(9) Of the total number of appellate decisions rendered in such fiscal year involving a finding of discrimination,

(i) The number and percentage for each respective issue of discrimination,

(ii) The number and percentage for each respective issue that involved a final action by an agency rendered without a hearing, and

(iii) The number and percentage for each respective issue that involved a final action by an agency rendered after a hearing; and

(10) Of the total number of appeals pending for any length of time in such fiscal year,

(i) The number that were first filed before the start of the then current fiscal year, and

(ii) The number of individuals who filed those appeals in earlier years.

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 203

RIN 1010–AD01

Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Relief or Reduction in Royalty Rates—Deep Gas Provisions

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This rule provides temporary incentives in the form of royalty suspension volumes for producing gas from certain deep wells (at least 15,000 feet below sea level). The rule also provides a royalty suspension supplement for drilling certain unsuccessful deep wells. The rule also provides price thresholds that may result in discontinuation of the royalty relief.

EFFECTIVE DATE: This rule is effective March 1, 2004.

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SUPPLEMENTARY INFORMATION: Title 30 CFR part 203 regulates the reduction of oil and gas royalty under 43 U.S.C. 1337(a)(3). Under section 1337(a)(3)(B), MMS 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 Gulf of Mexico (GOM) west of 87 degrees, 30 minutes West longitude.

Objective: The objective of the deep gas incentive provided in this rule is to increase the volume of natural gas production from the Outer Continental Shelf (OCS) by encouraging lessees to quickly explore for and develop deep-well gas reserves. That activity will provide near-term supplies to help alleviate potential natural gas shortages and help moderate prices over the next decade.

In the short-term, supply and demand for natural gas tend to be relatively inelastic, which can cause large fluctuations in price during periods of relative scarcity or abundance of supply. In recent years, higher prices during periods of tight supply have been evident, spiking at over $8 per million British thermal units (MMBtu) on the New York Mercantile Exchange (NYMEX) during the winter of 2000–2001. High and volatile natural gas prices contribute to a climate of uncertainty, thereby inhibiting continuous, sustained investment in deep gas development. High natural gas prices during periods of tight supply have hurt households, farmers, businesses, and negatively affected our economy as a whole. Without new sources of domestic natural gas, the United States (U.S.) will likely experience continued tightness of supply, price volatility, and increased reliance on imports from Canada and liquefied natural gas (LNG) from overseas.

While our nation's natural gas resources are substantial, much of the remaining resources on available Federally regulated lands (*i.e.*, those areas which remain open to leasing and exploration), will be increasingly costly to produce because of higher exploration and production costs and greater technical challenges of recovering gas from deep-water, deep formations, and harsh environments. Though significant potential natural gas finds may exist in the deep-water OCS and from areas in Alaska or onshore in the Rocky Mountain States, significant contribution from these areas is not expected until after 2008.

For new sources of gas supply in the near-term, the shallow waters of the GOM hold the greatest promise. MMS determined that one initiative to encourage rapid exploration and development of new natural gas reserves is to provide financial incentives to encourage new and earlier drilling of deep gas resources—approximately three miles and deeper—below existing platforms in the GOM. Natural gas prospects at this depth pose a technological challenge, but the gas can be accessed and transported using existing infrastructure in this mature oil- and gas-producing basin. Providing royalty relief can encourage timely and profitable deep gas production. Suspending some of the royalty payments due the Government on lease production can promote and accelerate new natural gas production by ensuring a viable rate of return to lessees for exploration and development of certain otherwise marginal deep gas prospects or by increasing industry's expected financial return from exploring and developing deep gas on their shallow water OCS leases relative to other (*e.g.*, foreign) investments.

The continued success of the Federal offshore oil and gas program is due, in part, to the judicious use of leasing, financial, and other incentives to promote continued industry interest and investment in new technologies for exploration and development in frontier areas of the OCS. The U.S. can benefit in many ways from increased domestic natural gas production. Exploration, development, and production of Federal natural gas resources by private firms yield significant economic benefits including payment of $2 to $4 billion in royalties annually to the Federal Treasury. The incentive in this rule is intended to provide significant social benefits by helping sustain domestic natural gas supplies and moderate energy costs to consumers, while minimizing costs to the Federal Treasury. The effects of this rule can help consumers by expanding the supply of natural gas from sources that might never have been discovered or accelerating production that may not have occurred until much later in the future.

MMS estimates that this incentive could provide about 4.4 trillion cubic feet (TCF) of additional hydrocarbon production (of which 3.6 TCE is gas) over the next 16 years, which will help moderate prices and save consumers about $500 million in natural gas costs per year over the next decade. Although Federal royalty payments will be lower while any gas production is royalty-free, MMS expects that the increased production will eventually provide royalty revenue that would offset the lost revenue experienced during early years of the incentive program. MMS estimates that the rule could result in a present value loss in Federal royalty collections over 16 years of from $150 million to $220 million (depending on price volatility) out of some $47 billion collected. Total Federal collections from leasing now run about $5 billion per year.

Background

Natural gas, one of the most important fuel sources in the U.S. economy, supplies almost a quarter of the Nation's energy needs. Natural gas is a relatively reliable source of energy because a high proportion of domestic consumption is met by domestic production. In 2002, the U.S. produced about 19 TCF of natural gas, which supplied about 84 percent of U.S. demand totaling about 23 TCF. Imports of natural gas (primarily from Canada) and a small amount of LNG from Algeria, Qatar, and Trinidad and Tobago, supplied the remaining 4 TCF (16 percent).

Heating and electricity generation have traditionally been the predominant uses of natural gas, but demand for natural gas is projected to grow in all sectors of the economy, especially as a fuel source for electricity generation. Natural gas fuels about 20 percent of current electricity generation, but this percentage is expected to increase dramatically because an increasing number of our electric generating plants are switching to natural gas for power generation and planned future capacity is expected to rely primarily on natural gas. This will contribute to a dramatic increase in U.S. demand for natural gas in the next 10–20 years. The Energy Information Administration (EIA) of the Department of Energy projects that the U.S. demand for natural gas could increase by more than 50 percent in the next 20 years, increasing from 22 TCF in 2003 to 35 TCF in 2025. Though LNG imports from overseas are expected to increase over time, helping to supply some of the demand growth, even optimistic estimates suggest that about 80 percent of the expected increase in consumption will need to be supplied from domestic sources.

In 2002, the Federal OCS was the single largest source of oil and gas for the nation—larger than any State or foreign supplier. The majority of Federal production comes from the GOM. The OCS currently provides about 14 billion cubic feet (BCF) of natural gas per day (about 5 TCF annually) for U.S. consumers, supplying about 25 percent of domestic demand. The OCS is expected to remain a significant source for increased supply of natural gas to meet U.S. demand in the long term because it contains about one-third of the remaining undiscovered technically recoverable natural gas resources in the U.S. MMS projects that the GOM could contain 193 TCF of undiscovered natural gas, which represents about 53 percent of the total OCS estimate of undiscovered gas resources (362 TCF).

Continued production of natural gas from the GOM OCS may be the key to a stable and secure natural gas future for the U.S., but there is concern about the ability of the OCS to maintain its current level of production over the coming decades. Total proven natural gas reserves on the GOM OCS have declined dramatically from nearly 46 TCF in 1986 to approximately 24 TCF in 1999. [Estimated Oil &Gas Reserves, Gulf of Mexico Dec. 31, 1999, OCS Report MMS 2002–007]. Recent gas discoveries in the mature producing areas of the GOM are smaller than previous reserves and are depleted more rapidly. The production rate per well has been declining. To maintain or increase the existing level of domestic natural gas supplies, the nation needs more well completions to offset these declines. Without dramatic change in exploration and development patterns, production from the GOM may not be able to meet the expected share of future natural gas supply needed from the OCS to meet growing demand. Energy producers now have to look in more remote locations, using innovative technologies, and the government needs to encourage identification and development of new sources.

President Bush's National Energy Policy (NEP) provides a long-term energy strategy for securing America's energy future and addresses production of traditional energy sources, alternative and renewable sources, and energy conservation and efficiency. Natural gas is an important cornerstone of the NEP because it is relatively efficient and clean-burning, as it produces fewer emissions than other fossil fuels, and is an abundant domestic resource. As such, the NEP encourages the environmentally responsible development of natural gas to meet the Nation's near-term demand.

The NEP recommended that the Secretary of the Interior consider economic incentives for offshore oil and gas development where warranted by specific circumstances. To encourage increased energy investment—a long-term process—industry needs certainty and stability, and incentives that are predictable and transparent. In particular, the NEP recommended that the Secretary of the Interior explore opportunities to provide royalty reductions for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic. This deep gas rule implements one part of MMS's responsibilities under the NEP to promote environmentally sound production of our Nation's energy resources, using royalty suspensions to reduce financial risks associated with production of OCS deep gas formations.

Deep Shelf Gas

Total GOM natural gas production has been fairly constant at about 5 TCF per year for the last 20 years. Currently, about 75 percent of this production comes from reservoirs in shallow waters of the shelf. However, since 1996, production from the shelf has been declining at a precipitous 30 percent rate, from 4.8 TCF in 1997 to about 3.4 TCF in 2002. During this time, increasing production from deep-water areas has kept OCS production stable. As shelf production continues to decline in both shallow and deep water, there could be a significant drop in OCS production of natural gas over the next 5–10 years unless new reserves can be found and brought on line quickly. To maintain GOM production levels near 5 TCF, or to increase aggregate production, a high level of exploration activity in both shallow and deep-water areas of the GOM will be needed.

The shallow waters of the GOM have been actively explored and any natural gas remaining in shallow-depth reservoirs, *i.e.*, less than 15,000 feet total vertical depth subsea (TVD SS) is expected to be found in a large number of smaller, isolated reservoirs. Many marginally economic wells will be required to exploit those resources. In contrast, relatively few wells, only about 2,100 (5 percent of total) have been drilled to deep depths on the shelf, including 64 in 2002. The potential for large new reservoirs with high production rates is greater at deep depths than in more mature, shallower areas.

Recent deep gas discoveries on the OCS have shown that these new deep-shelf completions can produce gas volumes of 20–80 million cubic feet per day (MMCFd) or more. However, deeper drilling requires upgraded rigs, higher well costs, and considerably longer drilling times. Greater well depths and higher pressures and temperatures make deep-shelf targets riskier and more costly to drill. Target reservoirs therefore need to be substantially larger at deep-depth to warrant the larger investment. So far, the failures from drilling deep gas wells on the shelf outnumber successes. Industry reports, and MMS data confirms, that there is only a 1 in 4 chance of successfully drilling a deep gas well, which can cost $8 to $20 million per well, at drilling depths 15,000–20,000 feet TVD SS. Increased experience and improvements in technology over time, encouraged by the economic incentives in this rule, should continue to reduce both the risks and costs.

Industry has made significant advances in developing technology to enable drilling to deep geologic horizons. Continued advances in directional drilling will help lower costs and foster recovery of additional resources from a single development site. New seismic technology provides an opportunity for industry to map promising prospects at deep depths, but the quality of imaging thus far is relatively poor. New and improved technologies are still needed for seismic exploration and to solve many of the technological and mechanical challenges that will lower drilling costs and enable safe and efficient drilling in conditions of extremely high temperature and pressure.

Renewed interest in deep-shelf gas in shallow water may help stem the tide of declining gas reserves and production from the GOM shelf. To date, operators who discover deep gas are able to bring production on line quickly, and at high flow rates. For example, the deep gas discovery in South Timbalier Block 204 in 2000 began production in 2001, and achieved peak production of 350 MMCFd in 2002. But higher flow rate wells can also decline rapidly. Therefore, a large number of wells will need to be drilled to sustain GOM production. Growing demand for natural gas and strong prices have renewed industry's interest in this expensive and technically challenging deep gas play and revived this mature producing province in the GOM.

To jump-start increased drilling of natural gas from deep horizons, MMS expanded its royalty relief program and began offering a royalty relief incentive for shallow water leases in OCS lease sales starting in 2001. This incentive provided a suspension of royalties on the first 20 BCF of deep gas production for all OCS tracts in less than 200 meters of water where a new deep gas reservoir 15,000 feet or greater subsea is drilled and begins production within the first 5 years of the life of the lease. Royalty relief is provided only when specified annual price threshold ceilings for natural gas are not exceeded. The incentive has revived bidding for leases in shallow water in the Central GOM and industry is making plans to drill to deep depths on these leases. Because of the significant infrastructure—platforms, producing facilities, and pipelines—that already exists in this mature producing basin, any new deep gas production can be transported quickly to markets.

However, these deep drilling incentives cover only the 1,240 new shallow water leases issued since 2001, a portion of the shelf's deep gas potential. Production from deep wells on 2,400 existing leases in shallow water, where significant infrastructure already is in place, is the most attractive source of additional natural gas on the OCS. MMS estimated in 2003 (OCS Report, MMS 2003–026 ''Gulf of Mexico OCS Deep Shelf Gas Update: 2001–2002'') that there could be 5 to 20 TCF—with a most likely value of 10.5 TCF—of recoverable natural gas present in deep depths underlying the shallow water shelf portion of the OCS. Recent analysis based on new seismic technology has suggested that even greater potential may exist for technically recoverable gas resources from deep depth locations. (DOI–MMS Press Release #3012, November 19, 2003). The majority of that potential (at least 60 percent) is expected to underlie active leases that were issued before 2001. This rule is targeted to provide an incentive for these 2,400 leases, where drilling could commence almost immediately and production could be on line within 1–2 years. Companies holding leases issued before 2001 will now have incentive to drill deep wells comparable to incentives provided for new leases, thereby encouraging more drilling of new deep wells and deepening of existing ones. Additional production from existing leases will help extend the economic life of those leases and the existing infrastructure in the GOM. Deep gas production will help bridge the expected mid-term shortfall in natural gas supplies until large field development from new deep-water and onshore prospects comes on line in the future.

