

(5) The latest major portion value that you received from MMS calculated under 30 CFR 206.174 for the same MMS-designated area.

(e) You may take less than your entitled share of AFA production for any month, but pay royalties on the full volume of your entitled share under this section. If you do, you will owe no additional royalty for that lease for that month when you later take more than your entitled share to balance your account. The provisions of this paragraph (e) also apply when the other AFA participants pay you money to balance your account.

§ 202.555 What portion of the gas that I produce is subject to royalty?

(a) All gas produced from or allocated to your Indian lease is subject to royalty except the following:

- (1) Gas that is unavoidably lost.
- (2) Gas that is used on, or for the benefit of, the lease.
- (3) Gas that is used off-lease for the benefit of the lease when the Bureau of Land Management (BLM) approves such off-lease use.

(4) Gas used as plant fuel as provided in 30 CFR 206.179(e).

(b) You may use royalty-free only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility when you use gas for one of the following purposes:

- (1) On, or for the benefit of, the lease at a production facility handling production from more than one lease with BLM's approval.
- (2) At a production facility handling unitized or communitized production.

(c) If the terms of your lease are inconsistent with this subpart, your lease terms will govern to the extent of that inconsistency.

§ 202.556 How do I determine the value of avoidably lost, wasted, or drained gas?

If BLM determines that a volume of gas was avoidably lost or wasted, or a volume of gas was drained from your Indian lease for which compensatory royalty is due, then you must determine the value of that volume of gas under 30 CFR part 206.

§ 202.557 Must I pay royalty on insurance compensation for unavoidably lost gas?

If you receive insurance compensation for unavoidably lost gas, you must pay royalties on the amount of that compensation. This paragraph does not apply to compensation through self-insurance.

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

(a) You must report gas volumes as follows:

(1) Report gas volumes and Btu heating values, if applicable, under the same degree of water saturation. Report gas volumes and Btu heating value at a standard pressure base of 14.73 psia and a standard temperature of 60 degrees Fahrenheit. Report gas volumes in units of 1,000 cubic feet (Mcf).

(2) You must use the frequency and method of Btu measurement stated in your contract to determine Btu heating values for reporting purposes. However, you must measure the Btu value at least semi-annually by recognized standard industry testing methods even if your contract provides for less frequent measurement.

(b) You must report residue gas and gas plant product volumes as follows:

(1) Report carbon dioxide (CO₂), nitrogen (N₂), helium (He), residue gas, and any gas marketed as a separate product by using the same standards specified in paragraph (a) of this section.

(2) Report natural gas liquid (NGL) volumes in standard U.S. gallons (231 cubic inches) at 60 degrees F.

(3) Report sulfur (S) volumes in long tons (2,240 pounds).

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

Subpart A—General Provisions

Sec.

203.0 What definitions apply to this part?

203.1 What is MMS's authority to grant royalty relief?

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203.4 How do the provisions in this part apply to different types of leases and projects?

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- 203.51 How do I apply for end-of-life royalty relief?
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- 203.53 What relief will MMS grant?
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REQUIRED REPORTS

- 203.81 What supplemental reports do royalty-relief applications require?
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Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal

- 203.250 Advance royalty.
- 203.251 Reduction in royalty rate or rental.

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

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

Subpart A—General Provisions

SOURCE: 63 FR 2616, Jan. 16, 1998, unless otherwise noted.

§ 203.0 What definitions apply to this part?

Authorized field means a field in a water depth of at least 200 meters and

in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude from which no current pre-Act lease produced, other than test production, before November 28, 1995.

Complete application means an original and two copies of the six reports consisting of the data specified in 30 CFR 203.81, 203.83 and 203.85 through 203.89, along with one set of digital information, which MMS has reviewed and found complete.

Determination means the binding decision by MMS on whether your field qualifies for relief or how large a royalty-suspension volume must be to make the field economically viable.

Draft application means the preliminary set of information and assumptions you submit to seek a nonbinding assessment on whether a field could be expected to qualify for royalty relief.

Eligible lease means a lease that results from a lease sale held after November 28, 1995; is located in the Gulf of Mexico (GOM) in water depths 200 meters or deeper; lies wholly west of 87 degrees, 30 minutes West longitude; and is offered subject to a royalty-suspension volume authorized by statute.

