you do not qualify for the amount of relief previously granted or for any relief at all.

Sec. 203.76 When might MMS withdraw or reduce the approved size of my relief?

We will withdraw approval of relief for any of the following reasons.

(a) You change the type of development system proposed in your application (e.g., change from a fixed platform to floating production system, or from an independent development and production system to one with subsea wells tied back to a host production facility, etc.).

(b) You do not start building the proposed development and production system within18 months of the date we approved your application, unless the MMS Director grants you an extension under Sec. 203.79(c). If you start building the proposed system and then suspend its construction before completion, and you do not restart continuous building of the proposed system within 18 months of our approval, we will withdraw the relief we granted.

(c) Your actual development costs are less than 80 percent of the eligible development costs estimated in your application's most likely scenario, and you do not report that fact in your post-production development report (Sec. 203.70). Development costs are those

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expenditures defined in Sec. 203.89(b) incurred between the application submission date and start of production. If you report this fact in the post-production development report, you may retain the lesser of 50 percent of the original royalty suspension volume or 50 percent of the median of the distribution of the potentially recoverable resources anticipated in your application.

(d) We granted you a royalty-suspension volume after you qualified for a redetermination under Sec. 203.74(c), and we find out your actual development costs are less than 90 percent of the eligible development costs associated with your application's most likely scenario. Development costs are those expenditures defined in Sec. 203.89(b) incurred between your application submission date and start of production.

(e) You do not send us the fabrication confirmation report or the post-production development report, or you provide false or intentionally inaccurate information that was material to our granting royalty relief under this section. You must pay royalties and late-payment interest determined under 30 U.S.C. 1721 and Sec. 218.54 of this chapter on all volumes for which you used the royalty suspension. You also may be subject to penalties under other provisions of law.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1878, Jan. 15, 2002]

Sec. 203.77 May I voluntarily give up relief if conditions change?

Yes, you may voluntarily give up relief by sending a letter to that effect to the MMS Regional office for your region.

[73 FR 69516, Nov. 18, 2008]

Sec. 203.78 Do I keep relief approved by MMS under Sec. Sec. 203.60-203.77 for my l

If prices rise above a base price threshold for light sweet crude oil or natural gas, you must pay full royalties on production otherwise subject to royalty relief approved by MMS under Sec. Sec. 203.60-203.77 for your lease, unit or project as prescribed in this section.

(a) The following table shows the base price threshold for various types of leases, subject to paragraph (b) of this section. Note that, for post-November 2000 deepwater leases in the GOM, price thresholds apply on a lease basis, so different leases on the same development project or expansion project approved for royalty relief may have different price thresholds.

For . . .	The base price thresh
(1) Pre-Act leases in the GOM,	set by statute.
(2) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale set a base price threshold,	indicated in your original lease agre the Notice of Sale under which your
(3) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale did not set a base price threshold,	the threshold set by statute for pre-

(b) An exception may occur if we determine that the price thresholds in paragraphs (a)(2) or (a)(3) mean the royalty suspension volume set under Sec. 203.69 and in lease terms would provide inadequate encouragement to increase production or development, in which circumstance we could specify a different set of price thresholds on a case-by-case basis.

(c) Suppose your base oil price threshold set under paragraph (a) is $28.00 per barrel, and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

(1) Pay royalties on all oil production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and Sec. 218.54 of this chapter) by March 31 of the current calendar year, and

(2) Pay royalties on all your oil production in the current year.

(d) Suppose your base gas price threshold set under paragraph (a) is $3.50 per million British thermal units (Btu), and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $3.50 per million Btu, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

(1) Pay royalties on all gas production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and Sec. 218.54 of this chapter) by March 31 of the current calendar year, and

(2) Pay royalties on all your gas production in the current year.

(e) Production under both paragraphs (c) and (d) of this section counts as part of the royalty-suspension volume.

(f) You are entitled to a refund or credit, with interest, of royalties paid on any production (that counts as part of the royalty-suspension volume):

(1) Of oil if the arithmetic average of the closing prices for the current calendar year is $28.00 per barrel or less, as adjusted in paragraph (h) of this section, and

(2) Of gas if the arithmetic average of the closing natural gas prices for the current calendar year is $3.50 per million Btu or less, as adjusted in paragraph (h) of this section.

(g) You must follow our regulations in part 230 of this chapter for receiving refunds or credits.

