UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

NTL No. 2010-N03

Effective Date: March 25, 2010
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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF

Guidelines for Royalty Relief Under 30 CFR Part 203

This Notice to Lessees and Operators (NTL) provides guidelines that apply to the revised regulations for pre-production or expansion project royalty relief which we published in the Federal Register on November 18, 2008 (73 FR 69490) and supersedes NTL 2002-N02. Due to the new regulations, Appendix I which pertains to the existing royalty relief application and evaluation procedure used for certain deepwater leases in the Gulf of Mexico, now applies to leases offshore Alaska as well.

Under 30 CFR Part 203, certain lessees may apply to MMS for a suspension of royalty payments or a reduced royalty rate by submitting a complete application. We describe the specific data elements, parameters, reports and computer model or spreadsheets required in a complete application in two separate Appendices to this NTL. They also explain the procedures we will follow for evaluating applications and implementing royalty relief. These appendices are:

> Appendix I: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF THE ROYALTY RELIEF FOR DEVELOPMENT AND EXPANSION PROJECTS, September 2009 and
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> Appendix II: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF ROYALTY RELIEF FOR END-OF-LIFE LEASES, September 2009.

These Appendices originally helped implement the section of the Deep Water Royalty Relief Act that applied to certain leases issued before 1996. Subsequent amendments to the regulations use this original application and evaluation process for other lease groups as well. The basic process described in these original guidelines remains the same, even if they may not always reflect this expanded program focus.

You should carefully review a copy of the appropriate guidelines if you intend to request royalty relief. They will help you structure your application to expedite our evaluation.

You can download the guidelines from the MMS website. They, along with the computer model or spreadsheet that you will need to prepare an application, are available at http://www.mms.gov/econ/econROYDW.htm under the subheadings for Case-by-Case Relief and RSVP for an application for royalty relief in deepwater or offshore Alaska or at http://www.mms.gov/ntls/ for an End-of-Life application.

If you have any questions on this NTL, you may contact Marshall Rose (703) 787-1538.

Paperwork Reduction Act of 1995 Statement: This NTL and its guidelines provide clarification, description, or interpretation of requirements contained in 30 CFR Part 203. The Office of Management and Budget has approved the collection of information required by these regulations and assigned OMB Control Number 1010-0071. This NTL and its guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated:

MAR 25 2010

Chris Oynes

Chris Oynes
Associate Director for
Offshore Energy and Minerals Management

Attachments:
Appendix I
Appendix II

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Appendix I to NTL No. 2010-N03

GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINSTRATION OF THE ROYALTY RELIEF FOR DEVELOPMENT AND EXPANSION PROJECTS

March 2010

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Recovery of Costs

According to Federal policy and statute, we charge you a fee for applying for royalty suspension volumes to recover our cost of processing your applications. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

Furthermore, our collection of such fees is specifically authorized by the Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996). The statute provides: "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ...for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337 (a) (3)."

We may issue a notice to lessees and operators (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you must make payments. We will revise the NTL periodically to reflect our cost experience and to provide other information necessary for the administration of this program.

OVERVIEW OF GUIDELINES
FOR DEEP WATER ROYALTY RELIEF APPLICATIONS UNDER 30 CFR PART 203

We (Minerals Management Service) issued regulations at 30 CFR Part 203 with an update in January 2002 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). This Act clarified and expanded the Secretary of the Interior's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases in order to promote development, increase production, and encourage production of marginal resources on producing or non-producing leases. This authority applies to oil and gas leases on the Federal Outer Continental Shelf (OCS) in water at least 200 meters deep in the Gulf of Mexico west of 87 degrees, 30 minutes west longitude that were issued in a lease sale held before November 28, 1995 or after November 28, 2000. Authorized lease(s) qualify for a royalty suspension volume if we determine the field, expansion project, or development project from which it would produce needs royalty relief to be economic.

You (affected lessees) may apply to our Gulf of Mexico Regional office for suspension of royalty payments by submitting the information specified under these regulations. These guidelines detail the format you should use for submitting the necessary information and the procedures and rationale we follow for evaluating applications. This edition of the guidelines reflect decisions made in connection with royalty relief cases over the last 3 years and expanded coverage under the updated regulations we issued in January 2002.

We advise you to review a copy of these guidelines if you intend to request deepwater royalty relief. We also encourage you to gain familiarity with our evaluation process by meeting with our Gulf of Mexico Regional Office prior to submitting an application. These guidelines do not add any requirements to the regulations, but they will help you decide whether to submit an application. Also, they will assist you in structuring your application so as to expedite our evaluation, should you decide to submit one. Be sure to use the most current version, as we will periodically update these guidelines to reflect our experience in processing applications.

Part of your submission requires you to use a computer model that you may obtain from our Regional Supervisor for Production and Development for the Gulf of Mexico OCS Region. The computer model and its documentation as well as these guidelines are also available on the MMS website at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

Any collection of information that we mention in these guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR part 203. The Office of Management and Budget approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not add information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated: 1/24/02

Carolita U Kallaur

Carolita U.Kallaur,
Associate Director
for Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: February 14, 2002

Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program

A. Introduction

These guidelines interpret regulations (30 CFR Part 203, Subpart B) which establish the terms and conditions for granting royalty suspension volumes under the Deep Water Royalty Relief Act (DWRRA). They apply to Outer Continental Shelf (OCS) oil and gas leases in water depths of 200 meters or more in the Central, Western, and portions of the Eastern Gulf of Mexico (GOM) that were in issued in lease sales held before November 28, 1995 or after November 28, 2000. Other guidelines interpret terms for reducing royalty rates under the OCS Lands Act (OCSLA).

As with the rule, we've written these guidelines in a plain English or conversational style. We (Minerals Management Service) give you (applicants, lessees, operators) directions on what to include in your application and what to do after we process it. Also, we explain how we will process your application and in some cases why we do it that way. Each section of these guidelines refers to the corresponding section in the regulations.

Guidelines are not strict rules like regulations, so we may consider requests for deviation from the guidelines when you provide compelling reasons for deviating from a provision, preferably before submitting a royalty relief application. Terms like "must" or "require" in these guidelines either replicate the regulations or indicate items we will ask you to provide if they do not appear in your application.

This installment of these guidelines incorporates changes we made in the underlying regulations in January 2002. These changes offered the right to apply for supplemental royalty relief to leases issued in sales held after November 2000 if they lie in water 200 meters or deeper in the Gulf of Mexico (GOM) wholly west of 87 degrees, 30 minutes West longitude. Also, the new regulations modified the relief qualification process. Some modifications apply only to leases issued after November 2000 (post-2000 leases) while others apply both to leases issued before the DWRRA (pre-Act leases) and to post-2000 leases. These modifications offer more opportunity, certainty, and flexibility for applicants. The following table summarizes continuing, discontinuing, and new elements in the application process for deepwater royalty relief.

PRINCIPAL ADDITIONS AND MODIFICATIONS IN 2002 TO DWRR APPLICATIONS

Element	*Applies to Pre-Act leases only*	*Applies to Post-2000 leases only*
Eligibility (Central, Western, and western part of Eastern Gulf of Mexico)	**Leases in 200m or more water depth issued before 1996.**	**Leases in 200m or more water depth issued after 2000.**
Unit of Application	**Whole field or Expansion project**	**Development or Expansion project**
Royalty-free production can come from	**Production from the field until the cumulative recovery volume from leases eligible to share in the relief equals the suspension volume.**	**Only production from resources identified in the application until cumulative production equals the suspension volume.**
Minimum suspension volume for non-producing leases	**For fields that did not produce before the Act, matches eligible lease suspension volumes (17.5, 52.5, 87.5 MMBOE) in equivalent water depths.**	**For development projects, matches volumes designated in sale and lease documents plus 10 percent of most likely reserves.**
Credit for sunk costs in application	**For fields with pre-Act leases that did not produce before the application, after-tax costs of and after discovery well used in qualification.**	**For development projects, after-tax cost of the project discovery well on each participating lease.**
Evaluation deadline for non-producing leases	**180 days for first determination, 120 days for a redetermination**	**150 days for first determination, 120 days for a redetermination**
Threshold oil and gas price levels for discontinuing relief	**Statute sets threshold price for light sweet crude oil and natural gas.**	**Original lease terms set threshold price for light sweet crude oil and natural gas.**

Element	*Formerly, but no longer applies to Pre-Act leases*	*Now applies both to Pre-Act and Post-2000 leases*
Discount rate used in evaluation	**Same rate used on viability and profitability tests, applicant chooses between 10% and 15%.**	**Use 10% on viability test, applicant chooses rate between 10% and 15% for profitability test.**
Credit for sunk costs in application for expansion project	**None**	**After-tax cost of the project discovery well on each participating lease.**
Minimum suspension volume for expansion project	**None**	**10 percent of most likely reserves.**
Evaluation deadline for expansion project	**180 days for first determination, 120 days for a redetermination**	**150 days for first determination, 120 days for a redetermination**
Deadline for starting fabrication	**Within 1 year of approval, extendable for up to 1 year.**	**Within 18 months of approval, extendable for up to 6 months.**
Deadline for filing Post-production Development Report	**60 days after the start of production, extendable for up to 60 days**	**120 days after the start of production, extentable for up to 30 days**
Correction for overestimating cost by 20% or more	**Retain only half of suspension volume granted.**	**Retain only half of smaller of suspension volume granted <u>or</u> most likely reserve size.**
Redetermination of field qualification or volume by MMS	**Available for new well or seismic data, 25% lower prices, or 20% higher cost.**	**Available anytime after relief relinquished or withdrawn. Otherwise, for new well or seismic data, 25% lower prices, 20% higher cost, or more efficient development system.**

B. Objectives of Deep Water Royalty Relief (DWRR) (supplements 30 CFR 203.1)

We may grant royalty suspensions in deep water for three purposes -- in order to increase production on leases already in production, to promote development on leases that have not produced (non-producing leases), or to encourage production of marginal resources on producing or non-producing deepwater leases. The program we use to implement this authority has three notable features. One, it applies only to the Western and Central Planning Areas of the GOM and the portion of the Eastern Planning Area of the GOM encompassing whole blocks lying west of 87 degrees, 30 minutes west longitude. Two, this authority only applies to deepwater leases issued in sales held before November 28, 1995 or after November 28, 2000. Three, we suspend royalties only for volumes of production needed to make the field or project economic, subject to minimum suspension volumes.

We implement these royalty relief provisions in conjunction with our stewardship responsibilities for sound management of public lands. This includes conservation of resources, obtaining a fair return to the public on OCS resources and ensuring that all OCS development is safe and consistent with sound environmental standards.

C. Relation of DWRR to Other Types of Royalty Relief (supplements 30 CFR 203.2)

We offer five types of royalty relief as described in the following table. Deep Water Royalty Relief (DWRR) is represented by rows b, c, d and e. Rows a and e represent relief available under the original OCSLA. Royalty suspensions are also available to some deepwater leases under 30 CFR 260 in their lease terms. Attachment A summarizes the main features of the various kinds of royalty relief.

If you have a lease...	And if you...	Then we may grant you...
(a) With earnings that cannot sustain production (End-of-life lease)	Would abandon otherwise potentially recoverable resources but seek to increase production by operating beyond the point at which the lease is economic under the existing royalty rate	A reduced royalty rate on current monthly production and a higher royalty rate (not to exceed the lease stipulated rate) on additional monthly production.[1] (See §§ 203.50 through 203.56.)
(b) Located in a designated GOM deep water area, acquired in a lease sale before November 28, 1995, or after November 28, 2000, and you propose in a DOCD or supplement to expand production significantly	Are producing and seek to increase ultimate resource recovery from one or more reservoirs not previously or currently producing in the field or lease, not simply extend recovery of reservoirs that already produced. (Expansion project)	A royalty suspension for additional production large enough to make the project economic. (See §§ 203.60 through 203.79.)

If you have a lease...	And if you...	Then we may grant you...
(c) Located in a designated GOM deep water area and acquired in a lease sale held before November 28, 1995 (Pre-Act lease)	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995 (Authorized field)	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic. (See §§ 203.60 through 203.79.)
(d) Located in a designated GOM deep water area and acquired in a lease sale held after November 28, 2000	Have not produced and can demonstrate that the suspension volume in your lease is not enough to make development economic (Development project)	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic. (See §§ 203.60 through 203.79.)
(e) Where royalty relief would recover significant additional resources or, in certain areas of the GOM, would enable development	Are not eligible to apply for end-of-life or deep water royalty relief, but show us you meet certain eligibility conditions	A royalty modification in size, duration, or form that makes your lease or project economic. (See § 203.80.)

[1]See the separate End-of-Life Lease Guidelines available from your regional MMS office for further explanation.

D. Basis for Granting DWRR (30 CFR 203.60, 63-64, 72)

Section 302(C) of the DWRRA states that an application may be made on the basis of an individual lease or unit. The term, "unit," isn't defined in the Act. The most fundamental issue we faced in implementing the DWRRA for pre-Act leases was should we base royalty relief on single leases or on some geologic or economic unit, such as a field?

Consistency with New Leases: We faced the same issue in the rule for Eligible leases (i.e., issued in sales after November 28, 1995 but before November 28, 2000). As we explain in detail in the preambles for our original rules implementing Sections 302 and 304 of the DWRRA, we believe the field basis for relief is consistent with the intent of Congress.

Under 30 CFR 260.110, an Eligible lease receives a suspension volume automatically, without demonstrating a need for the suspension to assure economic viability. These automatic volumes are established for the fields to which we subsequently assign the Eligible lease. We structured the rule and guidelines to apply royalty suspension provisions for pre-Act leases consistently with royalty suspension provisions for Eligible leases. Accordingly, we follow four principles.

First, we don't grant a royalty suspension volume to a field where any current lease produced before November 28, 1995, except in the case where you undertake a project to significantly expand production on your field. Since those leases which undertook the initial production from the field (and can be said to have taken the most risk) are not eligible for a royalty suspension volume under the DWRRA, neither should the lessees of leases on that producing field that begin production after the DWRRA's enactment. Under these circumstances, Congress certainly recognized that royalty relief isn't necessary to encourage production.

Second, we grant only one royalty suspension volume per Authorized field (i.e., a field not producing before November 28, 1995). We believe the Congress added "or unit" to Section 302 of the DWRRA to allow us to evaluate multi-lease fields. We don't compel unitization of fields applying for royalty relief. But, we expect leases in multi-lease fields that are not unitized to submit a joint application, as discussed in section F and we allocate a suspension volume as explained in section K.

Third, we may grant you a separate royalty suspension volume for each field that includes your lease and qualifies under section H. We may also give you relief for a project that will significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project. However, the reserves associated with the project must not have been included in the application for the field-based relief (e.g., excluded as uneconomic, newly recognized on better seismic, etc.).

Fourth, we apply the same price threshold terms (see section N) to pre-Act and certain eligible leases (refer to lease document). Congress prescribed the same royalty suspension volumes for both kinds of leases and we believe intended the same discontinuation of royalty relief at high prices for both kinds of leases.

Field Designation: Our definition of a field is based on geology and for the purpose of royalty relief is found in 30 CFR 203.0. We directly notify all affected lessees when we establish or redefine a field and issue the OCS Operations Field Names Master List (FNML), which lists all the tracts in each field on the GOM OCS each quarter, with monthly updates. Our Field Naming Handbook explains how we decide what constitutes a field. It identifies six major check-points we use for assigning leases to fields and gives 12 examples of geologic structures in the GOM and the associated field designations. We make this Handbook available via INTERNET on the GOM Region's website.

We assign leases to a field when a well on the lease qualifies as capable of producing in paying quantities under the regulations at 30 CFR 250, Subpart A. If a well doesn't qualify under the rule, we assign the lease to a field when hydrocarbons are first produced from the lease or the lease is allocated production under an approved unit agreement. We will also include other leases/blocks that, in our judgment, ultimately will be part of your field when we evaluate your application. You must submit in the application, data covering any of your leases that you believe will ultimately be part of the field.

Because we continually update field definitions for new leases, data, and qualifying wells, we recommend that you confirm the most current lease make-up of the field before filing an application. That step will preclude delays as described below in processing an application that doesn't conform to our current definition of your field.

We recognize that you may occasionally disagree with the determination that your lease is part of a particular field. To minimize disagreements, we use an informal process to consult with you when establishing and revising field designations. Our regional office will notify you of a preliminary field decision that affects your lease and offer you the opportunity for an informal review and consultation before finalizing your field designation. If you are still dissatisfied, you may appeal the final regional designation to the Director of MMS in accordance with the procedures in section N.

Post-2000 leases: To reduce lessee uncertainty regarding the amount of relief available and to accelerate the application evaluation process, we have changed the basis for relief from field to lease for leases issued after 2000. For applications that do not involve a pre-Act lease, we assign royalty suspension to the project defined by the applicant. Because of the large royalty suspension volumes mandated in the DWRRA, we cannot make this simplification for pre-Act leases. The volumes mandated by the DWRRA were based on estimates of relief appropriate for a typical deepwater field in the early 1990's. Without the large field-based minimums, we can now offer royalty suspension volumes more closely tailored to your project's estimated need. Further, we can offer additional royalty suspension as supplemental relief to post-2000 leases that may already have some royalty suspension in their issuing terms but need more to sanction development.

Application Criteria: The regulations identify five basic conditions for your lease before we will examine your application to suspend royalty payments on new production. Your OCS lease or unit must :

1. Have been issued as a result of a lease sale held before November 28, 1995 or after November 28, 2000;
2. Be in the GOM wholly west of 87 degrees, 30 minutes west longitude;
3. Be in a water depth of at least 200 meters; and
4. Have a discovery (for both pre-Act and post-2000 lease applications)
5. Have been assigned to a field (pre-Act lease applications, only).

The deepest water depth on any lease in a MMS designated field establishes the water depth for that field. However, once we approve an application for relief, the royalty suspension volume for an authorized field will not change based on the addition or subtraction of a lease. We establish the water depth for each lease based on the Lease Terms and Economic Conditions map. We publish these maps before lease sales for areas where the deepwater royalty relief program applies. We base these maps on bathymetric data from the National Oceanic and Atmospheric Administration. For purposes of drawing the map, if the water depth crosses a block, we include that block in the deeper water category for determining the volume suspension. However, the associated royalty rate for some pre-Act leases was based on the median water depth of the lease. We will use the version of the Lease Terms and Economic Conditions map in effect at the time you apply for royalty suspension to determine the water depth of your field.

E. Non-binding Assessments (supplements 30 CFR 203.61)

You may request a non-binding assessment of whether your non-producing, Authorized field or development project would qualify for royalty relief before submitting the first complete application. We offer this option to help those who seek an early indication about the chances for royalty relief on a marginal prospect.

We expect this option to be useful where you are reluctant to spend funds on reducing uncertainties about the commerciality of a field or project without at least an informal indication of its chances for royalty relief. This assessment also could shorten the time we need to evaluate your final application by identifying issues that otherwise would have led us to toll the clock to obtain an explanation or additional information. Finally, it may be useful for fields where you are not willing to risk having to meet the qualification requirements for a redetermination should we reject your complete application for relief.

Our assessment at this preliminary stage isn't binding for two reasons. One, further appraisal and planning can substantially change the approach, data, and assumptions from those we used for the early assessment. In contrast, your complete application for a binding relief determination presents the proposal upon which you agree to be bound as a condition for receiving the royalty relief we determine that you need. Two, we base our non-binding assessment on the premise that the expected values of the data you provide will be confirmed by the additional appraisal and planning you complete before filing a complete application. Should your appraisal and planning indicate that changes in the input assumptions are needed, the original results may change substantially. So, if you wish a binding commitment to royalty relief, you need to submit a complete application as described in section F.

We don't require a complete application for the non-binding assessment. However, we feel we can give you the most reliable indication about your prospect's chances for relief only if you give us virtually equivalent details. A draft application containing preliminary estimates for all the data elements in the Administrative, Geological & Geophysical (G&G), Engineering, Production, Cost, and Economic Viability Reports is essential to ensure that we are assessing the same prospect that you envision. To fully describe expectations for the prospect, you should submit a draft application consisting of all parts of the six reports, discussed in separate sections at the end of these guidelines. For a draft application, you need not include the certifications by an officer in your company and by an independent CPA firm as specified in 30 CFR 203.81 (b), (c), and (d) or in paragraph k of the Cost Report section.

We develop our non-binding assessment of your field's royalty relief prospects presuming that your additional appraisal work would acquire data essential both to making a determination on royalty relief and a decision on development. Therefore, the regulation says your draft application for a non-binding assessment must be accompanied by an appraisal plan that proposes to drill one or more additional wells should we render a favorable non-binding assessment. Further, you need to identify appraisal and delineation well locations and expenses planned before submission of the complete application so we may consider them as sunk costs for purposes of our nonbinding assessment.

We fully expect that uncertainty in your various estimates will be greater than would be the case in a complete application. However, all parts of an application contribute to a common view of the prospect. A fee, prescribed in a separate NTL, must accompany your draft application to cover our cost of developing a full assessment that dependably forecasts whether your prospect can expect to qualify for royalty relief. This fee is less than that for a complete application because we don't do a completeness review as part of our assessment. While any final applications we may be evaluating will take priority, we intend to complete our non-binding assessments as quickly as possible.