Summary of the Deep Gas Royalty Relief Program

This summary discusses the various components of the royalty relief provisions for deep gas production in shallow water. For leases eligible to receive such royalty relief, MMS will suspend royalty payments after certain deep drilling activities and outcomes occur. A lease will be eligible to receive royalty relief for deep gas wells if it:

(1) Is located in the GOM wholly west of 87 degrees, 30 minutes West longitude; and entirely in water depths less than 200 meters (or partly in water depths less than 200 meters if issued in lease sales that did not provide for non-discretionary deep-water royalty relief), and

(2) Was in existence on January 1, 2001; was issued in a lease sale held after that date, and the lessee exercised its option before 180 days after the effective date of the final rule or 180 days after the lease was issued, whichever is later, to substitute the terms of this rule for the deep gas royalty relief terms in the original lease instrument; or is issued in a future lease sale with terms that reference this rule, and

(3) Has production within 5 years after the effective date of final rule (or within 6 years if the lessee has obtained a 1-year extension) from a qualified deep well drilled after March 26, 2003, or

(4) Has no gas or oil production from a deep well with a perforated interval the top of which is 18,000 feet TVD SS or deeper, but has a certified unsuccessful original well, or a certified unsuccessful sidetrack whose length is at least 10,000 feet, drilled after March 26, 2003, to depth of at least 18,000 feet TVD SS within 5 years after the effective date of the final rule.

The form of the royalty relief is a royalty suspension volume (RSV) or royalty suspension supplement (RSS). An RSV under this rule is the amount of qualified deep well gas production from a lease, or allocated to a lease under a unit agreement, that will be royalty free as a result of the incentive earned from drilling certain successful wells and sidetracks. An RSS is the amount of future oil and gas production from, or allocated under a unit agreement to, a lease from all wells regardless of depth or drilling date or hydrocarbon (gas or oil) produced that will be royalty free as the result of the incentive earned from drilling certified unsuccessful wells and sidetracks.

For deep wells, *i.e.*, original wells or sidetracks, to qualify for RSV and RSS as specified in Table 1, they must meet certain requirements as described in detail below:

(1) The vast majority of shallow water leases have not yet drilled and produced gas or oil from deep depths. For those leases, drilling a new deep well may earn an RSV of 15 BCF when drilled (and perforated) to the vertical depth interval between 15,000 to less than 18,000 feet subsea; or an RSV of 25 BCF when drilled (and perforated) to vertical depths of at least 18,000 feet subsea. Drilling a sidetrack may earn a prorated RSV based in part on its measured depth (*i.e.*, length from the point of departure from the original hole), up to a maximum of 15 or 25 BCF (depending on which deep depth interval is reached).

(2) While the rule was being developed, MMS did not want to discourage or delay deep drilling, so the proposed rule provided that any new wellbore on which drilling started on or subsequent to March 26, 2003, targeted to below 15,000 feet vertical depth, could still qualify the lease for an RSV. The specification of an RSV for sidetracks, as well as the additional RSV for a second deeper qualified well, was added to the final rule as a result of MMS's review and analysis of public comments on the proposed rule. Because the proposed rule envisioned the possibility of royalty relief in these latter cases, they have the same effective date as original wells.

(3) If a new wellbore was drilled on a lease before March 26, 2003 (the publication date of the proposed rule in the **Federal Register**), but has yet to produce, the lease may still earn an RSV from a qualified well or sidetrack that produces the first deep gas on the lease. But any subsequent production from the earlier unqualified well or sidetrack cannot share in any RSV.

(4) Generally, an RSV cannot be earned on a lease that has a deep well that produced before March 26, 2003. However, MMS is providing an exception when those deep wells or sidetracks on a lease produced from the depth interval between 15,000 and 18,000 feet TVD SS. For those leases, to encourage additional deep drilling to deeper horizons, subsequent wells or sidetracks drilled (and perforated) to at least 18,000 feet TVD SS may qualify the lease for an RSV of 10 BCF for an original wellbore, or a prorated RSV—up to a maximum of 10 BCF—for a sidetrack, based in part on its measured depth (see table below).

(5) A lease will qualify for an RSS that may be applied to any subsequent gas and oil production from or allocated to the lease if it:

a. Has an unsuccessful original well or an unsuccessful sidetrack at least 10,000 feet in length that reaches a target on the lease at a depth of at least 18,000 feet TVD SS, and the drilling began on or after March 26, 2003, and no later than 5 years after the effective date of the final rule;

b. Has started drilling that well before producing gas or oil from an original well or sidetrack on the lease with a perforated interval the top of which is 18,000 feet TVS SS or deeper; and

c. Receives subsequent confirmation from MMS that the drilling effort was deep enough but unsuccessful. MMS relies on data that the lessee provides within 60 days after the well reaches its total depth.

(6) A lessee cannot obtain both a full RSV and a full RSS from the same wellbore. If a certified unsuccessful well later produces, then any portion of the RSS taken (plus gas and oil produced during periods that would have been royalty-free but for the fact that gas prices exceed the price threshold) would have to be subtracted from any RSV earned from that well. Also, the lessee could not use any remaining RSS earned from that well, beginning when the RSV is earned from that well.

(7) The RSS resulting from drilling a certified unsuccessful original well is 5 billion cubic feet of gas equivalent (BCFE) if the lease has not produced from any deep well before the certified unsuccessful well is drilled. The RSS for a certified unsuccessful sidetrack is prorated in the same proportion of the RSV as for an original well (0.8 BCFE plus 120 MCFE times the sidetrack measured depth, rounded to the nearest 100 feet), but no more than 5 BCFE, if the lease has not produced from any deep well. If the lease has produced from a deep well in the 15,000–18,000 feet TVD SS interval before a certified unsuccessful original well, or a sidetrack of at least 10,000 feet measured depth is drilled, the RSS resulting from drilling the certified unsuccessful original well is 2 BCFE.

The following table shows the royalty suspensions in BCF that a lessee can earn for deep wells—original wells or sidetracks—on a lease drilled and completed with a perforated interval the top of which is at or below 15,000 feet TVD SS, and the RSS, in BCFE, that a lessee can earn for certified unsuccessful original wells or sidetracks on a lease drilled to a least 18,000 feet TVD SS.

TABLE 1.—ROYALTY SUSPENSION VOLUMES (RSV) AND ROYALTY SUSPENSION SUPPLEMENTS (RSS) EARNED FROM DEEP GAS WELLS ON OCS LEASES IN SHALLOW WATERS OF THE GULF OF MEXICO

Depth of Well	Date of initial production or of reaching target depth	Type of well	For a qualified deep well, a lease receives an RSV on gas production from qualified wells of:	For a certified unsuccessful well, a lease receives up to 2 RSS on oil and gas production from any wells of:
A well 15,000 to less than 18,000 feet TVD SS (top of perforated interval).	Before production from a well 15,000 feet TVD or deeper.	Original	15 BCF	None.
		Sidetrack	4 BCF + (600 MCF times measured depth (to nearest 100 feet));. Up to maximum of 15 BCF	None.
A well 18,000 feet TVD SS or deeper		Original	25 BCF	5 BCFE.
		Sidetrack	4 BCF + (600 MCF times measured depth (to nearest 100 feet));. Up to maximum of 25 BCF	0.8 BCFE + (120 MCFE times measured depth (to nearest 100 feet)) if measured depth at least 10,000 feet; Up to a maximum of 5 BCFE.
A well 18,000 feet TVD SS or deeper (top of perforated interval).	At the same time as or after production from a qualified or unqualified well 15,000–18,000 feet deep.	Original	10 BCF	2 BCFE.
(If initial production is from a qualified well, then the RSV is added to the RSV earned by the qualified well).		Sidetrack	4 BCF + (600 MCF times measured depth (to nearest 100 feet));. Up to maximum of 10 BCF	2 BCFE.

A lease may earn two RSSs of up to 5 BCFE each plus an RSV up to 25 BCF. Thus, a lease could earn the right to produce as much as 35 BCF of natural gas royalty-free, that is, 10 BCFE because of two initial unsuccessful wells and then 25 BCF from a subsequent successful well drilled to at least 18,000 feet TVD SS. A current or successor lessee may also apply the RSV earned by the lease's first qualified well to any natural gas production from, or allocated under an approved unit agreement to, the lease from subsequent qualified wells.

However, if the qualified wells are drilled to a depth 15,000 to less than 18,000 feet TVD SS, then the maximum RSV volume that can be applied to gas production is 15 BCF. If the first qualified deep well was drilled 15,000 to less than 18,000 feet TVD SS, and the second to a depth 18,000 feet TVD SS or deeper, then the lease would earn 15 BCF initially plus another 10 BCF for the second qualified deep well. In this case, gas production from all qualified wells on the lease share in any remaining RSV up to a total of 25 BCF, as long as the aggregate amount of royalty suspension volume used does not exceed the 25 BCF earned by drilling the qualified wells.

A lease must have a qualified deep well before an RSV may apply to deep well gas produced on that lease, or allocated to the lease under a unit agreement. Therefore, if Lease A is in a unit and is allocated production from a qualified deep well on Lease B in the unit, then Lease A has no RSV unless it also has its own qualified deep well. If Lease A has earned no RSV, royalty must be paid on any deep well gas production allocated to it under a unit agreement.

Finally, once production begins from a qualified deep well on a lease, the lessee must use the applicable RSV continuously for all gas production on or allocated to that lease from qualified deep wells. In other words, the lessee cannot delay applying the RSV to applicable production, and must apply the relief only to production occurring after this rule becomes effective.

Any remaining RSV and RSS are subject to a natural gas threshold price of $9.34 per MMBtu, adjusted from year 2004 for inflation. If the average daily closing NYMEX natural gas price (for the nearby future delivery month) exceeds this adjusted level for that full calendar year, the lessee would have to pay full royalties on any production of natural gas or oil that would otherwise have royalties suspended due to royalty relief from a qualified deep well or certified unsuccessful deep well. Moreover, the volume produced during such a calendar year would count against the eligible RSV and RSS.

Modifications Made in the Final Rule

The main elements of the deep gas royalty relief program described in the proposed rule have been retained in this final rule. In particular, a lease drilling to and producing natural gas from depths of 15,000–18,000 feet TVD SS may earn a royalty suspension volume (RSV) of 15 BCF. A lease drilling to and producing natural gas from depths of 18,000 feet or deeper TVD SS may earn an RSV of 25 BCF. In each case the specified amounts of relief are earned if the first deep gas production on the lease occurs from an original well, *i.e.* a new wellbore not including sidetracks, that commenced drilling on or after the date of the proposed rule of March 26, 2003. Subsequent deep wells may share in the RSV earned by the first deep well.

The final rule clarifies what production the royalty suspension volume applies to. As discussed in more detail below, the royalty suspension volume applies only to gas production from qualified deep wells on the lease, and not to gas production from wells in shallower depths or from deep wells that are not qualified wells as defined in the rule. (The deep gas royalty suspension volume does not apply to crude oil production, even if it comes from a deep well.) Because the RSV applies only to production from certain wells, and not to production from the lease as a whole, the final rule applies the RSV to the production reported on the Oil and Gas Operations Report, Part A (OGOR–A), which is the only report of production on the well level that lessees or operators must file with MMS. The monthly report of sales and royalty (the Form MMS–2014) reports production by product and production month on a lease level from all wells at all depths, not on a well level. Hence, it is not possible to use the volumes reported on Form MMS–2014 as the base to which the RSV is to be applied.

The OGOR–A, however, reports *all* gas produced from an identified well, including flared gas, gas that is used as fuel on a lease, etc. In other words, volumes reported by well on the OGOR–A include both royalty-bearing and non-royalty-bearing production. Non-royalty-bearing production is not reported on the Form MMS–2014, but as explained above, that form reports production on a lease level. It is not possible to know from either the OGOR–A or the Form MMS–2014 how much production from a particular well was used as fuel or flared. Because the RSV will apply to production only from certain wells, the only practical option is to use the production figures reported on the OGOR–A. Consequently, it is not possible to apply the RSV exactly only to royalty-bearing production from those wells. At the same time, however, the non-royalty-bearing production from a particular well is generally a very small percentage of the total production.

The practical effect of applying the RSV to the production volumes reported on the OGOR–A is to reduce slightly the amount of actual royalty relief a lessee obtains below the stated volumes prescribed in the rule. However, because the percentage of non-royalty-bearing production generally is so small, we believe the effects are negligible.

In addition, the lease may earn a royalty suspension supplement (RSS) of either 5 BCFE or 2 BCFE up to 5 BCFE from drilling an original well or a sidetrack (of at least 10,000 feet measured depth) to a target depth of at least 18,000 feet TVD SS that is not capable of production, or meets certain standards for encountering non-commercial amounts of hydrocarbons. To earn an RSS of 5 BCFE for an original well, or up to 5 BCFE for a sidetrack, for drilling unsuccessfully to 18,000 feet TVD SS or deeper, the lease must not have produced gas or oil previously from any deep well. If the lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS, the lease will receive an RSS of 2 BCFE for either an unsuccessful original well or an unsuccessful sidetrack (of at least 10,000 feet measured depth). A lease may earn up to two RSSs of up to 5 BCFE each in failed attempts to locate deep gas resources from wells that began drilling on or after March 26, 2003.