(h) We change the prices referred to in paragraphs (c), (d), and (f) of this section periodically. For pre-Act leases, these prices change during each calendar year after 1994 by the percentage that the implicit price deflator for the gross domestic product changed during the preceding calendar year. For post-November 2000 deepwater leases, these prices change as indicated in the lease instrument or in the Notice of Sale under which we issued the lease.

[73 FR 69516, Nov. 18, 2008]

Sec. 203.79 How do I appeal MMS's decisions related to royalty relief for a deepwat

(a) Once we have designated your lease as part of a field and notified you and other affected operators of the designation, you can request reconsideration by sending the MMS Director a letter within 15 days that also states your reasons. The MMS Director's response is the final agency action.

(b) Our decisions on your application for relief from paying royalty under Sec. 203.67 and the royalty-suspension volumes under Sec. 203.69 are final agency actions.

(c) If you cannot start construction by the deadline in Sec. 203.76(b) for reasons beyond your control (e.g., strike at the fabrication yard), you may request an extension up to 1 year by writing the MMS Director and stating your reasons. The MMS Director's response is the final agency action.

(d) We will notify you of all final agency actions by certified mail, return receipt requested. Final agency actions are not subject to appeal to the Interior Board of Land Appeals under 30 CFR part 290 and 43 CFR part 4. They are judicially reviewable under section 10(a) of the Administrative Procedure Act (5 U.S.C. 702) only if you file an action within 30 days of the date you receive our decision.

Sec. 203.80 When can I get royalty relief if I am not eligible for royalty relief u

We may grant royalty relief when it serves the statutory purposes summarized in Sec. 203.1 and our formal relief programs, including but not limited to the applicable levels of the royalty suspension volumes and price thresholds, provide inadequate encouragement to promote development or increase production. Unless your lease lies offshore of Alaska or wholly west of 87 degrees, 30 minutes West longitude in the GOM, your lease must be producing to qualify for relief. Before you may apply for royalty relief apart from our programs for end-of-life leases or for pre-Act deep water leases and development and expansion projects, we must agree that your lease or project has two or more of the following characteristics:

(a) The lease has produced for a substantial period and the lessee can recover significant additional resources. Significant additional resources means enough to allow production for at least

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a year more than would be profitable without royalty relief.

(b) Valuable facilities (e.g., a platform or pipeline that would be removed upon lease relinquishment) exist that we do not expect a successor lessee to use. If the facilities are located off the lease, their preservation must depend on continued production from the lease applying for royalty relief. We will only consider an allocable share of costs for off-lease facilities in the relief application.

(c) A substantial risk exists that no new lessee will recover the resources.

(d) The lessee made major efforts to reduce operating costs too recently to use the formal program for royalty relief (e.g., recent significant change in operations).

(e) Circumstances beyond the lessee's control, other than water depth, preclude reliance on one of the existing royalty relief programs.

[67 FR 1879, Jan. 15, 2002, as amended at 73 FR 69516, Nov. 18, 2008]

Required Reports

Sec. 203.81 What supplemental reports do royalty-relief applications require?

(a) You must send us the supplemental reports, indicated in the following table by an X, that apply to your field. Sections 203.83 through 203.91 describe these reports in detail.

Required reports	End-of-life lease	Expansion project
(1) Administrative information Report.....................	X	X

(2) Net revenue & relief justification report.............	X	
(3) Economic viability & relief justification report (RSVP model imputs justified by other required reports)........	....	X
(4) G&G report..	....	X
(5) Engineering report....................................	....	X
(6) Production report.....................................	....	X
(7) Deep water cost report.................................	....	X
(8) Fabricator's confirmation report......................	....	X
(9) Post-production development report....................	....	X

(b) You must certify that all information in your application, fabricator's confirmation and post-production development reports is accurate, complete, and conforms to the most recent content and presentation guidelines available from the MMS Regional office for your region.

(c) With your application and post-production development report, you must submit an additional report prepared by an independent CPA that:

(1) Assesses the accuracy of the historical financial information in your report; and

(2) Certifies that the content and presentation of the financial data and information conform to our most recent guidelines on royalty relief. This means the data and information must--

(i) Include only eligible costs that are incurred during the qualification months; and

(ii) Be shown in the proper format.

(d) You must identify the people in the CPA firm who prepared the reports referred to in paragraph (c) of this section and make them available to us to respond to questions about the historical financial information. We may also further review your records to support this information.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1879, Jan. 15, 2002; 73 FR 69516, Nov. 18, 2008]

Sec. 203.82 What is MMS's authority to collect this information?