Once we provide a non-binding assessment, the regulation specifies that you must wait at least 90 days before submitting a final application on your field or project. This is the case because we feel that 90 days is the minimum time you should need to conduct the additional appraisal and planning required to review and finalize a complete application.

F. Applications (supplements 30 CFR 203.62-63, 71, 81, 83 & 85-89)

To apply for deepwater royalty relief, you need to file a complete application with the MMS Regional Director, Gulf of Mexico Regional Office, 1201 Elmwood Park Blvd., New Orleans, LA. 70123-2394. Applications may be for either:

1. An Authorized field that includes your pre-Act lease and did not produce before November 28, 1995.

2. A development project that involves only post-2000 leases and has not yet produced.

3. An expansion project on either your pre-Act lease your post-2000 lease that will expand production significantly. For a pre-Act lease, you must propose development in a Development Operations Coordination Document (DOCD) or supplemental DOCD approved after November 28, 1995. Because DOCD's don't require an estimate of production, we define significant expansion of production on a pre-Act lease as any project that involves a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, or multiple wells). We define significant expansion of production on a post-2000 lease as any project that adds new resources, not simply extends recovery of reservoirs already in production, with one or more new wells drilled into a reservoir that has not previously produced.

<u>Content:</u> You should finish all well appraisal work before you apply for royalty relief. A complete application includes the original and two copies (one copy for digital information) of:

1) Administrative Information Report;
2) G&G Report;
3) Engineering Report;
4) Production Report;
5) Cost Report; and
6) DWRR Economic Viability and Relief Justification Report

You can find details on the format and content of these reports in the Report Section later in these guidelines. A short form application, as mentioned in section K, case 3, includes only report 1) above. You owe a fee (see our most recent fee NTL, which can found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html) with each application you submit. A complete application for an expansion project also needs to reference an approved DOCD or supplemental DOCD.

Consulting and Certification: We will answer technical questions about your prospective application before we receive it and the processing fee. Such technical questions include: what we expect in the backup reports, how the RSVP model works, what needs to be in a complete application, and what are the currently prescribed economic inputs for the RSVP model. Also, we will describe our evaluation process and answer any question on these guidelines.

The regulation says you or your authorized representative must certify that all information submitted in the application is accurate, complete, and conforms to the format and detail specified in these guidelines. Your application also needs to be accompanied by a report prepared by an independent CPA expressing an opinion on the accuracy of the historical financial information presented and on whether it conforms to the presentation format specified in these guidelines. Attachment D to these guidelines describes what we expect the CPA to review and certify. You should identify an individual with the CPA firm who is knowledgeable about your field or project and is authorized to answer questions on it. Also, to expedite our review, please arrange to make him or her available to respond to questions we may have on the historical information. We still may need to review your records supporting the historical financial information in the application.

Multi-lease Applications: You should submit information about resources on all leases in the field or project. Also, you and other lessees on the field should plan either joint development or a joint application and make sure you meet the performance conditions for retaining approved relief. We've established the following joint application procedures.

1. We will accept only one joint application for all leases that are part of a field, as defined by the Regional Director, on the date of application, except as provided for in subparagraph 3 below. Our Regional Director for the GOM, maintains a list of all leases assigned to each field we've established. Also, we will accept only one application on a development project designed to produce a specific set of reservoirs.

2. You may submit separately to us proprietary G&G data that is a necessary part of the joint application, if you don't want to share that data with other lessees on your field. Your application isn't complete until we receive all the information stipulated in the rule for each lease on the field. In explaining our assumptions and reasoning behind our determinations, we won't disclose proprietary data.

3. We will waive the joint application requirement for a field or project if you show good cause for the waiver. You should fully explain this good cause and demonstrate that you made a good faith effort to obtain the participation of all lessees in the field or project. A

lease that is assigned to the field on the date of application but that isn't included in the application, because its lessee(s) fails or refuses to participate, won't share royalty relief for the field that is the subject of the application. We will include an estimate of the non-participating lease's portion of field or project resources and costs in our economic evaluation of your field or project. Also, we will evaluate the economics without royalties of those resources (up to the size of the royalty suspension volumes in the lease terms) on the field or project that are on eligible or RS leases (those that have royalty suspensions in their lease terms).

4. You or your successors may submit only one complete application for royalty relief during the life of the field or a specific development project, except in the following situations. You may submit another application if:

a) you are eligible to apply for a redetermination under section I,
b) we withdraw or you renounce previously approved royalty relief,
c) you apply for royalty relief for an Expansion project, or
d) you apply for end-of-life royalty relief.

G. Review (supplements 30 CFR 203.65-66)

We may take up to 20 working days after receiving your application to determine whether it's complete. If information is missing, we will attempt to give you an opportunity to submit the needed information during the 20-day period. If we deem the application complete, we will notify you and initiate the evaluation process. If not, we explain to you what the application needs to become complete.

If we propose to revise the make-up of your field after you file an application, we will not delay our completeness review. But, we will advise you that the field we intend to evaluate may differ from the one you described in your application. You may continue to contest this new field definition under the appeal process described in section N.

In situations where we modify your field by adding a lease during our evaluation, we may notify you that we need more information to complete our evaluation. If our regional office does finalize a change in your field make-up, we will ask you to agree to toll the evaluation clock until you can modify your application to include the new lease. We will also ask for an additional 60 days to review the new information. If you own or operate the added lease and decline our request to toll the clock, we will reject your application for inadequate information. If you don't own or operate the added lease and decline our tolling request, that added lease is still entitled to share any relief we approve for you by filing a short form application.

The DWRRA requires that we make a determination within 180 days after we deem your application complete (120 days in the case of a redetermination). The shorter period for the redetermination is based on the notion that we will have the head start of already being familiar with the field. Because they are more narrowly defined, we commit to making a determination on development projects and expansion projects within 150 days.

The 180/150/120-day time period won't begin until we determine and so notify you that your application is complete. Once we deem it complete, you may not initiate a modification (as opposed to a clarification) to your application. Notwithstanding this notification, if during the evaluation period, we find that data in the application are missing, unclear, inconclusive, or otherwise cannot be relied on, we will request new data or information needed to make the application reliable and accurate.

If we request more data, we ask that you agree to our tolling the 180/150/120-day time period from the time we make our request until you provide us the needed information. When you supply the needed information, we will restart the time period with the same number of days remaining for our determination as when the time was tolled. If, within 30 days after our request, you've not agreed to toll the evaluation clock or answered our questions, we will proceed to evaluate what we believe is the most logical development and production configuration for your field or project. Also, we reserve the right to proceed with our own interpretation of your original submission when your application presents inconsistent data. Otherwise, a complete but inconsistent application can be used to withhold data vital to our determination until late in the evaluation process.

We have a "fixed" application policy. During the 180-day evaluation period, you may not update your application based on new information such as actual costs, contracts, or revised design criteria except as described below. We do not believe it would be a fair and equitable process to allow a partial update of information and exclude other items such as oil and gas prices. You always have the option during the evaluation period to withdraw and resubmit the application.

Upon completion of our internal review (prior to a final decision), if our evaluation indicates a potential denial of your application, we may meet with you to identify the data in your application that we revised and to explain the reasons for the revisions. In such cases, we may give you an opportunity to address any misunderstanding which you believe we may have with your application, or to submit additional information to further explain and support the data in question. Also, with regard to the data in question, you may submit new supporting information such as actual costs or contracts. However, we will not revise any cost inputs to RSVP above your original estimates. Further, if you wish to submit additional information, we ask that you agree to a tolling of the evaluation period from the date of our meeting until we receive the information. We may also ask you for an additional tolling period to allow us time to review the new information.

You should notify us immediately if you begin drilling a well during the 180/150/120-day evaluation period. If you expect to complete the drilling operation within this period, we will ask that you agree to toll the clock so the new well information can be incorporated into our evaluation. We would toll the evaluation clock from the beginning of drilling operations at least until we receive the new information. If necessary, we would extend tolling for a specified period to provide time to complete our evaluation of the new information within the legal time limit. If you do not agree to tolling and to any request from us that you modify your application, we may reject your application request because the accelerated drilling program is not consistent with your application or because your application lacks required data.

If we determine that we need to audit sunk costs in order to evaluate your application, we request the 180/150/120-day evaluation period be tolled from the time you receive our notice until you provide and we receive the records necessary to conduct our audit. See section M for the procedures of how this audit determination will be made.

At the end of the 180/150/120-day evaluation period, we may extend for 30 days the time period for making the determination or redetermination without your consent, or for longer than 30 days if you agree. If we don't complete the determination for your field in the prescribed time period, together with any extension thereof, your field gets the minimum royalty suspension volume, as specified in section L below (except when you retract your application). If we don't complete a determination for your development project within its time limit, your project gets a royalty suspension for production during the number of months that a decision is delayed, plus all the royalty suspension volume for which you qualify. For instance, if we take 185 days instead of the maximum of 150 days to determine that your development project needs 35 MMBOE, your project gets a royalty suspension for its first two months of production plus 35 MMBOE. In the case of an Expansion project, the DWRRA specifies that we will collect no royalty on the new production for the first year of production, if we fail to make a determination on time.

H. Economic Evaluation Procedures (supplements 30 CFR 203.67-68)

Economic Measure: Over the years we've studied various measures to forecast whether or not a project might be economic. We've chosen to use net present value (NPV) in these types of assessments because we believe it best meets the characteristics needed to make proper and timely decisions. Specifically, NPV analysis is an appropriate measure of profit, reflects the time value of money, compares and ranks opportunities, indicates directly whether profit exceeds some minimum level, and is a widely used and understood measure of the value of a project. NPV analysis also avoids the analytical problems found with other measures. For instance, rate of return analysis has iteration requirements, can have multiple solutions, and can give ambiguous rankings for projects.

Further, Monte Carlo or probabilistic analysis techniques can be used with NPV calculations to incorporate varying degrees of uncertainty about the many variables that affect the result. This standard decision analysis approach is often used to evaluate projects at the exploration stage. To adapt this tool to evaluation at the development stage, we have added the feature of truncating extremely negative outcomes that may result from some of the simulations. This truncation procedure acts as a proxy for an option value analysis, which would serve to reflect the flexibility an applicant has (but that is not captured in a standard NPV decision analysis) to change a preliminary decision in light of emerging information. When disappointing reserve sizes join low prices or high costs, the prudent operator will in fact cut his losses long before completing full development by abandoning or at least postponing the project. We simulate that outcome by limiting the size of losses to a magnitude compatible with reaching that abort decision.

When the mean or expected NPV is equal to zero, an investment yields a rate of return equal to the chosen discount rate. If the NPV is less than zero, the investment earns a rate of return below the discount rate and is uneconomic. If the NPV is more than zero, the investment earns a larger rate of return and is economic. Therefore, in keeping with standard practice, we chose expected NPV as the decision criteria we use in the determinations discussed below. Our decision criteria is based on the mean NPV of simulations from a large sample of possible outcomes, including the limited losses in those trials where development is quite likely to be aborted.

We considered the use of a lower NPV criterion since a value only slightly less than zero could result in a large volume of relief. However, we dropped this idea due to the difficulty of identifying and justifying any such value.

<u>*Economic Tests:*</u> We subject applications for DWRR to up to three discounted cash flow (DCF) analyses. All three analyses use the same price assumptions but not necessarily the same discount rate assumptions.

(1) *Viability* (or Dual) *Test*. We determine whether any royalty suspension volume can make your development and attendant new production economic. For this test the DCF is calculated under assumptions most favorable for finding a positive NPV. Proposals that don't predict a positive NPV when no royalties are ever collected from the field and when no costs before the date of the application are counted are either beyond hope economically or exclude vital information. As part of this most favorable perspective, we specify that the lowest discount rate from the range we allow you to choose from will be used for this test. Currently the viability test uses a 10% discount rate.

You initially carry out this DCF analysis as part of the complete application using the Royalty Suspension Viability Program (RSVP v2.14) model that we provide. See Attachment E. In this analysis, we expect you to propose the system you intend to install if we approve royalty relief. Also, we expect you to define scenarios that fairly reflect the range of your uncertainty about the appropriate development scale for your field or project.

Subsequently, we review your analysis to confirm this determination and verify the system you propose is the most economical under the conditions used for this test. Our review also focuses on confirming that you've included appropriate costs and identified adequate resources to predict profits with the proposed system when neither royalties nor sunk costs are included in the DCF, calculated with a 10% discount rate.

We don't allow certain types of costs because they are not directly related to your production from your field. Paragraph h.of the Cost Report section lists costs we consider ineligible. One such item is expenditures for unsuccessful exploration activities, which we distinguish from delineation by the fact that they are not associated with a source of revenue or benefit to the field. RSVP v2.14 includes a feature to adjust for an ineligible element in well costs. When you propose drilling into previously un-penetrated reservoirs, the cost for that completion is included in the analysis only when that reservoir is sampled as not being dry. If the reservoir is to be penetrated by a well that goes through other reservoirs, a proportionate share of the completion costs for non-dry reservoirs are counted. The documentation for RSVP v2.14 more fully explains how this and other features of the model work.

In those instances where no amount of royalty suspension volume would make your field economic, we deny your application for royalty relief.

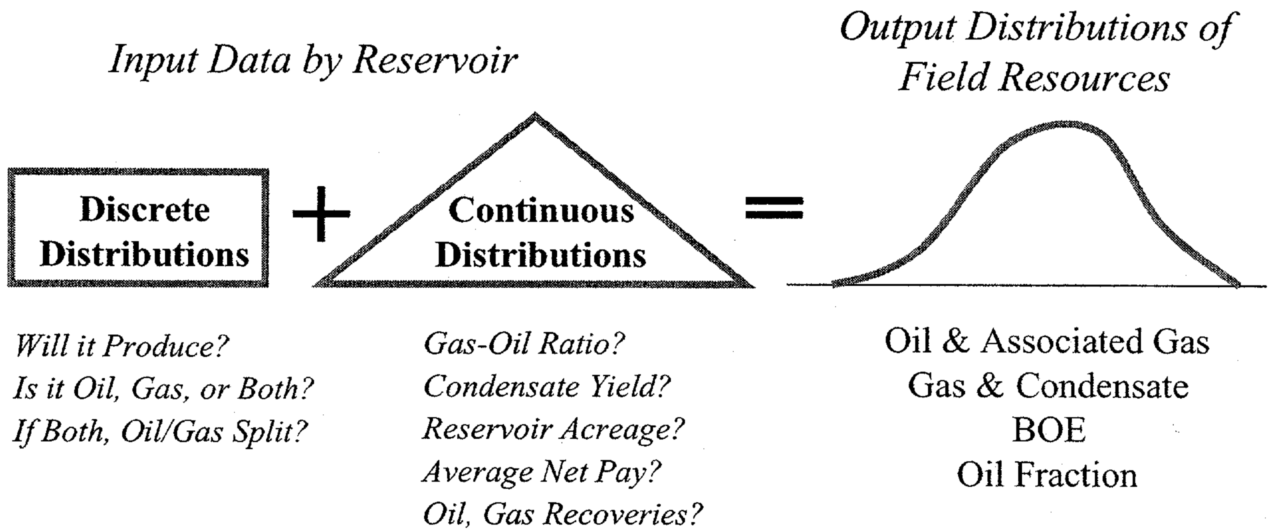
(2) *Profitability* (or Primary) *Test*. We determine if your proposed development is economic while paying lease royalties. As we are obliged to evaluate the most economical system for developing your field, we invite you to identify alternative systems that you considered and why you believe those are less economical than the one you propose. We evaluate whether the system you propose, or a logical alternative, is most economical should full royalties have to be paid. If we determine that the development of the field would be economic without relief, we deny your application. You choose which discount rate we use for this assessment from a range that we specify. Currently that range is from 10% to 15%. If you do not specify a particular discount rate, we will use 15%.

The following figure illustrate how RSVP develops the essential elements of the viability and profitability determinations. Each test requires 2 passes through the RSVP model. On the first pass, the Resource Module calculates a distribution for the size of the resource for the field or project (in BOEs) and for the oil portion of that resource. It does this by combining samples from up to 8 distributions for each reservoir. Discrete distributions (e.g., binomial) reflect estimates about whether each reservoir contains oil, gas or both, and how much of the reservoir will be oil. Continuous distributions (e.g., triangular) reflect estimates about the size, composition, and producibility of each reservoir.

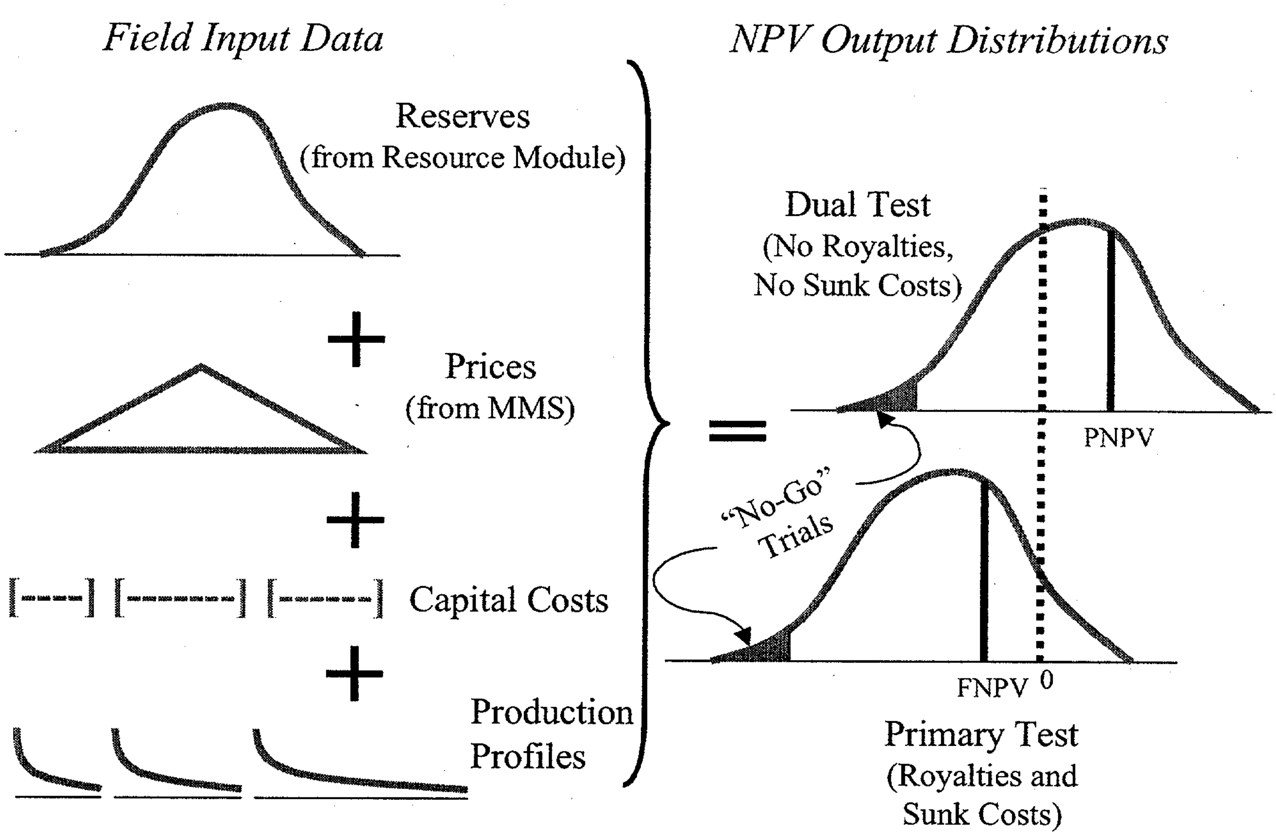
You then enter results from the Resource Module pass, along with up to 3 scenarios for capital costs and production rates, and rerun the model. The Viability Module correlates a narrowed distribution of resources (i.e., reserves) with capital costs and production rates and, using an MMS prescribed price path, calculates a distribution of NPV's. This distribution contains both profitable and unprofitable outcomes. The RSVP truncates "no-go" or loss-limited trials (those with abysmally large losses) to a loss equal to an estimate of expenses incurred up to the abort ("no-go") point. RSVP calculates a mean NPV from the distribution of profitable, unprofitable, and truncated loss trials. To qualify for relief, the mean NPV with neither royalties nor historic (sunk) costs (prospective NPV or PNPV) must be positive, while the mean NPV with full royalties and allowable sunk costs (full NPV or FNPV) must be negative. If your NPV is outside the FNPV to PNPV interval, then royalty relief at any level is not enough to make a difference. Your field or project is either already economic or royalty relief does not provide sufficient additional income to make development economic. (See the attached "RSVP" chart.) Documentation for RSVP provides a detailed explanation of how this spreadsheet model works and can be found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

Sunk Cost. Before moving on to the third test, we need to cover how and why we treat sunk cost as we do. Besides royalties, sunk costs are central to the profitability determination. Insofar as the overall goal of royalty relief is to promote the development of marginal fields, economic theory suggests that only costs that are relevant to the development decision of the operator need to be considered. Sunk costs don't affect that decision.