MMS received a variety of comments on the manner in which we intend to treat unitization agreements. MMS concluded that the structure offered in the proposed rule is appropriate. The RSV and RSS are lease-specific and not formally part of an MMS-approved unit agreement providing for production allocation. Hence, a lease must have a well drilled on it to deep depths to earn an RSV. The lease cannot be allocated any portion of another lease's RSV or RSS or redistribute its own RSV or RSS for use by other leases in the unit. MMS presumes that compensatory side arrangements between unit co-owners will evolve and prove to be a better way to deal with the distribution of royalty relief among unit owners than would be the case under formal MMS rules. In particular, such rules are subject to complications from changing partners and revision of lease and unit agreement terms.

We reconsidered the requirement that production must commence within 5 years after the date of the final rule for drilling to deep depths to qualify for relief. Some respondents recommended a longer period, in conjunction with discretion for MMS to grant extensions on a case-by-case basis. MMS acknowledges that circumstances beyond the lessee's control could prevent meeting the 5-year time frame. Accordingly, under certain conditions, MMS will extend the time required to start production for up to 1 year if drilling has reached the target depth and production would have started within 5 years following the date of the final rule, except for circumstances beyond the lessee's control.

The basic features of the incentive program were generally well received by those commenting on the Proposed Rule for Relief or Reduction in Royalty Rates—Deep Gas Provisions (68 FR 14868). In consideration of comments offered at a workshop held in Houston on April 30, 2003, and comments submitted by 14 separate respondents to the proposed rule one month later, MMS made some changes in this final rule. Changes in three areas are noteworthy—leases with multiple deep wells, sidetrack deep wells, and the price threshold.

Leases with Multiple Deep Wells: Under the proposed rule, a lease which first produced from deep depths (at least 15,000 feet TVD SS) as a result of a well commencing prior to the proposed rule would not have been eligible for deep gas royalty relief. MMS now believes that some relief from royalties is appropriate in the special instance where a lease has produced only from the 15,000–18,000 foot depth category and subsequently drills and produces after the proposed rule in the deeper depth category. This is the case because the prospective nature of a deeper depth drilling category is still unknown and some incentive could be effective at stimulating drilling to the deeper depths.

We set the RSV earned in these cases for original wells at the difference in RSV's between relevant depth categories. So, if a lease has produced from 15,000–18,000 feet TVD SS before the proposed rule, or has produced from this depth interval after the proposed rule from a well drilled before the proposed rule, the lease is still eligible to earn 10 BCF in relief [25 BCF–15 BCF] from subsequent drilling and production from 18,000 feet or deeper TVD SS. Of course, in neither case do the unqualified wells earn any relief; nor can production from such wells share in relief earned by other wells, regardless of the sequence in which the unqualified well produces.

Along these same lines, the proposed rule set the maximum RSV available to a lease equal to the RSV earned by the first qualified well. To encourage the operator to drill the most prospective target first, the final rule allows the lease's RSV to increase if a well is subsequently produced from a deeper depth category. So, drilling two qualified deep original wells—the first to 15,000–18,000 feet TVD SS, and the second to 18,000 feet or deeper TVD SS—earns the lease 15 BCF initially, followed by an extra 10 BCF for the second well. Thus, the lease has a total RSV of 25 BCF in this case.

The same increment of 10 BCF would apply if the first qualified well was a sidetrack, and the second an original well. If an original well were first drilled into the 15,000–18,000 foot depth interval, followed by a sidetrack into the deeper interval, the sidetrack could earn an RSV up to 10 BCF depending on the length of the sidetrack (as discussed further below). In addition to this change in royalty relief on multiple-well leases, the final rule permits the second well to share all of the lease's RSV even if it is not drilled into the deepest depth interval.

Sidetrack Deep Wells: We also decided to explicitly make deep sidetrack drilling eligible for relief in the final rule because sidetrack drilling may become an effective means to exploit deep gas resources. The proposed rule provided no specific incentive to drill additional sidetracks because MMS believed that the structure of the royalty relief expressly offered to original wells in the proposed rule would not have unduly biased drilling in favor of the more expensive original wells. However, MMS asked for comments on whether we also should include sidetracks. Responses emphasized the gap in our program which overlooked individual drilling opportunities containing potential resources too small to make undertaking an original well economical, even with royalty relief. Also, sidetracks occasionally are used to reclaim previously used platform slots, that is, to make maximum efficient use of existing facilities, which is an important feature of this program. For these reasons, MMS has decided to add sidetrack drilling to our royalty relief program in the final rule.

The rule is now structured so that original wells and sidetracks are treated the same with regard to lease and well eligibility, with three main exceptions. First, the magnitude of sidetrack relief differs from the relief MMS makes available to original deep wells. Second, sidetrack relief earned can never exceed the amount of relief that would have been earned by an original well drilled under the same circumstance, to the equivalent depth. Third, the amount of sidetrack relief is based on measured depth from the previously drilled hole to the bottom hole of the sidetrack, rather than drilling depth.

In general, the following equation gives the amount of relief earned by a qualified sidetrack well. The RSV is equal to 4 BCF plus 0.6 BCF per 1,000 feet of measured depth drilled, that is, the length of the sidetrack. Sidetrack relief is constrained to not more than 15 BCF for the first qualified deep well produced from 15,000–18,000 feet TVD SS or 25 BCF of the first qualified deep well produced 18,000 feet TVD SS or deeper. If deep production has already occurred from 15,000–18,000 feet TVD SS on the lease, then drilling and producing a sidetrack to 18,000 feet TVD SS or deep can earn the amount of relief given by the equation but no more than 10 BCF. Of course, if deep production has already occurred at 18,000 feet TVD SS or deeper, drilling a sidetrack (or original well) to this depth interval (or to the shallower depth interval) earns no relief.

A lease's eligibility for royalty relief is limited in several ways where there exists a sidetrack that commenced drilling to a deep depth interval before the proposed rule and either produced before the proposed rule or first produced from that deep depth interval after the date of the proposed rule. Otherwise, sidetracks are treated just like original deep wells. These restrictions mirror those imposed on drilling an original well before the proposed rule. First, the sidetrack does not earn relief and its production cannot share in any relief earned by other deep wells. Second, the lease cannot earn deep gas relief from any subsequent wells drilled to that same deep depth interval or to a shallower deep depth interval. Third, subsequent drilling of an otherwise qualified original well to a deeper depth interval earns relief in an amount equal to the difference in available RSV amount allowed for original wells in the relevant drilling depth categories, *i.e.,* 10 BCF. Hence, if a sidetrack is drilled and produced before the proposed rule to a depth of 15,000–18,000 feet TVD SS, and an original well subsequently is drilled and produces from a depth 18,000 feet TVD SS, or deeper, then the relief awarded the lease from the original well is 10 BCF [25 BCF–15 BCF]. Finally, subsequently drilling and producing another sidetrack at a deeper depth interval may earn a full sidetrack RSV (see our Response to Comment No. 7 below) up to the amount that could have been earned in the same circumstances had an original well been drilled, *i.e.,* up to 10 BCF.

Price Thresholds: 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 owing to actual gas prices exceeding the threshold prices.

MMS recognizes that if the gas prices existing in the summer of 2003 are expected to persist, that circumstance alone will induce significant increases in deep gas drilling. However, volatile price swings, such as those the U.S. has 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 explicitly included gas price volatility in analysis of how much more deep drilling and production and how much less royalty collection would occur under various price thresholds. MMS used the simulation model to determine the likelihood in each year that a specific threshold price would be exceeded by the actual average yearly price, under different assumptions about price volatility. 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.

To measure the effect of a specific price threshold on incremental deep gas production, 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. The likelihood that gas prices would exceed the applicable threshold price helps determine the expected reduction in the value of royalty relief. In this manner we are able to revise the drilling scenario and estimate the impacts of a price threshold option on aggregate program drilling and, ultimately, production.

To measure the effect of a specific price threshold on federal royalties, we consider the revised drilling scenario in the presence of anticipated gas price volatility. Those instances where the stipulated price threshold level is exceeded result in royalty payments on otherwise royalty free production. We then value the royalties collected during those years, in conjunction with forgone royalties in other years, and adjust the base case no-threshold royalty option. Forgone royalty is the difference between royalty lost from production that would have occurred anyway without the incentive and royalty gained from extra production due to the incentive.

MMS evaluated several options under each of two approaches—delayed application of a modestly higher price threshold or immediate application of a substantially higher price threshold—to easing the price threshold policy in the proposed rule. The delayed application options fared better on achieving incremental production while the immediate application options were more effective at reducing the forgone royalty. MMS determined that a $9.34/MMBtu gas price threshold in 2004 and escalated for inflation thereafter provided the best balance of incremental production and forgone royalty under the relatively high volatility conditions prevalent in the last decade. In comparison with a no price threshold policy, we estimate the $9.34 price threshold level provides about 96 percent as much incremental production while reducing the forgone royalty by 35 percent.

Itemized Responses to Comments on the Proposed Rule

The following section gives detailed responses to 13 categories of comments which MMS received on the proposed rule from 14 separate commentors.

1. Magnitudes of the Royalty Relief for Original Wells

Comments: Overall, the industry comments supported the RSV and RSS amounts MMS provided in the proposed rule for the two drilling depth intervals. Other comments included the following: Quantifying generic RSV's is difficult because each drilling target is different. Apply the same RSS amount as for successful wells. (Chevron). We support a tiered system of RSV's (BP). The RSV's proposed are adequate (El Paso, API). The dry hole supplement is quite small given the risk and cost involved in deep gas activities (Noble).

Response: MMS believes the RSS level should be kept at a fraction of the RSV amount to avoid creating an incentive to not complete a marginally economic and otherwise successful well. In the proposed rule, MMS asked questions about different combinations of royalty relief amounts, but for the most part commenters did not address these questions or their answers weren't responsive. Therefore, MMS has no new information that would support a change in the amounts of relief by drilling depth as specified in the proposed rule.

2. Lease Eligibility

Comments: Drop the stipulation that leases with previous deep gas production not be eligible for this program. It is unclear why such leases are excluded (Pioneer). Include leases issued by the States before 1953, and subsequently ratified as Federal leases by Section (6) of the Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1335) (Exxon). Don't restrict the program to leases lying entirely in water depths less than 200 meters. Expand the deep gas program to deep waters (AAC).

Response: Leases that already have deep gas production are more prospective in regards to additional deep depth drilling. Accordingly, the proposed rule targeted leases where deep depth drilling previously has either not occurred or has not been successful. Nevertheless, upon further investigation, it appears that, generally speaking, success at the 15,000–18,000 foot TVD SS depths does not have a dramatically positive effect on the anticipated drilling success at 18,000 feet TVD SS or deeper. Accordingly, the final rule modifies this constraint on lease eligibility. A lease with a deep depth producing well that was drilled prior to the proposed rule is eligible for royalty relief if, after publication date of the proposed rule, March 26, 2003, an additional well is drilled to a deeper depth interval and produces natural gas. MMS discusses elsewhere the specific terms of relief and amounts available to be earned.

The omission from the proposed program of leases that were issued by the States before 1953 was inadvertent. In this final rule, these leases are now eligible for relief, along with all shallow water leases issued under Federal lease sales held before 2001.

For leases lying partly in deep water, MMS prefers to avoid a situation in which any such lease can obtain non-discretionary relief from more than one categorical royalty relief program, *e.g.,* deep-water and deep-depth drilling. The framework and parameters of each program were designed assuming no further categorical royalty relief would be provided. As of the summer of 2003, there were 132 leases issued before 2001 and lying partly in water depths greater than 200 meters which are eligible for case-by-case or categorical royalty relief under sections 302 and 304 of the Deep Water Royalty Relief Act (DWRRA). Eighty-two of these leases were issued from 1996–2000 and are covered under the categorical royalty relief program under section 304 of the DWRRA. They are not eligible for the deep gas program. Fifty of the leases were issued before 1996, and are covered only by the discretionary royalty relief provisions of section 302 of the DWRRA, 43 U.S.C. 1337(a)(3)(c). MMS's final rule extends eligibility for deep gas drilling relief to these 50 leases, as well as to any lease issued from sales held in 2001 or thereafter without DWRRA royalty relief eligibility and lying at least partly in less than 200 meters of water depth.

3. Drilling a Deep Well Before Date of the Proposed Rule

Comments: Consider making deep wells drilled on leases with previous deep depth production eligible for relief if drilled to a substantially different depth, to new structures, or to depths at least 100 feet deeper (Pioneer, McMoran). Clarify eligibility of a well or lease if a deep well commenced drilling before March 26, 2003. If this well subsequently produces, what is the effect on eligibility for royalty relief and on any relief already earned (El Paso)? Allow eligibility for wells that commenced drilling before the date of the proposed rule if not completed by that time (API).

Response: Under the proposed rule, a lease would not be eligible for deep gas relief if it produced from deep depths before March 26, 2003. If a deep well commenced drilling before that date, and subsequently was the first deep well to produce after that date, the lease would not be eligible for deep gas relief under the proposed rule.