Expansion project means a project you propose in a Development Operations Coordination Document (DOCD) or a Supplement approved by the Secretary of the Interior after November 28, 1995, that will increase the ultimate recovery of resources from a pre-Act lease and that involves a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.).

Fabrication (or start of construction) means evidence of irreversible commitment to a concept and scale of development, including copies of a binding contract between you (as applicant) and a fabrication yard, a letter from a fabricator certifying that construction has begun, and a receipt for the customary down payment.

Field means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature or stratigraphic trapping condition. Two or more reservoirs may be in a field, separated vertically by intervening im-

pervious strata or laterally by local geologic barriers, or both.

Lease means a lease or unit.

New production means any production from a current pre-Act lease from which no royalties are due on production, other than test production, before November 28, 1995. Also, it means any production resulting from lease-development activities involving a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.) on a current pre-Act lease under a Development Operations Coordination Document—or its supplement—approved by the Secretary of the Interior after November 28, 1995.

Nonbinding assessment means an opinion by MMS of whether your field could qualify for royalty relief. It is based on your draft application and does not entitle the field to relief.

Performance conditions means minimum conditions you must meet, after we have granted relief and before production begins, to remain qualified for that relief. If you do not meet each one of these performance conditions, we consider it a change in material fact significant enough to invalidate our original evaluation and approval.

Pre-Act lease means a lease issued as a result of a lease sale held before November 28, 1995; in a water depth of at least 200 meters; and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Production means all oil, gas, and other relevant products you save, remove, or sell from a tract or those quantities allocated to your tract under a unitization formula, as measured for the purposes of determining the amount of royalty payable to the United States.

Project means any activity that requires at least a permit to drill.

Redetermination means your request for us to reconsider our determination on royalty relief if we have rejected your application or if we have granted relief but you want a larger suspension volume.

Renounce means action you take to give up relief after we have granted it and before you start production.

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Sunk costs means costs (as specified in 30 CFR 203.89(a)) of exploration, development, and production that you incur after the date of first discovery on the field and before the date we receive your complete application for royalty relief. Sunk costs include the costs of the discovery well qualified as producible under 30 CFR part 250, subpart A but do not include any pre-discovery activity costs or lease acquisition and holding costs such as cash bonus and rental payments.

Withdraw means action we take on a field that has qualified for relief if you have not met one or more of the performance conditions.

§ 203.1 What is MMS's authority to grant royalty relief?

The Outer Continental Shelf (OCS) Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104-58, authorizes us to grant royalty relief in three situations.

(a) Under 43 U.S.C. 1337(a)(3)(A), we may reduce or eliminate any royalty or a net profit share specified for an OCS lease to promote increased production.

(b) Under 43 U.S.C. 1337(a)(3)(B), we may reduce, modify, or eliminate any royalty or net profit share to promote development, increase production, or

encourage production of marginal resources on certain leases or categories of leases. This authority is restricted to leases in the Gulf of Mexico (GOM) that are west of 87 degrees, 30 minutes West longitude.

(c) Under 43 U.S.C. 1337(a)(3)(C), we may suspend royalties for designated volumes of new production from any lease if:

(1) Your lease is in deep water (water at least 200 meters deep);

(2) Your lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude);

(3) Your lease was acquired in a lease sale held before the DWRRA (before November 28, 1995);

(4) We find that your new production would not be economic without royalty relief; and

(5) Your lease is on a field that did not produce before enactment of the DWRRA, or if you propose a project to significantly expand production under a Development Operations Coordination Document (DOCD) or a supplementary DOCD, that MMS approved after November 28, 1995.

§ 203.2 When can I get royalty relief?

We can reduce or suspend royalties for OCS leases or projects that meet the criteria in the following table.

IF YOU HAVE A LEASE—	AND IF YOU—	THEN YOU MAY BE GRANTED—
That generates earnings which cannot sustain production (<i>End-of-Life lease</i>),.	Seek to increase production by operating the lease beyond the point at which it is economic under the existing royalty rate,.	A reduced royalty rate on current production flows along with a higher royalty rate on some additional production flows.
In designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995, and you propose activity in a DOCD or supplement to significantly expand production,.	Are producing and seek to increase ultimate recovery of resources from the field with a substantial investment (e.g., platform, multiple wells, subsea template) (<i>an expansion project</i>),.	A royalty suspension for an increment to production large enough to make the project economic.
In designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995 (<i>pre-Act lease</i>),.	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995 (<i>authorized field</i>),.	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic.