RSVP Resource Module



RSVP Viability Module



However, a relief qualification that includes sunk cost may indirectly encourage more development, and perhaps more exploration, than otherwise. Sunk costs in an evaluation make qualification for discretionary royalty relief more likely. The more likely a prospect of a given size is to qualify for relief, the larger is the expected value of a prospect yet to be explored. And, the higher is the payoff from drilling, the more and sooner drilling will take place. Also, the DWRRA directs that we consider all costs associated with exploring, developing, and producing from the lease. Hence, we consider certain eligible types of historical costs (i.e., sunk costs) in making this determination. When your field includes a pre-Act lease and has not produced, other than test production, before you submitted a complete application for royalty relief, we use a broad definition of allowable sunk cost. In this case, we include your eligible expenditures from the date of the first discovery of the field up to the date you submit a complete application, plus the costs of your discovery well if it is qualified as producible under 30 CFR 250, Subpart A in the profitability test.

We use a narrower definition of sunk cost for a development or expansion project application. A narrower definition of sunk cost, in comparison to the definition of sunk cost for pre-Act leases, is consistent with a narrower unit of operation. A specific project, rather than a whole field, is the object of the royalty relief program. In the case of a field, all the resources and development possibilities need to be evaluated. Thus, a field evaluation depends on more complete appraisal, and so provides a basis for the broad definition of allowable sunk costs. But, discerning the relevance of all post-discovery expenditures is more critical when the subject of the application is a specific project rather than an entire field. Such expenditures may benefit existing production as well as future production or may have been incurred on lease resources not included in the application. Therefore, on a development project or expansion project, we limit allowable sunk costs to the cost of the first well on each lease that discovers hydrocarbons in the reservoirs included in the application. Attachment B reproduces the definitions found in the regulations at 30 CFR 203.0, including the 2 forms of allowable sunk costs. Attachment C summarizes categories of allowable costs.

We limit the amount of sunk costs we count to those clearly related to developing your field that have not been recovered in previous transactions. We measure sunk costs on an after-tax expensed basis, using the nominal (current dollar) amounts without any interest or discount rate adjustments. Also, we include only sunk costs incurred by current owners of all leases that are both assigned to the field at the date of the application and included in the application.

We don't count any sunk costs in the profitability test for fields that produced prior to the date you submitted a complete application because they are irrelevant to whether fields continue production or not. We don't count any historical costs incurred by third parties, such as former leaseholders. Such costs are hard to verify and are not relevant to the current owner's decision of whether or not to develop and produce the field. We presume that former owner(s) willingly exchanged the possible future revenues that recover their historic costs for compensation received in transferring their share of the lease(s) to others. In turn, these current owners did not incur these third-party exploration and development costs, but they did or will benefit from their results. Therefore, the costs and benefits of third-party expenses have been fully considered through past market transactions involving the field.

(3) *Volume Test.* We approve your application for royalty relief if the most economical system for the viability test shows a positive NPV and the best system for the profitability test shows a negative NPV. Then, we compute a volume of production on which to suspend royalties that is sufficient to make your field economic. This volume calculation is the third determination.

We won't count sunk costs in computing the royalty suspension volume that will make the field or project economically viable. To do otherwise risks adding relief well beyond that necessary to make development economic. Also, it would direct more relief to just the wrong fields or projects. Those with relatively large sunk costs would qualify for relatively large volume suspension, but they are more likely to continue anyway because they have relatively smaller costs left to incur and that must be covered by future production. However, we ensure that inclusion of sunk cost in the profitability test gives you an unambiguous benefit by guaranteeing successful applications receive at least the minimum royalty suspension volumes specified in section L.

If we determine that it takes more than the minimum volume suspension to make your field or project economic, we will calculate the volume suspension using a similar DCF model. We use the resources, engineering design and prospective costs in the application, as verified and potentially modified by us for the viability test, in this calculation. One major difference in the way we conduct this test arises from your obligation to meet certain performance conditions, per 30 CFR 203.76 of the final rule, in order to realize an approved volume suspension. To incorporate that constraint, we base your volume suspension determination only on the most likely scenario and associated resource range in your approved application.

<u>Special Cases:</u> We apply slight variations to the general evaluation procedure described above in cases where ownership changes, where leases are added to a field, and for evaluating expansion projects.

(1) *Ownership Changes.* When changes in lease ownership occur, they can affect how we consider sunk cost. If there is a break in your ownership tenure, we count only your historical costs since you last obtained a share of the lease. If you've maintained continuous ownership but changed the share of the lease you own, we count your sunk costs on that lease in proportion to the share you owned when you incurred these costs. These principles apply until we make a final determination on your application. Accordingly, a break in ownership on a lease after you submit an application but before we make a final determination could result in a loss of some of the field's otherwise allowable sunk costs. However, after you submit an application, a redistribution of ownership shares on a lease among current or new owners, without a break in ownership, will not affect how we count the allowable costs.

The following table illustrates how we apply these principles to each lease on your field. The table entries represent the percentage ownership of the lease by company and period.

CASE	I	I	II	II	III	III	III
PERIOD	1	2	1	2	1a	1b	2
COMPANY							
A	80	40	80	80	80		40
B	20	20	20		20	60	20
C		40		20		40	40

Period 1 spans the time from when we begin counting sunk costs up to the first change in ownership. Period 2 runs from the end of period 1 until an application is filed. In cases I through III, all period 2 owners are assumed to retain shares during our evaluation process, i.e., during period 3. The results described below would not be affected by a redistribution of ownership shares during period 3 as long as there is no break in ownership in this period. This is the case because there are no sunk costs allowed in period 3, and satisfaction of the continuous ownership requirement would entitle the field to retain all of the sunk costs incurred in period 2.

In case I, we count all of the allowable sunk costs in period 1 since they were all incurred by current owners. Of course, we count all of the allowable sunk costs in period 2 as well since they too, were incurred by the current owners.

In case II, we count only 80 percent of allowable sunk costs spent in period 1. We don't count the remaining 20 percent as it is related to a non-current owner. Again we count all allowable costs in period 2.

Case III represents a situation in which there are two changes in ownership up to the time of application, and stable ownership through a final determination. We count only 20 percent of allowable costs from period 1a owing to continuous ownership by company B but not company A. The subsequent break in ownership for company A precludes our counting its costs from period 1a. For periods 1b and 2, we count all costs because there is continuous ownership from period 2 back to period 1b. That accounts for 100 percent of eligible shares in each period. We apply equivalent rules when ownership changes during the evaluation period.

In case IV, we have two breaks in ownership--one before the application is submitted (period 1b) and the other after submission, but before we make a final determination (period 3). No sunk costs are applicable in period 3. We count all allowable sunk costs in period 2 and in period 1b because all owners in those periods have maintained continuous ownership. We count only B's 20 percent of sunk costs from period 1a because A was compensated for its costs during period 1a in the transfer of all its ownership after that point.

CASE	IV	IV	IV	IV	V	V	V	V
PERIOD	1a	1b	2	3	1a	1b	2	3
COMPANY								
A	80		50	40	80		50	
B	20	100	50	20	20	100	50	20
C				40				80

The final case V is identical to case IV, except that during period 3, when we are evaluating the application, there is a break in ownership. The break in ownership makes companies B and C current owners for purpose of the application. So, we don't count any of A's sunk costs from periods 1a and 2, but we count all of B's sunk costs--50 percent in period 2, 100 percent in period 1b, and 20 percent in period 1a.

To ensure that we include the proper amount of allowable sunk costs in our determination, your application should clearly indicate the historic ownership shares of the current owners for each lease in the application, along with the distribution of allowable sunk costs by lease and time period. Moreover, you should notify us immediately when, during the application review process, there is any change in ownership shares on a lease in your field, with special attention to breaks in ownership. Your failure to indicate the historic and current ownership arrangements in a clear, accurate, and timely manner risks losing any relief that we may grant on the grounds that you provided inaccurate information that is material to our determination.

(2) *Fields Mixing Pre-Act, Eligible and/or post-2000 Leases.* If your pre-Act lease is on a field that already has a royalty suspension volume for new leases under 30 CFR 260.110, you may apply to share the volume suspension under conditions specified in 30 CFR 203.60 and 62-63. Also, your post-2000 lease may apply for development project relief even if it already has a royalty suspension volume. We evaluate your relief application in much the same manner as described above except that we conduct the three DCF determinations taking into consideration the volume suspension to be used by eligible and/or RS leases (those issued after 2000 with a royalty suspension) on the field/project.

Eligible leases (those issued within 5 years after the DWRRA) and RS leases automatically qualify for volume suspensions. Their lessees may or may not choose to join with a pre-Act lease on the same field that wishes to apply for relief. The lessee of the pre-Act lease must show good cause for us to waive the requirement that all leases on the field be part of an application for royalty relief. Upon appropriate application by a pre-Act lease on a mixed field, we will evaluate field economics including the suspension volume we judge the Eligible and/or RS leases will be able to use. This may be the full automatic suspension volume, or it may be less if we decide those leases will be unable to use their full suspension. Case 4, Section L explains how we allocate a volume suspension if we determine that you qualify to share in the field's royalty suspension volume.

An example may help clarify this description. Suppose lease A (the pre-Act lease) and lease B (the Eligible lease) are on the same field and that lease B entitles the field to a royalty suspension volume of 87.5 million barrels of oil equivalent (MMBOE). If we conclude that lease B can produce that much, we reject an application for relief for lease A if the field is economic with royalty free production of 87.5 MMBOE or less. If we decide that lease B can only produce 40 MMBOE, then we reject lease A's application if the field is economic with royalty free production of 40 MMBOE or less. We follow the same procedure when an RS lease is involved in a royalty relief application, either for a field with pre-Act leases or a development project. This approach means we presume any expected profits from lease B offset equivalent losses from lease A, regardless of whether they develop jointly or separately. In the event that we reject your application for lease A, you may be able to file an application for relief under the expansion project provisions explained in item 3 of this section.

Material change conditions on approved relief play a reduced role in this situation. Lease B's status as an Eligible lease, serves to shield its owners from loss or reduction of relief for a material change from the application. Likewise, an RS lease is exposed to loss of only the increment above the royalty suspension with which we originally issued it for violation of a material change condition. Development on lease A still must avoid the material change conditions described in section J. In such cases, we will be more inclined to look at a wider set of possible resource and cost paths before approving a relief application.

(3) *Expansion Projects*. We evaluate your applications for an expansion project with the same three determinations on a project specific basis. We count sunk costs in any of the determinations for an expansion project in the same way we do for a development project. Any royalty suspension volume amounts that we award will apply only to production from reservoirs targeted by your proposed expansion project.

You should note that your receiving a royalty suspension volume on production from a Authorized field doesn't preclude you from obtaining further relief. You may do so under the pre-DWRRA provisions of the OCSLA, the expanded OCSLA royalty relief provisions created by the DWRRA, or under the significant expansion of production portion of the DWRRA. However, your expansion project should recover reserves that were not considered in our original determination (e.g., excluded as uneconomic, or newly recognized based on better seismic, etc.). At least one of the new reservoirs you intend to recover with the expansion project must have a discovery well, as we do not grant relief solely for exploratory activities.

<u>Applicant Inputs:</u> In general, you the applicant provide the resource, productivity and development data, and the costs we use in the determinations. We devote most of the evaluation period to assessing the appropriateness and consistency of these inputs. The following discussion highlights characteristics that we look for in your submission.

(1) *Resource Estimates*. You should give your interpretations of the underlying geology with probability distributions, reflecting the uncertainties about your field's potential size and production. We expect you to use triangular distributions for the parameters used in the resource calculation. You may select other types of distributions from the options available with Crystal Ball in our RSVP v2.14 model, but you must give a detailed explanation of why your choice better represents your geology than the default triangular distribution. We carefully review the raw backup data and may adjust the geological interpretations if we determine others are more appropriate.

We verify your estimates for resources and reserves prior to determining economic viability. Part of our resources and reserves verification involves weighing whether you propose too many or too few reservoirs for development. We may decide to drop reservoirs because they add more cost than revenue to the project. In such cases we will exclude that reservoir's production and drop the associated costs from the analysis. We also drop these costs from the base for your material change performance condition of spending at least 80 percent of the estimated pre-production development costs in your most likely scenario. On the other hand, we may add reservoirs because they would contribute more revenue than cost to your project. In this case we presume that you'll develop the extra reserves in a later phase, so we include the extra costs and revenues after production begins.

(2) *Production and Cost Estimates*. You specify production and capital costs using up to three scenarios (conservative, most likely, optimistic) to reflect the level of uncertainty, if any, in the design scale of your final development system and in the production profile of your reservoirs. We structured the RSVP v2.14 model to simulate adjustments in cost and scale (e.g., number of wells, throughput capacity) based on the potential results of further delineation and project definition. The three scenarios are designed to correlate resource sizes with cost levels. That is, when larger than expected resource sizes are sampled (simulating better than expected delineation results), higher costs (e.g., larger capacity) also tend to be sampled, and vice versa. We will consider an alternative approach to selecting the development scenario for each trial if you convince us that it better reflects the decision variables that will guide your choice among the various scenarios. As in the resource module, you may use probability distributions for productivity and unit cost assumption in the viability module.

You must use care in configuring the development scenarios in RSVP v2.14. We will insist that the mean of the all-trial distribution of capital costs be no more than 7.5 percent above the capital cost estimate you give for the most likely scenario. Also, we insist that the most likely scenario cover at least 1/3 of all trials. These restrictions help ensure that your estimates for the most likely scenario are representative of the uncertainty you face and that your application is not being submitted too early in your decision process.

The 7.5 percent value is derived from one of the conditions under which you may request a redetermination. If your costs rise by more than 20 percent from the most likely estimate in your most recent previous application, you are entitled to a redetermination. That is, 20 percent is the largest capital cost increase that we consider consistent with other elements in your development plan. Conversely, a 5 percent cost decrease represents a conservative estimate of the cost savings you may be able to realize. The midpoint of this interval (7.5 percent) represents the largest average deviation of cost that we will allow. Costs that vary by more than 7.5 percent on average indicate that your application is premature. Greater variance suggests that you are not yet confident enough in your cost estimates to decide whether relief from a 12.5 (or in some cases 16.67) percent royalty is likely to make an unprofitable prospect profitable or not.

The following example clarifies this guidance. Suppose you claim that capital costs (including platform fabrication and installation) and well drilling and completion cost are as shown in the following table.

Scenario Estimate	Conservative	Most Likely	Optimistic	Mean, all trials
Platform cost	$250MM	$250MM	$250MM	
Confidence interval	$245 to $350MM [-2%/+40%]	$225 to $338MM [-10%/+35%]	$210 to $300MM [-16%/+20%]	$300MM
Number of wells	6	5	5	
Average cost/ well	$36 MM	$30 MM	$28 MM	
Well cost	$216MM	$150MM	$140MM	$170MM
Best estimate of capital costs		$400 MM		$470MM

RSVP v2.14 calculates the distribution of capital costs of all trials. Suppose the mean of this distribution is as shown in the right-hand column. The application envisions total capital costs 17.5 percent {[(470/400) - 1] * 100 percent} above the best estimate that your back-up data supports. Looked at another way, your application includes an excessive contingency cost estimate of 17.5 percent. That much uncertainty indicates that it is premature to tell whether royalties are the difference between profit or loss for your field or project.

In this situation, we will reduce by parallel amounts the top end of both your confidence interval on capital costs and the maximum values in your input distributions for average drilling and completion cost by enough so your application does not exceed our 7.5 percent standard. For instance, we may reduce the upper end of the confidence intervals in all three scenarios by 10 percent (to +36, +31.5, and +18 percent from +40, +35, and +20 percent, respectively) and the maximum possible values in the average drilling and completion cost distributions by a like proportion. That would be enough to lower the mean of all trials to what we judge to be more reasonable levels (e.g., platform cost of $265 MM down from $300 MM and well costs of $155 MM down from $170 MM. In this case your implied contingency factor would be lowered to an acceptable 7.5 percent {[((265 + 155)/400) - 1] * 100 percent}.

Where you've significantly reduced uncertainty with substantial delineation and planning, we look for you to more extensively document and explain the rationale if you decide to use fewer than three scenarios. Further, in these instances you may use point estimates in place of ranges or distributions. Your documentation in the various reports should clearly establish the results from such delineation and planning. In cases where you opt to use less than three scenarios, you must identify the most likely scenario.

As explained earlier, RSVP v2.14 includes a loss limit feature, which adjusts illogical trials. For instance, some random samples drawn when you propose large cost and resource uncertainty may pair very small resource sizes with extremely high development costs. This is unrealistic and you would have aborted development rather than lose the large amount of money the model calculates. The adjusted value used on these trials is the present value of non-construction costs you plan to spend in the first year after submitting the application. A few illogical trials are probably unavoidable with the combination of distributions you can chose, especially when you use only one scenario but the full permitted range of uncertainty. However, too many discarded samples distort the model's estimate of the value of your field. Therefore, we insist that the results of your model run must have no more than 20 percent of the trials discarded.

We check your production and development scenarios for consistency with the geologic data and cost data during the review. As with the information you provide on reservoirs, in cases where we find that assumptions other than those you provide are more appropriate, we reserve the right to make all necessary changes in the set of inputs. One assumption that we will carefully evaluate is your choice of what resource sizes are associated with the switch from one production and cost scenario to another. When your application doesn't explain the choices made, we may request tolling and clarification. If you cannot provide adequate justifications for your choices, we will investigate others and use those that maximize NPV for the field.

In other cases, we may find it necessary to adjust your assumptions to insure fair and consistent treatment across relief applications. For instance, some proposals may contain unusual arrangements involving deferred financing of development capital. Such cases may include little pre-production investment in the RSVP v2.1 calculation. In such cases you need to relate your deferred financing payments to the cost incurred by the owner of the equipment. We will use the present value of the deferred payment stream set by your contract with the owner to judge whether you meet the cost-performance conditions at the post-production development review. As we gain experience with applications, we may identify similar issues where we need to make adjustments for fairness and consistency. We will carefully review any such adjustments with you and specify them in the final determination letter.

MMS Inputs: To treat all applicants alike, we provide you with several of the economic assumptions for oil and gas production to be used in the DCF analyses.

(1) *Price and Discount Rate Assumptions:* The Economic Viability and Relief Justification Report section lists price and discount rate assumptions you are to use. We update the price assumptions as dictated by circumstances but at least annually on our web page at www.mms.gov/econ/update. We use the most recent set of economic assumptions that we issued before you filed your application to make all three DCF determinations.

We derive pricing assumptions from long-term projections of oil and gas prices made by major government and possibly private forecasters. We start with oil and gas price assumptions found in information provided by the Energy Information Administration (EIA), Department of Energy. We expect to update price assumptions at least annually in the spring, after the requisite data and forecasts become available from EIA. During periods of rapid change in oil and gas prices we may update our price assumptions more often. You may adjust our prices for the expected API gravity of your reserves, as described in our API gravity adjustment table, if you document these adjustments as discussed in the Economic Viability and Relief Report section. You should request approval for any other price adjustment and get our written approval before making any other adjustments. We consider any other change that we find to our price assumptions as reason for concluding either that the application isn't complete or that it should be rejected.

We also specify a range of discount rates from which you may choose a particular rate. We allow a choice because projects have different characteristics and operators have different risk preferences reflected in their target rates of return. The range we allow for the discount rate is based on historical industry returns and reflects before tax returns appropriate to a field with a discovery, i.e., where the risk of not finding oil or natural gas has been eliminated.

Until now, we insisted that the same discount rate be used for both the viability estimate and the profitability estimate. While ensuring that the application does not give an overly pessimistic portrayal of the field or expansion project, this equivalence of discount rates may be too restrictive. Development without royalty or sunk costs should be less risky than if these costs have to be covered. Thus, the cost of capital under the viability circumstances should be lower than when full royalties and sunk costs must be paid. To acknowledge this potential difference, we now accept applications that demonstrate fields or projects have a positive value for the viability test at a 10-percent real rate of discount. Note this change applies to applications both from pre-Act leases and from post-2000 leases. Applicants retain the right to set the discount rate we use for the profitability test at any value between 10 and 15 percent.

(2) Allowable Costs. The Cost Report section describes what we consider reasonable cost items for use in the DCF analysis. As with the discount rate assumptions, we may update individual items when new information supports a change.

You specify historic costs in the format described in Attachment C. Also, you provide a certification by an independent CPA that these expenditures are accurately reported, relevant to the field or project that is the subject of the application, and follow the proper format. Where sunk costs are important, we may audit your records as part of our verification.

We follow the cost accounting structure prescribed for Net Profit Share Leases (NPSL) in 30 CFR 220.011 - 220.015. We allow you to count all the costs described in Attachment C because they benefit the development and operation of your field. We allow you to include reasonable portions of joint costs that rightfully should be allocated to this field. Joint costs mean any of the cost items listed in Attachment C that benefits this field or project and one or more other operations. Because some joint cost may be difficult to allocate we also allow you to assign a modest overhead amount to certain cost items. We view technical and operations support activities as joint costs to be allocated to the field while finance, administration, and management activities should be covered by the allowed overhead.