MMS has reconsidered our position on this issue. Our prior stance was based on the notions that (1) drilling and production before March 26, 2003, reduced the economic risk associated with further deep gas drilling, and (2) drilling before March 26, 2003, was undertaken without the need for any incentive, so the production on the lease associated with this pre-rule activity should not be eligible for relief.

MMS's modified position is that early successful drilling of deep gas does indeed reduce the risk of subsequent drilling to the same depth interval, but is much less likely to reduce the risks of drilling to deeper depth intervals. Also, MMS has concluded that elimination of relief to the entire lease from deep original wells drilled before March 26, 2003, but produced afterwards and first on the lease from deep depths, could encourage delays in the commencement of production from these wells until a subsequent well produces from deeper depths and earns relief. Hence, given these observations, MMS has made changes in the final rule.

If an original well is drilled and produces from a perforated interval the top of which is 18,000 feet TVD SS or deeper before March 26, 2003, the lease is not eligible for deep gas royalty relief. However, if the pre-March 26, 2003, drilling and production was to depths of 15,000–18,000 feet TVD SS, then subsequent drilling and production from a qualified original well at a deeper depth interval, *i.e.,* at least 18,000 feet TVD SS, is eligible for deep gas relief in a lesser amount of 10 BCF, *i.e.,* equal to the difference in RSV's for the two depth intervals. None of the production from the first (unqualified) deep well is eligible to share the relief earned by other subsequent wells.

MMS has also reconsidered its position regarding the earlier formulation wherein the first deep well sets the upper limit on the RSV a lease can earn. This approach could encourage initial drilling to a less prospective but deeper depth, in order to capture a higher relief amount for the lease.

To avoid this potential misallocation of resources, MMS structured the final rule so the total magnitude of RSV that can be earned on the lease is independent of the order in which wells to different deep depths are drilled. Thus, in the case of wells drilled first to 15,000–18,000 TVD SS, and subsequently to 18,000 feet or deeper TVD SS, the lease could initially earn an RSV of 15 BCF, followed by earning an additional 10 BCF, so the aggregate amount earned by the lease, 25 BCF, is precisely what could have been acquired under the proposed rule from drilling the deepest well first. Further, deep wells less than 18,000 feet TVD SS may use up to all the RSV earned by the lease. Note that the increment of 10 BCF for the very deep well is also precisely the same amount of relief awarded to a very deep well in the case discussed earlier where a well to 15,000–18,000 TVD SS feet was drilled and produced before March 26, 2003, or drilled before this date and produced afterwards.

It is possible that a deep well could begin drilling before the date of the proposed rule and eventually produce after another successful deep well has been drilled and produced, resulting in royalty relief. In these cases, any royalty relief previously earned is retained. However, if the well that commenced drilling before the proposed rule produces first, a later successful well to that drilling depth category that would otherwise qualify for relief does not qualify. A third well will remain eligible for incremental relief of 10 BCF if drilled to a depth interval at least 18,000 feet TVD SS, if both of the previous two deep wells were in the 15,000–18,000 foot depth range. In other words, this third well will receive the difference in RSV between the amount available in its depth interval and the amount associated with the depth interval of the two previous wells. If one or more of the two previous deep wells was drilled to the same depth interval as the third deep well, then that third well earns no added relief for the lease. It may, however, share in any relief earned by a previously drilled qualified well.

The eligibility of sidetrack drilling for royalty relief in the final rule, which we discuss in detail in the next three sections, complicates somewhat the previously described arrangements. Conceptually, eligibility of sidetracks for royalty relief works in the same way as for original wells, except that the amounts of relief that can be earned in any situation are no more than, or, more typically, are less than those for original wells.

In summary, we make the following changes for successful deep original wells:

A. If a lease has been drilled and produced from deep depths before the proposed rule, the lease may remain eligible for an RSV if another well is drilled successfully to a deeper depth category. Under the proposed rule, production from a deep well that commenced drilling before the date of the proposed rule disqualified the lease from any further royalty relief. In the final rule, only further drilling to the same deep depth interval or shallower is disqualified. Subsequent drilling and production to the next deepest depth interval may earn up to 10 BCF of added relief.

B. Because the deeper depth well may benefit from the earlier success, the magnitude of relief earned is set equal to the difference between the RSV's potentially available at the two drilling depth intervals. In the case of a lease already having produced from a depth of 15,000–18,000 feet TVD SS, a subsequent successful deep well drilled to a depth of 18,000 feet TVD SS or deeper now earns up to 10 BCF.

C. If a lease has a deep original well which commenced drilling but had not produced before the date of the proposed rule, the original well will remain ineligible to earn relief or to use relief earned by other wells. MMS clarifies that the lessee can produce from that well at any time after the lease has earned deep gas royalty relief without jeopardizing the relief. If, however, that well produces from a depth 15,000 to less than 18,000 feet TVD SS before any qualified well produces at that depth interval, then the lease is ineligible for relief associated with that depth interval. Moreover, we add the flexibility to earn relief in the amount of 10 BCF for subsequent drilling to a deeper depth interval.

4. Eligibility of Sidetracks

Comments: MMS should amend provisions that would allow sidetrack drilling to deep depths to become eligible for royalty relief. With over 3,500 platforms, it makes sense to use a previously drilled wellbore to drill a new deep test well (NOIA). Sidetracks eligibility will encourage deep drilling at least cost (Noble, Rowan, Pioneer). Many platforms are already slot limited, so drilling sidetracks avoids costly platform modifications (ExxonMobil, Marathon, Merit). Sidetracks are also more benign to the environment because they involve less drill cuttings and lower emissions than original wells (Shell, API, ExxonMobil, Marathon).

Response: MMS agrees that including sidetrack drilling in the deep gas program is desirable. Although the average production of reserves from sidetracks is about two-thirds that of deep original wells per successful well drilling, that observation may suggest the marginal nature of certain drilling activities and their need for royalty relief incentives to undertake more of this type of drilling.

For the most part the net cost (gross cost less expected value of the royalty relief) of drilling a vertical well with royalty relief will be higher than the gross cost of drilling a sidetrack well without royalty relief. Hence, the proposed rule did not anticipate a substantial number of cases in which royalty relief for original wells but not sidetracks would result in inefficient drilling decisions. We now recognize that expanded use of sidetrack drilling presents a more important opportunity for accelerating deep depth gas production than we anticipated. Increases in the use of reclaimed slots and advancements in the technology of sidetrack drilling offer significant opportunities to extract more deep depth resources in an economical way.

Hence, we are adding sidetrack drilling to our deep gas incentive program in the same manner that relief applies to successful deep original wells, though the amounts of relief will vary in comparison to original wells. We do provide an RSS for certain types of unsuccessful sidetracks drilled to depths of at least 18,000 feet TVD SS. The minimum length the sidetrack must be drilled (measured depth) is 10,000 feet to qualify for an RSS associated with a drilling failure.

As is the case for original wells, sidetracks that begin drilling before the date the proposed rule was published are disqualified from royalty relief. If a deep sidetrack produced from 15,000–18,000 feet TVD SS before March 26, 2003, then any subsequent sidetracks or original wells to that same depth interval are also ineligible to earn royalty relief. Deep production undertaken before March 26, 2003, in the 15,000–18,000 foot interval also restricts the amount of relief that can be earned by either sidetracks or original wells drilled to a deeper depth interval to no more than 10 BCF. As with original wells, production from sidetracks that begin drilling before March 26, 2003, cannot share in any relief earned by qualified wells.

5. Defining Sidetracks for Deep Gas Royalty Relief

Comment: One comment requested clarification of the definition that MMS would use for sidetracks as compared to bypasses if a sidetrack royalty relief program is adopted in the final regulations. The commenter referred to a slide presentation on sidetracks presented by MMS at the workshop held in Houston, Texas on April 30, 2003, in which one of the slides stated that, ''A sidetrack is drilled to a different target reservoir from the original well,'' and ''A well deepened to a new target is a sidetrack.'' Two other related slides were also presented. A slide on bypasses stated, ''A bypass is drilled to the same target reservoir as the original well,'' and ''Bypasses are generally drilled because of a mechanical problem with the well, such as blockage or unwanted deviation.'' The third slide explained that, ''According to the proposed rule, bypasses would be eligible for royalty suspension volumes and RSS's [as adjuncts to original wells], but sidetracks would be eligible for neither.''

According to the comment, operators might infer that ''* * * any well in which a plug or whipstock is set and the well subsequently drilled to a different bottom hole location with a target in the same original objective reservoir, would be classified as a bypass.'' The comment continues by presenting the sidetrack and bypass definitions given in NTL 2000–N07, and pointing out that there are inconsistencies between the definitions given on the slides and in NTL 2000–N07. The NTL definitions are repeated here for reference:

''Sidetrack—a drilling effort in which an additional hole is drilled by leaving a previously drilled hole at some depth below the surface and above the total depth. A whipstock or cement plug is set in the previously drilled hole, which is the starting point for the sidetracking operations. The drilling of a well after a slot reclamation (which previously had a well) is considered a sidetrack. This section of the hole is directionally drilled to a new objective bottom hole location (target). This is also called a geologic sidetrack.''

''Bypass—a remedial drilling effort in which portions of a hole are redrilled around junk (*i.e.*, lost tools, pipe, or other material blocking the hole), ''lost holes'' are redrilled, or ''key seats'' or ''crooked holes'' are straightened. This is also called a mechanical sidetrack.''

The commenter is concerned that administration of the deep gas royalty relief program for sidetracks could become complicated if different representatives from MMS do not use the same definitions to classify sidetrack and bypass drilling operations. To prevent this problem from occurring, they suggest that MMS include sidetrack and bypass operations in the same category as that for original well operations, in consideration of royalty relief under this deep gas program (ChevronTexaco).

Response: Defining sidetracks uniformly and precisely is important. MMS accomplishes this by including a reformatted version of the ''sidetrack'' definition given in NTL 2000–N07 in 30 CFR 203.0 of this final rule. Further, the ''bypass'' definition from NTL 2000–N07 is incorporated in the definitions for ''original well'' and ''sidetrack'' in the final rule to recognize that bypass operations could occur while drilling either type of wellbore.

Qualified original wells drilled with or without a bypass are already covered by the royalty relief provisions published in the proposed rule. Royalty relief is provided in the final rule for qualified sidetracks, which themselves may have a bypass. Bypass operations are defined as a remedial drilling effort, and as such do not require a special classification for royalty relief.

Under regulations in the final rule at 30 CFR 203.43(b)(2), lessees are instructed to request confirmation of the RSV size that applies to the lease from the Regional Supervisor for Production and Development, within 30 days following the beginning of production that qualifies for royalty relief. The Regional Supervisor's response also will confirm how the deep well was classified for royalty relief purposes.

Comment: Under the definition of sidetracks in NTL 2000–N07, a deep well drilled from a reclaimed surface slot could be disqualified from royalty relief because it would be classified as a sidetrack. Wells drilled from a reclaimed slot would exceed the cost of a new (original) well drilled from an open slot on a platform due to the added cost to reclaim the slot needed to drill the well. Accordingly, the commenter requested that holes drilled from reclaimed slots receive the same size RSV's as original wells (ChevronTexaco).

Response: MMS uses a reformatted definition of sidetracks from NTL 2000–N07 in the final rule without making a modification that would allow holes drilled from reclaimed slots to be classified as original wells for the purpose of royalty relief. Thus, the portion of a hole drilled from a reclaimed slot is classified as a sidetrack. MMS assumes that some operators include the expense to abandon the old well in calculating their sidetrack drilling cost. In virtually all cases, however, abandonment expenses for an old well will be incurred by the lessees regardless of whether a sidetrack is drilled from that slot. Hence, MMS views these abandonment expenses as sunk costs. In fact, when reclaiming a slot, lessees should be able to save the cost of drilling and casing the portion of the well that is reused.

MMS recognizes that sidetracks drilled from reclaimed slots will be among the longest and most expensive of all sidetracks drilled because the kick-off point will be at a shallow depth. However, the variance in sidetrack costs with length has been taken into account in calculating the sidetrack RSV's. The final rule contains a variable RSV scale for sidetracks, that will be applied to typical sidetracks and to well bores drilled from reclaimed slots. A sidetrack theoretically could earn as much RSV as an original well that is drilled to the same depth, but it would have to be a very long sidetrack, *e.g.*, over 18,350 feet of measured depth if drilled to 15,000–18,000 feet TVD SS, and 35,000 feet of measured depth if drilled to 18,000 feet TVD SS or greater.

Comment: Another comment refers to an MMS workshop presentation that suggested to some observers that a sidetrack will be classified as a bypass when the operator abandons a new well completion after testing and then sidetracks to obtain a greater gas recovery. The sidetrack target would be at a bottom hole location higher on the geologic structure, but in the same reservoir. An inequity could result from the situation described because bypasses are not eligible for relief under the proposed rule. Moreover, if sidetracks were eligible for relief in the final rule, the size of the RSV may not be as large as the RSV for original wells. The commenter suggests that MMS allow a sidetrack to receive the same size RSV as an original well if the sidetrack is drilled to replace that well (ChevronTexaco).

Response: Inclusion of a ''sidetrack'' definition reformatted from NTL 2000–N07 and a definition for ''original well'' (replaces ''new well'' definition in the proposed rule) in the final regulations should clarify that all subsequent sidetracks would still be considered the original well, if the sidetracking operations were conducted prior to the rig moving off the well location. Also, bypasses from an original well or sidetrack are still considered the original well or sidetrack.