§ 203.3 Why must I pay a fee to request royalty relief?

(a) When you submit an application or ask for a preview assessment, you must include a fee to reimburse us for our costs of processing your application or assessment. Federal policy and law require us to recover the cost of services that confer special benefits to

identifiable non-Federal recipients. The Independent Offices Appropriation Act (31 U.S.C. 9701), Office of Management and Budget Circular A-25, and the Omnibus Appropriations Bill (Pub. L. 104-133, 110 Stat. 1321, April 26, 1996) authorize us to collect these fees.

(b) We will specify the necessary fees for each of the types of royalty-relief applications and possible MMS audits

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in a Notice to Lessees. We will periodically update the fees to reflect changes in costs as well as provide other information necessary to administer royalty relief.

§ 203.4 How do the provisions in this part apply to different types of leases and projects?

The tables in this section summarize how similar provisions in this part apply in different situations.

(a) Provisions relating to application content in §§ 203.51, 203.62 and 203.81 through 203.89.

Information elements	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Administrative information report	x	x	x
Net revenue and relief justification report (prescribed format)	x		
Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological & Geophysical (G&G), Engineering, Production, & Cost reports)		x	x
G&G report		x	x
Engineering report		x	x
Production report		x	x
Deep Water cost report		x	x

(b) Provisions relating to verification in §§ 203.70, 203.81 and 203.90 through 203.91.

Confirmation elements	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Fabricator's confirmation report		x	x
Post-production development report (approved by certified public accountant (CPA)		x	x

(c) Provisions relating to approval criteria contained in §§ 203.50, 203.52, 203.60 and 203.67.

Approval conditions	End-of-life lease	Deep water expansion project	Pre-act deep water lease
At least 12 of the last 15 months have the required level of production	x		
Already producing	x	x	
Well can produce			x
Royalties for qualifying months exceed 75 percent of net revenue (NR)	x		
Substantial investment (e.g., platform, multiple wells, subsea template)		x	
Determined to be economic only with relief		x	x

(d) Provisions related to redetermination in §§ 203.52 and 203.74 through 203.75.

Redetermination conditions	End-of-life lease	Deep water expansion project	Pre-act deep water lease
After 12 months under current rate, criteria same as for approval	x		
For material change in geologic data, prices, or costs		x	x

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(e) Provisions related to the format of relief in §§ 203.53 and 203.69.

Relief rate & volume	End-of-life lease	Deep water expansion project	Pre-act deep water lease
One-half pre-application effective lease rate on the qualifying amount, 1.5 times pre-application effective lease rate on additional production up to twice the qualifying amount, and the pre-application effective lease rate for any larger volumes	x		
Qualifying amount is the average monthly production for 12 qualifying months	x		
Zero royalty rate on the suspension volume and the original lease rate on additional production		x	x
Field Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)			x
Amount needed to become economic		x	x

(f) Provisions related to discontinuing relief §§ 203.54 and 203.78.

Full royalty resumes when—	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Average NYMEX price for last 12 months is at least 25 percent above the average for the qualifying months	x		
Average NYMEX price for last 12 months exceeds \$28/bbl or \$3.50/mcf, escalated by the gross domestic product deflator since 1994		x	x

(g) Provisions related to the end, loss or reduction of relief in §§ 203.55 and 203.76.

Relief withdrawn or reduced	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Recipient so requests	x		
Lease rate is at the effective rate for 12 consecutive months	x		
Conditions that we may specify in the approval letter in individual cases actually occur	x		
Not submitting post-production report that compares expected to actual costs		x	x
Change of development system		x	x
Excess delay in starting fabrication		x	x
Spending less than 80 percent of proposed pre-production costs but notifying us in post-production report		x	x
Amount of relief volume is produced		x	x

Subpart B—OCS Oil, Gas, and Sulfur General

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

ROYALTY RELIEF FOR END-OF-LIFE LEASES

§ 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 § 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 § 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 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]

§ 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 § 203.83) and
- (b) A net revenue and relief justification report (specified in § 203.84).

§ 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 § 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.

§ 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 § 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.

§ 203.54 How does my relief arrangement for an oil and gas lease operate if prices rise sharply?

