# 30 CFR Part 203, Subpart B Regulation
# Relief or Reduction of Royalty Rates – Deep Gas Provisions

## Benefit-Cost/Small Business and Regulatory Flexibility Economic Analyses

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## I. <u>Introduction</u>

The intent of this analysis is to satisfy the requirements of E.O. 12866 and the Small Business and Regulatory Flexibility Act (SBRFA). Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions and, for significant regulatory actions, submit a detailed report of their assessment to the Office of Management and Budget (OMB) for review. A rule may be significant under E.O. 12866 if it meets any of four criteria. The two that could apply to this rule are that it has an effect on the economy of $100 million or more in a year and that it raises novel legal or policy issues. For a major rule, SBRFA requires agencies to prepare an initial regulatory flexibility analysis when proposing a major rule. A rule may be major if it meets any of three criteria. The one that could apply to this rule is again that it has an effect on the economy of $100 million or more in a year. SBRFA requires an agency to prepare a final analysis when issuing a final rule that will have a significant impact on a substantial number of small entities.

The material presented in parts II through V describes the incentive provisions of this regulation, the compelling need for this regulatory action, considers a range of possible alternatives to serve that need, and analyzes the benefits and costs of the regulatory action. Gas producers gain additional profit and the public benefits from additional domestic gas production and reduced gas prices due to this regulatory action. The adverse effects of this regulatory action are the forgone Federal royalties on production that would have been generated without this program. Parts VI and VII review the novel policy issues and small business effects of this proposal. Seven appendices discuss assumptions about drilling and undiscovered resources used to quantify the effects of the proposal and several alternatives. Printouts of the spreadsheets used to calculate the effects reported here are included as well.

II. Regulatory Incentive Provisions

The rule offers a two-tiered royalty suspension program for leases issued before 2001 (old leases) in the Gulf of Mexico (GOM) in less than 200 meters of water depth (hereafter referred to either as *shallow water*).

The incentive program provides:

- A maximum royalty suspension volume (RSV) for a lease on the first 15 billion cubic feet (BCF) of deep gas production from a new well drilled and completed from 15,000 feet to 18,000 feet subsurface (i.e., below sea level) and on the first 25 BCF for a new well drilled 18,000 feet or deeper subsurface. The maximum RSV applies:
    - To leases that have not produced from a well 15,000 feet or deeper. Such leases account for over 90% of old, shallow water leases.
    - For an original (vertical) well, meaning one that uses neither a pre-existing wellbore nor a reclaimed slot on a platform. About 80% of wells drilled 15,000 feet or deeper subsurface (deep wells), on old shallow water leases are of this type. The remainder are sidetracks

In both deep depth drilling categories, these maximum suspension volumes approximate the smallest reservoir size that can be developed economically with such wells without benefit of a pre-existing platform and the presence of full royalties. Larger suspension volumes might be effective but could also provide more relief than necessary to drilling targets that could be undertaken in the status quo. Smaller suspension volumes might be adequate where pre-existing platforms and pipelines lower development costs, but these would be less effective for prospects that cannot be accessed from available infrastructure.

- A reduced RSV for a lease that drills and produces a sidetrack deep well or a well deeper than 18,000 feet subsurface after producing from 15,000 – 18,000 feet subsurface (deeper deep well). The reduced RSV:
  - For a sidetrack is equal to 4 BCF plus 0.06 BCF per hundred feet of length drilled up to a total of 15 BCF if it is completed in the 15,000-18,000 foot subsurface interval or 25 BCF if it is completed deeper than 18,000 feet subsurface. Sidetracks have accounted for 16% of deep wells and 21% of deep well completions on old, shallow water leases in recent years.
  - For a deep well to the deeper depth interval is 10 BCF if the deeper well is an original well, or 4 BCF plus 0.06 BCF per hundred feet of length drilled up to a total of 10 BCF if the deeper well is a sidetrack. About 6% of old, shallow water leases have produced from a deep well but could qualify for the reduced RSV and about 5% of old, shallow water leases have produced a well deeper than 18,000 feet subsurface after having produced one from 15,000-18,000 feet subsurface.
- A deep well drilled after the date of the proposed rule or a deep sidetrack or a deeper well drilled after the effective date of the final rule may qualify for the incentive. In all cases, the deep drilling must result in production that starts before 5 years following the effective date of the final rule.
- A maximum royalty suspension supplement (RSS) of 5 BCF, applied to future oil and gas production anywhere on the lease, is allowed in certain instances for an unsuccessful well drilled to a target reservoir 18,000 feet or deeper. The maximum

applies to an original well while a reduced RSS of 20% of what the RSV would have been applies for a sidetrack that is drilled at least 10,000 feet. No RSS is available after the lease has a successful deep well. The small sized credit provides a relatively powerful incentive to expedite exploratory drilling, because of the high risk in very deep depths. Larger suspension amounts per credit could cause drilling inefficiencies in some circumstances. The RSS is limited to the same lease for legal reasons. Two royalty suspension supplements can be earned per lease prior to production from a deep well, but only for drilling before a successful deep well on the lease.

- New leases (those issued after 2000) may opt to convert from the deep gas incentive terms with which they were initially issued to those terms in this regulation.
- Notwithstanding any remaining RSV or RSS, a lease must pay full royalty on all production when the annual average daily closing gas price on NYMEX exceeds $9.34 per million British thermal units (MMBtu). This price threshold value is escalated for inflation from the year 2004 at the GDP price deflator. Any production during a year when prices exceed the threshold counts against any remaining RSV and RSS. We chose the $9.34 price level because it achieves almost as much boost to production as would a no-threshold policy at lower expected forgone royalty than do alternatives that delay implementation of a price threshold for several years.

The limited duration of this royalty relief incentive will have two distinct effects on production: recovery of some otherwise uneconomic gas resources (incremental production) and recovery of some marginally economic gas resources that would not have been produced until several years in the future without the incentive (accelerated production).

We conducted this benefit/cost economic analysis, as we did the one for the proposed rule, assuming the price threshold will never be violated. We update the initial price sensitivity analysis to include sidetracks and deeper well relief using a more recent EIA price projection. An independent analysis in Appendix 4 addresses the potential effect that price threshold options may have on incremental production and royalty collections.

III. Need for the Incentive

A. Supply Gap and Price Volatility

Demand for natural gas is expected to rise strongly while domestic supplies are dwindling. Natural gas provides about one-fourth of the annual United States energy consumption. The National Petroleum Council *[Natural Gas, Meeting the Challenges of the Nation's Growing Natural Gas Demand*, NPC, December, 1999] forecasts that demand for natural gas will increase by about 30% in the United States by 2010 (from 22 to 29 trillion cubic feet (TCF)) annually. The Energy Information Administration (EIA) projects that U.S. demand for natural gas could increase more than 50% (to 35 TCF) by 2025 (Annual Energy Outlook, 2003). Because gas transportation is largely limited to pipelines, domestic production of natural gas provides the large majority (almost 85%) of U.S. consumption (versus 42% for crude oil) [*Annual Energy Outlook 2002*, EIA]. Approximately one-fourth of domestic natural gas is produced in Federal waters of the GOM, four-fifths of which is currently derived from leases located in shallow water.

Data available on the MMS website show shallow water production has been declining since the mid-1990s, down from 4.76 TCF in 1997 to 3.96 TCF in 2000. Since the mid-1980's annual gas production from the OCS has exceeded additions to proven reserves each year. As a result, total proven natural gas reserves on the GOM OCS have declined from nearly 46 TCF in 1986 to approximately 24 TCF in 1999 [*Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1999,* OCS Report MMS 2002-007]. Without a reversal of these trends, OCS production of natural gas could experience a significant decline over the next 5 to 10 years, resulting in less domestic supplies and higher more volatile natural gas prices to consumers and commercial users.

B. Regulatory Inconsistency and Market Failure

The incentive provisions in this rule are designed to offset some unintended obstacles under existing federal regulations which hinder the ability of existing lessees to undertake deep drilling. This rule is also focused on mitigating the effects of broader market failures that will make it progressively more difficult for shallow water production to provide its expected share of total supply. These obstacles and market failures include: 1) excessive royalty rates for deep gas prospects imposed by existing lease documents, 2) the transitory nature of OCS infrastructure, a key factor of OCS production, and 3) an externality associated with the inability of the operator or entrepreneur to capture the full benefits of a) information generated about a frontier area and b) the necessary technology developed for use in such an area.

We believe that the existing royalty rate is too high to encourage expeditious exploration and development of most deep OCS oil and gas fields, as required by the OCS Lands Act. The royalty rate imposed on OCS leases has traditionally been made uniform for the whole lease to eliminate one source of uncertainty for those who would bid on a new lease's uncertain potential, and to allow ease of unitization between adjacent leases with shared reservoirs. The original royalty rates on active leases were set with shallow depth drilling in mind, since this has been the most easily assessed and the predominant source of production on these leases. Because deep drilling is significantly more costly and risky than shallow drilling on the same lease, this uniform rate is usually too high to make exploring and producing most deep prospects economic. Over the 50 plus year history of OCS production in the Gulf of Mexico, the MMS proprietary data base (TIMS) shows that only about 5% of wells have been drilled below 15,000 feet true vertical depth, i.e., measured from the water surface. Since the gas from shallow and deep wells sells at the same price, the royalty share on the latter source needs to be less if it is to become a competitive source of shallow water production.

Further, the time has come to encourage production of the deep gas potential. Typically, when the resources that are economic to produce are exhausted, a lease is abandoned by returning it to the government and removing production infrastructure (platforms, pipelines). Once abandonment occurs, production of any remaining potential on the lease generally becomes more costly since new facilities must be installed. As production from traditional shallow wells winds down on many leases, the benefits to the operator from abandonment grow. MMS is seeking to adjust original lease terms to encourage the exploration and production of the deep zones now while extensive infrastructure is still in place in the shallow water.