Sidetracks do receive an RSV as specified in 30 CFR 203.41(a) of the final regulations. In cases where a sidetrack is drilled to the same depth interval as a qualified original well that produced more than test production (and the original well therefore already has earned the lease's RSV at that depth interval), the sidetrack may share in the relief previously granted. If the original well produces only test production, the sidetrack will earn its own RSV. If a sidetrack is drilled to a deeper depth interval than an original deep well, even after the original well produces more than test production, it earns a sidetrack RSV in addition to the RSV earned by the original well. In cases where an unsuccessful original well is drilled 18,000 feet TVD SS or deeper and then a deep sidetrack is drilled from the original well, an operator could receive an RSS for the original well in addition to earning a sidetrack RSV or even another RSS for that sidetrack if it is unsuccessful. Wells incapable of more than test production are not considered successful wells.

6. Sidetrack Relief Amounts for Successful Drilling

Comment: Sidetrack RSVs should be 10 BCF in 15,000–18,000 feet and 20 BCF for greater than 18,000 feet (Noble). A reduced sidetrack RSV of 3–5 BCF would be enough to spur drilling of marginal prospects (Merit). Royalty relief for sidetracks should not be differentiated by the depth of the associated original well or by offset distances (El Paso, ChevronTexaco). Use smaller RSVs for sidetracks than for original wells, but don't limit assessment to a comparison of costs—risk matters too. Don't limit sidetrack relief to depths greater than 18,000 feet, and apply the same RSS as in the proposed rule for deep original wells (ChevronTexaco).

Response: Although sidetrack drilling to deep depths represents only a modest proportion of recent drilling and production activity, that relationship could change considerably depending on the configuration of the royalty relief program. Accordingly, MMS decided to add eligibility of sidetrack wells to our deep gas program.

MMS's objective is to provide a proper incentive to encourage additional sidetrack drilling into deep depth targets whose potential reserve size would result in a marginally unprofitable development under existing royalty obligations. At the same time, MMS wanted to eliminate any potential for inefficient drilling decisions resulting from a distortion in the relative net costs of drilling vertical wells versus sidetracks.

MMS conducted an analysis of the expected full-cycle cost of drilling sidetracks of different lengths versus the cost of drilling original wells, accounting for the chance of drilling success. MMS also reviewed a very preliminary API draft study that estimated the marginal cost of drilling per foot of measured depths (lengths) drilled for sidetracks. However, because of very different methodologies (*e.g.*, the wells and sidetracks in the API study were drilled to all depths, and API used a statistical approach compared to the engineering model MMS used), the results are not directly comparable.

MMS identified a mathematical function for a sidetrack RSV which would result in approximately equal value of the RSV relative to the cost of drilling sidetracks and original wells on a before- and after-royalty relief basis. That is, the ratio of expected drilling costs net of royalty relief for both well types would be the same as the ratio based on drilling costs alone. This equivalence assures that drilling decisions are not distorted between well types by the royalty relief program.

The functional form for sidetrack relief that MMS derived is this: the RSV is equal to 4 BCF plus 0.06 BCF per 100 feet of measured depth drilled, *i.e.*, sidetrack length. The sidetrack relief is limited to the amount an original deep well could earn if produced in the same lease circumstances, *i.e.*, up to 15 BCF for the first deep well produced between 15,000–18,000 feet TVD SS (the ''shallower depth category'') or up to 25 BCF for the first deep well produced 18,000 feet TVD SS or deeper (the ''deeper depth category''). In cases where deep production has already occurred on the lease from the shallower depth category, drilling and producing a sidetrack in the deeper depth category can earn the full sidetrack RSV amount, but again, no more than an original well could earn in the same situation, equal to 10 BCF.

As discussed further below, sidetrack drilling can also generate a royalty suspension supplement (RSS) for an unsuccessful well under the same circumstances as an original unsuccessful well that has a perforated interval in the 18,000 foot TVD SS or deeper interval, with one additional condition, namely the sidetrack length must be at least 10,000 feet (measured depth). This requirement is imposed to preclude any incentive to drill short distances simply to earn an RSS. As with original wells, the sidetrack RSS is equal to 20 percent of the RSV that would have been earned by a successful sidetrack subject to a limit of 5 BCF, which is the RSS that would have been earned by an unsuccessful original well drilled to 18,000 feet TVD SS or deeper.

7. Production Start-Up Requirements

Comments: Five years is too short a time to explore and produce deep gas reserves, especially if drilling to deep depths must be from means other than an existing platform or if there is a need to build a pipeline (BP, Noble). Five years is not long enough to conduct activities and start production given the existing technological challenges (API). Provide for an extension on a case-by-case basis, when additional time for activities is justified (NOIA). Revise the rule to allow royalty relief for any otherwise qualified deep well if that well subsequently produces. This would account for unavoidable delays for weather, rig installations, and other reasons largely beyond the fault of the operator (El Paso).

Response: For leases issued beginning in 2001 with deep gas royalty relief provisions in the lease terms, the lessee must begin production from a deep well within 5 years of lease issuance. MMS believes it would be unfair to allow more than 5 years from the date of the final rule to begin production from a qualified well on leases many of which are further advanced in development than leases issued beginning in 2001. MMS therefore is allowing 5 years from the effective date of the final rule. MMS believes it is important to strongly encourage accelerated production, not just drilling, given the current state of the domestic natural gas market.

Nevertheless, in the interest of fairness, MMS has decided to allow some flexibility to extend this deadline for up to 1 year if MMS determines that the reasons for the delay are beyond the operator's control. For MMS to consider an extension, the operator has to demonstrate that he drilled to total depth within 5 years, that the delay through no fault of the operator occurred after reaching total depth, and that production otherwise could reasonably have been expected to commence within 5 years.

8. Unitization Comments and MMS Responses

Comment: One comment indicated that the proposed rule offered ''confusion and ambiguity'' about the treatment of unit and non-unit deep wells on the same lease. Specifically, it indicated that § 203.41(b)(3)(ii) is not only confusing but it seems ambiguous in that you could have a ''first successful qualified deep well on your lease'' when there is already another deep well ''on your lease'' (Noble).

Response: The referenced § deals with a lease that has both a unitized and non-unitized area within the lease. The language in the proposed rule stated that a lease, whether or not it is in a unit, earns an RSV only by drilling a qualified well, and that a subsequent deep well on that lease or any other leases in the unit does not earn an additional RSV for that lease. In other words, production is allocated among the leases in a unit; the royalty suspension volumes are not. This feature has not changed under the final rule. A related provision of the proposed rule—that the first qualified well on that lease determines that lease's final RSV—has been modified in the final rule.

The final rule adds the proviso that if the first qualified well is drilled to the shallower drilling depth category (15,000–18,000 feet TVD SS) and a subsequent qualified well is drilled to the deeper drilling depth category (at least 18,000 feet TVD SS), then the RSV earned by the lease will be increased pursuant to § 203.41(b).

MMS has rewritten the parts of §§ of 203.41 and 42 dealing with unitized and non-unitized wells on the same lease in two ways to clarify their meaning. A qualified well drilled in the unitized or non-unitized portion of the lease, after the first qualified well on a lease, earns for the lease an increased RSV only if it is drilled to a deeper depth category. Further, both the production from any qualified well on the non-unitized portion of the lease and the production allocated to the lease from qualified unit wells, will share in that lease's RSV.

Comment: The unitization proposal may actually provide a disincentive to drill wells on a unit basis. For example, if two leases are combined on a 50/50 basis to form a unit to test a prospect at 17,000 feet and it is anticipated that only one well will be necessary, the unit owners could conclude that the discovered reserves would have to be at least 30 BCF to allow each to receive the full incentive versus 15 BCF if the prospect were on one lease only (Noble).

Response: The rule provides an RSV as an incentive to drill a deep well. In the example, if the prospect was only on one lease, the owner(s) would get an RSV of 15 BCF for the deep well. If the prospect overlaps two unit leases, and one deep well is drilled, again the rule only provides one RSV of 15 BCF that goes to the lease with the deep well.

MMS's customary unitization policy affects the use of lease-based deep gas royalty relief in two ways. First, when a deep well penetrates a new reservoir and proves to be commercially producible, unit co-owners typically will revise the existing participating area for that reservoir based on available geological information. (The participating area percentages may be revised in light of the results of subsequent drilling activities.) Production from the reservoir will be allocated according to the participating area percentages. Because of this rule, MMS will require unit co-owners to establish a separate participating area for reservoirs produced by one or more qualified wells. The percentage allocated to a lease with a qualified well producing from that participating area will be subject to the RSV for that lease.

Second, in the case where all the unitized leases have shallow wells but only one lease has a qualified well located in a reservoir that geological information indicates is common with all the leases, the unitized leases without a qualified well will receive allocated production from the qualified well and royalty will be due on this production. Only deep well production allocated to the unitized lease with the qualified well would be royalty-free. In the example described in the comment if the well qualifies for deep gas relief, then it is accurate to say that production from the well must be at least 30 BCF for the lease with the qualifying well to receive the entire 15 BCF of relief.

To resolve the problem of not getting the relief as soon as possible in the above example, MMS stated at the Deep Gas Royalty Relief Workshop in Houston, Texas on April 30, 2003, that it would consider not allocating deep production for royalty purposes to a unitized lease without a qualifying well. Since this deep depth allocation would diverge from the way shallow depth production on the same unit is allocated for royalty purposes and from the way production is allocated from both shallow and deep wells for units without deep gas relief, MMS discarded this idea as an unnecessary source of confusion and administrative complexity. Therefore, for the final rule, MMS has decided not to revise its customary unitization policy. The unit working interest owners could still allocate production and share benefits under separate agreements to offset any imbalances they perceive from royalty relief going only to the unit participant with the deep well.

Comment: MMS is promoting the drilling of unnecessary wells in order for all leases in a unit to receive royalty relief. For example, suppose a four-lease unit exists, but only the lease with the completion receives the royalty suspension volume. The remaining three un-drilled leases do not share in the royalty suspension volume. The reservoir can be efficiently drained without drilling extra wells, but the un-drilled leases won't be entitled to any royalty free production on their allocated share of production unless they drill unnecessary wells. Allow the MMS the discretion to grant royalty suspensions for each lease in the unit after determining a successful well is not necessary to be drilled on each lease in the unit to develop efficiently the discovered reservoir (ChevronTexaco, Noble).

Response: The rule provides an incentive to drill a deep well. The RSV was based on the cost of a single deep well. Under the approach suggested in the comment, the owners could receive four RSV's (60 to 100 BCF) as an incentive for drilling one deep well, which is far more relief than the program intended.

Also, the proposal in the comment would require a reservoir interpretation and analysis by MMS. To avoid differences of opinion in this area, MMS considered and rejected a potential requirement for new leases issued beginning in 2001 that the deep well must produce from a new reservoir, *i.e.*, one that has not previously produced on any current lease. If MMS decided to utilize reservoir interpretations and analyses as proposed in the comment, then MMS would be inclined to include this ''new'' reservoir requirement in the regulation. In that event, the unitized leases in the example without a deep well would not be eligible for an RSV even with the drilling of a deep well into the reservoir. Furthermore, without subsurface well control on the three leases, MMS would not make a determination about whether or not additional deep wells are necessary for efficient development of the discovered reservoir.

Finally, as in the previous unit comment and response, unit co-owners may agree separately to adjustments to share the royalty relief benefits.

Comment: Another comment recommended that in any unit the RSV should be allocated in proportion to the royalty obligations in the unit agreement (API).

Response: MMS carefully considered and rejected this approach for several reasons. In some cases, the RSV cannot be allocated like production. A number of units contain State or Federal leases not eligible for deep gas royalty relief. Ineligible Federal leases in a unit might include those leases in water deeper than 200 meters or with deep well production from a well with a perforated interval the top of which is at least 18,000 feet TVD SS before March 26, 2003. Other units may contain leases issued after January 1, 2001, which have deep gas royalty relief with different magnitudes and lease provisions.

Using the lease-based approach also results in significantly less administrative burden. If the RSV were allocated, several allocations beyond the initial allocation may be needed—for example, if a new well leads to a change in the acre-feet shares assigned to each participating lease. Also, if royalty relief were allocated, the drilling of the first qualified well on each unitized lease would require a separate calculation of the remaining RSV and a reallocation of the revised suspension volume. In addition, when production data is updated, ''look-backs'' would be needed to confirm the accuracy of the reallocation or make necessary adjustments.

9. Price Thresholds

Comments: Raise the threshold or eliminate it to reduce or remove uncertainty about the availability of royalty relief. Don't count production against the RSV in periods when the price threshold is exceeded by actual prices (Noble). Price thresholds incur reporting and accounting difficulties and add complexity and uncertainty (Marathon). We believe price thresholds should be avoided. When prices are rising, lessees should be afforded the full suite of available incentives to meet demand. To eliminate the incentive in the face of tightening supplies is exactly the opposite of what should be done. Given the expectation of falling prices, lessees could time production and thereby delay drilling to periods of future royalty relief. With May 2003 prices above the threshold, there is no incentive to drill deep gas this year (Pioneer). The price thresholds impose barriers to effectively stimulate deep gas exploration and development. Accounting rules preclude royalty relief that might have to be paid back from being included in company income statements. To reduce investor uncertainty, do not count production against the RSV when prices exceed the threshold. Allow royalty relief up to the threshold price, and pay royalties on the extra revenues generated above the threshold price (El Paso).