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.

§ 203.55 Under what conditions can my end-of-life royalty relief arrangement for an oil and gas lease be ended?

(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

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return to the effective rate in the first full month following this termination.

(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.

§ 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 DEEP WATER EXPANSION PROJECTS AND PRE-ACT DEEP WATER LEASES

§ 203.60 Who may apply for deep water royalty relief?

Under conditions in §§ 203.61(b) and 203.62, you may apply for royalty relief if:

- (a) You are a lessee of a lease in water at least 200 meters deep in the GOM and lying wholly west of 87 degrees, 30 minutes West longitude;
- (b) We have assigned your lease to a field (as defined in § 203.0); and
- (c) You hold a pre-Act lease on an authorized field (as defined in § 203.0) or you propose an expansion project (as defined in § 203.0).

§ 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 § 203.3.
- (b) You must wait at least 90 days after receiving our assessment to apply for relief under § 203.62.
- (c) This assessment is not binding because a complete application may con-

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tain 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, § 203.61 was revised. This section contains information collection and record-keeping requirements and will not become effective until approval has been given by the Office of Management and Budget.

§ 203.62 How do I apply for relief?

You must send a complete application and the required fee to the MMS GOM Regional Director.

(a) Your application for deep water royalty relief must include an original and two copies (one set of digital information) of:

- (1) Administrative information report;
- (2) Deep water economic viability and relief justification report;
- (3) G&G report;
- (4) Engineering report;
- (5) Production report; and
- (6) Deep water cost report.

(b) Section 203.82 explains why we are authorized to require these reports.

(c) Sections 203.81, 203.83, and 203.85 through 203.89 describe what these reports must include. The MMS GOM Regional Office will guide you on the format for the required reports.

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

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 (c) of this section and § 203.64.

(a) The Regional Director maintains a Field Names Master List with updates of all leases in each designated field.

(b) 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

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the field. We will not disclose proprietary data when explaining our assumptions and reasons for our determinations under §203.67.

(c) 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.

§ 203.64 How many applications may I file on a field?

You may file one complete application for royalty relief during the life of the field. However, you may send another application if:

- (a) You are eligible to apply for a redetermination under §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.

§ 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 re-apply.

(b) We will evaluate your first application on a field within 180 days and a redetermination under §203.75 within 120 days after we say 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 §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.

§ 203.66 What happens if MMS does not act in the time allowed under § 203.65, including any extensions?

If we do not act within the timeframes established in §203.65, the conditions in the following table apply.

If you apply for royalty relief for—	And we do not decide within the time specified—	As long as you—
An authorized field	You get the minimum suspension volumes specified in §203.69.	Abide by §§ 203.70 & 76
An expansion project	You get a royalty suspension for the first year of production ..	Abide by §§ 203.70 & 76

§ 203.67 What economic criteria must I meet to get royalty relief on an authorized field or expansion project?

Your field or project must require royalty relief to be economic and must become economic with this relief. That

is, we will not approve applications if we determine that royalty relief cannot make the field or project economically viable.

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§ 203.68 What pre-application costs will MMS consider in determining economic viability?

(a) We will not consider ineligible costs as set forth in § 203.89(h) in deter-

mining economic viability for purposes of royalty relief.

(b) We will consider sunk costs (allowable expenditures on and after the discovery well as specified in § 203.89(a)) in accordance with the following table.

We will—	When—
Include sunk costs	The field has not produced, other than test production, before the application submission date.
Not include sunk costs ...	Determining whether an authorized field can become economic with any relief (see § 203.67).
Not include sunk costs ...	Determining how much suspension volume is necessary to make development economic (see § 203.69(c)).
Not include sunk costs ...	Evaluating an expansion project.

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

This section applies only to leases on which you have applied for and received a royalty-suspension volume under section 302 of the DWRRA. We will not collect royalties on a specified suspension volume for your field. Suspension amounts include volumes allocated to a lease under an approved unit agreement and exclude any volumes that do not bear a royalty under the lease or the regulations of this chapter.

(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) If the application for the field includes leases in different categories of water depth, we apply the minimum royalty-suspension volume for the deepest lease then associated with the field. We base the water depth and makeup of a field on the water-depth delineations in the "Royalty Suspension Areas Map" and the Field Names Master List and updates in effect at

the time your application is approved. These publications are available from the GOM Regional Office.