MMS is proposing to adjust the original royalty rates through the use of a royalty suspension volume, in part to address another form of market failure. The deep zones in the shallow water are still considered a frontier area. For example, outside the Norphlet trend area off Mobile, no commercially successful wells have yet been drilled deeper than

20,000 feet. That means little is known about where the best prospects are likely to be found, what flow characteristics and problems are associated with such reservoirs, and which technology and processes work best with the unusually high pressures and temperatures extant at deep depths. Yet MMS estimates there is 5 to 20 TCF of undiscovered gas in deep depths, largely those deeper than 18,000 feet [*The Promise of Deep Gas in the Gulf of Mexico*, OCS Report MMS 2001-037]. Recent estimates based on new seismic technology have raised the most likely and upper bound potential to 27 and 55 BCF respectively (DOI-MMS Press Release #3012, November 19, 2003). Thus, operators achieving early deep successes will resolve basin risk issues and identify best technologies thereby generating information valuable to later operators. Yet, these pioneers are unlikely to capture all the benefits of their breakthrough since they don't control all the deep prospects, so less than the optimal level of effort will be devoted to this activity. Temporary royalty reductions help compensate for this market shortcoming. Moreover, setting a zero royalty for a fixed production volume (i.e., royalty suspension) concentrates this compensation so it maximizes the private value of the incentive and ensures that the timing of the incentive coincides with the timing of the initial public benefits from the activity. Further, royalty reduction available only for activity undertaken during a limited period will expedite the activity while the transitory infrastructure is still available, and reward those who pioneer the technology and geologic understanding that opens this frontier area.

C. Goal of Policy Response

For the nation as-a-whole, increased drilling and production of deep prospects in the GOM will add information on this under-explored area. Such information will improve the results from subsequent deep drilling and foster better techniques for assessing deep potential. Also, that new information will improve MMS's ability to appraise the value of the deep resource potential on tracts offered in subsequent lease sales, thereby further helping to assure receipt of fair market value, an important responsibility of MMS. Increased production of deep gas and oil resources will extend the useful life of substantial infrastructure already installed in the shallow water GOM, promote domestic energy security and use of cleaner natural gas, generate added operator profits, and moderate domestic gas prices. Only the last two of these effects can be readily quantified. For the most part, we use estimates of added resources to be discovered as a proxy for all the benefits from options to the status quo.

After a review of alternative incentive options in part IV, cost-benefit analysis in part V estimates readily quantifiable measures of the net social benefits from incremental production and the loss of royalty associated with production that would have occurred anyway. These estimates include a measure of the benefits from the accelerated portion of production using a present value process to measure the gain from earlier production of reservoirs than would otherwise occur.

IV. Alternatives

Responses to this need to jump-start deep gas exploration and production vary from doing nothing in hopes that rising prices, together with other Federal incentives, will open this horizon and reverse the decline in OCS gas production, to providing one of several royalty relief incentives targeted to deep gas potential. Incentive options range from reducing royalty rates on deep production, suspending royalties until deep gas producers recover a fixed value, or suspending royalties for one of several volumes. In this section we qualitatively explain why the rate reduction and value suspension approaches are inferior to the royalty suspension volume approach. We also add the effects of sidetrack and deeper well qualification to the analysis of the two best of the six alternatives analyzed in the initial study. Finally, we review the procedural issue of why we don't use an auction process to distribute the royalty suspensions.

A. Inadequacy of Existing Incentives

Existing Federal incentives are not likely to increase OCS gas production much in the near-term. Over the past 7 years, the Minerals Management Service (MMS) has implemented several royalty suspension programs. Royalty suspensions foster greater recovery of oil and gas by increasing industry's expected financial return relative to other (e.g., foreign) investment opportunities. Deepwater royalty suspensions have been offered since 1996. Most of the interest in deep water is directed to oil rather than gas fields. Also, because of long lead-times associated with deepwater projects (10 to 20 years), it will still be years until deepwater production becomes a major contributor to our nation's domestic supplies. For the same reason, deepwater sources have only limited ability to respond to near term shortages and price increases. Since the deepwater royalty incentives were introduced in the 1996 lease sales, only 29 of over 3,400 deepwater leases have posted production, with five of those leases on fields that produced before 1996.

Deep gas drilling incentives have been offered for new shallow water leases issued after 2000. These incentives cover only a fraction of the shallow water deep gas potential, as we estimate that most of the undiscovered deep gas resources are on old leases issued before 2001. These older leases are in areas that industry generally feels has the best potential since they were acquired first. Even new shallow water leases face 5 to 10 year lead times from lease issuance to production, in part because exploration drilling is generally postponed until the end of the primary lease term for all but the best prospects. Through mid-2003, though some 1,239 new leases have been issued with deep gas royalty relief, only 1 has produced at deep depths. Accordingly, production from deep wells on existing leases in shallow water, where significant infrastructure already exists and some deep exploration has already occurred is the most promising source on the OCS for additional natural gas in the near-term.

Before the lease sales held in 2001, MMS had not exercised its royalty relief authority in lease terms for new shallow water leases in over 20 years. Except for deep wells, few financial and technical obstacles inhibited drilling and initiating production in shallow water. However, little of the deep reservoir potential on existing leases has been explored because deep wells pose a high risk of geologic or mechanical failure and entail higher cost than drilling other wells on the lease. TIMS data show that only about 20% of all exploration and development wells drilled deeper than 15,000 feet TVD SS have produced versus 54% for such wells drilled to shallower depths. Cost estimates for wells drilled deeper than 15,000 feet TVD SS run $9 to $23 million [*The Promise of Deep Gas in the Gulf of Mexico*, OCS Report MMS 2001-037] versus $4 to $6 million for wells drilled to say 12,000 feet TVD SS [estimates used in MMS proprietary tract evaluation model, MONTCAR]. TIMS data show that only about 170 of some 2,400 active pre-2001 leases in shallow water have produced from reservoirs deeper than 15,000 feet TVD SS. Yet, significant undiscovered resources could be produced from these deep reservoirs.

B. Alternative Volume Suspensions

Five different volume suspension alternatives to the incentive provisions in the regulation were evaluated for the proposed rule. Appendices 1 and 5 describe the rationale for and attributes of each of the 5 alternatives to the proposal.

The comparison of the 6 volume suspension alternatives showed that the RSV levels actually proposed (alternative #1) provided the largest net social benefit. Alternatives #4 - #6 were inferior to #1 on both net social benefit and forgone royalty measures. Since the incentive terms in the proposed rule cover the large majority of the wells likely to benefit from the final rule incentive, we do not revise the analysis of all 6 volume alternatives for the final rule. However, the earlier analysis indicated that alternatives #2 and #3 may have cost-effectiveness advantages since they provided almost as much net social benefit (80 to 90%) for about half the amount of forgone royalty. Since alternatives #2 and #3 are very similar, we only retain #3 in the final rule analysis. Alternative #3 involves an RSV of 10 BCF (rather than 15 BCF) for a lease with a qualified original well to 15,000-18,000 feet subsurface and 20 BCF (rather than 25 BCF) for a lease with a qualified original well to at least 18,000 feet subsurface. Other features of the incentive structure, including RSV's for sidetracks and deeper wells and RSS's, remain the same as for that in the final regulation.

C. Non-Volume Suspension Relief Options

1. Royalty Rate Reduction

The option of simply reducing royalty rates on production from completions deeper than 15,000 feet has some attractive features. Royalty, even at a reduced rate, provides some revenue to government from the beginning of any new production, moderates the forgone royalty associated with production that would have occurred in the absence of royalty relief, and reduces the royalty loss if MMS makes errors in forecasting the royalty suspension level necessary to achieve the desired incentive. Also, royalty rate reductions can be useful when the incentive is to be applied to production that can occur in a variety of ways that individually deserve different suspension amounts. In such situations, a uniform royalty rate reduction applicable to all types of production approaches would avoid the complication of supplemental conditions and constraints on lessee choice needed to prevent the incentive from distorting the lessee's selection of the most efficient mode of production.

But royalty rate reduction is an inferior incentive tool on many counts. The profit boost from a royalty rate reduction would be stretched over the life of the deep well rather than concentrated at the beginning of the production period as with a royalty suspension. That means lessees with larger reservoirs would reap proportionally larger benefit with a royalty rate reduction because they produce more at lowered royalty rates than do smaller, marginally economic reservoirs more in need of the incentive. Stretched out receipt of the relief would also increase the risk to the lessee that the reservoir discovered would be too small or the relief would be rescinded too soon to yield the intended or expected boost to profits. Further, since discount rates are higher for private entities than the government, a royalty rate reduction provides a lessee with less incentive than a volume suspension that is of equivalent cost to the government.

In summary, because the deep gas incentive is aimed at a narrowly defined target, i.e., new deep wells, whose costs and risk can be reasonably estimated, there is no need to default to and accept the limitations of the more general incentive structure of a royalty rate change. Carefully chosen royalty suspension volumes will be a more efficient and familiar set of incentives. Since the Deep Water Royalty Relief Act (DWRRA) of 1995, royalty suspension volumes have become the customary incentive tool both for lessees and MMS. That familiarity reduces uncertainty and possible conflict that would be associated with a new relief structure.

2. <u>Royalty Value Suspension</u>

The DWRRA granted the Secretary the authority to suspend royalties for a "period, volume, or value of production… which suspensions may vary based on the price of production from the lease;". Royalty suspension can be viewed as a way to help operators recover development capital by increasing early cash flow retained by operators from their projects. Suspension for a given dollar value is a precise way to grant just the intended amount of relief for the selected class of projects. Also, this approach has the theoretical advantage of increasing the number of barrels or cubic feet of relief provided as prices decline, and reducing the number as prices increase.

But, there are a number of practical disadvantages too. Inflation will reduce the value of a fixed dollar amount of relief, obliging creation of an escalation procedure. Such a procedure requires careful selection of the appropriate escalator, subsequent monitoring and perhaps controversy, and adds uncertainty to long term planning by lessees. Also, establishing production value across many different lessees can be complicated. Different participants on the same lease may sell their product shares at different prices which they may not disclose to their partners. So granting a value suspension to a lease can lead to complex accounting issues relating to how fast, and when, the value suspension is used up. Also, providing a value suspension may compromise proprietary information among companies participating in a lease or well. Further, audits periodically result in adjustment of the value assigned to a lease's product and to the allowed transportation cost deductions, thereby requiring periodic correction in the amount of relief previously taken on a value basis. The recent royalty-in-kind initiative is driven in part as a way to avoid recurrent conflict between oil and gas producers and MMS as to the appropriate production value against which to assess royalty. Perhaps for reasons like these, Congress mandated that the deep water program during 1996 – 2000 use the simpler volume of production measure for royalty suspensions.