Response: At the time MMS was preparing the proposed rule, natural gas prices were in the range of $3.50 per MMBtu. During the summer of 2003, as MMS prepared the final rule, natural gas prices were in the range of $5.50 per MMBtu, *i.e.*, above the threshold price levels expected for 2003. The price threshold level suggested in the proposed rule was based on price expectations that prevailed at that time, on historic price volatility, and on revenue considerations. That is, the level was set so that the loss of royalty relief occasioned by higher-than-expected gas prices would be more than offset by the higher realized gas prices. Since that time, however, gas prices have surged and EIA projections for future average gas prices have risen as well. Moreover, we've noted a distinct pattern for gas prices to show considerably more volatility in recent years compared to historic trends. As a result, we conducted an in-depth analysis to determine whether the incremental production effects of the deep gas royalty relief program would be adversely influenced by retention of this earlier proposed price threshold formulation. This analysis incorporates the important influence that price volatility can have on the drilling incentive and on royalty collections. The results, provided in the economic analysis to this rulemaking, showed that there would be significant degradation in incremental program benefits from retention of the price threshold formulation offered in the proposed rule.

The current expectations for the gas market are for higher, more volatile future prices compared to earlier expectations reflected in the proposed rule. The higher prices should lead to increased demand for drilling equipment and larger capital expenditures for exploration and production of additional gas supply. However, supply of capital equipment generally does not respond as quickly as demand, leading to increased prices for costs of acquiring the needed capital equipment to expand production. As a result, OCS operators may not fully benefit from increased natural gas prices when such increases are rapid and may not be sustained.

The incentive provided by this rule remains a significant tool to promote deep and costly drilling regardless of market prices. These revised base cases and incremental outcomes have been incorporated in the economic analysis and demonstrate the continued viability of relief and the need to adjust the price threshold formulation.

In light of these observations, MMS concludes that (1) the previous revenue relationships may not apply in the current circumstances, and (2) the effect of the higher gas prices on drilling decisions may be dampened in the short term by the proposed price thresholds, and (3) despite added supplies offered at higher prices, program benefits from providing royalty relief in the amount, form, and time described in this rule remain substantial. Accordingly, MMS agrees with the comments that some response is needed to modify the price thresholds in light of the current and revised expectations about future gas market conditions.

The final rule revises the original price threshold provision by raising the market price level which suspends royalty relief from $5 per MMBtu (expressed in year 2000 dollars) to $9.34 per MMBtu (expressed in year 2004 dollars). When expressed in same year dollars, this represents a 70 percent increase in the price threshold. The threshold price rises at the full increase in inflation in subsequent years. MMS compared incremental production and forgone royalty estimates for a variety of price thresholds using a calculation that accounts for the effects price volatility can have on the incentive. The specific revised price threshold level now chosen poses a small risk that the price threshold will be exceeded. However, if this price threshold is violated, then the forgone royalty would be substantially less, in part because gas prices would be so high. Because the chance of violation is low, the chosen policy should have only a minor effect on drilling and discoveries compared to the absence of a threshold while adequately protecting taxpayers from lost revenue should gas prices escalate more than now expected. The economic analysis for this rulemaking examines a variety of different price threshold options.

10. Scope of Royalty Relief for Leases

Comment: Allow royalty relief in the proposed amounts by block, not lease (McMoran, El Paso).

Response: Please see responses to comment numbers seven and eight. The royalty relief program MMS designed is lease-based. Because the offshore oil and gas program is administered mostly by lease, the lease'based formulation of royalty relief allows for a convenient interface with the existing regulatory structure. Moreover, under this stipulation almost all shallow water leases are subject to similar provisions of deep drilling royalty relief.

In contrast, there were only 72 leases (1 percent) having more than one block, and only 9 leases with more than 2 blocks in the summer of 2003. In almost all cases, the extra blocks were only portions of normal size blocks where it was most practical to combine into one lease for bidding in a lease sale. Thus, the lease area for most multiple block leases is close to that for single block leases. In the unique case where a lease contains several blocks and is significantly larger than a normal lease, further relief may be appropriate under the special case royalty relief provision (30 CFR 203.80). Modification of the program to accommodate relief on a block basis is not appropriate.

11. Defining Drilling Depth Interval Requirements

Comment: Utilize drilling depth to a pre-defined target instead of to the top of the perforated interval to define the classification of a deep well. Otherwise, the definition in the proposed rule may encourage poor decisions on completion activities in order to qualify for relief (Pioneer).

Response: ''Drilling depth to a pre-defined target'' is an uncertain measure because seismic data are used to define the drilling objective. In contrast, the ''top of the perforated interval'' is an exact measurement of the location of productive hydrocarbons.

Moreover, MMS believes that the differences between the proposed and suggested definitions will have significance for royalty relief in only a limited number of cases, for instance, where the reservoir target happens to straddle the 15,000 foot TVD SS or the 18,000 TVD SS depth. MMS further believes that in those few cases, operators will base their completion decisions on sound engineering practices and will be reluctant to qualify their wells by making poor completion decisions.

To remove some uncertainty, the final rule is explicit about the treatment of the RSV in the situation where a single well involves multiple leases. Where a (directional or sidetrack) deep well begins on one lease but is completed on a second lease, then the production from, and any royalty relief earned by, the qualified well belongs to the second lease. If the qualified well has separate perforated intervals (either of which would qualify) on two leases, then the lease with the perforated interval that produces first earns the royalty suspension volume. Finally, if the perforated interval of the qualified well extends across two leases, then the lease where the surface of the well is located earns the RSV. These procedures avoid allocating or doubling up on RSV and are consistent with the treatment of royalty relief in a unit situation.

12. Ultra-Deep Depth Drilling Category

Comment: The bulk of deep gas drilling opportunities is below 20,000 feet TVD SS. MMS should provide at least an RSV of 45 BCF for successful drilling to this depth (BP). We would like to see a third tier of relief for ultra-deep drilling. Many companies believe the real targets of opportunity lie below 20,000 feet TVD SS. The difference in cost to drill 18,000 feet versus 20,000 feet TVD SS is dramatic. We think an RSV of 35 BCF is appropriate (NOIA). We support an RSV of 35 BCF for drilling below 20,000 feet TVD SS (Noble, Rowan, Marathon).

Response: The anticipated royalty savings associated with drilling a qualified very deep well successfully, *i.e.*, to at least 18,000 feet TVD SS, is more than $20 million at gas prices in the summer of 2003. MMS believes an incentive of this size is appropriate at this time for accelerating drilling below 18,000 feet TVD SS, as well as below 20,000 feet TVD SS. The fact is that very little drilling has taken place so far at either drilling depth in shallow water. Data since 1998 show 249 deep wells were drilled. Of these, 17 percent were to at least 18,000 feet and 7 percent to at least 20,000 feet. Overall the success rate was 8 percent, although it was higher at the ultra-deep interval. Because of the sparse data, it is difficult to predict accurately the true chances of drilling success, the potential size of discoveries, the cost of drilling in ultra-deep depths, and thus the additional production likely from an increment to the available RSV. Moreover, adding this third tier of relief will complicate the regulatory requirements and delay publication of the final rule. MMS will continue to consider the need for granting increased royalty relief for ultra-deep wells, but it is premature to do so in this rule.

13. Auction Mechanism

Comments: The industry was unanimous in its opposition to a bidding system offered for possible future use that would serve to distribute the rights to deep gas royalty relief.

These rights would have to be acquired before drilling of a designated nature, such as discussed in this final rule, could become eligible to earn royalty relief. Regardless of whether the bid variable was a cash bonus or the RSV (or RSS) amount itself, comments indicated that such a system could have perverse and unintended consequences.The system would appear to benefit primarily those wells that would be drilled anyway (BP). It would defeat the purpose of the rule by denying relief to those who need it most and it would delay drilling and reduce the number of total wells drilled (NOIA). Winning bidders would not necessarily use the property rights acquired to drill deep wells (Rowan). It introduces uncertainty that could inhibit planning activities necessary for deep drilling success (Exxon). The program has no benefit and numerous pitfalls that could undermine the deep drilling initiative (Marathon). The bidding system would not accelerate development of deep gas (El Paso). The system could eliminate certain lessees from competing for the incentives (ChevronTexaco).

Response: MMS recognizes that adoption of a bidding system to distribute royalty relief is, at best, premature. 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. As envisioned, the MMS proposed auction would result in the government forgoing the same total amount of royalty payments as expected for this rule, but may result in more drilling by awarding less royalty relief to those companies that need a smaller incentive, therefore freeing up a larger quantity of relief to be allocated to those companies that would require more relief than is granted in this rule to undertake deep drilling.

Unlike this rule, which essentially allocates the same quantity of relief regardless of actual need, in theory there should be an auction framework capable of allocating variable amounts of royalty relief based on need. MMS recognizes that the ability of an auction mechanism to achieve this goal would depend on, among other considerations, a design framework that could discourage a bidding scenario in which relief is allocated to those who need it least, and awarded to those least likely to utilize it. An auction procedure with these characteristics has not yet been developed; hence more research is needed in this area. So, implementation of the deep gas royalty relief program will proceed without an auction feature.

Procedural Matters

Regulatory Planning and Review (Executive Order 12866)

According to the criteria in Executive Order 12866, this rule is a significant regulatory action for which a Regulatory Analysis has been prepared. The Office of Management and Budget (OMB) has made that determination under Executive Order 12866.

(1) The preferred alternative adopted in this rule will have an economic effect of $100 million or more by reducing consumer expenditures on natural gas by about $500 million each year and may have a slightly adverse effect on other units of government. An economic analysis of this regulatory action was prepared and will be available at *http//www.mms.gov/econ*. This rule reduces royalties for lessees that drill and produce natural gas from deep wells in shallow water areas of the GOM. The RSV's offered should increase deep drilling activity on existing leases over the period of the program and make additional resources economic. The deep gas royalty suspensions are likely to reduce net Federal royalty collections. MMS's best estimate of this reduction is from $150 to $220 million in net present value over a 16-year period, depending on gas price volatility.

The royalty relief program for deep gas drilling will have two distinct effects: (1) recovery of some otherwise uneconomic gas resources, and (2) accelerated recovery of some marginally economic gas resources. MMS data indicate that about 10–20 percent of the undiscovered gas resources in the most prospective depths, *i.e.*, 18,000 TVD SS or deeper, could be converted from unprofitable to profitable by the incentives provided in this rule. MMS estimates that those resources are located in approximately 20–30 percent of undiscovered gas reservoirs.

MMS estimates that about one-fourth of the economically explorable gas reservoirs at drilling depths 18,000 feet TVD SS or deeper would be drilled 1–5 years sooner if the proposed rule is implemented. These reservoirs are associated with less than 10 percent of the undiscovered resource. MMS estimates that application of the program to undiscovered gas resources at depths 18,000 feet TVD SS or deeper could increase production of gas by over two TCF. Application of MMS's proposed program to reservoirs in the 15,000 to less than 18,000-foot TVD SS range of drilling depth could affect another 1–2 TCF of gas. The deep drilling program will affect only a part of these resources in any one year.

(2) This rule will not create any inconsistencies with actions by other agencies because royalty relief is confined to leasing in Federal offshore waters that lie outside the coastal jurisdiction of State and other local agencies. Careful review of the lease sale notices, along with stringent leasing policies now in force, ensures that the Federal OCS leasing program, of which royalty relief is only a component, does not conflict with the work of other Federal agencies.

(3) This rule has no effect on entitlements, grants, user fees, loan programs, or their recipients. However, the rule does have the effect of postponing distributions of royalty revenue. MMS distributes about 1 percent ($40 million) of the OCS revenue it collects annually in the GOM to neighboring States under Section 8(g) of the OCSLA. Royalty suspensions from the deep gas program could affect up to 5 percent of the total production from the GOM in any one year. If deep gas production occurs in the 8(g) zone at the same proportion as elsewhere in the GOM, these State distributions could be reduced by $1 to $2 million per year for 5–10 years. However, extra production that occurs because of the incentive will also provide extra royalties, mostly after the RSVs have been produced. Given uncertainty about the number, location, and size of deep gas discoveries, it is even possible that the extra royalties could fully offset the initial drop in both Federal and State royalties. This would occur if our program generates 25 percent more incremental gas resources than the most likely scenario evaluated in the Economic Analysis.

(4) This rule raises a novel legal or policy issue. The RSS for an unsuccessful deep gas well expands the scope of royalty relief to reward efforts for exploration in frontier well depths whether or not they eventually produce. As explained in the preamble to the Proposed Rule (68 FR 14868), MMS believes this creates a more cost-effective royalty relief program compared to one that only rewards success in this very risky environment. Also as explained in the economic analysis accompanying the proposed rule, several features of the rule essentially eliminate any moral hazard potential of the RSS.

In addition, RSV's have been used for several years as an incentive to accelerate exploration and production in deep-water. Application to deep gas is a logical extension of that policy. A well-defined program for deep gas drilling is more administratively efficient than the elaborate case-by-case requirements of the application process for deep-water royalty relief. The focus here is on a straightforward definition of well depth and circumstances to qualify for royalty relief.