We use a stochastic model to handle the uncertainty associated with estimates and allow a potentially generous rate of return on a discovered field. Therefore, you may not claim contingency costs or other cost multipliers specifically intended to characterize uncertainty. Rather, you should use ranges as described above for estimating scenarios for capital costs. We view cost contingencies or multipliers as an ineligible cost as they are an alternative way to consider uncertainty whose use in RSVP, in effect, double-counts uncertainty.

Summary: You provide the necessary information and demonstrate that your field or project can be made economic with royalty relief using standard assumptions and methodology that we provide. We then verify and employ the same information and methodology to evaluate whether your field or project is economic without relief, confirm that royalty relief can make an your otherwise uneconomic field or project economic, and compute the magnitude of relief you need to make the field or project economic. All of these determinations are based on forecasts that estimate the value of your field, except that certain sunk costs are included in the profitability test.

In general, we framed both the qualification tests and relief volume calculation following the principle that the DWRRA aimed to give substantial, but not excessive, incentive to develop marginal fields or projects. Thus, our economic tests are structured so as to minimize the error of rejecting relief for a field that really should qualify, and the volume calculation is structured so as to minimize the error of giving more volume suspension than is necessary to make a field economic. That is, our calculation of volume suspension tends to give the minimum volumes unless there is strong evidence that a larger amount is needed. Our calculation has this tendency because we exclude sunk costs and because we set an upper bound on the discount rate.

I. Redeterminations (supplements 30 CFR 203.74-75)

You may request that we reconsider denial of an application or reconsider the size of the royalty suspension volume granted in an approved application. We offer redetermination unconditionally after we withdraw or you renounce relief. In other circumstances, we make available a redetermination if there is a significant change in the factors upon which we made our original determination, before you start the new production subject to the royalty suspension. You may request a redetermination only in the following cases:

1. There is a change in your resource information (e.g., gross resources, quality of product, flow rates) that is of sufficient magnitude that the results of our initial determination would have been materially different had the previous complete application included the new data. The regulation says the new resource information must result from new G&G activity such as a new well or new 3-D seismic data that did not exist at the time of the previous application. Reinterpretation of existing data doesn't qualify as a significant change in resource information. You may use a change in resource information to qualify for only the first

redetermination on your field. Additional redeterminations are available only for changes 2, 3 and 4 below.

2. You propose a new development system that improves the profitability, *under equivalent market conditions*, of the field or specified set of reservoirs relative to the development system proposed in the prior application. It must be clear that the original application did not consider or deem the new development system feasible. This situation might arise because new technology becomes available or a new owner with a different perspective takes over field development after the initial application. The initial application may have failed because of high prices that have since fallen. In any case, the new application needs to demonstrate that the new approach more efficiently develops the resource than what we originally evaluated. By more efficient, we mean either clearly lower costs or clearly larger recovery, so that estimated profit would increase using the price forecast we used in the previous evaluation.

3. Average annual prices of oil and gas fall by more than 25 percent below their level at the time of your most recent previous application. We determine these averages as follows.

   (a) Calculate the arithmetic average of closing prices for light sweet crude and for natural gas at Henry-Hub on the New York Mercantile Exchange (NYMEX) for the most recent 12 calendar months.

   (b) Weight the average prices for oil and gas calculated in (a) above by specific proportions of oil and gas (in barrels of oil equivalent). The specific proportions you should use are those identified in the most likely development and production scenario you used for the viability test (see Production Report section) in your most recent previous application for royalty relief. For example, if your most likely scenario foresees a development that will produce 80 percent natural gas and 20 percent oil, we weight the average closing prices of natural gas and oil prices for the preceding 12 months by 80 percent and 20 percent, respectively, in calculating the combined price.

   (c) Perform the same calculations in (a) and (b) above, but use the arithmetic average of closing prices for light sweet crude and for natural gas at Henry-Hub on the NYMEX for the 12 calendar-months preceding the date you filed your most recent previous application.

   (d) If the weighted average price calculated under (b) is more than 25 percent less than the weighted average price calculated under (c), you are entitled to a redetermination.

4. Prior to starting construction of the development and production system, you increase your estimate of the eligible development costs for the most likely scenario by at least 20 percent over your corresponding estimate in your most recent previous application. You should fully explain why development costs increased and how you estimated the size of the increase in your application for a redetermination.

Your request for a redetermination needs to include a complete new application in accordance with section F. We will evaluate the request to determine if you're eligible for a redetermination. If you are, we will review the redetermination application in accordance with section G and evaluate it in accordance with section H. Be aware that if you request that we reconsider the size of a royalty suspension volume we granted, you risk losing that volume.

J. Changes in Material Fact (supplements 30 CFR 203.70, 76-77 & 90-91)

We reserve the right to withdraw our approval of or reduce the size of your royalty suspension volume if there is a change in material fact. Withdrawal or reduction of relief serves two relatively modest purposes. One, it replaces more complex "look-back" procedures for correcting errors in our relief assessments that are inevitable in analyses based on forecasts. Two, it fosters applications with reliable information by encouraging you to have done enough delineation and planning so that you are willing to be held to a general approach, schedule, and cost estimate.

We use specific performance conditions to identify whether or not a change in material fact has occurred. We don't expect these performance conditions to be perfect predictors of the entire set of changes that would have reversed results of the original analysis. Many sets of changes could evolve that in combination would alter results or offset each other. However, we believe that the limited, but specific performance conditions that we've selected balance our obligation to protect the public's financial interest with your right to know ahead of time what you must do to keep relief. Our relief approval notice to you will define the specific performance conditions that you must meet in order to retain your royalty relief.

Generally, we will withdraw an approved royalty suspension volume for any one of the following material changes.

1. You change the type of development system from the one you proposed in the approved application. We presume you are sufficiently committed to the proposed system that you are comfortable being bound to it as a condition of relief. A change from that system invalidates the basis on which we determined your need for royalty relief because it indicates that we evaluated the wrong system. It is immaterial whether or not a substituted system, if we evaluated it, would reverse the original approval. The following list of currently distinct systems illustrates possible changes in the type of development system:
   (a) from a dedicated production system to a shared one (e.g., stand-alone platform to tieback);
   (b) from a system with well heads on deck to one with well heads on the seafloor;
   (c) from a fixed platform to a floating production system.

2. You don't start continuous construction of the development and production system described in your application and our approval letter within 18 months of the date we approved your application, notwithstanding any suspensions of operations or production. A longer delay invalidates the basis on which we determined your need for royalty relief because it indicates that the evaluation was done prematurely. Again, it is immaterial whether or not the delay

would reverse the original approval. However, because delays can occur for reasons beyond your control, you may request up to a 6-month extension of this deadline as specified in section N.

Starting of continuous construction means continuous fabrication. Starting and then suspending fabrication of the production facility does not fulfill this performance condition.

To verify that conditions 1 and 2 above have been met, you need to give us evidence of a timely commitment to the approved development and production system in the form of a fabricator's confirmation report.

For a production and development system acquired as a conventional purchase of a newly built facility, this report should include three items:

1) A copy of the contract(s) under which the fabrication yard is building the approved system for you,
2) A letter from the contractor building your system to our Regional Supervisor for Production and Development certifying when continuous construction has started on a specific system, and
3) Evidence that you've paid an appropriate down payment or equivalent manifestation that you've started acquiring the approved development system.

For unconventionally acquired systems (e.g., refitted existing facilities, leased facilities, farmed-in arrangements, etc.) we will specify in the approval letter what equivalent evidence you should give us of timely commitment.

3. (a) You incur actual development costs before commencing production, other than test production, that are less than 80 percent of your estimated pre-production development costs. Your estimate of development costs includes those for the most likely development and production scenario in your approved application as identified in our approval letter. RSVP v2.14 calculates this estimate for you. We use a post-production development report to determine whether your actual capital costs meet this threshold. Pre-production expenditures of less than this share of the costs planned for the most likely scenario invalidates the basis on which we determined your need for royalty relief because it indicates that our evaluation over-weighted a high cost option. You must submit and certify all costs you incur up to start of production, not just enough costs to get above 80 percent of your estimate. That way later adjustments to this cost total, say for disallowed cost items, are least likely to result in a violation of the 80-percent condition. Both estimated and actual figures must cover the period between the application and first production. If your development plans call for a rolling start of production, say as you complete several wells sequentially on the same rig mobilization, we will define start of production as initial production from all wells included in the startup campaign.

   If you inform us of the actual development cost shortfall in the post-production development report, you are entitled to retain part of your royalty relief. Except in cases discussed below where automatic relief (that issued with the lease) is involved, you retain the smaller of one-half of the granted suspension volume or one-half of the most likely production specified in the application. Formerly, the correction for excessively overestimating actual costs was retention of only half of the volume suspension we originally granted. That correction has no real effect when the minimum suspension volume prescribed by the Act more than doubles the field's expected production. Thus, we have changed the way we determine what you retain if you notify us that actual pre-production costs were less than 80 percent of their expected level.

(b) In a redetermination situation, we will withdraw approval of the application if actual development costs turn out to be less than 90 percent of the estimated development costs. You'll not be permitted to retain any of the approved royalty suspension volume. Second chance applications have had the opportunity for additional, more careful delineation and planning, and are therefore expected to incur smaller overestimation cost errors, and are subject to harsher penalties when the violations do occur.

To verify condition 3, you need to give us a post-production development report, including a CPA certification, within 120 days after the start of new production. It certifies the accuracy, completeness and conformity to the detail, as specified at paragraph l. of the Cost Report section, of the information you provide. Our Regional Director for the GOM may extend your due date for up to 30 days. This report should compare actual expenditures, between the date you file your application and the date you start new production, with the comparable estimates from your application's most likely development and production scenario. If your post-production report shows that you violate the cost performance condition in 3. you may keep only part of the relief we gave you.

Our ability to enforce these performance conditions is out of our control in the case of fields that mix leases issued with and without a royalty suspension. No Congressionally mandated automatic relief backstops relief we grant to an expansion project, so we can fully enforce performance conditions in those applications. Eligible lease(s) that participate in a field application keep automatic relief regardless of whether subsequent development violates the application. Unlike eligible leases, RS leases relinquish any automatic relief when they apply successfully for discretionary relief (that approved through application). As explained in the next section, RS leases can reclaim their automatic relief by renouncing discretionary relief. Only the pre-Act lease(s) or post-2000 leases lose all relief for a change of the proposed development system or excess delay in starting fabrication. As for pre-production costs, we require that the pre-Act or post-2000 lease (s) certify all pre-production costs for the field or project. The pre-Act or post-2000 lease(s) keep the right to share relief if this total is at least 80 percent of the application's estimate of these costs. If this total is less than 80 percent of the application estimate, pre-Act or post-2000 leases must pay royalties when field or project production reaches the smaller of one-half the volume suspension we granted to the field or one-half the of the most likely production specified in the application.

If we grant a good cause exception for Eligible lease(s) on the field not to participate in the application, we then hold the pre-Act lease(s) to what it proposed in the application, just as above. The Eligible lease(s) has the automatic suspension volume but is excluded from any relief approved as result of the application, so its performance or lack thereof is immaterial.

We will rescind our approval of your royalty suspension volume and revoke your relief as of the date we approved it if:

(1) You fail to submit the fabricator's confirmation or the post-production development report by the due date,
(2) We discover that you spent less than 80 percent (90 percent in a redetermination) of your estimated development costs and you did not notify us of this fact in your post-production development report, or
(3) We find that you provided false historical information or intentionally inaccurate data that was material to our granting royalty relief.

You owe royalties and late payment interest determined according to 30 U.S.C. 1721 and 30 CFR 218.54 on all production on which you have not paid royalty. You also may be subject to penalties under other provisions of the law.

When we withdraw your previously approved royalty suspension volume for reasons other than that you submitted false information or intentionally inaccurate data, you may initiate a new application for a suspension volume. We review and evaluate the new application in accordance with sections G and H above.

K. Renounce Relief (supplements 30 CFR 203.77)

The option to renounce relief after we have awarded it may seem unnecessary. But, that option provides an escape process should you the applicant find that emerging conditions make you better off had you never applied for royalty relief in the first place. In other words, the renounce provision is a subtle form of insurance associated with supplemental royalty relief. This section identifies some of the circumstances when you may benefit from exercising the option to renounce already approve royalty relief.

Under provisions of section 203.69, the relief we grant to a development project applies only to the project wells covered by the application. Further, it replaces any royalty suspension volume with which we issued the participating leases. This later stipulation prevents lessees from doubling up on royalty suspension by applying discretionary relief to reservoirs identified in their application and automatic relief to other reservoirs on their lease. After a successful application, you may choose to renounce the discretionary relief and reclaim the automatic relief if the reservoirs in the application prove unable to use much royalty suspension. Or you may want to do the same if you subsequently find that reservoirs outside the application are more attractive to develop. For example, say your lease has automatic relief of 7 MMBOE and we approve relief of 12 MMBOE for a development project for reservoir A. Then after further drilling and analysis, your decide reservoir A will only produce 4 MMBOE. You may renounce the relief of 12 MMBOE, produce the 4 from reservoir A and reclaim 3 (7 – 4) MMBOE for use on reservoir B, which was not included in the application. You may not transfer 8 (12 – 4) MMBOE to reservoir

B. Likewise, by renouncing relief you may bring reservoir B into production before reservoir A and claim royalty suspension of up to 7 MMBOE on production from B.

Also, after a successful application you may find or decide you will violate a performance condition we set as a prerequisite for realizing approved royalty relief. While you may normally re-apply even if we withdraw your relief, you may find it advantageous not to wait for the formal withdrawal. This is because we treat already incurred development costs as sunk costs in the subsequent analysis. To minimize the conversion of costs from prospective to sunk, thereby reducing the amount of costs we consider in determining your need for royalty relief, you may renounce relief and accelerate reapplication. Also, you may wish to renounce discretionary relief and reclaim automatic relief if development costs turn out to be well below what you expected, you change from the development system proposed in your successful application, or you do not start fabrication in time on that development system. In the example above, if you spend less than 80 percent of the level anticipated in your application, your discretionary relief would be halved to 6 MMBOE while renouncing that relief would restore your 7 MMBOE automatic relief.

Renouncing relief is essentially equivalent to returning to the state that existed before you filed a royalty relief application. That means, for instance, that only 1 of 2 leases in an approved application cannot renounce relief. Either both or neither may renounce relief. You need to exercise the option to return to automatic relief volumes before those amounts have been produced, to avoid owing back royalties plus interest.

L. Volume Suspensions and Allocations (supplements 30 CFR 203.69 & 71)

This section explains how we apply the royalty suspension volumes in section 302 of the DWRRA to production from your pre-Act lease or to your post-2000 lease. For purposes of this section, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter don't count against royalty suspension volumes. Also, for purposes of this section, production includes volumes allocated to your lease under an approved unit agreement. Test production that is normally royalty bearing does pay royalties but does not count against the suspension volume. The following provisions apply only to those leases that have applied for and received a royalty suspension volume under section 302 of the DWRRA.

Minimum Suspension Volumes: A minimum royalty suspension volume is mandated for all Authorized fields that qualify for royalty relief. We determine the water depth of a field by the water depth delineations in the version of the Lease Terms and Economic Conditions Map and the FNML that are current at the time of your application. If your application for the field includes leases in different water depth categories, we apply the minimum royalty suspension volume associated with the deepest lease. The minimum royalty suspension volumes are:

(a) 17.5 MMBOE for fields in 200 to 400 meters of water;
(b) 52.5 MMBOE for fields in 400 to 800 meters of water; and
(c) 87.5 MMBOE for fields in more than 800 meters of water.

Requirements of the DWRRA, which mandated specific royalty suspensions for eligible leases (those issued between 1996 and 2000 in deep water in the Gulf of Mexico), do not apply to leases issued subsequently. Royalty suspensions offered on RS leases are subject to the regulations in 30 CFR Part 260. Royalty relief provisions on RS leases are now announced in the notice of sale, and are subject to revision with each sale.

We set a variable minimum royalty suspension volume for development projects and for expansion projects as follows. We add an increment of royalty-free production to the base royalty suspension volume with which a qualifying project starts the application process. The base royalty suspension for the project is the sum of the automatic royalty suspension volumes already available to active participating leases. (If we issued your lease with a royalty suspension for a value or period, the base royalty suspension is the volume equivalent based on the data in your approved application for other forms of royalty suspension.) Active participating leases are ones that have or plan to drill into a reservoir identified in the application. If one or more of the active participating leases have used up some or all of their automatic volumes, the minimum suspension volume for a development project is reduced by the amount of the already used royalty relief on that lease. The increment we add to this base is10 percent of the median resource size upon which we based approval of your application. Since the distribution of reserves tends to be skewed, we consider the median or midpoint of the resource distribution, as found by RSVP, to be the most representative measure of the resource size. The RSVP median is based on inputs from your application as we may have adjusted them and explained to you during our evaluation.

For instance, consider a development project that has a median resource size of 60 MMBOE, so there is a 50 percent chance that the actual resource size is above 60 MMBOE and a 50 percent chance that it is below this median level. If the project qualifies for relief and is located on two RS leases each of which we issued with a royalty suspension volume of 9 MMBOE, it will get a royalty suspension increment of 6 MMBOE added to the previous automatic royalty suspension volume of 18 MMBOE. That makes the discretionary royalty suspension volume equal to at least 24 MMBOE. If one of those 2 RS leases neither has nor proposes to drill a well as part of the project, perhaps because they expect to be allocated production from the other lease, then the minimum royalty suspension volume for the project would be (9 + 6 =) 15 MMBOE. Further, if drilling proposed on one of the project's leases ultimately is not undertaken, we will reduce the suspension volume originally awarded to the project. In the approval letter we will note this condition and indicate what the reduced size of the relief will be if it is not met. We will determine what that reduced size is by estimating the volume suspension needed by a project that does not incur the cost of that phantom proposed well, subject to the minimum based on the lease that does have a well. An expansion project targeting a resource size of 60 MMBOE would get at least 6 MMBOE of royalty suspension for a successful application.

Termination of royalty suspension volumes - Your royalty suspension will continue until the end of the month in which the cumulative production from the applicable leases in the field or project reaches the approved royalty suspension volume. We intend to provide monthly field or project production data to participating lessees who request it when their field or project has almost produced its suspension volume. However, these data may become available only after field or project production has exceeded the royalty suspension volume. Nonetheless, you still owe royalties beginning on the first day of the first month following the month in which cumulative production reaches the royalty suspension volume. Any royalties paid late will be subject to interest pursuant to 30 CFR 218.54.

Field Allocation Rules: Fields in deep water may consist of one or more types of lease, including leases issued before November 28, 1995, between November 28, 1995 and November 28, 2000, and after November 28, 2000. Also, fields may consist of leases that are either producing or nonproducing. We follow certain general principles to ensure that royalty relief adheres to the provisions of the DWRRA. These principles are described below.

1. Leases on a field that produced from any current lease before November 28, 1995 are not entitled to a volume suspension based on an eligible lease or an application by an authorized field (field-based royalty suspension). However, any RS lease on that field does get the volume suspension with which we issued it. Also, a pre-Act or post-2000 lease on the field may still apply for expansion project relief.

2. All leases on a field at the time of an application must participate in the application. If a lease chooses not to participate, the others must show good cause for us to evaluate the application covering only part of the field. If we approve field-based relief in this situation, the lease that declined to participate will not share in any of the relief we grant. If the declining lease is an eligible or RS lease, its royalty free production will still count toward the field's royalty suspension volume.

3. A field is entitled to at most one field-based royalty suspension volume. Once we establish that field's royalty suspension volume, the simple addition of pre-Act, eligible, or post-2000 leases to the field won't change the total royalty suspension volume available to that field. This is the case even if the royalty suspension volumes associated with any of the new leases exceed the authorized royalty suspension volume on the field. Such a situation could occur if the field overlaps the 400 or 800 meter contours and an eligible lease is added to the field in the deeper water category after an eligible lease in the shallower water category began production on the field. Also, it could occur if a pre-Act lease added to the field lies in deeper water depth category than the leases included in the field when we approved the royalty suspension volume. RS leases get their full automatic royalty suspension volume, even if we assign them to a field that has finished producing all of its field-based royalty suspension volume. But the RS lease's royalty-free production counts against the field's royalty suspension volume, for as long as any field royalty suspension volume remains.

4. A field with an authorized royalty suspension volume as a result of establishment of relief from an eligible lease may have its relief amount increased. This would happen if we grant a royalty suspension volume to a pre-Act lease on the field that exceeds the established amount of relief on the field. In this case, all pre-Act, eligible, and post-2000 leases approved for royalty relief would then share in the newly determined higher royalty suspension volume for the field.

5. Pre-Act leases never automatically share in the relief established on the field by eligible leases. They need to apply for and be granted relief in order to share in the authorized relief. Post-2000 leases do not share in such field-based royalty suspension volume, but their royalty-free production counts against any remaining royalty suspension volume for the field.