The Office of Management and Budget (OMB) approved the information collection requirements in part 203 under 44 U.S.C. 3501 et seq. and assigned OMB control number 1010-0071.

(a) We use the information to determine whether royalty relief will result in production that wouldn't otherwise occur. We rely largely on your information to make these determinations.

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(1) Your application for royalty relief must contain enough information on finances, economics, reservoirs, G&G characteristics, production, and engineering estimates for us to determine whether:

(i) We should grant relief under the law, and

(ii) The requested relief will ultimately recover more resources and return a reasonable profit on project investments.

(2) Your fabricator confirmation and post-production development reports must contain enough information for us to verify that your application reasonably represented your plans.

(b) Applicants (respondents) are Federal OCS oil and gas lessees. Applications are required to obtain or retain a benefit. Therefore, if you apply for royalty relief, you must provide this information. We will protect information considered proprietary under applicable law and under regulations at Sec. 203.63(b) and part 250 of this chapter.

(c) The Paperwork Reduction Act of 1995 requires us to inform you that we may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

(d) Send comments regarding any aspect of the collection of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 4230, 1849 C Street, NW., Washington, DC 20240.

[63 FR 2618, Jan. 16, 1998, as amended at 65 FR 2875, Jan. 19, 2000]

Sec. 203.83 What is in an administrative information report?

This report identifies the field or lease for which royalty relief is requested and must contain the following items:

(a) The field or lease name;

(b) The serial number of leases we have assigned to the field, names of the lease title holders of record, the lease operators, and whether any lease is part of a unit;

(c) Well number, API number, location, and status of each well that has been drilled on the field or lease or project (not required for non-oil and gas leases);

(d) The location of any new wells proposed under the terms of the application (not required for non-oil and gas leases);

(e) A description of field or lease history;

(f) Full information as to whether you will pay royalties or a share of production to anyone other than the United States, the amount you will pay, and how much you will reduce this payment if we grant relief;

(g) The type of royalty relief you are requesting;

(h) Confirmation that we approved a DOCD or supplemental DOCD (Deep Water expansion project applications only); and

(i) A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the effect on production (Deep Water applications only).

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1879, Jan. 15, 2002]

Sec. 203.84 What is in a net revenue and relief justification report?

This report presents cash flow data for 12 qualifying months, using the format specified in the ``Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases'', U.S. Department of the Interior, MMS. Qualifying months for an oil and gas lease are the most recent 12 months out of the last 15 months that you produced at least 100 BOE per day on average. Qualifying months for other than oil and gas leases are the most recent 12 of the last 15 months having some production.

(a) The cash flow table you submit must include historical data for:

(1) Lease production subject to royalty;

(2) Total revenues;

(3) Royalty payments out of production;

(4) Total allowable costs; and

(5) Transportation and processing costs.

(b) Do not include in your cash flow table the non-allowable costs listed at 30 CFR 220.013 or:

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(1) OCS rental payments on the lease(s) in the application;
(2) Damages and losses;
(3) Taxes;
(4) Any costs associated with exploratory activities;
(5) Civil or criminal fines or penalties;
(6) Fees for your royalty relief application; and
(7) Costs associated with existing obligations (e.g., royalty overrides or other forms of payment for acquiring the lease, depreciation on previously acquired equipment or facilities).
(c) We may, in reviewing and evaluating your application, disallow costs when you have not shown they are necessary to operate the lease, or if they are inconsistent with end-of-life operations.

[63 FR 2618, Jan. 16, 1998, as amended at 63 FR 57249, Oct. 27, 1998]

Sec. 203.85 What is in an economic viability and relief justification report?

This report should show that your project appears economic without royalties and sunk costs using the RSVP model we provide. The format of the report and the assumptions and parameters we specify are found in the ``Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program,'' U.S. Department of the Interior, MMS. Clearly justify each parameter you set in every scenario you specify in the RSVP. You may provide supplemental information, including your own model and results. The economic viability and relief justification report must contain the following items for an oil and gas lease.
(a) Economic assumptions we provide which include:
(1) Starting oil and gas prices;
(2) Real price growth;
(3) Real cost growth or decline rate, if any;
(4) Base year;
(5) Range of discount rates; and
(6) Tax rate (for use in determining after-tax sunk costs).
(b) Analysis of projected cash flow (from the date of the application using annual totals and constant dollar values) which shows:
(1) Oil and gas production;
(2) Total revenues;
(3) Capital expenditures;
(4) Operating costs;
(5) Transportation costs; and
(6) Before-tax net cash flow without royalties, overrides, sunk costs, and ineligible costs.
(c) Discounted values which include:
(1) Discount rate used (selected from within the range we specify).
(2) Before-tax net present value without royalties, overrides, sunk costs, and ineligible costs.
(d) Demonstrations that:
(1) All costs, gross production, and scheduling are consistent with the data in the G&G, engineering, production, and cost reports (Sec. Sec. 203.86 through 203.89) and
(2) The development and production scenarios provided in the various reports are consistent with each other and with the proposed development system. You can use up to three scenarios (conservative, most likely, and optimistic), but you must link each to a specific range on the

distribution of resources from the RSVP Resource Module.