MMS developed an economic analysis of this regulatory action in accordance with requirements for a major rule under OMB and statutory criteria. This analysis describes why market forces alone will not increase deep gas development in the short term, considers possible royalty relief alternatives to serve that need, and analyzes the social benefits and costs and related transfer payments associated with several royalty suspension alternatives. Two options provide the highest level of added production and net social benefits:

A. The RSV in this final rule of 15 BCF for successful wells to 15,000–18,000 feet TVD SS and 25 BCF for successful wells (or 5 BCF for unsuccessful wells) to 18,000 feet TVD SS or deeper depths, plus reduced amounts for deep sidetracks and for deeper wells on leases that have deep wells, and

B. As in option A, but limiting RSV to 10 BCF for successful wells to 15,000–18,000 feet TVD SS and to 20 BCF for successful wells (or 5 BCF for unsuccessful wells) to 18,000 feet TVD SS or deeper.

These two options were selected over other alternatives considered in the proposed rule that included higher suspension levels as a substitute for royalty relief for unsuccessful drilling.

MMS ranked alternatives based on estimates of their net social benefits. Net social benefits are the sum of the net gains to producers and consumers associated with the additional production attributable to this rule. These gains are measured as changes in consumer and producer surplus compared to a status quo or baseline amount that would occur in the absence of the incentive. Consumer surplus is the difference between the value consumers place on the additional production and its market value. Producer surplus is the difference between the market price and the cost of additional production (including the cost of drilling unsuccessful wells). Transfer payments, on the other hand, consist primarily of changes resulting from the rule in the amount of Federal royalty payments and domestic expenditures to purchase status quo quantities of gas. This summary reviews the performance of the superior options based on several criteria: added production, forgone royalty, and net social benefits from production that would not have occurred without an incentive for deep gas drilling. The comparison of alternative incentive levels reported below were made with updated EIA gas price forecasts but omit the dampening effects of a potentially binding price threshold. The relative effect of alternative price threshold options is largely independent of the RSV level and hence plays little, if any, role determining the choice between alternative levels of the RSV.

MMS estimates that option A, the royalty suspension level adopted in the final rule, would generate a cumulative added production of 3.8 TCF of gas and 0.81 TCFE of condensate over the next 16 years (before considering the slight dampening effect a potentially binding price threshold may have on incremental production). In contrast, option B would generate added production of 3.3 TCF of gas and 0.71 TCFE of condensate over the same time frame (again ignoring the price threshold effect). Added production consists of production from reservoirs unlikely to be drilled under normal conditions and from a portion of reservoirs only likely to be drilled in the future after information, technology, and costs improve, *i.e.*, accelerated production.

Using assumptions about prices, discount rates, and well flow rates, MMS estimated the net social benefits to society from increased deep gas production. As discussed above, this primary measure of social welfare effects eliminates the sizeable transfers from producers to consumers associated with reduced prices, and from government to producers in the form of reduced royalty payments. The incremental supply added to domestic stocks as a result of the incentive generates a net gain to society. Under option A, the adopted incentive, MMS estimates a net social gain of $290 million in present value versus $238 million under option B.

Comparing increased production to forgone royalty-bearing production provides another perspective on the effects of the rule. MMS estimates that royalty would be forgone under option A on 2.8 TCFE of gas and oil production that would have occurred anyway. That implies a ratio of extra production to forgone royalty-bearing production of 1.64 [(3.8 TCF + 0.8 TCFE)/2.8 TCF]. For option B, this ratio is also 1.74 [(3.3 TCF + 0.7 TCFE)/2.3 TCF]. Hence, either of these deep gas incentive options is preferable to no such incentive.

Some of the forgone royalty would be offset by royalty collections on the condensate and on added gas production after the royalty suspensions have been used. Taking those into account and distributing the production over the next 16 years, MMS estimates a net reduction in present value of royalty receipts of $227 million under the proposal versus $37 million for the second alternative. These results suggest that option B provides only about 85 percent of the production effects and the net social benefits of option A. Option B costs only about 20 percent of the forgone royalty revenues as option A.

Regulatory Flexibility (RF) Act

MMS chose the incentive form that combines an RSV for successful deep gas wells and an RSS for unsuccessful deep wells for three reasons:

(1) It is large enough to generate substantial deep drilling activity;

(2) It is the most cost-effective incentive structure for the Government because it does not waste as much relief as alternatives on prospects that will be drilled anyway; and

(3) It concentrates most of the incentive on the very deep (18,000 feet or deeper subsurface) zones where MMS believes most of the undiscovered potential is to be found.

A detailed analysis of the small business impacts and alternatives considered can be found in the economic analysis of this regulation which is available at *http://www.mms.gov/econ.*

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. Of the approximately 130 such companies active offshore in the GOM, we estimate that as many as 91 (70 percent) companies qualify as small firms.

Because this program is administered on a categorical rather than an application basis, minimal administrative time and cost is needed to qualify for royalty relief. Since no special analysis or independent review would be necessary to accomplish these compliance activities, MMS sees very little burden on normal operations of either small or large companies. For this rule, paperwork costs are only 1/10 of 1 percent of benefits and are the minimal cost necessary to allow for the monitoring essential to a consistent administration of this program across all participants. While administrative costs are the same for all the categorical incentive alternatives, the benefits are different. The alternative MMS chose results in the largest benefit to producers and to the small entity share of producers. Further, two reasons (risk sharing and location advantages) suggest that small OCS entities could get a disproportionate share of the large benefits of this rule.

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 RSS 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, MMS expects 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 one expects to 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 MMS believes 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, will be available on the MMS website for the duration of this program.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is a major rule under 5 U.S.C. 804(2), the SBREFA. This rule:

(1) Does have an annual effect on the economy of $100 million or more. This rule introduces a royalty relief program for deep gas that will save consumers $500 million annually for about a decade, of which about $19 million is a gain in consumer surplus attributed to additional gas consumption. Also, there is a gain in producer surplus of over $12 million annually that otherwise would not have occurred as well as additional industry employment. The change from the status quo in royalty collected by the Federal government under the revised rulemaking would exceed the $100 million per year threshold in 10 out of 16 years in which meaningful amounts of program-related production are generated. This incentive will cause Federal royalty to be reduced by more than $100 million during each of about 5 years early in the program and to be increased by more than $100 million during each of about 5 years late in the program. The benefits of the rule on the economy more than offset the net royalty losses. A comparison of two types of production provides a proxy measure of this net social benefit. MMS estimates the magnitude of new gas production that ultimately occurs because of the incentive in the rule is about 1.5 times the size of gas production on which the government forgoes royalty. The government only forgoes royalty on that portion of production that would have occurred anyway without the incentive. Moreover, consumers of natural gas will benefit from additional domestic gas supplies and have lower market prices.

More lessees may take advantage of the new deep gas royalty relief provisions over the next few years than have ever applied for end-of-life or deep-water royalty relief. However, the incremental drilling and production induced by this royalty relief will be small relative to total gas drilling and production in the GOM. The main thrust of the initiative is to increase and help accelerate new gas production to promote timely production otherwise inhibited. Even a small moderation of prices due to added deep gas production would result in a significant savings in gas expenditures and dampen natural gas prices in the market. Further, the rule would impose no costs on any local or private entity, but may initially impose some small costs ($1 to $2 million per year) on Gulf Coast States in the form of reduced payments under section 8(g) of the OCSLA. However, production that otherwise would not occur will result from these incentives. That production will produce extra royalty payments, mostly after the RSV has been produced. Participation in the program by lessees is voluntary.

MMS considers the key adverse economic effect of this program, with regard to the $100 million dollar annual benchmark, to be forgone Federal royalties on deep gas production that would have been generated without this program. Lower royalties mean more taxable income to companies. However, the results cited in the discussion accompanying this rule measure the effect on forgone Federal revenues without consideration of tax receipt increases. Note that this is a transfer payment in that the government loss is also an operator gain from pursuing a socially desirable activity—deep gas production.

MMS forecasts that without the deep gas royalty relief program, 53 wells would be drilled annually to depths of 15,000–18,000 feet TVD SS and 24 wells to drilling depths below 18,000 feet TVD SS. Based on trends in drilling deep depths during the past 10 years in shallow water, MMS would expect 18 successful wells in the 15,000–18,000 feet TVD SS drilling depth and five successful wells at deep drilling depths 18,000 feet TVD SS or deeper without the incentive. With the incentive, MMS estimates there would be 62 wells drilled to depths 18,000 feet TVD SS or deeper, of which 49 would be unsuccessful, and 33 of them on leases having other production to which the RSS could be applied. In both drilling depths, some of these wells will be sidetracks or deeper wells on leases with deep production that qualifies them for a reduced royalty suspension.

Over the 2003–2009 period, the absence of this deep gas royalty relief program would save the government about 470 BCF in new RSV and RSS awarded for drilling activities that would have occurred anyway. These savings may decline before the program ends in about 2009 because of the availability of less prospective reservoirs in later years of the program. Further, in any one year, only about 20–25 percent of the accrued amount of RSV and RSS could actually be used.

Offsetting most of these initial royalty losses are the extra royalties from two sources: (a) the condensate portion of production from the added deep gas wells and (b) gas production in later years beyond the RSV from additional reserves discovered because of the incentive. Along with the additional 38 new wells (62–24) drilled annually to depths 18,000 feet TVD SS or deeper, MMS expects an additional 18 new wells (71–53) would be drilled annually to depths of 15,000–18,000 feet TVD SS. MMS estimates that these incremental wells ultimately would lead to gas production of about 3.8 TCF, of which 1.4 TCF would be royalty-free and 2.3 TCF would be royalty-bearing. MMS anticipates that the royalties on this 2.3 TCF of gas production would begin in 2008 and continue until about 2020. A further offsetting benefit also comes from extra private profits from production that would otherwise not occur. A detailed economic analysis of this regulatory action was prepared and will be available at www.mms.gov/econ. This economic analysis explains our monetary calculations.

(2) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or

geographic regions. The deep gas incentive should materially moderate expected gas prices by adding to the overall supply.

(3) Does not have significant adverse effects on competition, employment, investment, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. Companies eligible for the deep gas royalty relief should produce more natural gas and earn more income, while encountering no negative effects.

Paperwork Reduction Act (PRA) of 1995

MMS examined the proposed rule and these final regulations under section 3507(d) of the PRA. Because of the changes to the current 30 CFR part 203 regulations, MMS submitted the information collection (IC) requirements of this rule to OMB for approval as part of the proposed rulemaking process. The IC requirements in the final regulations remain unchanged from the proposed rule, and a new submission to OMB is not required.

The PRA provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number. OMB approved the additional requirements to collect information under revisions to 30 CFR part 203 under OMB control number 1010–0153, current expiration date of April 30, 2006. When this final rule becomes effective, MMS plans to roll these IC requirements into those already approved for 30 CFR part 203 (OMB control number 1010–0071).

MMS uses the information collected in this final rule, 30 CFR 203.40 through 203.48, to determine whether a lessee has fulfilled the drilling and production requirements or exercised an option to earn the royalty relief offered to deep gas wells under this part. These decisions have enormous monetary impacts to both the lessee and the Federal Government. Royalty relief can lead to increased production of natural gas and oil, creating profits for lessees and possible royalty and tax revenues for the government that they might not otherwise receive. MMS uses industry notification of drilling intent and production to determine eligibility of the lease to receive royalty relief. The well data collected enables MMS to confirm that a well was an unsuccessful well and that the lessee is eligible for the RSS offered in the program.

The title of this collection of information is ''30 CFR Part 203, Deep Gas Provisions.'' The frequency of response is occasional. Respondents include approximately 130 Federal OCS oil and gas lessees and operating rights holders. Responses are required to obtain or retain a benefit. The IC does not include questions of a sensitive nature. MMS protects information considered proprietary under applicable law and 30 CFR 250.196.

The following table lists the new IC requirements and respective burdens for this rule. The approved annual burden of this collection of information is 361 hours. Based on a cost factor of $50 per hour, the hour cost burden of the new paperwork requirements would be $18,050. There are no non-hour cost burdens in the final regulations.

TABLE 3.—BURDEN BREAKDOWN

30 CFR 203 section	Reporting requirement	Hour burden	Annual number	Annual burden hours
43(a) 46(a)	Notify MMS of intent to begin drilling	1 hour	89 notices	89
43(b)(1)(2)	Notify MMS that production has begun and request confirmation of the size of RSV.	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 submissions	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		168 responses	361

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

Federalism (Executive Order 13132)

According to Executive Order 13132, this rule does not have meaningful Federalism implications. As noted above, it may initially have some small consequences ($1 to $2 million a year) on Gulf Coast States in the form of reduced payments under section 8(g) of the OCSLA. However, additional resources discovered under this incentive will make up for these initial reductions from production that otherwise would not occur. Largely after the RSV's have been produced, extra royalties and payments for Federal and Gulf Coast States will result from this extra production. Also, the added economic activity in those States associated with new deep drilling will generate new tax revenues. Therefore, a Federalism assessment is not required because the rule would not have a direct or substantive effect on the relationship between the Federal and State Governments, nor does it impose responsibilities or costs on States or localities.

Takings Implication Assessment (Executive Order 12630)

According to Executive Order 12630, the rule does not have significant takings implications; therefore a Takings Implication Assessment is not required. This rule has no takings effect because it only specifies circumstances under which royalty payments to the Federal Government by OCS lessees might be reduced. MMS believes that the lessee of such a lease would be better off financially under this rule than in the absence of it.