6. Pre-Act or post-2000 leases simply added to a field with an established royalty suspension volume may share in that relief only if the field's authorized relief resulted from an approved application that grants relief on a pre-Act lease. To claim the right to share in relief, the added lease should file the short form application described in sections F.

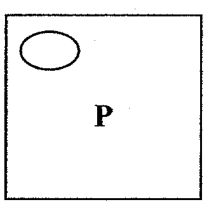
7. All of the pre-Act, eligible, and post-2000 leases on a field with an approved royalty suspension volume may share in any remaining royalty relief authorized for the field. The amounts shared by post-2000 leases will be counted against any royalty suspension volumes issued with these leases. However, such leases may share the field's approved suspension volume in an amount that exceeds the royalty suspension volume with which we issued the RS lease.

8. The addition of a lease to an expansion or development project to which we have granted a royalty suspension volume does not change the project's royalty suspension volume.

9. We may grant a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes west longitude. A field that lies on both sides of this meridian receives a royalty suspension volume only for those leases lying entirely west of the meridian.

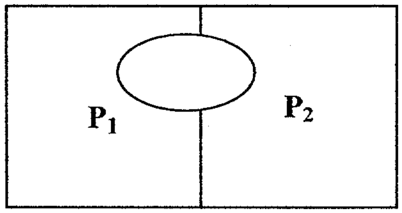
The following cases illustrate how we apply these principles to determine how much royalty suspension volume is available to a field and to distribute, subject to applicable price threshold conditions, this volume among the pre-Act (P), eligible (E), post-2000 RS (R), and post-2000 non-RS (N) leases on the field. Squares represent lease blocks, ovals represent fields, and parallelograms represent projects in the following schematics.

Case 1



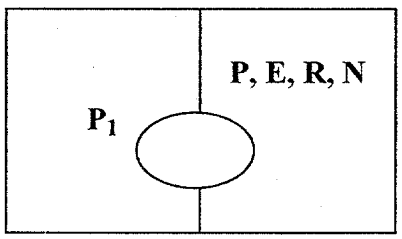
If your field consists of a single pre-Act lease and we approve your application for royalty relief, you owe no royalty payment on production from the lease up to the royalty suspension volume we granted.

Case 2



If your field consists of more than one pre-Act lease and we approve your application for relief, all such pre-Act leases owe no royalty payment until their cumulative production equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) until cumulative production equals your field's suspension volume.

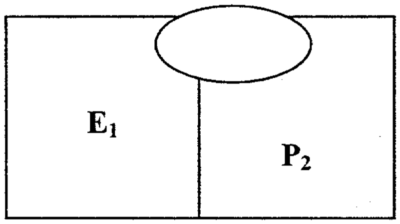
Case 3



If we add your pre-Act lease, eligible lease, or post-2000 to a field that has a royalty suspension volume as a result of an approval of an application from one or more pre-Act leases, the field's royalty suspension volume won't change, even if your added lease is in deeper water. Your added lease may receive a royalty suspension volume only to the extent of its production before the cumulative production from the field equals its approved royalty suspension volume. In this case, a royalty suspension volume for an RS lease is not necessarily limited to the suspension volume in the lease document. Also, an RS lease gets to produce royalty free the full suspension volume with which we issued it even if cumulative production exceeds the approved royalty suspension volume for the field.

The rule doesn't require that your added pre-Act or post-2000 lease submit the full application that the original applicants did. A full application isn't necessary because we've already evaluated the field and see no need to reevaluate that determination. Accordingly, your added pre-Act or post-2000 lease can apply for relief by filing the Administrative Information report (see Section F of these guidelines) with the GOM Regional Office.

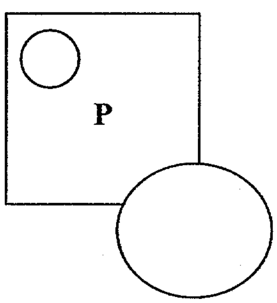
Case 4.



If your pre-Act lease is part of a field that has a royalty suspension volume for eligible leases under 30 CFR 260.110, you cannot share in this relief unless you file and we approve a joint application pursuant to 30 CFR 203.60 and 62-63 and section F.

A post-2000 lease on the field at the time must be part of the application to share the field-based volume suspension in excess of the amount provided in its lease terms. We will waive the joint application requirement if you show good cause for the waiver, but will include the value of the existing relief in our evaluation of your application for the additional relief. If your application meets the economic viability and profitability tests, all of the leases share the single new royalty suspension volume until total cumulative production from the field attains that royalty suspension volume.

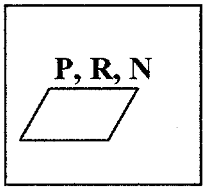
Case 5



Your lease may receive more than one royalty suspension volume. You may get a suspension volume under this rule for each field that includes your pre-Act lease and that meets the evaluation criteria described under section H. Also, you may apply for additional relief for a project to significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project. However, your expansion project should anticipate recovering reserves that we didn't consider in making our original determination. Unlike a redetermination for larger relief, applications for relief for significant expansions don't risk loss of any unused part of the earlier relief.

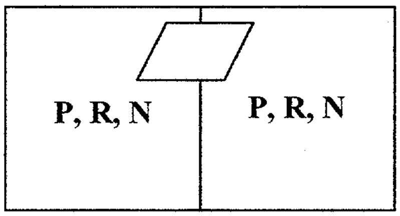
For a development or an expansion project that qualifies for a royalty suspension volume, the rule applies as follows:

Case 6



If your pre-Act or post-2000 lease is the only lease in the project and we approve your application based on significant expansion of production, you owe no royalty payment on the incremental production from the project until that production equals the royalty suspension volume we granted.

Case 7



If your development or expansion project includes more than one lease and your application is approved, no lease owes royalties on incremental production from the project until the cumulative production from the project equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) from the project until cumulative production equals the project's suspension volume. Unused suspension volume granted to the project may not be applied to production from the project's leases that were not included in the application for relief.

M. Audits (supplements 30 CFR 203.89 & 91)

We may conclude that an audit is necessary to evaluate an initial application or a redetermination. This conclusion is most likely for applications that have large sunk costs and small estimated losses under the economic determination. If this contingency should occur, we may request that the 180 or 150-day evaluation period be tolled from the time you receive notice until you provide all the records and pay the prescribed fee necessary to conduct the audit. All terms of the relief contract are subject to audit. See 30 CFR 203.81 or the Cost Report, paragraph m. for certification requirements.

Your post-production development report is also subject to audit. We may use such audits to help confirm that a change in material fact (see section J above) has occurred, as well as to determine the applicability of any possible penalties.

N. Appeals (supplements 30 CFR 203.79)

You may appeal three decisions that bear on our relief determinations and redeterminations under 30 CFR 203.79. These decisions are -- our field designations, whether to extend fabrication deadlines that you must meet to keep relief, and our judgments on your eligibility for relief or on the appropriate size of your royalty suspension volume.

We use a staged consultation process for designating a lease as part of a field. As explained in section D, our GOM Regional office will contact affected lessees and offer them a chance to review and discuss the proposed designation before finalizing a new field designation or a change to an existing one. Our Regional office's final lease designation on a field may be appealed to the Director, MMS, in the same manner bid rejections are appealed. You should file a written request for this administrative review within 15 days of our notifying you of such designation. The Director's response to this request, either affirming or reversing the earlier decision, cannot be appealed further within the Department of the Interior.

You may file a written request with the Director, MMS for an extension if you are unable to comply with the performance condition specified in section J 2 above for reasons beyond your control (e.g., strike at the fabrication yard or weather caused delays in construction). We may grant an extension of up to six months to comply. Again, the Director's decision on this request is the final decision of the Department.

Except as explained above, our relief determinations and redeterminations are final agency actions. You are not entitled to further administrative review, including review by the Secretary of the Interior. Like all final agency actions, our decisions are judicially reviewable under Section 10(a) of the Administrative Procedures Act (5 U.S.C. 702). You must file your request for judicial review of our determination or redetermination under 43 U.S.C. 1337 (a)(3)(*C*) within 30 days of our decision.

O. Other Issues (supplements 30 CFR 203.73 & 78)

Gas-to-oil conversion factor - Your royalty suspension volume is measured in barrels of oil equivalent (BOE). For the purposes of this rule, 5.62 thousand cubic feet of natural gas equals one BOE. We measure natural gas in accordance with 30 CFR 250, Subpart L. We have traditionally used this conversion factor in the GOM and it is the same ratio used in 30 CFR 260.116 for calculating royalty suspension volumes for Eligible leases.

Non-royalty bearing production - We don't count any lease-use production that otherwise isn't subject to royalty toward the royalty suspension volume.

Price thresholds - Section 302 of the DWRRA directs us to retract royalty relief during periods when prices are very high. We continue the practice for post-2000 leases, but at a different price threshold level. Current price threshold information can be found on our website at: http://www.mms.gov/econ.

1. We retract royalty relief on the oil portion of production from pre-Act and certain eligible leases (refer to your lease document) when oil prices are too high. Oil prices are too high when the arithmetic average of daily closing prices during a calendar year on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, escalated as in paragraph 3 below. We retract royalty relief on the oil portion of post-2000 lease production if the NYMEX light sweet crude oil price exceeds the level we specify in the notice of sale when we issued your lease. In both cases, we average the daily NYMEX closing prices quoted for the next nearest delivery month. For

instance, the average reported for July is typically the closing prices for August delivery for July 1 – 25 and for September delivery for July 26 – 31. You can determine the average oil price and inflation rate only after the end of the year, so a finding that price thresholds have been exceeded applies to royalties on the previous year's oil production.

a) You owe royalties at the lease stipulated royalty rate on your previous years' production of oil from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest within 90 days of the end of the period specified for the average price calculation. When this period is specified as the previous calendar year, as it is for pre-Act and certain eligible leases, this payment is due by March 31 of the current calendar year. For post-2000 leases, this payment is due by the date specified in your notice of sale. Payment should be made in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of oil from the previous year for which you did not pay royalty.

b) For pre-Act and post-2000 leases, you also owe royalties on all your oil production in the current calendar year. However, you may seek a refund or credit with interest the oil royalties that otherwise would be suspended for your pre-Act lease if prices fall enough. Specifically, the arithmetic average of the current calendar year's closing oil prices on the NYMEX must be $28.00 per barrel or less, escalated as in paragraph 3 below. Likewise, you may seek a refund oil royalties paid by your post-2000 lease that has royalty relief if the NYMEX light sweet crude oil price is below the level specified in your lease document.

2. We also retract royalty relief on the natural gas portion of production from pre-Act and certain eligible leases (refer to your lease document) when gas prices are too high. Gas prices are too high if the arithmetic average of daily closing prices on the NYMEX for natural gas at Henry-Hub in the previous calendar year exceeds $3.50 per million British thermal units (Btu), escalated as in subparagraph 3 below. We retract royalty relief on the natural gas portion of your post-2000 lease production if the NYMEX gas price exceeds the level we specify in the notice of sale when we issued your lease. In both cases, we average the daily NYMEX closing prices quoted for the next nearest delivery month.

a) You owe royalties at the lease stipulated royalty rate on your previous year's production of natural gas from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest within 90 days of the end of the period specified for the average price calculation. When this period is specified as the previous calendar year, as it is for pre-Act and certain eligible leases, this payment is due by March 31 of the current calendar year. For post-2000 leases, this payment is due by the date specified in your notice of sale. Payment should be made in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of natural gas from the previous year for which you did not pay royalty.

b) For pre-Act and Post 2000 leases, you also owe royalties on all your natural gas production in the current calendar year. However, you may seek a refund or credit with interest the natural gas royalties that otherwise would be suspended for your pre-Act lease if prices fall enough.

Specifically, the current calendar year's arithmetic average of the closing prices on the NYMEX for natural gas at Henry-Hub must be $3.50 per million BTU or less, as adjusted in paragraph 3 below. Likewise, you may seek a refund natural gas royalties paid by your post-2000 lease that has royalty relief if the NYMEX natural gas price is below the level specified in your lease document.

3. We escalate the prices referred to in paragraphs 1 and 2 above for pre-Act and certain eligible leases for each calendar year after 1994 by the percentage by which the implicit price deflator for the gross domestic product has changed since 1994. For post-2000 leases, we escalate prices from other base years, as specified in your notice of sale and lease document.

Administrative Report
(supplements 30 CFR 203.83)

a. General

You use this report to identify your field or project and to summarize its background and what relief you seek. You or your authorized representative should certify that all the information submitted in an application or post-production development report is accurate, complete, and that the presentation of data and information conforms to our guidelines. All the non-historical eligible costs you claim should be either direct or allocable indirect costs for the field or project. You should certify, either by independent review or company official, that all these costs are relevant to the field in question and that only those costs necessary for the proper operation of the field operations have been included.

b. Format

This report should be a hard copy text, with separate numbered paragraphs for each of the boxes in the following table. Any attachments, such as for paragraph 4 should immediately follow the relevant paragraph. You should mark any data or information you consider to be proprietary.

Administrative Information
Field Name
Serial number of leases in the field, names of the title holders of record, the lease operators, and the identification of whether the field/lease is part of a unit
Lessee's well designation, the API number, location, spud date, and status of each well that has been drilled on the field/lease or project; identify the discovery well
Location of any new wells proposed under the terms of the request
Description of field/project/lease history including royalty rate(s) and water depth
Full information as to whether royalties or payment out of production will be paid to anyone other than the United States, the amount to be paid, and the amount of reduction in such payment if relief is granted
Your opinion as to the amount of relief needed to make the field or project economic.[1]
For an Expansion project, confirmation that a DOCD or supplemental DOCD has been approved
A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the affect on production
Management certification (30 CFR 203.81(b)) that all information in the application is accurate, complete, and conforms to the guidelines. This certification can be included in the application transmittal letter.

[1] If you have relief and seek more, we ask that this opinion be supplemented with a certification that you are voluntarily relinquishing any previous relief.

Economic Viability & Relief Justification Report
(supplements 30 CFR 203.85)

a. General

You use this report to show that your development would be viable (have a positive before tax net present value or NPV) without paying royalties when using our RSVP model and the economic inputs we supply. Costs you incur before the date of application are not relevant for this report. You are not to use ineligible costs as defined in the Cost Report section in this DCF analysis either. Attachment E explains how to get the RSVP model along with documentation.

You may use your own model in addition to ours if you can justify why our model doesn't adequately represent your situation. However, we reserve the right to use our model in the evaluation and subsequent determination.

b. Economic Assumptions

Under the regulations, you must use the economic assumptions listed and discussed below. You should justify all your other inputs with the G&G, Engineering, Production, and Costs Reports discussed elsewhere in these guidelines.

We may update these economic assumptions on a quarterly basis. It is your responsibility to revise the cell entries and the Crystal Ball input windows in the RSVP area labeled "Oil Price and Gas Price Input". Current values for the following assumptions are listed on our website at www.mms.gov/econ/update.

Starting Prices - The RSVP model selects starting oil and gas prices for each trial from triangular distributions with the parameters shown above. We determine these prices using the Refiner Acquisition Cost for imported crude in the Petroleum Administration for Defense District (PADD) III (compiled by the DOE/EIA) and the landed natural gas price represented by the NYMEX Henry Hub price for the next delivery month. The starting oil prices are independent random variables. The starting gas prices are dependent on the starting oil prices with a +1 correlation factor.

Price Adjustments - Starting oil prices apply to 30° API gravity crude oil. Starting gas prices apply to 1,028 Btus per cubic foot of gas. You should certify the existence and specify the size of any gravity differences or Btu content differences between the expected product of your field or project and these standards. You may specify these quality differences as distributions.

The RSVP model computes oil quality adjustments from the 30° API basis, using the following table. Note these adjustments may differ from those used by EIA and other sources.

Oil Price Quality Adjustment Table

API Gravity	Price Adjustment	API Gravity	Price Adjustment
65	($2.13)	41	$0.87
50.8	$0.00	35	$0.75
50	$0.12	30	$0.00
45	$0.87	0	($4.50)

The model interpolates the price adjustment it uses for gravity values between those in the table. For example, if the model samples your crude oil gravity on a trial as 37.6, then it linearly interpolates between price adjustment values $0.75 and $0.87 using the following equation:

$$[((37.6 - 35)/(41 - 35)) * (0.87 - 0.75)] + 0.75 = \$0.802$$

The model would then increase whatever starting oil price it picked on that trial by $0.802.

The RSVP model also increases or decreases the starting gas price when you specify a Btu content that is different than the standard of 1,028 Btu per cubic foot of gas. The size of the adjustment depends on the price and hydrocarbon content sampled on each trial. For example, if the model picks a Btu content of 950 Btu/mcf together with a starting gas price of $2.00/mcf, it adjusts the starting gas price actually used on that trial by the ratio of trial-specific Btu content to the standard BTU content (950/1,028). The resulting starting gas price used on this trial would be $1.85, i.e., $2.00 * (950/1,028).

Real Price Growth Rates - We base these annual rates primarily on long-term oil and gas price projections inherent in the three world price scenarios published in the DOE/EIA Annual Energy Outlook. When we believe it is appropriate, we adjust by projections from other major forecasters. We may use decline rates (negative growth rates). The growth rate for the real gas price in the first period (RIGP1) has a direct dependency on the growth rate for the real oil price in period 1 (RIOP1). The growth rate for the real oil price in period 2 (RIOP2) has a direct dependency on RIOP1, and RIGP2 has a direct dependency on RIOP2.

Real Cost Growth or Decline Rates - We may use an annual rate to represent an expected change in costs. This change may be partially related to the expected price changes. Cost growth rates are generally some fraction of the price growth rates. Decline rates may also be employed.

Year Scenario Starts - The year the first, second, and third economic scenarios commence.

Discount Rate Range - A range of risk-free annual, real before-tax rates from which you choose a value for us to use for the profitability test DCF analyses. The value you use for the viability test performed in connection with the application is the bottom of this range.

Tax Rate - The federal income tax rate we use for determining after-tax sunk costs.

Random Number Seed - We specify an arbitrary seed value to start the random number generator in the model. We do this to allow for output reproducibility.

Overhead Cost Allowance - We specify a modest overhead allowance rate that you may use for Labor, Material, Abandonment and Other Costs categories for joint cost items which you are unable to clearly allocate to your field.

c. Cash Flow

You should provide your output from running our RSVP model. If you use your own model as well, at least provide the following information:

1. discount rate you use,
2. annual oil and gas production,
3. annual oil and gas revenue,
4. total gross revenue,
5. oil and gas transportation costs,
6. operating costs,
7. capital expenditures,
8. total net revenue,
9. before-tax cash flow without royalties, overrides, sunk costs, and ineligible costs.
10. the before-tax NPV your model calculates or implies.

You should show that all costs, gross production, capital costs, and scheduling are compatible with the data you provide in the G&G, engineering, production, and cost reports.

d. Format

You should provide the input data in the RSVP model format specified in its documentation on a 3.5-inch diskette. You should also give us a hard copy of your output results in the RSVP model format to ensure the results we obtain are the same. You should mark on the hard copy as well as electronic files any data or information that you consider proprietary.

e. Check list Table

The table below is provided for quick reference.

Deep Water Royalty Relief Economic Viability Report	
Economic Assumptions (Provided by MMS)	- Starting oil and gas prices - Real price growth - Real cost growth or decline rate, if any - Base year - Range of discount rates - Tax rate (for use in determining after-tax sunk costs)
Price Adjustment	- Quality adjustments for gravity, Btu content
Projected Cash Flow Analysis as of Application Date Using Annual Totals and Constant Dollar Values	- All costs, gross production, and scheduling should be consistent with the data in the G&G, engineering, production, and cost reports - The up to three development and production scenarios (conservative, most likely, and optimistic) you provide in the various reports should be consistent with each other and your proposed development system - Oil/gas production - Total revenues - Capital expenditures - Operating costs - Transportation costs - Before-tax net cash flow
Discounted Values	- Discount rate that you select from within the range we prescribe - Show before-tax NPV without royalties, overrides, sunk costs, and ineligible costs

Geologic and Geophysical Report
(supplements 30 CFR 203.86)

a. General

You use this report to describe the resources in the field you propose to develop. A number of definitions exist for resources and reserves. In this country, the definitions standardized by the Society of Petroleum Evaluation Engineers (SPEE) are the most common. SPEE figures for proved reserves are generally conservative, despite the inclusion of established improved recovery methods, thus contributing to a large reserve growth. DOE has estimated this growth can be as large as eight times the initial figure. In order to minimize the effects of this conservatism and to provide an analysis that considers the uncertainties involved, we don't mandate a specific definition of resources and reserves. Rather, the model has you list the specific reservoirs you've found along with their attendant risk of occurrence and provide distributions for certain characteristics for each reservoir.

b. Detailed Data

You should provide seismic data, well data, and map interpretations as listed in the table under paragraph g below.

c. Reservoir Data

You develop the resource and reserve distributions for your field using the resource module of our RSVP model. The resource module uses two kinds of estimates that you provide to develop this standardized calculation of the reserves and resources.