In summary, because the volume suspension approach is simpler to structure than a value suspension approach, it is less prone to weaken the intended incentive by confusing or adding uncertainty to a lessee's deep drilling activity. The industry understands and has responded well in the past to the volume approach and MMS has continued its use after the period mandated in the DWRRA to avoid inconsistency with established program formulations and in accounting for royalty on unitized tracts. A similar situation exists in shallow water, where leases issued during the past few years have financial terms expressed as royalty suspension volumes for deep depth drilling.

D. Adjustments Made in the Final Rule

1. Incentives for Sidetrack Wells

No specific incentive for deep sidetrack wells was included in the proposed rule. We based this initial decision on the judgment that properly including sidetracks would add significantly to the complexity of the incentive and on historical data indicating that sidetracks were too few and too small to make that complexity worthwhile. Also, analysis with available cost data indicated that royalty relief for original (or non-sidetrack) wells but not sidetrack wells would not be large enough on average to change relative costs of these two options sufficiently to distort the drilling decision.

Respondents to the proposed rule raised compelling reasons to change this judgment. Most telling was the fact that reusing infrastructure by reclaiming platform slots from abandoned wells would be excluded from the incentive because they are classified as sidetracks. Also, the average cost is not a good representation because sidetrack lengths and thus drilling costs vary so widely. Thus, some important distortions could occur with no sidetrack incentive. Fortunately, without being inordinately complex we were able to devise an RSV and RSS structure for sidetracks that solved these problems. (See Appendix 1.) As explained later in this analysis, the inclusion of a reduced sidetrack deep well incentive actually improves the benefit/cost ratio for this program because some added discoveries will now be generated from sidetracks rather than original wells, thereby costing less in forgone royalties.

Several factors contribute to the relatively small net increase in the addition to gas reserves due to adding an incentive for deep sidetracks. One factor is that sidetrack wells are likely to be associated with smaller production than original wells. This expectation results from the nature of drilling deep wells. Casing strings telescope down from the surface as wells penetrate deeper into the earth. Sidetracks (other than in slot reclamation situations) are generally limited to smaller diameters than the original well from which they emerge because they kick-out below the surface. A well diameter originally designed for a depth of say 12,000 feet doesn’t need to be as large as one designed for 17,000 feet. Thus, production capacity is less likely to be constrained in an original deep well from the surface than in a deep sidetrack drilled from a shallower original well that is often smaller at the surface.

Data specific to deep depths offers inconclusive estimates on the relative size of past production from sidetracks and non-sidetracks. For instance, reserve estimates for reservoirs associated with deep sidetracks run about 40% the size of those associated with deep non-sidetrack wells. On the other hand production from deep sidetracks old enough to have produced and been abandoned roughly equals that for abandoned non-sidetrack deep wells. As there are problems with both of these measures, we turned to a broader indicator of sidetrack's relative production size. A much larger sample of data from TIMS -- all wells on shallow water leases drilled over the past 15 years to all depths -- indicates that an average sidetrack produces about 2/3's as much as an average original well. We adopt that ratio as representative for future deep wells in the shallow water.

Part of adopting this ratio involves adjusting the size of reservoirs whose discovery is attributed to the incentive. In the initial analysis we used the average size estimated from the distribution of undiscovered deep gas resource accumulations for non-sidetrack wells. Dividing that single average between sidetrack and non-sidetrack wells, means a slightly larger average size (about 7.5%) is attributed to non-sidetracks than in the initial analysis. The overall average still matches the initial analysis, but now 21% of the discoveries are assigned to smaller sidetracks.

The second factor reducing the significance of adding sidetracks to the incentive is that some incremental sidetracks may displace a few incremental original wells that would have been drilled when the incentive applied only to original wells, as in the initial benefit/cost analysis. This is at least the implication of comments to the effect that the proposed rule would cause the more costly original well to be drilled when a less costly sidetrack could do the job.

To gauge the displacement effect associated with adding sidetracks to the incentive, we looked at historical proportions of leases in three categories. One category, those that only have a non-sidetrack deep well (60%), suggests a share of leases with deep prospects where no displacement sidetrack opportunities exist (e.g., no available platform slots or existing wells close enough to serve as a base for a sidetrack to a deep target). A second category, those that have only a sidetrack deep well (20%), suggests a share of leases either where sidetracks are much cheaper than original wells or where other considerations (e.g., free slot) favor a sidetrack, so a relatively small incentive for a sidetrack well would not displace a nonexistent original well. The third category, those that have both a non-sidetrack and a sidetrack deep well (20%), suggests a share of leases where an incentive only for non-sidetracks may affect the choice of well types. Some incremental non-sidetrack deep wells in the initial benefit/cost analysis thus could have been drilled at the expense of sidetrack wells that would have been drilled on this third category of leases. By equalizing incentives for the two types of wells, we may gain some sidetracks at the expense of a reduced gain in non-sidetrack wells on these leases. Lacking other information, we therefore presume that half of the added original wells on this category of lease (or 10%) in the initial analysis will not be added when sidetracks are eligible for an equivalent royalty incentive.

A third factor affecting the sidetrack results is the conservative nature of the projected increase in drilling intensities. We based our findings on the assumption that, aside from some displacement discussed above, added sidetracks will occur in the same proportions as original wells, using the status quo (no relief) as the standard for each well type. But, relief provided may open up entirely new opportunities and generate technological improvements that will allow operators to more fully exploit both existing and new reservoirs. Such outcomes are not captured by an extrapolation of past trends and relationships.

2. Incentive for Deeper Well

Leases that already have a successful deep well in the 15,000-18,000 foot category become eligible for a reduced incentive if they subsequently drill a sub-18,000 foot well. We excluded leases in this situation from the incentive in the proposed rule based on a judgment that a deep discovery resolves much of the risk associated with deep drilling. This conclusion is too general according to comments on and analysis since the proposed rule. Just as success shallower than 15,000 feet subsurface is only weakly associated with success drilling deeper, success in the 15,000-18,000 foot interval is only weakly associated with drilling deeper than 18,000 feet subsurface. To avoid unintentionally by-passing a few very deep prospects, we decided to add a reduced incentive for exploring the deeper zone after success in the less deep zone.

Compared to the other parts of the incentive, the fiscal cost of this feature is likely to be small. Past experience indicates that about 5% of existing shallow water leases with production at 15,000-18,000 feet subsurface then drill and produce a well deeper than 18,000 feet subsurface. Yet, some very deep discoveries could be encouraged by an incentive that is only about 40% the size it is in other situations. To be consistent we include leases that both have and have not had a deep production before the proposed rule. The main effect of this rule change will be to increase the base number of wells from which increased drilling due to the incentive occurs.

E. Auctioning RSVs

We briefly considered alternative mechanisms of distributing a royalty suspension volume to lessees. One, a case-by-case approach was quickly dropped. While case-by-case review could conceivably eliminate forgone royalty, it would add delay and much uncertainty about approval and thus interfer in the delicate deep drilling decision. As such we believe it would do little to increase new deep drilling in the near future.

Another approach would seek to allocate approximately the same total royalty relief with an auction process rather than with a uniform allocation to all lessees. Under the auction process not all lessees would receive the same relief and allocation would work as follows. Authorized leaseholders, those with leases awarded prior to 2001, would submit to MMS an offer of the volume of royalty relief they would require to undertake deep well drilling. MMS would rank the offers from the least amount of royalty relief to the greatest, taking into consideration the depth of the wells (15,000-18,000 ft or sub-18,000 ft). MMS would select the best ranked (lowest) offers until their cumulative amount reached a predetermined cutoff level of royalty relief. MMS would then renegotiate the terms of existing leases of the selected leaseholders to provide the royalty relief per their individual offers. The remaining offers—those requiring the largest royalty relief—would not be accepted. For any royalty relief awarded, the leaseholder must begin drilling a deep well within a designated time period.

The eligibility requirements that MMS would apply under the proposal would also apply under this approach. For example, leaseholders that have already drilled successful deep wells to at least 18,000 feet subsea before the proposed rule is published would not be eligible for this program. However, leaseholders who first drill a successful deep well after the proposed rule would be eligible to receive royalty relief if their bid for royalty relief was accepted. MMS would ask leaseholders to specify in their offers the depth of wells they would drill, and the volume of royalty relief suspension volume they seek on a successful well. Leaseholders would specify separate royalty relief suspension volumes in their submission, one for 15,000-18,000 ft depth and the other for the sub-18,000 ft depth. Leaseholders can also specify a royalty relief supplement for up to two unsuccessful wells in the sub-18,000 ft depth. The magnitude of the royalty relief supplement per well should not exceed 5 BCF.

This alternative approach may result in added drilling activity and production for lower or the same Federal forgone royalties compared to the preferred alternative, because it encourages lessees who would drill without relief to accept lower relief amounts than they would receive under a fixed allocation system. However, due to a number of unresolved implementation issues, we decided to seek comments also on this concept rather than include this feature in the proposed rule. Unlike sidetrack comments, we expect to use any auction comments to guide the design of future royalty relief opportunities.

One issue is the cutoff for accepting the ranked offers in this approach. It should be related to the incremental production MMS estimates the relief can generate and the total Federal cost expended. Factors relevant to this determination include, for example, the total number of wells MMS expects to produce, the volume of royalty relief provided to each well, the expected number of wells that would not be drilled without royalty relief, the number of bids judged to have been offered by authorized lessees who can claim relief from new drilling activities and who actually intend to drill to deep depths, and the likelihood of drilling success. In using those estimates to determine the pool of accepted offers, MMS would seek to allocate approximately the same total royalty relief as the preferred alternative. All of these magnitudes are based on forecasts which are always subject to error. Whereas the adopted categorical approach fixes the size of the relief and lets government revenues bear the risk of erroneous forecast, the auction approach would fix the maximum size of the government revenue exposure and let the drilling response bear the risk of an erroneous forecast. How much is MMS likely to save and at what cost in terms of drilling delayed or forgone as a result of employing this alternative allocation mechanism?

Other issues are associated with this approach, and resolving them satisfactorily would involve a delay until this additional analysis could be performed. That delay alone would compromise the effectiveness of this incentive since it is justified by the expectation of a near-term result. The following are some of these unresolved issues:

(1) The risk to the integrity of the auction approach if successful bidders choose not to drill within the specified period and thus inadvertently penalize unsuccessful bidders. A fee for participating in the auction might avoid this risk if it could be structured properly. Identification and evaluation of a fee structure or other ways to minimize this risk will take time and could add another form of distortion to lessee drilling decisions.