(c) You will get a royalty-suspension volume above the minimum if we determine that you need more to make developing the field economic.

(d) For expansion projects, the minimum suspension volumes do not apply. If we determine that your expansion project may be economic only with relief, we will determine and grant you the royalty-suspension volume necessary to make the project economic.

(e) A royalty-suspension volume will continue through the end of the month in which cumulative production reaches that volume. The cumulative production is from all the leases in the authorized field or expansion project that are entitled to share the royalty suspension volume.

§ 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 and 203.90 through 203.91 describe what these reports must include. MMS's GOM Regional Office will tell you the formats.

Required report	When due to MMS	Due date extensions
Fabricator's confirmation report.	Within 1 year after approval of relief	MMS Director may grant you an extension under § 203.79(c) for up to 1 year.
Post-production report	Within 60 days after the start of production that is subject to the approved royalty-suspension volume.	With acceptable justification from you, MMS's GOM Regional Director may extend due date up to 60 days.

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§ 203.71 How does MMS allocate a field's suspension volume between my lease and other leases on my field?

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

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

If—	Then—	And—
We assign an eligible lease to your field after we approve or establish relief.	We will not change your field's royalty-suspension volume.	The newly assigned leases may share in any remaining royalty relief.
We assign a pre-Act lease to your field after you submit a complete application.	We will not change your field's royalty-suspension volume.	The newly assigned leases may share in any remaining royalty relief by filing the short form application specified in §203.83 and authorized in §203.82.
We assigned a pre-Act lease to your field before you submitted the royalty relief application.	We will not change your field's royalty-suspension volume.	The newly assigned lease will not share in the relief if it did not participate in the application.
We reassign a well on a pre-Act lease to another field.	The past production from that well counts toward the royalty suspension volume of the field to which the well is reassigned.	The past production from that well will not count toward any royalty suspension volume granted to the field from which it was reassigned.

(b) If your authorized field has an automatic royalty-suspension volume established under §260.110 of this chapter, we will suspend payment of royalties on production from all eligible

leases in the field until their cumulative production equals the automatic volume. The following conditions also apply as appropriate:

If—	Then—	And—
Another eligible lease is assigned to your field.	Your field's royalty-suspension volume does not change.	The newly assigned lease may share in relief only to the extent that cumulative production from your field is less than the automatic volume.
A pre-Act lease applies (along with the other leases in the field) and qualifies (subject to the field's automatic suspension volume) for royalty relief under §§203.67 and 203.69.	Your field's royalty-suspension volume may increase or stay the same.	All leases in the field share the one, higher royalty-suspension volume if we approve the application; or The eligible leases in the field keep the automatic volume if we reject the application.

(c) If you have an expansion project with more than one lease, the royalty-suspension volume for each lease equals that lease's actual incremental production from the project (or production allocated under an approved unit agreement) until cumulative incremental production for all leases in the project equals the project's approved royalty-suspension volume.

cated entirely west of the meridian will receive a royalty-suspension volume.

§ 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 §203.62 in two circumstances.

(d) 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 lo-

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

(b) An expansion project on your lease may receive a separate royalty-

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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 § 203.67.

§ 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.

§ 203.74 When will MMS reconsider its determination?

Under certain conditions, you may request a redetermination if we deny your application, if you want your approved royalty-suspension volume to change, after we withdraw approval, or after you renounce royalty relief. To be eligible for a redetermination, at least one of the following three conditions must occur.

(a) You have significant new G&G data and you previously have not either requested a redetermination or re-applied 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) Your current reference price decreases by more than 25 percent from your base reference price. For royalty relief on deep water expansion projects and pre-Act deep water leases:

(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 oil and gas

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for the most recent full 12-calendar months preceding the date of your most recent, complete 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 §§ 203.85 and 203.88) from your most recently approved application for this royalty relief.

(c) 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 recent, complete application for this royalty relief.

[63 FR 2618, Jan. 16, 1998; 63 FR 24747, May 5, 1998]

§ 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 § 203.62. We will evaluate your application under § 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.

§ 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, tension leg platform to a moored catenary system such as a SPAR platform, 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 within 1 year of the date we approved your application—unless the MMS Director grants you an extension under § 203.79(c).