One, you should submit probability estimates for the chance of hydrocarbon occurrence (constant) as well as the chance that it is all oil or all gas for each reservoir that will be included in the viability and suspension analysis. If a reservoir in your application is penetrated by a well, then the chance of hydrocarbon occurrence is 100 percent. Since your application is predicated on a discovery well, at least one reservoir always has a 100 percent chance of hydrocarbon occurrence. Any risk that a well will not produce due to mechanical problems should be included in your cost report with an appropriate input to RSVP as an estimate for remedial action. An explanation and justification of your risk assumption and estimated cost of remedial action is required.

Two, in order to assist in our data validation, you should also provide probability distributions for acres, net thickness, gas-oil ratio or yield, and oil and gas recoveries per acre-foot for each reservoir. You may use any of the distributions available with our RSVP v2.1 model, but you should carefully defend a choice other than a triangular distribution. You should submit maps showing the aerial extent of each reservoir for the minimum, most likely, and maximum cases. Where delineation with drilling or seismic data has eliminated your uncertainty about the size of any of these characteristics, you may substitute point estimates for distributions. However, you should explain why other values have no chance of occurrence, if you use point estimates in lieu of distributions.

Also, you must specify the degree of dependency, if any, among the expectations for individual reservoirs and defend the correlation between those reservoirs.

d. Aggregation

The resource module combines reservoir estimates into a resource distribution for your field or project. The aggregation model uses a random number generator to determine reservoir existence on a specific trial. On each trial where an individual reservoir is found to exist, the module samples the distributions of its characteristics and computes a resource size. Those reservoirs found to exist are then aggregated to get the resource estimate for that trial.

The outputs from this module, which on each trial are represented by a field BOE value with an attendant oil percentage, become the inputs to the viability module of the RSVP model. Thus, the resource module is incorporated into the RSVP model to provide trial specific inputs throughout the economic viability simulation analysis.

Attachment E explains how you can get the RSVP v2.14 model template that you and we use to aggregate this data into estimates of resources and reserves for the purposes of royalty relief evaluation.

e. Consistency

The development system you choose, as well as prospective costs and production profiles are all interrelated and tied to the resource and reserve level. You may specify up to three scenarios (conservative, most likely, and optimistic) to portray scales, costs and production profiles appropriate to different parts of your field's resource distribution. As we explain for the other reports necessary for a complete application, you should develop an internally consistent development schedule, cost schedule, and production profile for each scenario that you submit. Also, you should tie each scenario to a specific range on the resource (BOE) distribution. Provide careful justification for the break points between the scenario ranges that you pick.

f. Format

Our letter to lessees of October 1, 1990 describes the format you are to use for digital velocity surveys. You may submit the rest of the detailed G&G data as described in the table under paragraph g. or, if not indicated otherwise, in the format of any state-of-the-art processing technique that is readable by our GOM Regional office. The distributions put out by the RSVP model will satisfy your requirements under 30 CFR 203.86 (d) or paragraph c above. You should provide additional explanation if you substitute point estimates for distributions for any of the data specified in this section.

You should mark on hard copy as well as electronic files any data or information you consider to be proprietary. See Attachment D for a schematic of the format of the RSVP v2.1 model template.

g. Check list Table

The table below is provided for quick reference.

Geologic and Geophysical Report	
Seismic Data	- Non-interpreted 2D or 3D survey lines (8mm tape) (SEGY format or IES format) - Interpreted 2D or 3D seismic survey lines identifying all known and prospective pay horizons, wells, and fault cuts - Digital velocity surveys - Plat map of "shot points" - "Horizon slices" of potential horizons
Well Data	- Hard copies of all well logs 1" electric log should show: = pay zones and pay counts, = lithologic and paleo correlation markers at least every 500 ft. 1" type log should show: = missing sections from other logs where faulting occurs 5" electric log should show: = pay zones and pay counts and = labeled points used in establishing Ro and Rt 5" porosity logs should 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 - Digital copies of all well logs spudded before December 1, 1995 in either LAS or LIS format - Core data, if available - Well correlation sections - Pressure data, including the maximum shut-in pressure at the wellhead - Production test results - PVT analysis, if available - Summary table of wells indicating which sands and fault blocks will be targeted for completion/recompletion

Map Interpretations	For each reservoir included in the application: - Structure maps, top and base of sand maps showing well and seismic shot point locations - Maps for min, max, and most likely aerial extent of each reservoir - Isopach maps for net sand, net oil, net gas, all with well locations - Maps indicating well surface and bottom hole locations, location of development facilities, and shotpoints - Identification of reservoirs not contemplated for development and justification for preclusion of these reservoirs
Reservoir Data	For each reservoir included in the application: - Probability of reservoir occurrence with hydrocarbons and an explanation of how you determined each chance of occurrence that is less than 100 percent - Probability the hydrocarbon in the reservoir is all oil, and the probability it is all gas - Distributions or point estimates for the parameters used to estimate the reservoir size i.e., acre, net thickness, etc. - Most likely values for porosity, salt water saturation, oil and/or gas volume formation volume factor, and recovery factors (%) - Distributions for oil and/or gas recovery per acre-foot with an explanation or example of how the minimum and maximum values were calculated for each unique calculation - Gas/oil ratio distribution or point estimates for each oil reservoir. - Yield distribution or point estimates for each gas reservoir
Reserves and Resources Data	- Reservoir simulation report, if available - Aggregated BOE reserve and resource distributions for the field or project. - Description of anticipated crude quality (e.g., gravity). - Break points on the aggregated reserve/resource distribution showing the portion of the range over which to use each of the up to three (conservative, most likely, and/or optimistic) production profiles specified in the production report.

Engineering Report
(supplements 30 CFR 203.87)

a. General

You use this report to elaborate on the design of the production facilities you need to develop this field or project. We take your submission of such a design as evidence of your belief that the field or project merits development and qualifies for royalty relief. The development scenarios and timing assumptions you submit in your royalty relief application should be consistent with any and all documents previously filed for activities on your lease. You should describe alternative development options that were considered but not chosen along with the reason for non-selection. You should fully explain the rationale for your choice of the selected approach and show why it is the most economical (least-cost) one. If a different system would be more economical without royalty relief, you should indicate where and how it differs from what you proposed. You should also show that development and production of all of the project's recoverable resource were reasonably considered in the formulation of the selected approach.

b. Development Concept

You should provide us with a complete description of the type, size, and location of the system you intend to use along with a schedule for its construction.

c. Planned Wells

You should tell us the number of wells you intend to drill, their measured depths, and their type (platform, subsea, vertical deviated, horizontal) as well as your drilling schedule (number and type by year). Also, you should tell us the intended type for each completion, the intended reservoir for each completion, and your schedule (number of completions by year).

d. Production System Equipment

The production schedule is a very sensitive component of net present value. In the event that the actual production rate exceeds your initial planned rate, we need to know the limiting component(s). You should tell us the production system capacity for oil and gas. Also, you should tell us the number, size, length, and location of any and all flow lines tying together subsea wells and or subsea structures with the producing facility.

e. Multi-phase Development Plans

In some cases, you may intend to develop a field in several phases as opposed to entirely at once. We may or may not agree with such an intention due to considerations such as resource conservation, diligence, technical capability, etc. If you submit a multi-phase plan, you should describe the conceptual basis for developing in phases as well as the goals and milestones you require to continue with subsequent phases.

f. Uncertainty

We are referring to your uncertainty about the size of the actual reserve and resource and thus the attendant number of wells, initial production rates, decline rates, etc., not any uncertainty about the type of development concept you'll use. You may provide up to three schedules of development (conservative, likely, optimistic). A schedule of development includes the development system construction schedule, drilling schedule, completion schedule, and the production system installation schedule. Make each one consistent with its counterpart production profile (conservative, likely, optimistic) you provide in the Production and Cost reports. If you submit fewer than three distinct scenarios, you should explain why other development scales or schedules are not efficient for part of the possible range of resource size.

g. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment E for the RSVP v2.14 model format. We prefer that you provide the data described in paragraphs a, b, c, d, and e. in hard copy text with separate lettered divisions for each of the applicable sections of this report.

h. Check list Table

The table below is provided for quick reference.

Engineering Report	
Development Concept	- Description of the proposed development concept (fixed, floater, subsea tieback, etc.) including basic design specifications. - Description of alternative development options along with the reasons for non-selection. - Construction and installation schedule.
Planned Wells	- Number of wells planned - Type of well (platform, subsea, vertical, deviated, horizontal) - Well depth - Drilling schedule - Completion description: normal, dual, horizontal, etc. - Completion schedule

Production System Equipment	- General process description including the production capacity for oil and gas and a description of the limiting component - Surface facilities - Subsea structures - Flowlines and umbilicals - Production system construction and installation - Special problems such as hydrates, paraffin, sand, etc.
Multi-phase Development Plans	- Conceptual basis for developing in phases and goals/milestones required for commencing subsequent phase
Uncertainty	- Schedules of development consistent with each of the up to three field production profiles (conservative, likely, optimistic) provided in the production report

Production Report
(supplements 30 CFR 203.88)

a. General

You use this report to justify the future flow rates that you expect for wells from your field or project. You should explain any significant deviation from flow rates at comparable wells and fields. Your projections may be based on analogy, actual production tests, decline curves, computer modeling, or other accepted engineering methods. However, your discussion in this report should explain the methods used in developing the estimates along with any attendant assumptions.

b. Production Profiles

You should estimate the expected production for each well completion and for the field or project, by year for each year of production for oil, condensate, gas, and associated gas as well as the composite BOE production. You should also estimate water production if any of your operating costs (processing fees, chemical costs, etc.) are based on these volumes. You may submit up to three separate production profiles (conservative, most likely, optimistic). Each profile for the field should represent the production schedule you expect if a specific range on the field's aggregated reserve and resource distribution exists (conservative, most likely, optimistic). You should justify these ranges in the G&G Report. Also, you should insure that each production profile for the field is consistent with the applicable (conservative, most likely, optimistic) scenarios used in the Engineering Report and the Cost Report.

You should describe the specific production drive mechanism you expect for each reservoir.

c. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment D for the format for the RSVP v2.1 model. We prefer that you submit annual production data by product in hard copy.

d. Check list Table

The table below is provided for quick reference:

Production Report	
Production Profile	- Projected production for each well completion and for the field, by year for each year of production for oil, condensate, and gas as well as the composite BOE. Water production should also be provided if directly related to any operating costs. - Explanation of the methods used to develop the profiles.
Uncertainty	- Up to three production profiles (conservative, most likely, optimistic) as described above - Each production profile for the field should be consistent with a specific point on the aggregated reserve and resource distribution and represent a conservative, most likely, and an optimistic case
Miscellaneous	- Production drive mechanism for each reservoir

Cost Report
(supplements 30 CFR 203.81(b) & (c), 89 & 91)

a. General

You use this report to justify and explain how you estimated the various costs that you have and will incur to develop and produce this field or project. You should limit your cost estimates to the items identified in paragraphs b through f below and report them in the categories listed in Attachment C. We believe they cover all the elements that clearly benefit the development and operation of your field or project. Allowable costs include the portion of joint costs in those categories that you can reasonably attribute to your field or project and a 5 percent overhead rate on costs in the Labor, Material, Abandonment, and Other Costs categories. We review your cost estimates, and once validated, use them to evaluate the application. As part of our validation we will consider the consistency of up to three cost scenarios (conservative, most likely, optimistic) with the applicable production and engineering scenarios as well as the applicable resource and reserve ranges. You should document the basis for all your cost estimates (e.g., contract with supplier, cost for a project of similar size and water and drilling depth, vendor estimate, commercially available cost estimating software, etc.). If you expect to encounter any unusual conditions or if you are considering alternative development options that could cause costs to vary significantly from the estimates presented, you should fully describe those conditions or options.

b. Sunk Costs

You should report sunk costs, defined in Attachment B, as follows:

(1) by the cost categories listed in Attachment C; indicate the overhead allowance for each applicable category,
(2) in AFE format for each eligible well; indicate the cost code (Attachment C) and the overhead allowance, if any, for each item, and
(3) in an itemized format for non-well costs; indicate the cost code, overhead allowance, and time period the costs were incurred.

We count only eligible sunk costs for which you provide documentation. Eligible sunk costs include only those historical costs incurred by you or your current partners in the application, not those of third parties. To help identify which sunk costs we should count, you should report separately by lease the size and timing of proportionate shares and breaks in ownership for all current owners, along with the timing and distribution by lease of the eligible sunk costs.

We count sunk costs on an after-tax, expensed basis using nominal (current dollar) amounts without any interest or discount rate adjustments. We may audit your sunk costs as discussed in sections G and L. An independent CPA must certify these historical costs in the same manner as explained in paragraph m of this Cost Report. We use these sunk costs only in the DCF evaluation for the profitability test (as explained in section H) and in determining whether there has been a change in material fact (as explained in section J).

c. Delineation and Development Costs

You should submit all the cost elements for this component listed in the table under paragraph o. You should associate applicable costs with specific reservoirs whenever possible. For example, tell us the specific reservoir intended for completion with each completion cost item. You may base your estimates on actual costs (such as the cost of previous wells drilled in the field), engineering estimates from vendors, or equivalent costs at analogous projects. Cost estimates should be itemized in an Authorization for Expenditure (AFE) format. Specific items that may be included in the cost elements are as follows:

Wells - Rig cost, casing and tubing, mud, consumables, equipment (wellhead valves and other equipment necessary for interaction with topside facilities), services (cement, chemicals, insurance, transportation), drill bits, etc.

Completions - additional cementing, perforating, sand control, packers, etc.

Subsea Completions - wellhead production tree, flowline controls and valves, miscellaneous equipment provided for both cluster and satellite wells, etc.

Production System - where applicable, platform fabrication or conversion and installation; topside facilities (production processing equipment; production control system; power, utility, and safety equipment; accommodations; wellhead equipment; storage facilities, etc.); riser system; mooring system; subsea equipment; pipelines, flowlines, and umbilicals; engineering design; project management; etc.

d. Production Costs

You should submit all the cost elements for this component listed in the table under paragraph o. You should specify the bases for these costs (historical, engineering estimate, or analogous project). Specific items that may be included in the elements are as follows:

Operating Costs - your costs for inspection, maintenance, repair, payroll, support and crew transport, insurance, workovers, consumables.

Equipment Leasing - your cost to lease any equipment.

Overrides* - royalty overrides and other forms of payment you incurred to acquire a financial position in lease(s) associated with this field.

* We will not use these costs in our DCF evaluations.

e. Transportation Costs and Allowances

You should submit all the cost elements for this component listed in the table under paragraph o. This component should include all costs, both arm's length and non-arm's-length, that are likely to be allowed as a deduction (transportation allowance) by MMS for royalty computation purposes, based on existing rules and recent precedents. You should specify the basis for these costs (historical, engineering estimate, or analogous project). Specific items that may be included in the elements are as follows:

Tariffs - Your cost per bbl or MCF to be paid to a third party to use their pipeline system to bring the product to market.

Transportation system costs – All of your costs that can be used to calculate a transportation allowance other than tariffs. Note that these costs can overlap items reported elsewhere in the application. You must indicate the specific costs items and amounts where such an overlap occurs. Transportation system cost elements may include:

(1) Annual capital investment, repair and maintenance costs for:
(a) Flowlines delivering bulk product from subsea manifolds or wellheads to a remote host facility not located on an adjacent lease/block;
(b) Portions of umbilicals dedicated to flow assurance (chemical transport);
(c) Platform based treatment for additional dehydration and enhanced liquids extraction performed solely for a transportation purpose, above what is required to meet sales contract specifications and needed to cope with flow assurance issues caused the colder temperatures, increased pressures, and greater distances experienced in deep water;
(d) Platform modifications (including extra buoyancy)to accommodate items under (c) above.

(2) Specific volumes and costs of chemicals needed for flow assurance.

(3) Your cost per barrel or MCF to be paid to a third party for platform based additional dehydration and enhanced liquids extraction costs. As for the similar "other than arm's-length capital and maintenance costs" (item 1c, above), these costs are solely for transportation purposes required to meet sales contract specifications and needed to cope with flow assurance issues caused by colder temperatures, increased pressures, and greater distances experienced in deep water.

Non-royalty bearing fractions of the flowline – Transportation allowances are intended only for the flowline capacity dedicated to the transportation of oil and gas, not for water. Therefore, you must give annual projections of water production so we can estimate the fraction of the flowline cost that is not royalty bearing.

Gas plant processing costs - Your annual or per barrel or per MCF non-tariff costs expended off lease to process the gas to increase liquid recovery.

f. Abandonment

You should tell us your estimate for future costs to plug and abandon wells and to remove production systems that did not exist at the date of application. Separately, tell us the cost to abandon wells or facilities that do exist at the time of your application that you plan to use to produce the field or project. You should include an estimate or distribution of prospective salvage value for all potentially reusable facilities and materials.

g. Overhead Costs

We allow you to add an overhead charge of up to 5 percent of the sum of the direct costs for labor, materials, abandonment, and other costs, as defined in Appendix C. This allowance is designed to cover your finance, administration, and management activities appropriate for the field. We do not require documentation of this amount, but neither do we allow other calculations of an overhead charge

You should indicate the overhead cost for each item in your cost estimates and sunk costs. The following provides clarification regarding which specific items are eligible for an overhead allowance:

Drilling and CompletionCosts – your tangible drilling and completion costs are considered material costs and your direct supervision is a labor cost. Any intangible materials (bits, cement, etc.) that you purchase and provide to the contractor can be included in the material category. All of these costs are eligible for the 5 percent overhead allowance. All other drilling and completion costs are considered contract services and are ineligible for an overhead allowance.

Production System Costs – your fabrication expenses are considered material costs and are eligible for an overhead allowance. Installation and contract engineering and project management are contract services, which are ineligible for the allowance.

Operating Expenses – items such as company personnel costs (labor) and chemical and fuel expenses (material) are eligible for an overhead allowance. Overhead is not allowed for cost categories such as transportation, insurance, communication, and contract services. For well and subsea system repairs, some overhead may be allowed in accordance with the above rules for drilling and completion costs.

Technical and Operations Support – these activities, if conducted by company personnel, are eligible for an overhead allowance, otherwise, they are considered a contract service.

Abandonment Cost – the 5 percent overhead allowance may be applied to all abandonment costs.

h. Ineligible Costs

We will not consider certain types of costs in our royalty relief analysis, either due to the requirements of the law or because they are not properly associated with the production for which the relief is being granted. A partial list of such costs are your:

1) acquisition costs,
2) royalty relief application fees,
3) lease rentals,
4) exploration costs,
5) damages and loses,
6) taxes,
7) interest or finance charges,
8) legal expenses and fines or penalties,
9) Costs associated with obligations existing before the application. These may include but are not limited to royalty overrides or other forms of payment for acquiring a financial position in a lease. Also, they include expenditures for plugging wells and removal and abandonment of facilities existing on the date of application and that are not to be used to produce oil or gas for sale from the field or project,
10) Costs of producing and using hydrocarbons on the lease, either for fuel or re-injected into the reservoir for disposal or pressure maintenance (since these volumes do not count against any royalty suspension volumes), and
11) Any historical costs incurred by third parties.

We reserve the right to add to this list and to make determinations regarding the eligibility of all costs you submit in the application.

i. Uncertainty

In order to model the uncertainty inherent in applications submitted at an early project stage, you may describe your costs in one of three ways. One, you may provide a separate cost scenario (conservative, most likely, optimistic) for each of up to three field production profiles you listed in the Engineering Report. For the purpose of this discussion, we consider a scenario to be a listing of total costs, in constant dollar terms for the base year, by category as well as an annual scheduling of such costs by category. The base year is the year of application. Two, you may also model uncertainty about capital costs within each scenario by specifying a confidence interval (i.e., a minimum and maximum percentage of the scenario value). Three, as with the resource data, you may model uncertainty about drilling, operating, and transportation charges with probability distributions. You must explain the basis you used for selecting the number of scenarios, each probability distribution, and confidence interval you use.

j. Contingency

You may not include explicit contingency factors in your cost estimates. Uncertainty you have about omitted costs items, remedial action on a well that does not produce at first, or about future cost inputs (e.g., rig day rates) should be incorporated into the way you configure your scenarios, cost distributions, and confidence intervals. We allow the average of your distribution of capital and well costs to be as much as 7.5 percent above your best itemized estimate for these costs. In effect, we allow you to include up to a 7.5 percent contingency on these costs when they are accounted for in the configuration of your scenarios, cost distributions and confidence intervals. Separate contingencies built into your itemized estimates of capital or well costs would constitute a redundant inclusion of uncertainty.

k. Scheduling

You should include, for each of the up to three cost scenarios, an annual listing (in constant, base year dollars) of your anticipated cost expenditures by category. The term category is intended to refer specifically to the items under "delineation and development costs" in the right hand column of the table in paragraph o.

l. Post-production Development Report

To retain the approved DWRR, you should file a post-production development report within 120 days after you start production. If your development plans call for a rolling start of production, say as you complete several wells sequentially on the same rig mobilization, we will define start of production as production from all wells included in the startup campaign. The only exception to this requirement occurs if the Regional Director for the GOM grants you an extension. You should submit actual costs for all of the elements of the development cost component (listed in paragraph c. above) with supporting records. In addition, you should provide costs by category in the Allowable Cost Report format as listed in Attachment C. We use this information for decisions involving changes of material fact.

m. Certification

Your application and post-production development report should be accompanied by a report prepared by an independent CPA that expresses at least a qualified opinion that the historical financial information in the application and post-production development report is accurate and that the presentation of data and information conforms to our guidelines. You should identify the individuals in the CPA firm who prepared these reports and you should make them available to us to respond to questions which may arise regarding the evaluation of your historical information. We reserve the right to also review your records on the historical financial information in your report.

n. Format

The documentation for the RSVP model shows and explains the model's format for data and can be found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

o. Check list Table

The table below is provided for quick reference.