(2) The choice of a reasonable period of time in which to expect operators to commence drilling after their offer is accepted. Setting the period too long would complicate

repeat auctions should the early drilling response to the first auction prove inadequate.

(3) Should MMS accept offers in a single sale at the outset of the program, or allocate the relief in a series of sales held over several years? Multiple sales would allow MMS to correct problems identified but may result in the cumulative grant of more relief than intended. Also, it may complicate planning by lessees and constrain the competition needed for a successful auction.

(4) If the total royalty relief allocated using the auction process turns out to be substantially lower than the total under this rule, the auction approach could result in less drilling activity than would have resulted under this rule. Should the total royalty relief granted under the auction proposal be the same as would be offered under the proposal, greater or smaller?

No respondents to the proposed rule favored further investigation of auctions for royalty relief. Typically, an auction is an efficient mechanism to ensure that the item being sold goes to the party that values the item most highly, and in conjunction with enough competition, yields a fair return to the seller. In our case, we want the item to go to those who can afford it least, i.e., have sub-marginally economic prospects and need royalty relief to induce drilling. We worry that precisely such bidders will be easily out-bid by lessees who would drill without relief, and by those who want the option but not the obligation to drill. So, while an auction procedure might be designed so as to reduce the fiscal cost of the program, such a program is likely to adversely affect the program's capability to accelerate drilling activities.

## V. Measuring Benefits and Costs

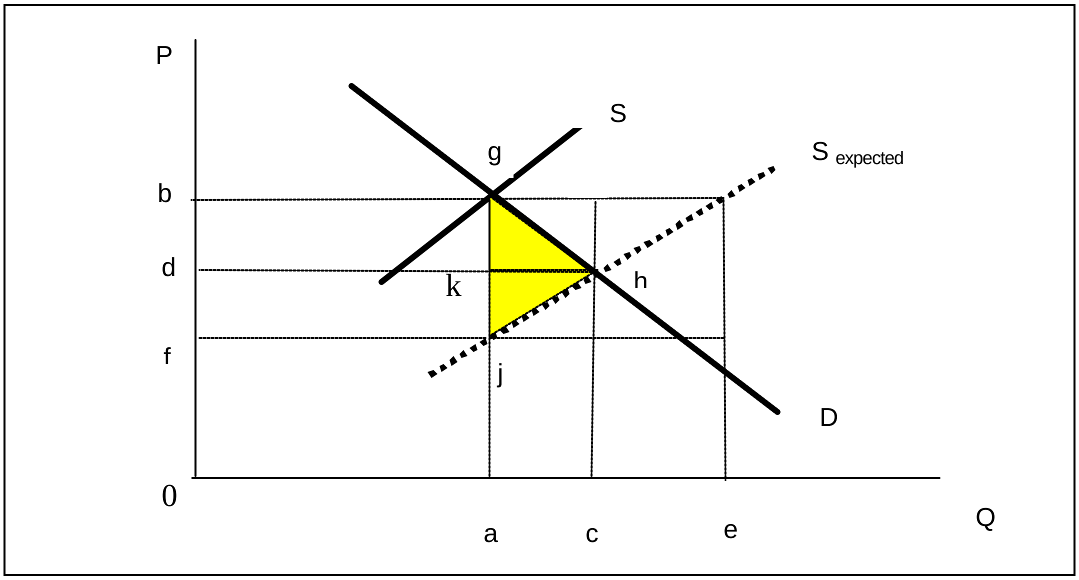
The royalty relief program for deep gas drilling will generate real benefits to the nation from increased exploration and production. It will also result in substantial transfers, from producers to consumers in the form of slightly reduced prices spread over all domestic gas sales and from government to owners of those leases in the GOM that respond to the deep drilling incentive in the form of reduced royalty collections. In this section we explain how we calculated these benefits and transfers, and put the change in royalty collections within the context of all royalty receipts from the OCS and from the deep gas component only.

### A. Net Social Benefits

Figure 1 illustrates conceptual amounts that need to be estimated to value the benefits and costs of this incentive. A supply shift from S to $S_{expected}$ due to the increased deep gas production (e – a) is expected to result from the drilling incentive. Associated with that supply shift is a royalty cost saving (b – f) for certain gas producers, those taking advantage of the deep drilling royalty suspension incentive. In response to this shift the market clearing quantity adjusts from a to c and the price from b to d. Consumers gain from the market price reduction spread over all gas. Much of this gain is a transfer from producers who gross less on the production they would sell in the absence of the incentive.

Certain producers gain extra profits on the increased production made possible by the royalty suspension (some of which displaces other gas supply) and on the transfer of royalty from the government associated with deep gas production that would have been

Figure 1: Net Social Benefits




profitable even without the relief. Social benefits can be calculated with estimates of net increase in market equilibrium quantity (c – a = h – k) and in royalty cost savings by certain producers (b – f = g – j). Net social benefits (represented by the triangle ghj) are the sum of the net gains after deduction of the transfers to producers and consumers associated with the additional production attributable to this rule.

B. Change in Equilibrium

An estimate of the price moderation and supply increase effects can be developed using estimates of gas demand and supply elasticity, of future gas consumption, and of the additional production from the royalty relief. A review of estimates in economic literature and models designed for MMS recommends use of a domestic demand elasticity value of -0.72 and a supply elasticity value of about 1.0 [William G. Foster, "Petroleum Supply and Demand Elasticity Estimates", January 28, 2000]. Assuming a flat gas price of $4.11 /mcf and an annual consumption of 25 TCF (the middle of the NPC demand forecast and a level EIA expects by the middle of this decade [*Annual*

*Energy Outlook 2002*, EIA]), we find incremental production from the regulatory incentive provisions to be 0.222 TCF (0.89%) in a typical year.

Increased supply of 0.222 TCF (e – a in Figure 1) from deep depth drilling could reduce prices by about 5.1 cents (1.25%) per MCF compared to what they would otherwise be. If we then factor in the response of this price decline on current gas supplies, we determine the net effect to be a decline in the equilibrium market price (b – d in Figure 1) of 2 cents (0.5%) per MCF. Associated with this reduction in equilibrium price is an increase in equilibrium quantity (h – k) of 0.087 TCF or 39% of the initial supply increase of 0.222 TCF.

Before turning to an estimate of the royalty cost saving, we note that a price reduction of 2 cents saves consumers about $500 million ($0.02 per MCF * 25 TCF) annually in expenditures on natural gas. However, from a social benefit perspective a large part of it would be offset by reduced income to gas producers.

The royalty cost savings are available only to those producers able to take advantage of the deep gas incentive, not all gas suppliers. With a landed gas price of $4.11 per MCF, a one-sixth royalty would generate $0.685 per MCF, so we take that as the value of the royalty cost savings (g – j). The net social benefit (ghj) averages about $30 million annually [(87 BCF * $0.685/MCF)/2].

The net social benefit estimate can be split into net changes in consumer surplus and producer surplus using the relative sizes of the elasticity of overall U.S. gas demand and overall U.S. gas supply. The 'kh' dimension (equilibrium quantity change) is the same for both parts of the net social benefit triangle. The corresponding percentage change in price along the demand curve is larger (making the consumer surplus about 60 percent of the net social benefit triangle) than along the supply curve because the absolute value of the estimated elasticity of gas demand is less than that of gas supply (leaving the producer surplus about 40 percent of the net social benefit triangle).

C. Production, Fiscal, and Social Welfare Effects of Alternative Royalty Suspensions

This section explains how we computed the expected programmatic effects, determined the present value of the benefits and cost of the incentive, and compared the proposal to the alternative of a reduced RSV in the two drilling depth categories. Appendix 1 details the source of the drilling intensity, reservoir size, and price assumptions. Table 1 summarizes the common assumptions used to estimate the values for each alternative.

We measured the likely effects of the deep gas incentive with a 6 step process. Please see a description of that process in Appendix 2 as well as the resultant spreadsheets in Appendix 5. The title at the top of each spreadsheet indicates the alternative it covers. For the proposed rule, we compared six alternative RSV amounts by adjusting the drilling intensity based on the strength of each alternative royalty suspension option relative to the proposal and repeated steps 3 through 6.

Comments on the proposed rule caused us to change three elements, two of which affect the initial benefit/cost economic analysis of the deep gas incentive program. We estimate the effects of these changes by extrapolating from the detailed analysis already done in support of the proposed rule, whose provisions still reflect the bulk of the effect of this rule. Table 2 summarizes the assumptions used for these extrapolations.

**Table 1: Assumptions**

| **Assumption** | **Value** |
|---|---|
| Elasticity of U.S. Gas Demand | -0.72 |
| Elasticity of U.S. Gas Supply | 1.09 |
| Average landed price of gas | $3.50/mcf |
| Likelihood price threshold exceeded | 0 |
| Average transportation cost of OCS gas | $0.25/mcf |
| Royalty Rate for OCS gas | 16.7% |
| Average tax rate for OCS lessees | 0% |
| Discount rate | 7% |
| Gas to Oil production ratio in deep reservoirs | 26 mcf/bbl |
| Thermal Gas to Oil ratio | 5.62 mcf/bbl |
| Likelihood of Deep Drilling Success | 33% at 15K'- 18K',<br>20% at 18K' or deeper |
| Cost of Drilling a Deep Well | $9 to $23 million |
| Average size discovered deep reservoirs | 21 BCFE at 15K'-18K',<br>30.5 BCFE at 18K' or deeper |
| Average size undiscovered deep fields | 45.5 BCFE at 15K'-18K',<br>97.3 BCFE at 18K' or deeper |
| Average size deep fields whose discovery is accelerated | 60 BCFE at 15K'-18K',<br>97.3 BCFE at 18K' or deeper |
| Average period accelerated production moved forward | 6 years |
| Share of extra reserves drilled under the incentive that are accelerated rather than added | 50% at 15K' – 18K',<br>25% at 18K' or deeper |
| Average # production wells per undiscovered field | 2 |
| Average deep well flow rate | 2.5 BCF/year at 15K'-18K',<br>4.6 BCF/year at 18K' or deeper |
| Average duration of RSS production | 2 years |
| Share of leases with RSS able to use it | 67% |