Sec. 203.86 What is in a G&G report?

This report supports the reserve and resource estimates used in the economic evaluation and must contain each of the following elements.

(a) Seismic data which includes:

(1) Non-interpreted 2D/3D survey lines reflecting any available state-of-the-art processing technique in a format readable by MMS and specified by the deep water royalty relief guidelines;

(2) Interpreted 2D/3D seismic survey lines reflecting any available state-of-the-art processing technique identifying all known and prospective pay horizons, wells, and fault cuts;

(3) Digital velocity surveys in the format of the GOM region's letter to lessees of 10/1/90;

(4) Plat map of ``shot points;'' and

(5) ``Time slices'' of potential horizons.

(b) Well data which includes:

(1) Hard copies of all well logs in which--

(i) The 1-inch electric log shows pay zones and pay counts and lithologic

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and paleo correlation markers at least every 500-feet,

(ii) The 1-inch type log shows missing sections from other logs where faulting occurs,

(iii) The 5-inch electric log shows pay zones and pay counts and labeled points used in establishing resistivity of the formation, 100 percent water saturated (R<INF>o</INF>) and the resistivity of the undisturbed formation (R<INF>t</INF>), and

(iv) The 5-inch porosity logs show pay zones and pay counts and labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time;

(2) Digital copies of all well logs spudded before December 1, 1995;

(3) Core data, if available;

(4) Well correlation sections;

(5) Pressure data;

(6) Production test results;

(7) Pressure-volume-temperature analysis, if available; and

(8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) Map interpretations which includes for each reservoir in the field:

(1) Structure maps consisting of top and base of sand maps showing well and seismic shot point locations;

(2) Isopach maps for net sand, net oil, net gas, all with well locations;

(3) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and

(4) An explanation for excluding the reservoirs you are not planning to develop.

(d) Reservoir-specific data which includes:

(1) Probability of reservoir occurrence with hydrocarbons;

(2) Probability the hydrocarbon in the reservoir is all oil and the probability it is all gas;

(3) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for the

parameters used to estimate reservoir size, i.e., acres and net thickness;

(4) Most likely values for porosity, salt water saturation, volume factor for oil formation, and volume factor for gas formation;

(5) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for recovery efficiency (in percent) and oil or gas recovery (in stock-tank-barrels per acre-foot or in thousands of cubic feet per acre foot);

(6) A gas/oil ratio distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each reservoir;

(7) A yield distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each gas reservoir; and

(8) Reserve or resource distribution by reservoir.

(e) Aggregated reserve and resource data which includes:

(1) The aggregated distributions for reserves and resources (in BOE) and oil fraction for your field computed by the resource module of our RSVP model;

(2) A description of anticipated hydrocarbon quality (i.e., specific gravity); and

(3) The ranges within the aggregated distribution for reserves and resources that define the development and production scenarios presented in the engineering and production reports. Typically there will be three ranges specified by two positive reserve and resource points on the aggregated distribution. The range at the low end of the distribution will be associated with the conservative development and production scenario; the middle range will be related to the most likely development and production scenario; and, the high end range will be consistent with the optimistic development and production scenario.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1879, Jan. 15, 2002]

Sec. 203.87 What is in an engineering report?

This report defines the development plan and capital requirements for the economic evaluation and must contain the following elements.

(a) A description of the development concept (e.g., tension leg platform,

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fixed platform, floater type, subsea tieback, etc.) which includes:

(1) Its size along with basic design specifications and drawings; and

(2) The construction schedule.

(b) An identification of planned wells which includes:

(1) The number;

(2) The type (platform, subsea, vertical, deviated, horizontal);

(3) The well depth;

(4) The drilling schedule;

(5) The kind of completion (single, dual, horizontal, etc.); and

(6) The completion schedule.