Deep Water Royalty Relief Cost Report	
Ownership history and sunk costs - certified by CPA	- All documented eligible costs, in nominal (current dollar) amounts, actually incurred subsequent to and including the first discovery well on the field. We count sunk costs on an after-tax, expensed basis - All changes in lease ownership since discovery of the field as well as the timing and distribution by lease of all sunk costs - Provide sunk costs in the formats referred to in paragraph b
Delineation and development costs - from historical records, engineering estimate, or analogous project in AFE format	- Platform well drilling costs and average well depth - Platform well completion costs - Subsea well drilling costs and average well depth - Subsea well completion costs – Production system costs (platform, topside facilities, subsea equipment, flowlines, umbilicals, engineering, project management, etc.)
Production Costs - historical, engineering estimate or analogous project review or company official.	- Itemized operating and processing costs - Equipment leasing costs - Taxes (won't be used in our DCF evaluations) - Existing royalty overrides (won't be used in our evaluation)
Transportation Costs - historical, engineering estimate or analogous project	- Transportation system costs (used to determine transportation allowance, see paragraph e) - Percent Water content of bulk movements - Oil and/or gas tariffs from pipeline or tankerage - Gas plant processing costs for NGL

<table>
<tr><td>Uncertainty</td><td>- A cost scenario consistent with each one of the up to three field development and production profiles (conservative, likely, optimistic)
- If desired, express the uncertainty of capital cost for each scenario with confidence intervals and of drilling, operating, and transportation costs with probability distributions</td></tr>
<tr><td>Contingency Costs</td><td>- Not allowed</td></tr>
<tr><td>Scheduling</td><td>- Provide costs on an annual basis (in real dollars for the base year) for the delineation and development cost component</td></tr>
<tr><td>Abandonment</td><td>- Estimate the costs that have not been incurred at the time of application to plug and abandon wells needed to produce the field or project.
- Include an estimate of the salvage value of reusable facilities and materials</td></tr>
<tr><td colspan="2">File a post-production development report 120 days after you start the production subject to an approved royalty suspension. Report actual expenditures for the above cost components up to the date production starts. Retain supporting records for these costs and make them available to us upon request.</td></tr>
</table>

Attachment A: Royalty Relief System Summary

Royalty Relief Procedure	Deep Water		
	Expansion Project	**Pre-Act Lease**	**Development Project**
Information Elements (§§ 203.62, and 203.81 through 203.89)			
(1) Administrative information report	x	x	x
(2) Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological and Geophysical (G&G), Engineering, Production, & Cost reports)	x	x	x
(3) G&G report	x	x	x
(4) Engineering report	x	x	x
(5) Production report	x	x	x
(6) Deep water cost report	x	x	x
Confirmation Elements (§§ 203.70, 203.81 and 203.90 through 203.91)			
(1) Fabricator's confirmation report	x	x	x
(2) Post-production development report approved by an independent certified public accountant (CPA)	x	x	x
Approval Conditions (§§ 203.60 and 203.67)			
(1) Already producing	x (Field)		
(2) A producible well into a reservoir that has not produced before	x	x	x
(3) Royalties for qualifying months exceed 75% of net revenue (NR)			
(4) Substantial investment on a pre-Act lease (e.g., platform, subsea template)	x		
(5) Determined to be economic only with relief	x	x	x
Redetermination Conditions (§§ 203.74 through 203.75)			
(1) For material change in geologic data, prices, costs, or available technology	x	x	x

Royalty Relief Procedure	Deep Water		
	Expansion Project	Pre-Act Lease	Development Project
Relief Rate and Volume, subject to certain conditions (§§ 203.69)			
(1) Zero royalty rate on the suspension volume and the original lease rate on additional production	x	x	x
(2) Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)		x	
(3) Suspension volume is at least the minimum set in the Notice of Sale, the lease, or the regulations	x		x
(4) Amount needed to become economic	x	x	x
Full Royalty Resumes When (§§ 203.78)			
(1) Average NYMEX price for last calendar year exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product (GDP) deflator since 1994.	x (Pre-Act leases)	x	
(2) Average prices for designated periods exceed levels we specify in the Notice of Sale and the lease.	x (Post-200 leases)		x
Relief Withdrawn or Reduced (§§ 203.76 through 203.77)			
(1) If recipient requests.	x	x	x
(2) Recipient does not submit post-production report that compares expected to actual costs.	x	x	x
(3) Recipient changes development system.	x	x	x
(4) Recipient excessively delays starting fabrication.	x	x	x
(5) Recipient spends less than 80 percent of proposed pre-production costs prior to start of production.	x	x	x
(6) Amount of relief volume is produced.	x	x	x

Attachment B: Definitions (from 30 CFR 203.0)

Authorized field - A field

(1) Located in a water depth of at least 200 meters and in the Gulf of Mexico (GOM) west of 87 degrees, 30 minutes West longitude;
(2) That includes one or more pre-Act leases; and
(3) From which no current pre-Act lease produced, other than test production, before November 28, 1995;

Complete application - The fee specified in 30 CFR 203.3 and an original and two copies of the six reports consisting of the data specified in 30 CFR 203.81, 83 and 85-89, which we've reviewed and found complete.

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

Development project - A project that is located on one or more contiguous leases that:

(1) Were issued in a sale held after November 28, 2000;
(2) Are located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude; and
(3) Have had no production (other than test production) before the current application for royalty relief.

Draft application - 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 - A lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 1995, and before November 28, 2000;
(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper;
(3) Lies wholly west of 87 degrees, 30 minutes West longitude; and
(4) Is offered subject to a royalty suspension volume.

Expansion project - A project you propose in a DOCD or a Supplement approved by the Secretary of the Interior after November 28, 1995, that will significantly increase the ultimate recovery of resources from a pre-Act lease or a lease issued in a sale held after November 28, 2000. A significant increase adds new resources, not simply extends recovery of reservoirs already in production. For a pre-Act lease, the expansion project must also involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.). For a lease issued after November 28, 2000, the expansion project must involve a new well drilled into a reservoir that has not previously produced. In all cases, an expansion project must be located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude.

Fabrication (or start of construction) - Evidence of an 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 continuous construction has begun, and a receipt for the customary down payment.

Field - 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 impervious strata or laterally by local geologic barriers, or both.

Lease - Either a lease or a unit of multiple leases.

New production - 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 additional production resulting from new lease-development activities on a current pre-Act lease or a lease issued in a sale after November 28, 2000, under a DOCD or a Supplement approved by the Secretary of the Interior after November, 28, 1995, that significantly expands production.

Nonbinding Assessment - An opinion by us of whether your field could qualify for royalty relief. It's based on your draft application and doesn't entitle the field to relief.

Performance Conditions - Minimum conditions you must meet, after we've granted relief and before production begins, to remain qualified for that relief. If you don't 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 - A lease that:

(1) Results from a sale held before November 28, 1995;
(2) Is located in the GOM in water depths of 200 meters or deeper; and
(3) Lies wholly west of 87 degrees, 30 minutes West longitude.

Production (for purposes of Deep Water Royalty Relief) - 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.

Redetermination – Our reconsideration of our determination on royalty relief because you request it after:

(1) We have rejected your application;
(2) We have granted relief but you want a larger suspension volume;
(3) We withdraw approval; or
(4) You renounce royalty relief.

Renounce - Action you take to give up relief after we've granted it and before you have produced an amount equal to the royalty suspension volume with which we issued your lease.

Royalty suspension (RS) lease - A lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 2000;

(2) Is in locations or planning areas specified in a particular Notice of Sale offering that lease; and

(3) Is offered subject to a royalty suspension volume specified in a Notice of OCS Lease Sale published in the Federal Register.

Sunk costs for on an authorized field means the after-tax eligible costs that you (not third parties) incur for exploration, development, and production from the spud date of the first discovery on the field to the date we receive your complete application for royalty relief. The discovery well must be qualified as producible under part 250, subpart A of this title. Sunk costs include the rig mobilization and material costs for the discovery well that you incurred prior to its spud date.

Sunk costs for an expansion or development project means the after-tax eligible costs that you (not third parties) incur for only the first well on each of the project's leases, as approved by us, that encounters hydrocarbons in the reservoir(s) included in the application and meets the producibility requirements under part 250, subpart A of this title on each lease participating in the application. Sunk costs include rig mobilization and material costs for the discovery wells that you incurred prior to their spud dates.

Withdraw (our) approval - Action we take on a field that has qualified for relief if you haven't met one or more of the performance conditions. (This is different from a withdrawal application in which the applicant removes the application from consideration before any MMS determination or action.)

Attachment C: Allowable Cost Categories
Associated with the Cost Variables Used to Determine Qualification for Royalty Relief
(supplements 30 CFR 203.89)

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consists of expenditures associated with several different cost categories. This attachment summarizes categories of allowable costs, drawn from 30 CFR 220.011 and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on End-of-Life Royalty relief includes an almost identical attachment (Attachment 1) on allowable costs. *Italics* in this Attachment C denote passages that deviate from Attachment 1 to Appendix II (the End-of-Life Lease guidelines).

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only your costs or portions of your costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation *that would continue should lease operations cease. For example, we don't allow installment payments for a capital expenditure that was financed* or the costs of abandonment for pre-existing wells and facilities *that will not be used to produce the field or project.* These obligations remain regardless of the economic performance of your lease, so they are not considered relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

   1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

   2. Salaries and wages of technical employees within technical branches of your organization who are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

   3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task. This is an example of a joint allocable cost.

   4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

   5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This allowance, together with the corresponding amounts in items B, I, and J below is designed to cover your finance, administration, and management activities appropriate for the field.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

   1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. Joint transportation costs must be allocated pursuant to the above referenced NPSL regulations. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm's- length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services, provided under a non-arm's-length contract, must be included in the appropriate cost categories described above and below. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities that you *own or* acquire that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the tract to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

1. We allow costs associated with abandonment of wells *you plan to drill if we approve royalty relief and wells that have been drilled and will be used to produce the field or project.*

2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *another* reservoir included in the project and with modification of platform equipment for project specific purposes.

3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You must identify and explain any costs in this category. These costs may include up to a 5 percent overhead.

K. Other Credits (cost code 1100) cover credits to lease operations for:

1. Lease property you lease to or use in non-lease operations,
2. Your sale of information derived from test wells and geological and geophysical surveys, and
3. For any and all amounts earned or otherwise due you as a result of lease operations.

Ineligible costs are listed in the Cost Report.

Attachment D: Suggestions to Streamline CPA Certification

The purpose of CPA certification is for an independent expert to confirm that only allowable costs incurred by the applicant are used for qualification. This certification must be submitted along with the completed application and conform to the following guidance to start our evaluation period.

At a minimum, we expect the CPA to confirm or identify deviations from at least the following items:

1. Application includes only charges incurred on or for the sole benefit of the subject lease(s) or discovery well(s).

2. Application includes only allowable charges as described in Appendix C of these guidelines.

3. Application includes only allowable costs that were incurred for services rendered or goods bought for the discovery well(s) and, for fields with pre-Act leases, between the discovery and the application date.

4. Application values for large cost elements are supported by backup invoices or other, comparable sub-ledger records.

The applicant's own accounting system may not match that described in Attachment C. When that is the case, the following procedural checks should suffice to certify accuracy of historical financial information and conformity to MMS guidelines.

To confirm applicability and accuracy of costs, identify and list other audits performed for the qualifying period used in the application that contain these lease(s) and associated facilities.

a. If one or more other audits have been performed, review cost structure provided in the application to be sure it is consistent with costs for the application lease(s) shown in the other audits. Identify any inconsistencies.
b. If no other audits have been performed for the qualifying period, audit a random sample of sub-ledger records for charges assigned to the lease(s). Check invoices for any unusually large or erratic items (e.g., double previous month's level).

To confirm inclusion of only allowable costs, determine which categories in the applicant's own accounting system are likely to record charges not allowed under MMS regulations and guidelines (30 CFR 220.013 and Attachment C of these guidelines). Review cost elements in these categories of the applicant's own accounting system which should record any non-allowed costs. Eliminate charges for any items found to be non-allowable from the amount confirmed in procedure 1 above.

To confirm inclusion of only costs incurred during the qualification period, examine the dates services were rendered or goods were received for allowable costs. Costs should be recorded in the period when they actually occurred. Review cost elements in the beginning months of the qualification period to ensure they were actually incurred during the qualification period. Eliminate costs that were incurred prior to the qualification period.

Attachment E: RSVP Computer Model Layout
(supplements 30 CFR 203.85)

We've constructed a template model, Royalty Suspension Viability Program (RSVP), for the Economic Viability and Relief Justification report. It is to be used with Windows, Excel version 7 and Crystal Ball version 4.0 software. You may obtain the RSVP template from:

Regional Supervisor for Production and Development
Minerals Management Service
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, LA 70123-2394

Crystal Ball is a registered trademark of Decisioneering, Boulder, Colorado, (www.decisioneering.com; phone (303) 337-0900 or 800-289-2550; FAX (303) 337-3560).

The RSVP model uses probability (Monte Carlo) methodology to develop a resource estimate from your input data and a net present value for your field from the production profile and cost components you supply. We provide details on how the model works in extensive documentation available with the model.

Also, you may download these guidelines, the model and its documentation from the MMS home page (http://www.gomr.mms.gov/homepg/offshore/royrelef.html). From that screen, you then go to Managing Offshore Resources, Gulf of Mexico, Offshore Information, Royalty Relief Information.

The Documentation for the RSVP Model offers an example complete with inputs and results. We highly recommend that you confirm the example outputs before proceeding with extensive additional analyses.

The reserve model is integrated into RSVP as shown in the template. You can get resource output distributions in addition to those programmed in RSVP by alternative selection of Crystal Ball output parameters as discussed in the model documentation. Outputs of the Resource module are in columns X through AR. Those for the viability module are in columns BX through CW. The inputs and outputs should be provided on a 3.5-inch diskette.

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Appendix II to NTL No. 2010-N03

GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF ROYALTY RELIEF FOR END-OF-LIFE LEASES

March 2010

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ATTACHMENTS

Recovery of Costs

Under Federal policy and statute, we'll charge you a fee for applying for royalty relief to recover our cost of processing your application. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

The Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996) authorizes our fees. The statute provides "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ... for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337(a) (3)."

We may issue a revised notice to lessees (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you make payments. Currently, we charge $8,000 to review your application and an additional $12,500 if we decide we need to audit your historical data to confirm that you qualify for relief. We will revise the NTL periodically to reflect our cost experience in administering this program.

OVERVIEW OF GUIDELINES FOR END-OF-LIFE ROYALTY RELIEF UNDER 30 CFR PART 203

We issued final regulations (30 CFR Part 203) in January 1998 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). As part of that rule-making, we simplified and revised the way we implement authority the Secretary of the Interior has under 43 U.S.C. 1337(a)(3)(A) to reduce or eliminate royalties. This authority applies to oil and gas leases anywhere in the Federal Outer Continental Shelf (OCS). Leaseholders who have inadequate revenues to sustain production qualify for royalty relief if we determine that a modification in the royalty arrangement will result in recovery of additional resources.

Affected lessees may apply to the Minerals Management Service (MMS) for a reduced royalty rate by submitting the information specified under the final regulations. The specific data, reports, and spreadsheets in an application are described in supplementary guidelines, issued as an attachment to this Notice to Lessees and Operators (NTL). These supplementary guidelines also explain the procedures we will follow for evaluating applications and implementing royalty relief, and our rationale for excluding selected cost items from consideration.

We advise that you carefully review a copy of these guidelines if you intend to request End-of-Life Royalty Relief. They do not add any requirements to the regulations, but they will help you structure your application so as to expedite our evaluation. Be sure to use the most current version of these guidelines as we will periodically update them to reflect our experience in processing applications.

The NTL, the computer spreadsheet, and these guidelines are available from your regional office or on the MMS website at http://www.mms.gov.

Any collection of information that we mention in these guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR Part 203. The Office of Management and Budget has approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated: 5 March 1999

Carolita U. Kallaur

Carolita U.Kallaur,
Associate Director for
Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: March 5, 1999

Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases

A. Introduction

These guidelines interpret regulations (30 CFR Part 203.50 through 203.56 and 203.81 through 203.84) which establish the terms and conditions for granting reductions in royalty rates to end-of-life leases under the Outer Continental Shelf (OCS) Lands Act. This form of relief applies to Federal leases anywhere on the OCS that have meaningful levels of production. Other guidelines interpret regulations for deep water royalty relief.

As with the rule, we have written these guidelines in the "plain English" or conversational style. We (Minerals Management Service) instruct you (applicants, lessees, operators) on how to determine when you qualify for royalty relief and how you apply for it in a way that most efficiently facilitates our review. Also, we explain how we administer relief you may receive.

Guidelines are not strict rules like regulations, so we may deviate from individual elements of them if an applicant makes a convincing argument to do so. We will consider requests for departure from the guidelines only when an applicant provides compelling reasons for deviating from a provision before, or when submitting, a royalty relief application.

For purposes of royalty relief, designated unit operators may act as the applicant on behalf of all lessees (payors). Operators acting as applicants are responsible for assuring that the application contains accurate revenue, royalty, and transportation and processing allowance data on all sales from the lease. When not privy to all actual revenue, royalty and cost allowance data, operators must fully explain how they estimated those amounts and alert all payors that we may require such data and explanation from each one before we can make a final decision on an application.

B. Royalty Rate Reductions - General

Under 43 U.S.C. 1337 (a)(3)(A), we may reduce or eliminate the royalty or net profit share specified for your producing OCS lease to promote increased production. The purpose of royalty relief is to allow you reasonable financial returns so as to increase ultimate resource recovery (e.g., oil, gas, or sulphur) and augment receipts to the Federal Treasury. Therefore, we will modify the royalty rate where sound engineering and economic principles indicate that this change will extend the productive life of your lease.

We use only historic data to determine if you need end-of-life royalty relief. That reliance presumes that you continue to operate your lease in a way that does not significantly alter historical practice. We rely on certain procedures to protect the integrity of a decision based on historic data. If you have recently instituted or plan significant changes to your operation, you should implement such changes and operate for 12 months in your new configuration before seeking to qualify for royalty relief. Otherwise, we will defer action on your application until that circumstance is achieved. Until your application fully reflects the effect of recent significant changes to your operation, we cannot be confident that you need royalty relief to continue operations. We will wait up to 2 years for you to provide updated data reflective of your new configuration. Further, we will terminate your relief if you subsequently do things that we have notified you are significant changes to your operation.

C. Qualifications for Relief

Producing leases that have inadequate revenues to sustain continued production, i.e., end-of-life leases, can apply for royalty relief. The term "lease" refers to either a lease or an approved unit. To qualify for royalty relief, you need to show that your lease satisfies the following production and economic conditions.

1. To be eligible for royalty relief, the rule specifies that your lease must satisfy certain production requirements during a qualification period. By ***production***, we mean the sum of dispositions for oil and gas reported by the operator on MMS-4054 Form (OGOR-B report) to MMS. Under the rule, ***qualification months*** consist of the most recent 12 of the last 15 calendar-months in which you satisfy the following production requirements.

   For an oil and gas lease, the production requirement during a *qualifying month* is an average of at least 100 barrels of oil equivalent (BOE) per day. For a non-oil and gas lease, any positive level of production will satisfy the production requirement needed in a *qualifying month.*

   To allow for lags in data availability and you time to prepare an application, your 15 month period may end up to 120 days before the date we receive your certified application. Part of your application is an independent opinion from a certified public accountant (CPA). To expedite a CPA review, Attachment 3 outlines the confirmation procedures we believe are necessary for an independent opinion on the reliability of the data in your application.

2. To demonstrate that your lease is becoming uneconomic, the rule specifies that you must show that royalties you paid ***(ROY)*** exceed 75 percent of ***net revenues (NR)*** generated during your qualification months. The clearest way to show this is by substituting your data into the formulas below. Define ***Royalty Share*** *(RS)* as:

$$RS = \frac{ROY}{NR}\ (100\%) \quad \text{where}$$

ROY is the net royalty that you have paid under the existing royalty arrangement, after determining royalty due and deducting any ***transportation and processing allowances*** (*TPA*) that you are permitted under regulations at 30 CFR 206 and recent precedents.