Table 2. Adjustment Assumptions for Final Deep Gas Rule Analysis

| | Parameter | 15,000-18,000' | ≥ 18,000' | Source |
|---|---|---|---|---|
| A | Increase in original well drilling intensity for non-sidetracks but not for sidetracks with proposed incentive at $3.50/MCF gas price | **46%** | **218%** | Based on MEFS related to undiscovered deep gas field size distribution |
| B | Success rates with future deep drilling by non-sidetrack wells | **33%** | **20%** | Lower than history since harder targets remain |
| C | Average size of reservoir (BCFE) found with increased deep drilling | **45.5** | **97.3** | Based on undiscovered deep gas field size distribution |
| D | Acceleration premium | **0.33** | **0.33** | Benefit of earlier production of gas |
| E | Acceleration part of added reserves | **50%** | **25%** | Presume little very deep drilling without incentive |
| F | Accelerated reservoir size relative to size of average undiscovered reservoir | **132%** | **100%** | Reflects better quality of accelerated over incremental reservoir |
| G | Increase in drilling intensity for non-sidetracks but not for sidetracks with alternative #3 incentive at $3.50/MCF gas price | **30%** | **195%** | Interpolated between proposal and high RSV with no RSS option |
| H | Increase in drilling intensity gas for sidetracks with ramped incentive at $3.50/MCF gas price | **46%** | **218%** | Derived from, and so equivalent to that for non-sidetrack wells |
| I | Sidetrack share of deep wells | **16%** | **16%** | Based on relation from 2001 and 2002 (only period over which sidetracks distinguished from by-pass wells in TIMS data base) |
| J | Sidetrack share of deep completions | **21%** | **21%** | |
| K | Sidetrack reservoir size relative to size of reservoirs associated with deep non-sidetrack wells | **2/3** | **2/3** | Based on 1988-2000 production with half of sidetrack amount moved to original as by-pass wells |
| L | Displacement of added non-sidetrack wells by sidetracks now with equivalent incentive | **10%** | **10%** | Eligible sidetracks displace this share of non-sidetrack wells added initially when only non-sidetrack wells were eligible. |
| M | Addition to baseline very deep wells from making leases that already have a deep well eligible | **N/A** | **6%** | Based on TIMS counts as of July, 2003 |
| N | Portion of leases with a deep success then a very deep success | **N/A** | **5%** | Based on proportion in currently active shallow water leases with deep wells |
| O | Addition to baseline deep wells with new EIA gas price instead of $3.50/MCF gas price | **20%** | **74%** | Based on price increase share of full price increase equivalent to proposed incentive |
| P | Increase in drilling intensity from higher base level associated with new EIA gas price and royalty relief | **39%** | **99%** | Interpolated between increase in intensity estimated at $4.50/MCF gas (for proposed rule) and at $3.50/MCF |

Tables 3 summarizes the baseline and average annual increase in drilling and reserves each year from incentives for original and sidetrack wells under 2 alternatives – the rule and the alternative of a reduced incentive at both drilling depth categories for original wells (alternatives 1 and 3 in the first benefit/cost analysis). We include the estimate from the proposed rule, under which only original wells were eligible, to show the effects of adding eligibility for sidetracks and deeper wells.

Table 3 describes the average annual increase in drilling and reserves each year the incentive program is in effect. The row headings show the incentives associated with each alternative while the second and third columns summarize the associated drilling intensity and discovery sizes. The data in the "no incentive" row show the baseline levels and the other rows the addition to this baseline associated with each alternative. The far right column shows the volumes from column J of the spreadsheets in Appendix 5 for each year the incentive is effective. These results indicate that making sidetracks and deeper wells eligible for royalty relief adds about 28% to the base or "no incentive" expected level of discoveries and about 16% to the additional resources discovered as a result of the deep gas incentive program.

Table 4 continues the same rows as in table 3, with column 2 showing the cumulative deep production associated with the baseline and the additions associated with each alternative. The third column shows the ratio of added deep production (incremental plus the acceleration premium) relative to the production on which royalties are forgone because this production would have occurred anyway without the incentive. All cases have a ratio larger than one indicating they add more new production than the amount of production on which royalty is forgone. The next 2 columns in table 4 show the size of transfers, to consumers and to producers, in present value terms. The last 2 columns show the size of royalty losses to the government and social benefits associated with each alternative in present value terms. The last column demonstrates that the largest net social gain is associated with alternative #1, indicating it is the best policy alternative. The inclusion of sidetracks and deeper well eligibility doesn't alter that finding.

Table 3: Annual Accrued Effect of Incentive at $3.50/MCF Gas Price on Sidetrack and non-Sidetrack Deep Wells

| **Option** | **# of Deep, Very Deep Wells Drilled Annually (successful)** | **Expected Size of incremental (accelerated) reservoirs, BCFE** | **Incremental hydro-carbons discovered, BCFE** | **Acceleration premium for hydro-carbons discovered earlier, BCFE** | **Total hydro-carbon + Acceleration premium Discovered, BCFE** |
|---|---|---|---|---|---|
| No incentive, original wells only | 37 (12) and 11 (3) | 21 and 30.5 | | | 344 |
| No incentive, original, sidetrack and deeper wells | 44 (15.2) and 13.9 (4) | 21 and 30.5 | | | 442 |
| | **Added Wells** | **Discovery Sizes** | **New Production** | **Production Moved Forward** | **Added hydro-carbons** |
| Proposed Rule, Alternative 1: original wells only with 15 BCF 15,000-18,000 ft and 25 BCF >18,000 ft or 5 BCF for up to 2 unsuccessful wells>18,000 ft | 17 (6) and 24 (4) | 45.5 (60) and 97.3 (97.3) | 384.9 | 92.4 | 477 |
| Final Rule Alternative 1: original & deeper wells + sidetrack incentive ‡ | 15.3 (5.4) + 3.7 (1.6) & 21.7 (3.5) + 4.8 (1.1) | 48.9 (64.5) + 32.6 (43.0) & 104.6 (104.6) + 69.7 (69.7) | 444.9 | 107.6 | 552 |
| Proposed Rule, Alternative 3: original wells only with 10 BCF 15,000-18,000 ft, 20 BCF >18,000 or 5 BCF for up to 2 unsuccessful wells >18,000 ft | 11 (4) and 21.5 (3.5) | 45.5 (60) and 97.3 (97.3) | 317.4 | 68.4 | 386 |
| Final Rule, Alternative 3: original & deeper wells + sidetrack incentive ‡ | 10 (4) + 1.8 (0.9) & 19 (3) + 3.4 (0.8) | 45.5 (60) + 30 (39.6) & 97.3 (97.3) + 64.2 (64.2) | 366.1 | 79.6 | 446 |

‡ Sidetrack incentive equals 4 BCF + 0.06 BCF per 100 ft, or 20% of that amount for unsuccessful sidetracks at least 10,000 ft long to targets at least 18,000 ft deep

## Table 4: Cumulative Effect of Incentive at $3.50/MCF Gas Price

| Option | Deep Gas Production from Undiscovered Fields, TCF | Added Production, TCFE relative to Forgone Royalty, TCF | Present Value of Transfer from Producers to Consumers, million $ | Present Value of Transfer from Government to Producers, million $ | Present Value Royalty Receipts from New Deep Gas Production, million $ | Present Value Net Social Benefits from Incentive, million $ |
|---|---|---|---|---|---|---|
| No incentive, original wells, sidetracks and deeper wells (original wells only) | 4.9 (3.8) | na | | | | na |
| | **Added Deep Production** | **Added over Baseline Production** | **Consumer Gain** | **Producer Gain** | **Government Loss** | **Social Gain** |
| Proposed Rule, Alternative 1: original wells only with 15 BCF 15,000-18,000 ft, 25 BCF >18,000ft or 5 BCF for up to 2 unsuccessful wells>18,000 ft | 2.35 | 1.36 | $2,740 | $834 | -$267.4 | $152.7 |
| Final Rule Alternative 1: original + deeper wells & sidetrack incentive ‡ | 2.73 | 1.49 | $3,095 | $883.5 | -$185.8 | $172.5 |
| Proposed Rule, Alternative 3: original wells only with 10 BCF 15,000-18,000 ft, 20 BCF >18,000 or 5 BCF for up to 2 unsuccessful wells >18,000 ft | 1.90 | 1.46 | $2,128 | $647 | -$128.3 | $119.3 |
| Final Rule, Alternative 3: original + deeper wells & sidetrack incentive ‡ | 2.20 | 1.50 | $2,423 | $723.2 | -$106.9 | $135.9 |
| ‡ Sidetrack incentive equals 4 BCF + 0.06 BCF per 100 ft, or 20% of that amount for unsuccessful sidetracks at least 10,000 ft long to targets at least 18,000 ft deep | | | | | | |

Comparison of the second and the next to last columns in Table 4 offers another point of view on the relative merits of the alternatives. Some of the forgone royalty would be offset by royalty collections on the condensate associated with the added gas reserves and on added gas production after the royalty suspensions have been used. Taking those into account and distributing the production over the next 15 years, we estimate a net reduction in present value of royalty receipts of $186 million with the final rule terms versus $107 million with alternative #3. Under the proposed rule terms (the first original well per lease only eligible) the reduction estimates were $267 million for alternative #1 and $128 million for alternative #3. This convergence in royalty cost results from the bigger drop in RSV associated with sidetracks and deeper wells from that for original wells (some of which are displaced by sidetracks) in alternative #1 than alternative #3 and to the greater concentration of forgone royalty in the early, less discounted years with alternative #3 than alternative #1. These comparisons suggest that alternative 3 promises 80% of the production effects (2.20 TCF versus 2.73 TCF) for about 57% of the forgone royalty cost to the government.

D. Price Sensitivity

Because current expectations are for gas prices to be higher than the $3.50/MCF level we used when developing the analysis for the above analysis for this rule, we've also conducted a price sensitivity analysis on the status quo and the two main alternatives. This sensitivity analysis addresses the issue of variability in drilling intensity as gas prices change for all of the measures shown in Tables 3 and 4. We compared the most recent EIA/MMS price projection, which combines the long term EIA projection in the most recent Annual Energy Outlook issued in December, 2002 and the EIA Short Term Energy Outlook projection issued in July, 2003. This most up-to-date (composite) gas price projection averages $4.11/MCF at Henry-Hub over the next 15 years or about 17%

higher than our base price assumption of $3.50/MCF. Historic ratios were used to convert wellhead to Henry-Hub and million Btu to MCF.

The assumptions we used to adjust the expected drilling intensity are as follows. Elsewhere we have noted that we based the price threshold on a price level at which market conditions achieve about the same results to the operator as the incentive. That is, a price of $5.00/MCF is roughly equivalent to royalty relief at $3.50/MCF. Thus, a price of $4.11/MCF alone should achieve about 40% the effect as the incentive provisions. That translates into 18 successes out of 53 deep wells annually and 6 successes out of 24 very deep wells annually when sidetracks and deeper wells are included with the original wells.