(c) You do not tell us in your post-production development report (§ 203.70), and we find out your actual development costs are less than 80 percent of the eligible development costs estimated in your application's most likely scenario. Development costs are those incurred between the application submission date and start of production. If you tell us about this result in the post-production development report, you may retain 50 percent of the original royalty-suspension volume.

(d) We granted you a royalty-suspension volume after you qualified for a redetermination under § 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 § 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 § 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.

§ 203.77 May I voluntarily give up relief if conditions change?

You may renounce approved royalty-suspension volumes as soon as you anticipate violating one of the withdrawal conditions, or for any other reason, before you start production.

§ 203.78 Do I keep relief if prices rise significantly?

No, you must pay full royalties if prices rise above the statutory base price for light sweet crude oil or natural gas.

(a) Suppose the arithmetic average of the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds \$28.00 per barrel, as adjusted in paragraph (f) of this section. In this case, we retract the royalty relief authorized in this section 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 § 218.54 of this chapter) by April 30 of the current calendar year, and

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

(b) Suppose the arithmetic average of the daily closing NYMEX natural gas prices for the previous calendar year exceeds \$3.50 per million British thermal units (Btu), as adjusted in paragraph (f) of this section. In this case, we retract the royalty relief authorized in this section and you must:

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

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

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

(d) 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 oil prices for the current calendar year is \$28.00 per barrel or less, as adjusted in paragraph (f) 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 (f) of this section.

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

(f) We change the prices referred to in paragraphs (a), (b) and (d) of this section during each calendar year after 1994. These prices change by the percentage the implicit price deflator for the gross domestic product changed during the preceding calendar year.

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§ 203.79 How do I appeal MMS’s decisions related to Deep Water Royalty Relief?

(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 § 203.67 and the royalty-suspension volumes under § 203.69 are final agency actions.

(c) If you cannot start construction by the deadline in § 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 rea-

sons. 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.

REQUIRED REPORTS

§ 203.81 What supplemental reports do royalty-relief applications require?

(a) You must send us the supplemental reports listed below that apply to your field. §§ 203.83 through 203.91 describe these reports in detail.

Required reports	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Administrative information report	x	x	x
Net revenue & relief justification report	x
Economic viability & relief justification report (RSVP model inputs justified by other required reports)	x	x
G&G report	x	x
Engineering report	x	x
Production report	x	x
Deep water cost report	x	x
Fabricator’s confirmation report	x	x
Post-production development report	x	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 GOM Regional Office.

(c) You must submit with your application and post-production development report an additional report prepared by a 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 conforms to our most recent guidelines on royalty relief.

(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.

§ 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.

(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:

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(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 §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]

§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) Lessee's designation, the API number and location 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).

§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:

(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;

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(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]

§ 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:

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(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 (§§ 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.

§ 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 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_o) and the resistivity of the undisturbed formation (R_i), 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; and

(7) Pressure-volume-temperature analysis, if available.

(c) Map interpretations which include 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) Identification of reservoirs not contemplated for development.

(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 appro-

priately reflect the uncertainty) for each reservoir; and

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

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

(1) Its size 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:

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(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:

(1) The conceptual basis for developing in phases and goals or milestones required for starting later phases; and

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

(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 (§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.

§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.

§203.89 What is in a deep water 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 cost, which are all your eligible post-discovery exploration, development, and production expenses (no third party costs), and also include the eligible costs of the discovery well on the field. Report them in nominal dollars and only if you have documentation. We count sunk costs in an evaluation (specified in §203.68) as after-tax expenses, using nominal dollar amounts.

(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 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).

§ 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's GOM Regional Supervisor—Production and Development, 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.

§ 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. Keep supporting records for these costs and make them available to us on request.

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal

§ 203.250 Advance royalty.

Provisions for the payment of advance royalty in lieu of continued operation are contained at 43 CFR 3483.4.

[54 FR 1522, Jan. 13, 1989]

§ 203.251 Reduction in royalty rate or rental.

An application for reduction in coal royalty rate or rental shall be filed and processed in accordance with 43 CFR group 3400.

[54 FR 1522, Jan. 13, 1989]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

PART 206—PRODUCT VALUATION

Subpart A—General Provisions

Sec.
206.10 Information collection.

Subpart B—Indian Oil

206.50 Purpose and scope.