NR is your net revenues as defined by: $NR = GVP - AC - TPC$, where

Gross Value of Products (GVP) is gross proceeds all lease owners receive under arm's-length contracts for sale of production in marketable condition. Our Oil and Gas Payor Handbook, Volume III, Product Valuation gives details on how to compute this *GVP* as well as *TPA*.

In cases where a unit operator serves as the applicant on behalf of multiple payors, he must illustrate how he calculated *GVP*, *ROY*, and *TPA* on his part of sales. Integral to that illustration is a careful explanation of the basis for determining the amounts authorized by regulation at 30 CFR 206 and recent precedents. We will compare those amounts attributed to other payors on the lease from operator's calculation with what they actually reported to MMS. Where we find material discrepancies, we will request documented calculations from those payors.

Allowable Costs (AC) is a variable representing the sum of your expenses during the qualification months that are necessary for the continued operation of your lease. We follow the cost accounting structure prescribed for Net Profit Share Leases in 30 CFR 220.011 - 220.015 because it describes actual expenditures that benefit the on-going operation of your lease. Attachment 1 summarizes costs we consider allowable for end-of-life royalty relief qualification.

Generally, you may include expenses for operating and maintaining the existing wells and facilities on your lease and costs for replacement or side track wells completed in the same producing reservoir because these expenses are necessary for full recovery of the resources. With the exception of certain rentals described in Attachment 1, you may not include charges for recovering the capital cost of equipment or reserves (i.e., amortization, depreciation, depletion) because they are development costs not consistent with an end of life circumstance.

If you expend funds to place production in salable condition to obtain the *GVP* used for royalty calculation, you may include expenses for the requisite treatment activities (separation, dehydration, stabilization, etc.) that take place prior to the sales point. If these activities are carried out under an arm's-length contract with a nonaffiliated plant, allowable expenses equal the fees you pay for the treatment activities. Otherwise, we only allow fees in the amount that you can show reflect the actual costs incurred by the affiliated plant in treating your production. We follow the definition of affiliation (10 percent or more ownership) used in 30 CFR 206.101. Gas plant processing costs for activities designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration should be included in the transportation and processing allowance category described below.

You may also include reasonable portions of joint costs which rightfully should be allocated to this lease. Joint costs mean any of the cost items listed in Attachment 1 that benefit this lease and one or more other operations or leases. For instance, costs associated with producing reservoirs or part of reservoirs in State waters from a facility on a Federal lease are generally not allowable costs for Federal royalty relief purposes. However, if the State/Federal parts of the field are unitized, then we may allow the portion of unitized costs allocated to production from the Federal part of the lease. Because some joint costs may be difficult to allocate, we also allow you to assign a 5 percent overhead amount to certain cost items.

As the rule states, we may, in our review and evaluation of your application, disallow certain costs when we consider them to be unnecessary for the ongoing operation of your lease.

Transportation and Processing Costs (TPC) is a variable representing the sum of your reasonable, actual costs for transportation and processing associated with the oil and gas produced from your lease. *TPC* is based on the ***transportation and processing allowance (TPA)*** you are permitted under the regulations at 30 CFR 206 and recent precedents. You should illustrate and explain how you determined the *TPA* shown on the Report of Sales and Royalty Remittance (Form MMS-2014) you submitted during the qualifying period.

The *TPA* represents the part of your total *TPC* incurred to handle the lessor (royalty) share of the total product. Your *TPC* should never exceed your *TPA* divided by your royalty rate.

An example helps clarify the calculation for relief qualification.

Suppose $GVP = 100$, $AC = 54$, $TPA = 2$, and the effective royalty rate in the qualifying months is 1/3.

Then, $TPC = 2 / (1/3) = 6$;
$ROY = (1/3) * (100 - 6)$ or $= [(1/3) * 100] - 2 = 31.33$; and
$RS = [31.33/(100 - 54 - 6)] *100$ percent $=$ 78.3 percent

If your actual *TPC* is less than the amount calculated in this way, you should use the actual amount of your costs, with one exception. The exception is that in cases where you have approval of the MMS Royalty Management Program to report a tariff approved by the Federal Energy Regulatory Commission (FERC) in lieu of actual transportation costs, you may claim the part of the tariff associated with the royalty portion of production as the transportation allowance. However, for the remaining non-royalty portion of production, you must count only the reasonable actual costs, as opposed to any imputed costs or tariffs, incurred in transportation of the non-royalty portion of your production.

Processing costs can be claimed only for gas plant products, as defined in the regulations. The processing costs approved by the MMS Royalty Management Program can be claimed as part of the actual costs associated with the royalty portion of gas plant production. For the remaining non-royalty portion of the gas plant products, you must count only the actual costs, as opposed to any imputed costs, incurred in the processing of these products.

D. Form of Relief

Upon qualification, we will reduce the royalty rate to a fixed ***royalty relief rate*** of half of the lease's effective royalty rate, where the ***effective royalty rate*** represents the average royalty rate applied to the gross production volume during the 12 months included in the qualifying period. You may still claim the *TPA* credit against royalties owed after we grant relief.

If we have given relief to this lease before, the original lease rate may not be the same as the *effective royalty rate*. The following example illustrates how to find your *effective royalty rate* when more than one fixed rate has applied during the qualifying period.

Suppose that for 4 months production totals 500 (that is, averages 125/month) and one royalty rate (1/6) applies, and for the other 8 months production totals 2,000 while another royalty rate (1/3) applies.

The production-weighted average royalty rate over the qualifying period or the *effective royalty rate* is {[(500 * (1/6)) + (2,000 * (1/3))]/(500 + 2,000)} * 100 percent = 30 percent, so the *royalty relief rate* would be 15 percent.

If you operated under a net revenue share royalty system, you must derive an *effective royalty rate* for each month by dividing royalties owed by well-head value (*GVP* - *TPC*). The following example illustrates how to find your *effective royalty rate* for one month when your royalty was determined by a net revenue or net profit share system.

Suppose your monthly royalty obligation is 50 percent of *GVP* (of say 3,000) less *TPC* (of say 700) and less an allowable operating cost (of say 920).

Your *effective royalty rate* for the month is {[(0.5 * (3,000 - 700 - 920))]/(3,000 - 700} * 100 percent = 30 percent

The calculation must be repeated for each of the 12 qualifying months and the result for each month weighted by the production volume in the same month. If the production-weighted average of your *effective royalty rates* in all 12 qualifying months worked out to be 30 percent, your *royalty relief rate* would again be 15 percent.

The royalty relief rate will apply to production up to the ***royalty relief volume***. It is equal to the monthly average number of barrels of oil equivalent produced over the 12 months in the qualification period. For natural gas production, 5,620 cubic feet of gas is equivalent to one barrel of oil.

> With the production numbers from the above example, the *royalty relief volume* would be (500 + 2,000)/12 = 208.3.

Any monthly volume of production above and up to 2 times the *royalty relief volume* will bear royalties at 1.5 times the effective royalty rate. Production above 2 times the relief volume amount pays the effective royalty rate. The following illustration continues the example.

> Suppose production reaches 300 in a month after relief is granted.
>
> You would owe royalties on the first 208.3 at a 15 percent rate, while you would owe royalties on the remaining 91.7 at a 45 percent rate (1.5 * 30 percent).

You should compute an average royalty rate each month, which serves as the rate for calculating actual royalties due. You find it by taking the production-weighted average of the rate associated with production up to the relief volume (equal to ½ the *effective royalty rate*), and the rate associated with additional production (equal to 1.5 times the *effective royalty rate* for up to double the *royalty relief volume* and the effective royalty rate for any greater volume). The following illustration completes the example.

> The average royalty rate for a month with production of 300 is {[(208.3 * 0.15) + (91.7 * 0.45)]/300} * 100 percent = 24.17 percent.
>
> If production climbs to 420, the average royalty rate is {[(208.3 * 0.15) + (208.3 * 0.45) + (3.4 * 0.3)]} * 100 percent = 30 percent. In effect, the average *relief royalty rate* gradually increases (as monthly production) rises to a cap at the pre-relief *effective royalty rate*.

E. Suspension of Relief

You owe royalties at the *effective royalty rate* on all production during any month in which sweet crude oil and natural gas prices increase by more than 25 percent. You should calculate the increase as the difference between the current weighted 12 calendar-month rolling average of NYMEX (New York Mercantile Exchange) and the weighted 12 calendar-month average of NYMEX prices during your qualification months. The weighting factors for oil and gas are the percentages of your total production provided by each product during the 12 qualifying months. In these cases, the *effective royalty rate* will apply to all your production.

Suppose you produced an average of 3,500 bbls of oil and 2,810 mcf of gas (with 1.1 MMbtu per mcf) per month during your 12 qualifying months. Converting gas to BOE using a factor of 5,620 scf/bbl, your production weighting factors are {3,500/[(3,500 + (2,810/5.62)]} * 100 percent = 87.5 percent oil and 12.5 percent gas.

Suppose over your 12 qualifying months average NYMEX oil prices were $12/bbl and average NYMEX gas prices were $2 per million Btu. Your base price level is ($12 * 0.875) + [(2 * 1.1) * 0.125] = $10.775/BOE. If average NYMEX prices weighted by these factors exceed ($10.775 * 1.25) = $13.47/BOE, you would owe royalties at your pre-relief or effective rate. This happens if the average NYMEX oil price rises to $15/bbl and the average NYMEX gas price rises to $2.50/MMBtu over the same 12 month period. It also would happen if the average NYMEX oil price rose to $15.08/bbl and gas prices remained at $2/MMBtu.

F. Termination of Relief

End-of-Life royalty relief ends in any of three situations.

1. At any time you may renounce, by written notification to the MMS Regional Director for your area, the royalty relief granted under these guidelines. After we acknowledge the change, you will owe royalties at the pre-relief or effective rate as of the next full month when royalties are due.

2. Relief ends when your average royalty rate equals the effective rate for 12 consecutive months. This would happen if prices remain more than 25 percent above their average level in your qualifying months or if your production is double or more the relief volume for 12 consecutive months.

3. We reserve the right in individual cases to specify activities that will end relief because they are not compatible with an end-of-life circumstance. If we choose to reserve this right in your individual case, we will notify you in our letter approving your end-of-life relief what activities are incompatible with continuation of relief and when relief would terminate. Also, we will indicate the terms to which your royalty obligation will revert in the event such activities occur.

G. Withdrawal of Relief

If we find that you provided false or intentionally inaccurate information that was material to our granting you relief, you must pay full royalties and late payment interest determined under 30 U.S.C. 1721 on all production on which you used the royalty relief. You may also be subject to penalties under other provisions of law.

H. Review And Audit

All data you submit in support of the relief application is subject to review and audit.

I. Procedures for Submitting Applications

You should file your application for royalty relief with the MMS Regional Director for your area. Under the rule, your application must contain two reports: (1) Administrative Information; and (2) Net Revenue and Relief Justification. Attachment 2 describes what should be in these reports.

Attachment 3 outlines procedures for an acceptable CPA certification. Attachment 4 illustrates a spreadsheet format you should use in the Net Revenue and Relief Justification Report.

Ordinarily we would not expect the operator and owners who file an application for royalty relief to change while we are evaluating the application. To preserve the integrity of a pending application, we insist that the designated operator remain unchanged until we render a relief decision. However, owners may change during our evaluation period without affecting a pending application. After we have rendered a relief decision, operators as well as owners are free to change without affecting relief we have already granted.

Before you can reapply either for relief after your previously held relief has ended, or for more relief, the rule holds that your lease must have 12 qualifying months under the same royalty or relief terms. When you have had the same royalty terms for 12 qualifying months, you still have to pass the qualifications listed in Section C above.

J. Procedures for Review, Evaluation, And Decision

We will review the royalty relief application for completeness and verify that the data are reasonable. If we determine that you do indeed meet the qualification requirements, then we'll give you royalty relief because it should induce meaningful quantities of incremental production. We will notify you in writing of the *royalty relief volume* amount, the *effective royalty rate*, the threshold average oil and gas price level at which suspension and possible termination of relief occur (for an oil and gas lease), other conditions or clarifications of the arrangement, and the date on which the new terms would begin. Your new arrangement normally would start on the first day of the month following the date we approve your relief.

If your application is incomplete or we decide your data are not reasonable, we will give you the opportunity to submit additional or revised information. If your response cannot clear up our concerns, we will deny your request for royalty relief. If we deny your request, we will explain our decision and rationale to you in writing. We retain the application fee. You may appeal any of our decisions to the Director, MMS, within 30 days, under the provisions of 30 CFR 290.

Attachment 1
Allowable Cost Categories Associated with the Cost Variables
Used to Determine Qualification for Royalty Relief

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consist of expenditures associated with several different cost categories. This attachment summarizes categories of allowable cost, drawn from 30 CFR 220.011, and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on deep water royalty relief includes an almost identical attachment (Attachment C) on allowable costs. *Italics* in this Attachment 1 denote passages which deviate from Attachment C in the other guidelines.

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only costs or portions of costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation that *you incurred before the qualifying period. For example, we don't allow amortization or depreciation charges for equipment or facilities you acquired before the qualifying months. You incurred such capital costs because you anticipated being able to recover them without royalty relief.* Likewise we don't allow the costs incurred for the abandonment of pre-existing wells and facilities. These obligations remain regardless of the economic performance of your lease, so they are not relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

2. Salaries and wages of technical employees within technical branches of your organization that may not work in the area of the lease but are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task.

4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This, together with the corresponding amounts in items B, I, and J, below is designed to cover your finance, administration, and management activities appropriate for the lease.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm's-length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services provided under a non-arm's-length contract must be included in the following cost categories. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities which you acquire *during the qualifying months* that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the lease to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

1. We allow costs associated with abandonment of wells *you drilled during the qualification period* but not costs associated with wells existing before *the start of the qualification period.*

2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *a producing* reservoir included in the project and with modification of platform equipment for project specific purposes.

3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You should have any costs in this category specifically approved by the Director, MMS, or appropriate delegated authority. You may include an overhead allowance of up to a 5 percent of the other costs in this category.

K. Other Credits (cost code 1100) cover credits to lease operations for:

1. Lease property you lease to or use in non-lease operations,

2. Your sale of information derived from test wells and geological and geophysical surveys, and

3. For any and all amounts earned or otherwise due you as a result of lease operations.

In addition to those costs listed at 30 CFR 220.013, the following costs are not allowable:

1. OCS rental payments on the lease(s) in the application.

2. Damages and losses.

3. Taxes.

4. Any costs associated with activities that are exploratory in nature.

5. Civil or criminal fines or penalties.

6. Royalty relief application fees.

7. Costs associated with prior existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease).

Attachment 2
Reports Required for a Complete Application

The rule specifies that your application must include the following information.

1. **Administrative Information Report** - You use this report to identify your lease or unit and to summarize its background. It includes:

    - Serial number and block designation of your lease, names of the titleholder of record, the lease operator, the identification of whether the lease is part of a unit and description of lease or unit history.

    - Company designation, the API number, location and status of each well that has been drilled on the lease.

    - Full information as to whether you are obligated to pay royalties or payment out of production to anyone other than the United States, the amount to be paid, and your efforts to reduce them.

2. **Net Revenue and Relief Justification Report** - You use this report to summarize your lease or unit's production, revenue and cost history for your qualifying months.

- It consists of a cash flow statement with the following items for each of 12 qualifying months (i.e., those most recent 12 of the last 15 months which had production of at least 100 barrels of oil equivalent per day). Attachment 4 illustrates the spreadsheet format we recommend that you use for your cash flow statement.
    1. All lease production subject to royalty computed in accordance with the lease and applicable regulations.
    2. Total revenues received on all lease production.
    3. Total royalties paid on all lease production.
    4. Allowable costs (using the cost categories identified in Attachment 1).
    5. Total transportation and processing costs allowed under MMS regulations.
    6. Calculation of net income and revenue share.

- The spreadsheet should demonstrate that royalties paid exceed 75 percent of net revenues generated during the qualifying months.

- You must have this report certified by an independent certified public accountant (CPA) expressing any specific reservations or the lack of any reservations about the accuracy of the historical financial information and that the presentation and interpretation of the data elements conform to the MMS guidelines. Attachment 3 describes the essential elements of this CPA certification.

- You should carefully explain any significant variability within a cost variable or category.

Attachment 3
Procedures For Streamlining CPA Certification

The purpose of CPA certification is for an independent expert to confirm that only allowable operating, transportation, and processing costs are used for qualification. Three steps are critical: (1) separating charges incurred on the subject lease(s) from ones incurred elsewhere; (2) identifying and eliminating any charges not allowed under MMS regulations and guidelines; and (3) dividing the remaining operating charges into two parts, those authorized to claim a 5 percent overhead and those not authorized to claim overhead.

The applicant's own accounting system may not match that described in Attachment 1 of the MMS end-of-life Guidelines. When that is the case, the following procedural checks should suffice to certify accuracy of historical financial information and conformity to MMS guidelines.

1. To confirm applicability and accuracy of costs, identify and list other audits performed for the qualifying period used in the application that contain these lease(s) and associated facilities.
   a. If one or more other audits have been performed, review cost structure provided in the application to be sure it is consistent with costs for the application lease(s) shown in the other audits. Identify any inconsistencies.
   b. If no other audits have been performed for the qualifying period, audit a random sample of sub-ledger records for charges assigned to the lease(s). Check invoices for any unusually large or erratic items (e.g., $2 million, or double previous month's level).

2. To confirm inclusion of only allowable costs, determine which categories in the applicant's own accounting system are likely to record charges not allowed under MMS regulations and guidelines (30 CFR 220.013 and Attachment 1 of end-of-life guidelines).
   a. Review cost elements in these categories of the applicant's own accounting system which should record any non-allowed costs. Eliminate charges for any items found to be non-allowable from the amount confirmed in procedure 1 above.
   b. Compare any transportation and processing costs shown in the application with transportation and processing allowances claimed against past royalty payment obligations. Certify that the two figures are consistent.

3. To confirm that only authorized overhead is claimed, allocate cost categories from the applicant's accounting system either to those authorized to charge overhead (labor, material, abandonment, or other as described in Attachment 1) or to those not allowed to (contract services, transportation, rentals, insurance, communications, ecological and environmental). Either of two options may be used to check the size of the overhead subset of allowed costs.
   a. If a majority (>50 percent) of charges in an applicant's cost category fall into MMS categories that are authorized overhead, the whole category of costs is allocated to the overhead subset, otherwise the whole category of costs is allocated to the non-overhead subset.
   b. In each category of the applicant's accounting system, charges authorized overhead may be identified and combined with like charges in the other categories of the applicant's accounting system.

Attachment 4
Spreadsheet Format for Production, Revenue and Cost Data

We urge you to report your data in the format shown on this and the next two pages. You may get a computer (Excel) version of this spreadsheet, which includes formulas to preform the appropriate calculations, from your Regional MMS Director or MMS website at http://www.mms.gov.

Zeros or "ROY/NR" in the following spreadsheet tables indicate cells where formulas calculate values based on entries in the blank cells. Entries in the "Month/Year" column are simply illustrations to be replaced by the qualification period relevant to your application.

End-of-Life Royalty Relief
Relief Qualification Worksheet (page 1)

Month/Year	Royalties Paid (ROY)	Gross Value of Production (GVP)	Allowable Costs (AC)	Transportation & Processing Costs (TPC)	Net Revenue (NR) (GVP - AC - TPC)	Royalty Share
Jan-98	$0.00	$0	$0	$0	$0	ROY/NR
Feb-98	$0.00	$0	$0	$0	$0	ROY/NR
Mar-98	$0.00	$0	$0	$0	$0	ROY/NR
Apr-98	$0.00	$0	$0	$0	$0	ROY/NR
May-98	$0.00	$0	$0	$0	$0	ROY/NR
Jun-98	$0.00	$0	$0	$0	$0	ROY/NR
Jul-98	$0.00	$0	$0	$0	$0	ROY/NR
Aug-98	$0.00	$0	$0	$0	$0	ROY/NR
Sep-98	$0.00	$0	$0	$0	$0	ROY/NR
Oct-98	$0.00	$0	$0	$0	$0	ROY/NR
Nov-98	$0.00	$0	$0	$0	$0	ROY/NR
Dec-98	$0.00	$0	$0	$0	$0	ROY/NR
12 month total/average	$0	$0	$0	$0	$0	ROY/NR

End-of-Life Royalty Relief

Production/Royalty Summary - All Products by Month/Year (page 2)

Product	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
Oil												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
Gas												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
NGL												
Sales Volume												
Sales Value												
Transportation												
Processing												
Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid												
Other Products												
Sales Value												
Total T&P												
Royalties Paid												
All Products												
Sales Value	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

End-of-Life Royalty Relief
Allowable Costs (page 3)

Code	Category	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
100	Labor												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
200	Material												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
300	Transportation												
400	Contract Services												
500	Lessee Owned												
	Rentals												
600	Insurance												
700	Communications												
800	Ecological &												
	Environmental												
900	Abandonment												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1000	Other Costs												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1100	Other Credits												
	Total Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0