As for the effect of the incentive at these alternative price levels, we believe it is reasonable to assume the reduction in the minimum economic field size (MEFS) is proportional to the increase in the price level. Applying those MEFS to our estimates of the undiscovered field size distribution allows us to estimate the change in drilling intensity in the same way we did originally, by comparing the counts of economic fields with and without royalty. In the $4.11/MCF base case, we project 35% more deep wells (as opposed to 46% more in the $3.50/MCF base case) and 155% more very deep wells (as opposed to 218% more in the $3.50/MCF base case) with alternative #1. With alternative #3, we project 15% more deep wells and 145% more very deep wells.

Tables 5 and 6 shows the key inputs and results. The results indicate that should $4.11/MCF prove to be a more accurate projection than $3.50/MCF over the next 15 years, the 18% price increase raises net social benefits by about 75% under either alternative. The same price change would reduce forgone royalty by 30% under alternative #1 and by 65% under alternative #3. The foregone royalties are reduced in each case because, despite more expensive losses on status quo production, the level of aggregate royalty-bearing production rises sufficiently to more than offset these losses.

**Table 5 Sensitivity of Proposal to Price Assumption: Annual Accrued Effects of Incentive**

| **Base and Alternatives at $3.50/MCF** | **# of Wells Drilled Annually (successful)** | **Expected Size of incremental (accelerated) reservoirs, Bcfe** | **Total hydrocarbon + Acceleration premium Discovered, Bcfe** |
|---|---|---|---|
| No incentive, original wells, sidetracks and deeper wells | 44 (15.2),<br>13.8 (4) | 21,<br>30.5 | |
| Added by Final Rule Alternative 1: original + deeper wells & sidetrack incentive ‡ | 19 (7),<br>26.5 (4.6) | 45.5 (60),<br>97.3 (97.3) | 552 |
| Added by Alternative 3: original + deeper wells & sidetrack incentive ‡ | 11.8 (4.9),<br>22.4 (4.2) | 45.5 (60),<br>97.3 (97.3) | 446 |
| **Base and Alternatives at $4.11/MCF** | | | |
| No incentive at EIA/MMS price trend averages $4.11/MCF | 52.8 (17.6),<br>24.1 (4.8) | 21 and 45.5,<br>30.5 and 97.3 | |
| Added by Final Rule Alternative 1: original + deeper wells & sidetrack incentive ‡ | 18.4 (6.1),<br>37.5 (7.5) | 45.5 (60),<br>97.3 (97.3) | 764 |
| Added by Alternative 3: original + deeper wells & sidetrack incentive ‡ | 11.6 (3.9),<br>35.1 (7) | 45.5 (60),<br>97.3 (97.3) | 667 |
| ‡ Sidetrack incentive equals 4 BCF + 0.06 BCF per 100 ft, or 20% of that amount for unsuccessful sidetracks at least 10,000 ft long to targets at least 18,000 ft deep | | | |

## Table 6 Sensitivity of Proposal to Price Assumption: Cumulative Effect of Incentive

| Option | Deep Production from Undiscovered Fields, TCF | Added Production, TCFE relative to Forgone Royalty, TCF | Royalty Receipts from New Deep Gas Production , $millions | Present Value of Transfer from Producers to Consumers, million $ | Present Value of Transfer from Government to Producers, million $ | Net Social Benefits from Incentive, million $ |
|---|---|---|---|---|---|---|
| **Base and Alternatives at $3.50/MCF** | | | | | | |
| No incentive | 4.90 | Na | Na | na | Na | Na |
| Added by Final Rule Alternative 1: original + deeper wells & sidetrack incentive ‡ | 2.73 | 1.49 | -$185.8 | $3,095 | $883.5 | $172.5 |
| Added by Alternative 3: original + deeper wells & sidetrack incentive ‡ | 2.2 | 1.50 | -$106.9 | $2,423 | $723.2 | $135.9 |
| **Base and Alternatives at $4.11/MCF** | | | | | | |
| No incentive at EIA/MMS price trend averages $4.11MCF | 5.71 | na | Na | na | Na | Na |
| Added by Final Rule Alternative 1: original + deeper wells & sidetrack incentive ‡ | 3.77 | 1.62 | -$227.3 | $4,828 | $1,433 | $289.7 |
| Added by Alternative 3: original + deeper wells & sidetrack incentive ‡ | 3.3 | 1.73 | -$36.5 | $4,223 | $1,140 | $237.5 |

### E. Total Royalty Collections With and Without the Incentive

MMS regularly forecasts royalty receipts as part of the annual budget process. To do that we incorporate and apply a price forecast prescribed by OMB to our own estimate of

OCS production. We made one adjustment to our royalty forecast for this rule to make it more consistent with the budget forecast. The simple average of the 11 year OMB wellhead price forecast is $3.55/mcf compared to a flat wellhead price of $3.25/mcf used in our economic analysis. We inflated our royalty effects estimate by 9% ($3.55/$3.25) to remove a price assumption difference effect from the estimate of royalty with and without the incentive. That price assumption adjustment changes the cumulative loss of royalty from $111 million to $121 million over the next 16 years. See columns I and J on the spreadsheet titled “Forecast Royalties With and Without the Incentive in Appendix 5.

Our latest budget forecast is for cumulative OCS royalty receipts of $52.1 billion from 2003 though 2013 (i.e., the next 11 years) with no deep gas incentive. Over the same period we estimate royalty receipts under our deep gas incentive would be $51.6 billion or 1% lower. See columns H and K on the last spreadsheet in Appendix 5. Because the royalty suspension supplement can be applied to oil as well as gas, this broad measure of royalty offers the most complete estimate of the royalty effect. The 11 year period, however, is not long enough to reflect the additional royalty receipts from incremental deep gas production after the royalty suspension volumes have been used up. The net gas royalty loss diminishes over a longer period as production from new, larger reservoirs discovered under the incentive produce beyond the royalty suspension volumes and pay royalty on production that would not have occurred without the incentive. If we assume royalty receipts continue at the level we forecast for 2013, then by 2020 the deep gas incentive will result in a negligible 0.14% reduction ($120 million) in cumulative royalty receipts of some $86 billion.

Royalty receipts only from deep gas sources provide another perspective on the royalty effect of the incentive. Future production will emerge from 3 kinds of deep gas wells:

**(1)** Those already in production. None of the wells that account for this deep gas production are eligible for the incentive and so will continue to pay royalty. The 162 producing deep gas wells in the shallow water have recently provided about 7.7% of total gas production. If no new deep production emerges on these leases, their share of total production will decline over time as their deep wells deplete. We assumed these wells maintain their same 7.7% share of gas production from currently existing wells.

**(2)** Those that would be drilled in the absence of the incentive. We estimate that even without the incentive 115 additional successful deep wells would be drilled anyway over the six years the incentive is in effect on leases that have no prior deep gas production. Appendix 1 to the economic analysis to the proposed rule explains why these discoveries are likely to be smaller on average than discoveries with the more extensive drilling induced by the incentive.

**(3)** Those extra wells that will be drilled because of the incentive. New production will come from wells that would not be drilled in the absence of the incentive, which we estimate at 3.32 TCFE (trillion cubic feet on gas equivalent), 2.73 TCF of which is gas. The condensate and the gas production after the RSV from these added wells will pay royalty and so will offset some of the forgone royalty.

Table 7 shows the amounts of gas and gas equivalents that would result from each of these 3 kinds of deep wells. It summarizes calculations shown on the last spreadsheet in

Appendix 5. Common assumptions in these calculations include a gas to oil ratio of 26 MCF/bbl meaning gas makes up 82.2% of the thermal content of production from deep wells and deep well production rates of 2.5 BCF/year in the 15,000-18,000 feet TVD SS interval and 4.6 BCF/year in the 18,000 feet TVD SS and deeper category.

Table 7: Gas Production and Royalty Receipts in the Next 15 Years With and Without the Incentive (assuming $3.50/MCF average gas price)

| | Royalty-bearing Production Without incentive (Status Quo) | Royalty-free Production With Incentive | Royalty-bearing Production With Incentive | Total Production With Incentive |
|---|---|---|---|---|
| From Existing Deep Wells on Ineligible Leases (Status Quo) | 3.49 TCFE of which 2.87 TCF is gas | 0 | 3.49 TCFE of which 2.87 TCF is gas | 3.49 TCFE of which 2.87 TCF is gas |
| From New Deep Wells that Would be Drilled Anyway (Status Quo) | 5.08 TCFE of which 4.18 TCF is gas | 2.23 TCF | 2.85 TCFE of which 1.95 TCF is gas | 5.08 TCFE of which 4.18 TCF is gas |
| From Added Deep Wells | 0 | 1.13 TCF | 2.175 TCFE (1.598 + 0.589) of which 1.60 TCF is gas | 3.31 TCFE of which 2.73 TCF is gas |
| Total Deep Well Production | 8.57 TCFE | | 8.53 TCFE | 11.88 TCFE (38% increase from Status Quo) |
| Total Deep Gas Production | 7.04 TCF | 3.37 TCF | 6.41 TCF | 9.78 TCF (39% increase from Status Quo) |
| Total Royalty Receipts from Deep Gas | $4.13 billion | 0 | $4.02 billion | $4.02 billion (2.7% decrease from Status Quo) |

The first 2 rows show a status quo situation in the absence of the incentive. Row 3 adds the effect of the incentive. The last column of rows 4 and 5 show the incentive adds about 39% to the status quo deep gas production. Row 6 uses an implicit royalty value of

$0.52/mcf (derived from the results of the budget analysis) to calculate that the incentive reduces royalty receipts by about 2.7%.

F. Price Threshold

The natural gas price threshold that MMS laid out in the proposed rule came under considerable scrutiny during public review and comment. Respondents expressed concern that MMS was about to introduce a drilling incentive program under which no otherwise eligible activity would qualify for the incentive because the average of current year gas price exceeded the threshold price for the year.

MMS recognizes that if the gas prices existing in the summer of 2003 are expected to persist, that the circumstance alone will induce significant increases in deep gas drilling. However, volatile price swings, such as those in the U.S. have experienced recently, will dampen the incentive to invest in finding new reserves, even if average prices for natural gas remain high.