(c) A description of the production system equipment which includes:

(1) The production capacity for oil and gas and a description of limiting component(s);

(2) Any unusual problems (low gravity, paraffin, etc.);

(3) All subsea structures;

(4) All flowlines; and

(5) Schedule for installing the production system.

(d) A discussion of any plans for multi-phase development which includes the conceptual basis for developing in phases and goals or milestones required for starting later phases.

(e) A set of development scenarios consisting of activity timing and scale associated with each of up to three production profiles (conservative, most likely, optimistic) provided in the production report for your field (Sec. 203.88). Each development scenario and production profile must denote the likely events should the field size turn out to be within a range represented by one of the three segments of the field size distribution. If you send in fewer than three scenarios, you must explain why fewer scenarios are more efficient across the whole field size distribution.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1880, Jan. 15, 2002]

Sec. 203.88 What is in a production report?

This report supports your development and production timing and product quality expectations and must contain the following elements.

(a) Production profiles by well completion and field that specify the actual and projected production by year for each of the following products: oil, condensate, gas, and associated gas. The production from each profile must be consistent with a specific level of reserves and resources on the aggregated distribution of field size.

(b) Production drive mechanisms for each reservoir.

Sec. 203.89 What is in a cost report?

This report lists all actual and projected costs for your field, must explain and document the source of each cost estimate, and must identify the following elements.

(a) Sunk costs. Report sunk costs in dollars not adjusted for inflation and only if you have documentation.

(b) Appraisal, delineation and development costs. Base them on actual spending, current authorization for expenditure, engineering estimates, or analogous projects. These costs cover:

(1) Platform well drilling and average depth;

(2) Platform well completion;

(3) Subsea well drilling and average depth;

(4) Subsea well completion;

(5) Production system (platform); and

(6) Flowline fabrication and installation.

(c) Production costs based on historical costs, engineering estimates, or analogous projects. These costs cover:

(1) Operation;

(2) Equipment; and

(3) Existing royalty overrides (we will not use the royalty overrides in evaluations).

(d) Transportation costs, based on historical costs, engineering estimates, or analogous projects. These costs cover:

(1) Oil or gas tariffs from pipeline or tankerage;

(2) Trunkline and tieback lines; and

(3) Gas plant processing for natural gas liquids.

(e) Abandonment costs, based on historical costs, engineering estimates, or analogous projects. You should provide the costs to plug and abandon only wells and to remove only production systems for which you have not incurred costs as of the time of application submission.

You should also include a point estimate or distribution

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of prospective salvage value for all potentially reusable facilities and materials, along with the source and an explanation of the figures provided.

(f) A set of cost estimates consistent with each one of up to three field-development scenarios and production profiles (conservative, most likely, optimistic). You should express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost estimate with a minimum and maximum percentage of the base value.

(g) A spending schedule. You should provide costs for each year (in real dollars) for each category in paragraphs (a) through (f) of this section.

(h) A summary of other costs which are ineligible for evaluating your need for relief. These costs cover:

(1) Expenses before first discovery on the field;

(2) Cash bonuses;

(3) Fees for royalty relief applications;

(4) Lease rentals, royalties, and payments of net profit share and net revenue share;

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

(8) Interest or finance charges, including those embedded in equipment leases;

(9) Fines or penalties; and

(10) Money spent on previously existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease, expenditures for plugging wells and removing and abandoning facilities that existed on the application submission date).

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1880, Jan. 15, 2002]

Sec. 203.90 What is in a fabricator's confirmation report?

This report shows you have committed in a timely way to the approved system for production. This report must include the following (or its equivalent for unconventionally acquired systems):

(a) A copy of the contract(s) under which the fabrication yard is building the approved system for you;

(b) A letter from the contractor building the system to the MMS Regional Director for your region certifying when construction started on your system; and

(c) Evidence of an appropriate down payment or equal action that you've started acquiring the approved system.

[63 FR 2618, Jan. 16, 1998, as amended at 73 FR 69516, Nov. 18, 2008]

Sec. 203.91 What is in a post-production development report?

For each cost category in the deep water cost report, you must compare actual costs up to the date when production starts to your planned pre-production costs. If your application included more than one development scenario, you need to compare actual costs with those in your scenario of most likely development. Also, you must have this report certified by an independent CPA according to Sec. 203.81(c).

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1880, Jan. 15, 2002]

Subpart C--Federal and Indian Oil [Reserved]

Subpart D--Federal and Indian Gas [Reserved]

Subpart E--Solid Minerals, General [Reserved]