To test the potential benefit of different approaches to easing the disincentive created by a price threshold, MMS conducted a simulation analysis of the deep gas royalty relief program in this rule using alternative price threshold options. Each program option was measured in regards to total TCFE of production and present value of royalty receipts to the federal government, in comparison to no deep gas royalty relief program at all.

The simulation analysis focused on ten threshold price options in conjunction with the remaining elements of this rule's deep gas royalty relief program. The analysis assumes that average gas prices emerge in the marketplace according to year 2003 Energy Information Administration projections. To account for price volatility, we provided that each year's prices would be generated within a stochastic mean reversion process in which possible variations from mean values can be described by a volatility factor, representing a measure of the standard deviation of the logarithms of the feasible gas prices. Reviewing historical price data, a volatility factor of 20 percent was found for gas prices over the past 20 years. Within the past 10 years, the observed volatility factor was found to be about 30 percent. Accordingly, our analysis evaluates the effects of different price threshold provisions under both a 20 percent and 30 percent volatility factor.

For each of the 10 options and 2 volatility factors, we used the simulation model to determine the likelihood in each year that the prevailing threshold price, if any, would be exceeded by actual prices, i.e., by the average yearly price. To the extent this might happen, the profitability of drilling would be adversely affected because the expected value of royalty relief is diminished as the likelihood of losing some portion of royalty relief increases in the presence of volatile prices. We assume the level of drilling is reduced proportionately to the expected reduction in the value of royalty relief occasioned by the price threshold policy. In this manner we are able to estimate the impacts of a price threshold option on aggregate program production.

To measure the effect of specific price threshold options on federal royalties, we considered the likelihoods that gas prices would exceed the applicable threshold price for each year of production. In a year t, the average gas price will exceed the threshold gas price with probability F (T=t). In comparison to no deep gas program at all, under this state of nature there would be no change in royalties on production that would have occurred anyway from introduction of a deep gas royalty relief program when the price threshold is exceeded, since in both the status quo and new program scenarios full royalties would be due. At the same time, there would be a gain under the royalty relief program for royalties collected in year t on induced incremental production, which otherwise would have been royalty free, and which now must pay royalties in that year since the price threshold is exceeded. The value to the federal government of this added royalty is based on our estimate of the mean yearly price in year t conditional on that price exceeding the threshold price, the amount of incremental production that otherwise would not have to pay royalties, and the applicable royalty rate.

Next, we consider the state of nature where the threshold price is not violated in year t, given by 1-F (T=t). In this instance, there is a loss in federal royalties collected owing to the relief program itself, because royalty relief is provided to some of the production that would have occurred anyway, through the provision of RSV and RSS. That is, the use of the royalty suspension volumes and royalty suspension supplements will reduce federal royalties on status quo production. (Royalty reductions on incremental production up to the royalty suspensions are not included in the calculations because this production would not have occurred without the deep gas royalty relief program.) In this state of nature, the value of forgone royalties in year t is measured at the mean yearly price conditional on that price being less than the threshold price.

Finally, there are two additional components that mitigate the amount of forgone royalties. Both occur regardless of whether the threshold price is violated or not. The first consists of royalties collected on incremental oil and gas liquids production which are not subject to, but are indirectly induced by the royalty relief program. The second consists of royalties collected on incremental gas production once the lease has exhausted the royalty suspensions that it has earned.

Both of these two effects which reduce the magnitude of forgone royalties, occur in the two states of nature, so these offsets do not need to be probabilistically weighted. Moreover, the applicable price for measuring the magnitude of these effects is simply the mean price anticipated for year t.

The year-by-year inputs and calculations for the 20 cases studied are shown in detail in the price threshold spreadsheets in Appendix 5. A summary of the findings is given below in Table 8. The table shows results for both a 20% and a 30% price volatility assumption. The former is more representative of the period from the mid-1980's to the present, while the latter is more representative of the period form the mid-1990's to the present.

The results support the concern that retaining the price threshold formulation from the Proposed Rule (Case #'s 10 and 20) would likely have a very adverse effect on incremental deep gas production. For example, compared to a no threshold policy (Case #'s 0 and 00), the imposition of a $5.41 (per mm Btu) price threshold in 2004 would reduce incremental deep gas production by 1/4 in the presence of 20 percent volatility (from 4.58 TCFE to 3.38 TCFE) and by almost 1/3 with 30 percent price volatility (from 4.58 TCFE to 3.00 TCFE). This is deemed to be an unacceptably large degradation in our program's effectiveness.

In contrast, options such as imposing threshold prices of $9.34 beginning in 2004 (case #'s 6 and 16) fares much better on the production side showing only minor reductions (1 to 4%) compared to a no threshold policy. Moreover, as expected, this threshold policy reduces the amount of forgone royalties compared to the no threshold policy. Under the $9.34 price threshold, forgone royalties decline by 3 percent in the 20 percent volatility scenario (from $227 to $219 million) and by 35 percent in the 30 percent volatility scenario (from $227 million to $147 million). These continuous but high level threshold policies are deemed preferable to the no threshold policy (on the basis of less forgone royalties) and to the $5.41 price scenarios in the Proposed Rule (on the basis of much larger incremental production).

Table 8. Summary of Price Threshold Effects on Production and Fiscal Revenue (assuming $4.11/MCF average gas price)

| Case | Price Threshold Policy (expressed in year 2000 $) | Price Path | Risk of Price Theshold Violation | Incremental Production (TCF) | Net Forgone Royalty, before tax (Millions$) |
|---|---|---|---|---|---|
| | | 20% Price Volatility | | | |
| 0 | None | MMS/EIA | 0.0% | 4.58 | 227 |
| 1 | $8 waived to 2012 | MMS/EIA | 0.0% | 4.58 | 219 |
| 2 | $7 waived to 2012 | MMS/EIA | 0.1% | 4.58 | 207 |
| 3 | $6 waived to 2012 | MMS/EIA | 0.2% | 4.57 | 182 |
| 4 | $7 waived to 2009 | MMS/EIA | 0.3% | 4.56 | 209 |
| 5 | $5 waived to 2012 | MMS/EIA | 0.7% | 4.54 | 181 |
| 6 | $8.63 continuous* | MMS/EIA | 0.4% | 4.53 | 219 |
| 7 | $8 continuous | MMS/EIA | 0.7% | 4.52 | 212 |
| 8 | $7 continuous | MMS/EIA | 2.2% | 4.39 | 172 |
| 9 | $6 continuous | MMS/EIA | 6.8% | 4.12 | 94 |
| 10 | $5 continuous | MMS/EIA | 17.6% | 3.38 | (24) |
| | | 30% Price Volatility | | | |
| 00 | None | MMS/EIA | 0.0% | 4.58 | 227 |
| 11 | $8 waived to 2012 | MMS/EIA | 0.2% | 4.57 | 217 |
| 12 | $7 waived to 2012 | MMS/EIA | 0.3% | 4.56 | 205 |
| 13 | $6 waived to 2012 | MMS/EIA | 0.5% | 4.55 | 181 |
| 14 | $5 waived to 2012 | MMS/EIA | 0.9% | 4.52 | 180 |
| 15 | $7 waived to 2009 | MMS/EIA | 2.1% | 4.44 | 181 |
| 16 | $8.63 continuous* | MMS/EIA | 3.2% | 4.40 | 147 |
| 17 | $8 continuous | MMS/EIA | 4.8% | 4.33 | 123 |
| 18 | $7 continuous | MMS/EIA | 8.8% | 4.15 | 60 |
| 19 | $6 continuous | MMS/EIA | 15.6% | 3.68 | (14) |
| 20 | $5 continuous | MMS/EIA | 26.8% | 3.00 | (106) |

* Equivalent to $9.34 in year 2004 dollars.

Further, the potential forgone royalties, or more precisely, the differences in forgone royalties among price threshold options, need to be placed in perspective. The total present value of royalty collection from future deep gas production under the rule over the next 15 years is on the order of $3-4 billion.

Several threshold price policy options were formulated to begin sometime after the deep gas program commences, e.g., in year 2009 at a threshold price of $7.58 (case #'s 4 and 15). These types of delayed threshold options typically generate relatively small reductions in the program's incremental production, with modest expected increases in forgone royalties at low threshold prices and much smaller increases and possibly even gains in royalties at higher threshold prices. These results are due in part, to the deleterious effect on production from employing threshold prices that are too low, resulting in excessive losses in expected program benefits, even if implementation is delayed several years.

There is a worthwhile program benefit from delaying the introduction of the threshold price constraint that is not captured in our calculations. If the threshold is imposed after some significant incremental amounts of drilling could potentially be undertaken, then that policy formulation provides an additional incentive to accelerate drilling and resulting production into those years preceding the time the threshold becomes activated. Since accelerated production is an important goal of this policy, a properly set price threshold introduced with a delay represents an attractive policy option.

VI. Regulatory Flexibility (RF) Act

Several factors make promulgation of this rule at this time important. U.S. demand for natural gas is expected to rise strongly over the next decade while domestic supplies are dwindling. Imported gas provides only a small share of domestic supplies because of the inherent difficulty and danger of transporting gas. A large and promising source of domestic gas, deep reservoirs on existing OCS leases in the shallow water part of the GOM, has been little explored. This is because the costs and risks of drilling deep reservoirs are high relative to drilling shallow reservoirs on these same leases. Further, these higher costs would rise if much of the extensive infrastructure (platforms and pipelines) developed to support the production of shallow reservoirs gets removed as the shallow reservoirs deplete. That means there is a significant chance these deep resources would never be produced if not encouraged now.

A. Objectives of, and legal basis for, the rule

To accelerate and increase drilling into deep reservoirs, this rule:

(1) Suspends royalty payments for specified volumes of deep production that begins in the 5 years after the rule becomes effective; and

(2) Allows producers to apply designated amounts of royalty suspension supplements to other lease production for deep drilling that fails to encounter producible reserves.

Together, these measures will reduce the royalty costs associated with deep drilling and production below the royalty costs of other production on the same lease.

Title 30 CFR Part 203 regulates the reduction of oil and gas royalty under 42 U.S.C. section 1337(a)(3). Under section 1337 (a)(3)(B), we may reduce, modify, or eliminate royalties on certain producing or non-producing leases or categories of leases to promote development or increased production or to encourage production of marginal resources, in the GOM west of 87 degrees, 30 minutes west longitude.

B. Number of small entities to which the rule will apply

Companies that extract oil, gas, or natural gas liquids, or are otherwise in oil and gas exploration and development activities and operate leases on the OCS, will be most affected by this rule. The Small Business Administration (SBA) defines a small business as having:

- Annual revenues of $6 million or less for exploration service and field service companies.
- Fewer than 500 employees for drilling companies and for companies that extract oil, gas, or natural gas liquids.

Under the North American Industry Classification System Code 211111, Crude Petroleum and Natural Gas Extraction, MMS estimates that a total of 1,380 firms drill oil and gas wells onshore and offshore. Of these, approximately 130 companies are active offshore in the GOM. Merger and acquisition activity is constantly adjusting the exact number of operators. Publicly available data (from Compustat, Standard and Poor's, McGraw-Hill, and from Dunn & Bradstreet via Hoovers' sites on the internet) indicate that 39 (30 percent) of these companies active in offshore activities qualify as large firms according to SBA criteria, leaving about 91 (70 percent) companies that qualify as small firms with fewer than 500 employees. Further breakdown of the small entity operators indicate that 28 percent have between 100 and 500 employees, 53 percent have between 1 and 100 employees, and the rest have no employees as they are fully staffed by contractors. As explained in the next section, compliance costs are minimal for small as well as large entities.

C. Reporting, recordkeeping and other compliance requirements

The rule requires reporting within the meaning of the Paperwork Reduction Act in four situations. These situations are:

(1) Notify the Production and Development Division of MMS in the GOM region (MMS-PD) of intent to commence drilling a deep well;

(2) Notify MMS-PD that production has commenced from the deep well and request confirmation of the size of royalty suspension volume;

(3) Provide MMS-PD with data from the deep well to confirm that the well drilled was a certified unsuccessful well and request supplement; and

(4) Notify MMS-PD of a decision to exercise an option to replace the deep gas royalty suspension terms in the lease document with the terms in the rule.

The frequency of reporting is on occasion. Responses are voluntary but are required to obtain or retain a benefit. We will protect information considered proprietary according to 30 CFR 203.63(b) and 30 CFR 250.196.

Because this program is administered on a categorical rather than a lease-by-lease basis, minimal administrative time and cost is needed to qualify for royalty relief. The notifications in items (1) and (2) above only entail sending a letter affirming that an action which is a normal part of business operations has occurred. Item (3) involves sharing data from well logs and seismic surveys that the company would develop even in the absence of this rule as a normal part of its exploration business. The notification in item (4) involves making a business decision about which of two alternative incentives best fit the prospects faced by the individual lease. The professional skills involved include those normally used in the operation of all OCS leases -- geologists, geophysicists, engineers, and economists. Since no special analysis or independent review would be necessary to accomplish these compliance activities, we see very little burden on normal operations of either small or large companies. Beyond the paperwork notifications, there are no other compliance costs associated with this rule.

The following passages and table are derived from our Paperwork Reduction Analysis. The rule would increase the total paperwork hour burden of the 30 CFR part 203 regulations by 361 hours annually, spread across the entire industry. Based on a cost factor of $50 per hour, the burden of the new paperwork requirements would be $18,050 for the entire industry. This cost pales in comparison to the $10 to $20 million that it costs to drill a single well on the OCS to the deep depths covered by this rule. We estimate transfers to OCS producers both large and small entities from reduced royalty obligations will average about $38 million per year [($101 million * 6 years)/16 years]. The small business proportional share would be $27 million. So, even if small businesses were to bear 100 percent of this compliance costs, it would represent less than 1/10$^{th}$ of one percent of the average annual gross benefits obtained by small business in the form of their proportional share of added industry profits. The last sub-section of this Regulatory Flexibility section mentions two reasons, i.e., risk sharing and location advantages, to think that small OCS entities could get a disproportionate share of the large benefits of this rule, so small entities could get significant positive net benefits from this rule as well. Furthermore, choosing to engage in this program, and hence incurring the nominal compliance cost, is voluntary. Non-participation is not detrimental, since companies that choose not to participate are no worse off than they would be in the absence of the rule.

Except for the row associated with §48(b), these annual measures of burden costs cover the 5 to 6 years in which the incentive would be effective. The switch option of §48(b) is only available for 6 months after the rule becomes effective. We assume the small business share of compliance costs is proportional to the small business presence in offshore activities, i.e., 70 percent. This means that small business would incur up to 253 burden hours in year 1 and 204 burden hours in years 2 through 6.

### Table 8: INDUSTRY BURDEN BREAKDOWN

| 30 CFR 203 Section | Reporting Requirement | Hour Burden | Annual Number | Annual Burden Hours |
|---|---|---|---|---|
| 43(a) 46(a) | Notify MMS of intent to commence drilling. | 1 hour | 89 Notices | 89 |
| 43(b) (1)(2) | Notify MMS that production has commenced and request confirmation of the size of royalty suspension volume. | 2 hours | 25 Notices | 50 |
| 46(b)(1) (2) | Provide data from well to confirm and attest well drilled was an unsuccessful certified well and request supplement. | 8 hours | 19 Sub-missions | 152 |
| 48(b) | Notify MMS of decision to exercise option to replace one set of deep gas royalty suspension terms for another set of such terms. | 2 hours | 35 Notices | 70 |
| **TOTAL REPORTING BURDEN – 1 year** | | | 168 Responses | 361 Hours |
| **TOTAL REPORTING BURDEN - 2-6 years** | | | 133 Responses | 291 Hours |

D. <u>Federal rules that may duplicate, overlap or conflict with the rule</u>

We are not aware of any Federal rules that conflict with the rule. Two other kinds of royalty relief apply to OCS leases, but do not overlap this rule. Deep water royalty relief has been granted to leases in water at least 200 meters deep in the GOM since 1996, but no leases covered by this rule are eligible for deep water royalty relief. Also, any OCS lease may apply for royalty reduction when it nears the end of its economic life, but this form of relief is only relevant to mature production on a lease, not to development of new reservoirs covered by this rule.

A different royalty relief incentive for deep gas drilling has been included for newly issued leases in the five OCS lease sales held since the beginning of 2001. This incentive is not available to older leases issued before 2001, so they do not overlap the main set of leases targeted by this rule. However, a provision of this rule allows newly issued leases a one-time option to switch to the incentives in this rule. This switching provision is included to be fair and is voluntary. Lessees paid a premium in their bid for the new leases because their lease terms included deep gas royalty relief. Lessees of older leases had no expectation of royalty relief so their lease bids included no such premium. Allowing new lessees to switch lets those who paid for deep gas royalty relief in their bonus bid choose the more favorable of the two incentives. This switching provision also optimizes the incentive effects of the rule because it will promote more deep gas development by those lessees that choose to switch. Finally, switching enables administrative simplifications when lessees on the same unit choose the same incentive terms. We estimate the aggregate small entity share of the one-time paperwork cost for the switch to be proportional to their presence in offshore activity, i.e., 70 percent of $3,500, or about $2,500.

The rule slightly overlaps two regulations applicable to OCS leases. OCS lessees must submit an application for permit to drill (30 CFR 250.414) to the local MMS district office for review, processing, and eventual entry into an agency-wide data base. This application is a more involved submission than the letter required in the rule notifying

MMS-PD of intent to commence drilling. We require the simplified but duplicate version of this application because it is a minimal action that provides important lead time for coordinating other MMS actions that may concern the lease. For example, a potential royalty suspension requires adjustment if the subject lease participates in our royalty-in-kind program. OCS lessees must also notify the local MMS district office when production begins on the lease (30 CFR 250.180). If the deep well is not the first production on the lease, the notice required under this rule would not be duplicative. It, also, would be vital to help avoid confusion when a lease has both royalty-bearing and now royalty-free production. Most of the older leases in shallow water have to be in production already as a condition of holding their lease. The notification would be redundant only when the deep well is the first production on the lease. We believe it is simply easier to set this minimal notice burden on the start of all deep production than to create separate notice rules depending on whether a lease has prior production or not. Even when redundant, the notice serves as a useful check on a long-standing routine report.

E. Significant alternatives to the rule

The Regulatory Flexibility Act requires the agency to consider alternatives to the rule. The paperwork costs are less than 1/10$^{th}$ of 1 percent of these benefits and are the minimal necessary to allow the monitoring essential to a consistent administration of a categorical relief program across all participants. The alternative of a case-by-case relief program, where each operator would apply to participate would enormously increase the paperwork burden and associated costs for all participating lessees, both small and large entities. While case-by-case review might reduce forgone royalty, it would add uncertainty about approval and thus discourage new drilling relative to the categorical program. Also, an application process would discourage participation especially by small operators who are unlikely to have the staff needed to assemble and defend an appropriate application.

Alternative forms of the categorical deep gas incentive we considered included: (1) reduction of royalty rates for production emerging from new deep wells, (2) suspending royalty for a fixed value rather than a volume of new deep production, (3) a royalty suspension volume only for successful deep wells, (4) different royalty suspension volumes, and (5) no incentives. These alternatives are fully discussed in section IV of this economic analysis. The administrative costs are the same for all the categorical incentive alternatives. Only the benefits are different. The alternative we chose results in the largest benefit to producers and to the small entity share of producers. Additionally, this incentive structure also may especially benefit small operators more than the alternative categorical incentive structures mentioned above.

The RSS feature improves the ability of small companies with limited drilling programs to spread their risk. Success on one or two of many deep wells that a large operator drills in a given period can pay the costs incurred for the unsuccessful wells. Small operators may be able to drill only one or two deep wells in a given period. The royalty suspension supplement can reduce the net cost of unsuccessful deep wells immediately, so the small operator does not necessarily have to wait for a deep well success in a later period to offset at least some unsuccessful exploration costs. This is a feature not found in any of the alternative categorical incentive structures which confer royalty relief only on successful wells.

Because of the risk, high cost, and technical complexity, we expect most lessees/operators involved in exploration and development in deep drilling depths of the GOM to be large companies. However, the location eligible for deep gas royalty relief is in shallow water, where we find relatively more small operators compared to those found in deep water. Thus, relatively more of those OCS operators who will benefit from the deep gas incentive in this rule may be in the small business category than those who benefit from deep water royalty relief. For these reasons we believe this rule is likely to provide at least a proportionate share of its benefits to small businesses. Compliance guides to assist both small and large entities, including the presentation slides used in the industry workshop held in April, 2003 and the summary Table 1 from this document, are available on the MMS website.