Energy Supply, Distribution, or Use (Executive Order 13211)

This rule is a significant rule and is subject to review by OMB under Executive Order 12866. This rule does not have a significant adverse effect on energy supply, distribution, or use. This rule increases and accelerates the production of gas from deep wells in shallow waters of the GOM by providing for an RSV for successful deep production and an RSS for unsuccessful deep drilling efforts, so it has a positive effect on energy supply based on our regulatory analysis.

Unfunded Mandates Reform Act (UMRA) of 1995

This rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have any Federal mandates nor does the rule have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the UMRA (2 U.S.C. 1531 *et seq.*) is not required.

Civil Justice Reform (Executive Order 12988)

According to Executive Order 12988, the Office of the Solicitor has determined that the rule does not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the Order.

National Environmental Policy Act (NEPA) of 1969

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the NEPA is not required.

Consultation and Coordination With Indian Tribal Governments (Executive Order 13175)

In accordance with Executive Order 13175, this rule does not have tribal implications that impose substantial direct compliance costs on Indian tribal governments.

List of Subjects in 30 CFR Part 203

Continental shelf, Government contracts, Indian lands, Minerals royalties, Oil and gas exploration, Public lands-mineral resources, Reporting and recordkeeping requirements, Sulphur.

Dated: October 7, 2003.

Rebecca W. Watson,

Assistant Secretary—Land and Minerals Management.

■ For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 30 CFR part 203 as follows:

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

■ 1. The authority citation for part 203 continues to read as follows:

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

■ 2. The definitions for *certified unsuccessful well, deep well, original well, participating area, qualified well, reservoir, royalty suspension supplement, royalty suspension volume, sidetrack,* and *sidetrack measured depth* are added alphabetically to § 203.0 as follows:

§ 203.0 What definitions apply to this part?

* * * * *

Certified unsuccessful well means an original well, or a sidetrack with a sidetrack measured depth of at least 10,000 feet, on your lease that—

(1) You begin drilling on or after March 26, 2003, and before March 1, 2009, and before your lease produces gas or oil from a deep well with a perforated interval the top of which is at least 18,000 feet true vertical depth below the datum at mean sea level (TVD SS);

(2) You drill to at least 18,000 feet TVD SS with a target reservoir on your lease, identified from seismic and related data, deeper than that depth;

(3) Fails to meet the producibility requirements of 30 CFR part 250, subpart A, and does not produce gas or oil, or the MMS agrees is not commercially producible; and

(4) For which you have provided the notices and information in § 203.46.

* * * * *

Deep well means either an original well or a sidetrack with a perforated interval the top of which is at least 15,000 feet TVD SS. A deep well subsequently re-perforated less than 15,000 feet TVD SS in the same reservoir is still a deep well.

* * * * *

Original well means a well that is drilled without utilizing an existing wellbore. An original well includes all sidetracks drilled from the original wellbore before the drilling rig moves off the well location. A bypass from an original well (*e.g.*, drilling around material blocking the hole or to straighten crooked holes) is part of the original well.

Participating area means that part of the unit area that MMS determines is reasonably proven by drilling and completion of producible wells, geological and geophysical information, and engineering data to be capable of producing hydrocarbons in paying quantities.

* * * * *

Qualified well means a deep well:

(1) For which drilling begins on or after March 26, 2003;

(2) That produces natural gas (other than test production), including gas associated with oil production, before March 1, 2009; and

(3) For which you have met the requirements prescribed in § 203.43.

* * * * *

Reservoir means an underground accumulation of oil or natural gas, or both, characterized by a single pressure system and segregated from other such accumulations.

* * * * *

Royalty suspension supplement means a royalty suspension volume resulting from drilling a certified unsuccessful well that is applied to future natural gas and oil production generated at any drilling depth on, or allocated under an MMS-approved unit agreement to, the same lease.

Royalty suspension volume means a volume of production from a lease that is not subject to royalty under the provisions of this part.

Sidetrack means, for the purpose of this subpart, a well resulting from drilling an additional hole to a new objective bottom-hole location by leaving a previously drilled hole. A sidetrack also includes drilling a well from a platform slot reclaimed from a previously drilled well or re-entering and deepening a previously drilled well. A bypass from a sidetrack (*e.g.*, drilling around material blocking the hole, or to straighten crooked holes) is part of the sidetrack.

Sidetrack measured depth means the actual distance or length in feet a sidetrack is drilled beginning where it exits a previously drilled hole to the bottom hole of the sidetrack, that is, to its total depth.

* * * * *

■ 3. In § 203.4, the introductory paragraph is revised to read as follows:

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

The tables in this section summarize the similar application and approval provisions for the discretionary end-of-life and deep water royalty relief programs in §§ 203.50 to 203.91. Because royalty relief for deep gas on leases not subject to deep water royalty relief, as provided for under §§ 203.40 to 203.48, does not involve an application, its provisions do not parallel the other two royalty relief programs and are not summarized in this section.

* * * * *

■ 4. A new § 203.5 is added to subpart A to read as follows:

§ 203.5 What is MMS's authority to collect information?

The Paperwork Reduction Act of 1995 (PRA) requires us to inform you that MMS may not conduct or sponsor and you are not required to respond to a collection of information unless it displays a currently valid OMB control number. OMB approved the information collection requirements in this part 203 under 44 U.S.C. 3501 *et seq.* in two actions. The information collection requirements in §§ 203.50 through 203.91 are approved under OMB control number 1010–0071, and those in §§ 203.40 through 203.48 are approved under 1010–0153.

■ 5. A new undesignated heading and new §§ 203.40 through 203.48 are added to subpart B to read as follows:

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

§ 203.40 Which leases are eligible for royalty relief as a result of drilling deep wells?

Your lease may receive a royalty suspension volume under §§ 203.41 through 203.43, and may receive a royalty suspension supplement under §§ 203.44 through 203.46, if it:

(a) Was:

(1) In existence on January 1, 2001;

(2) Issued in a lease sale held after January 1, 2001 and before April 1, 2004 and the lessee has exercised the option provided for in § 203.48; or

(3) Issued in a lease sale held on or after April 1, 2004 and the lease terms provide for royalty relief under §§ 203.41 through 203.47;

(b) Is located:

(1) In the GOM, wholly west of 87 degrees, 30 minutes West longitude;

(2) Entirely in water less than 200 meters deep, or partly in water less than 200 meters deep and no deep-water royalty relief provisions in statutes or lease terms apply to the lease; and

(c) Has not produced gas or oil from a deep well with a perforated interval the top of which is 18,000 feet TVD SS or deeper that commenced drilling before March 26, 2003.

§ 203.41 If I have a qualified well, what royalty relief will my lease earn?

(a) This paragraph and paragraph (b) of this section apply if your lease has not produced gas or oil from a deep well that commenced drilling before March 26, 2003. Subject to the administrative requirements of § 203.43, the provisions of § 203.44(d), and the price conditions in § 203.47, you earn a royalty suspension volume shown in the following table in billions of cubic feet (BCF) or in thousands of cubic feet (MCF) applicable to gas production as prescribed in § 203.42:

If you have a qualified well that is . . .	Then you earn a royalty suspension volume on this amount of gas production, as prescribed in this section and § 203.42:
(1) An original well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS.	15 BCF.
(2) A sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS.	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 15 BCF.
(3) An original well with a perforated interval the top of which is 18,000 feet TVD SS or deeper.	25 BCF.
(4) A sidetrack with a perforated interval the top of which is 18,000 feet TVD SS or deeper.	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.

(b) We will suspend royalties on gas volumes produced on or after March 1, 2004 reported on the Oil and Gas Operations Report, Part A (OGOR–A) for your lease under 30 CFR 216.53, as and to the extent prescribed in § 203.42. All gas production from qualified wells reported on the OGOR–A, including production that is not subject to royalty (except for production to which a royalty suspension supplement under §§ 203.44 and 203.45 applies), counts toward the lease royalty suspension volume.

Example 1. If you have a qualified well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, you earn a royalty suspension volume of 15 BCF of gas production from qualified wells on your lease, as prescribed in § 203.42. However, if the top of the perforated interval is 18,500 feet TVD SS, the royalty suspension volume is 25 BCF.

Example 2. If you have a qualified well that is a sidetrack with a perforated interval the top of which is 16,000 feet TVD SS, that has a sidetrack measured depth of 6,789 feet, we round the distance to 6,800 feet and you earn a royalty suspension volume of 8.08 BCF of gas production from qualified wells on your lease, as prescribed in § 203.42.

Example 3. If you have a qualified well that is a sidetrack with a perforated interval the top of which is 16,000 feet TVD SS, that has a sidetrack measured depth of 19,500 feet, you earn a royalty suspension volume of 15 BCF of gas production from qualified wells on your lease, as prescribed in § 203.42, even though 4 BCF plus 600 MCF per foot of sidetrack measured depth equals 15.7 BCF.

(c) This paragraph and paragraph (d) of this section apply if your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS (regardless of whether drilling began before or after March 26, 2003), and you subsequently have a qualified well on your lease with a perforated interval the top of which is 18,000 feet TVD or deeper. Subject to the administrative requirements of § 203.43, the provisions of § 203.44(d), and the price conditions in § 203.47, you earn a royalty suspension volume specified in the following table, applicable to gas production as prescribed in § 203.42. This royalty suspension volume is in addition to any royalty suspension volume your lease already may have earned, if any, as a result of a qualified well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS.

If your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS, and you subsequently have a qualified well that is . . .	Then, you earn a royalty suspension volume on this amount of gas production, as prescribed in this section and § 203.42
(1) An original well or a sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS.	0 BCF.

If your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS, and you subsequently have a qualified well that is . . .	Then, you earn a royalty suspension volume on this amount of gas production, as prescribed in this section and § 203.42
(2) An original well with a perforated interval the top of which is 18,000 feet TVD SS or deeper.	10 BCF.
(3) A sidetrack with a perforated interval the top of which is 18,000 feet TVD SS or deeper.	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(d) We will suspend royalties on gas volumes produced on or after March 1, 2004 reported on the Oil and Gas Operations Report, Part A (OGOR–A) for your lease under 30 CFR 216.53, as and to the extent prescribed in § 203.42. All gas production from qualified wells reported on the OGOR–A, including production that is not subject to royalty (except for production to which a royalty suspension supplement under §§ 203.44 and 203.45 applies), counts toward the lease royalty suspension volume.

Example 1. If you have drilled and produced a well with a perforated interval the top of which is 16,000 feet TVD SS before March 26, 2003 (and therefore, it is not a qualified well and has earned no royalty suspension volume) and later drill:

(i) A well with a perforated interval the top of which is 17,000 feet TVD SS, you earn no royalty suspension volume.

(ii) A qualified well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, you earn a royalty suspension volume of 10 BCF of gas production from qualified wells on your lease, as prescribed in § 203.42.

(iii) A qualified well that is a sidetrack with a perforated interval the top of which is 19,000 feet TVD SS, that has a sidetrack measured depth of 7,000 feet, you earn a royalty suspension volume of 8.2 BCF of gas production from qualified wells on your lease, as prescribed in § 203.42.

Example 2. If you have a qualified well (i.e., drilled after March 26, 2003) that is an original well with a perforated interval the top of which is 16,000 feet TVD SS and later drill a second qualified well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, we increase the total royalty suspension volume for your lease from 15 BCF to 25 BCF, as prescribed in § 203.42.

Example 3. If you have a qualified well (i.e., drilled after March 26, 2003) that is a sidetrack with a perforated interval the top of which is 16,000 feet TVD SS, that has a sidetrack measured depth of 4,000 feet, and later drill a second qualified well that is a sidetrack with a perforated interval the top of which is 19,000 feet TVD SS, that has a sidetrack measured depth of 8,000 feet, we increase the total royalty suspension volume for your lease from 6.4 BCF to 15.2 BCF, as prescribed in § 203.42. The difference of 8.8 BCF represents the royalty suspension volume earned by the second sidetrack.

(e) After your lease has produced gas or oil from a deep well with a perforated interval the top of which is 18,000 feet TVD SS or deeper, your lease cannot earn a royalty suspension volume as a result of drilling any subsequent qualified wells.

(f) The royalty suspension volume determined under this section for the first qualified well on your lease (whether an original well or a sidetrack) establishes the total royalty suspension volume available for that drilling depth interval on your lease, regardless of the number of subsequent qualified wells you drill to that depth interval.

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

(g) If a qualified well on your lease is within a unitized portion of your lease, the royalty suspension volume earned by that well under this section applies only to your lease and not to other leases within the unit.

(h) If your qualified well is a directional well (either an original well or a sidetrack) drilled across a lease line, the lease with the perforated interval that initially produces earns the royalty suspension volume. However, if the perforated interval crosses a lease line, the lease where the surface of the well is located earns the royalty suspension volume.

(i) Any royalty suspension volume earned under this section is in addition to any royalty suspension supplement for your lease under § 203.44 that results from a different wellbore.

(j) If your lease earns a royalty suspension volume under this section and later produces from a deep well that is not a qualified well, the royalty suspension volume is not forfeited or terminated. However, you may not apply the royalty suspension volume under this section to production from the deep well that is not a qualified well, even if it begins producing after your first qualified well.

(k) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any royalty suspension volumes allowed under paragraphs (a) and (b) of this section.

§ 203.42 To which production do I apply the royalty suspension volume earned from qualified wells on my lease?

(a) This paragraph applies to any lease that is not within an MMS-approved unit. Subject to the requirements of §§ 203.40, 203.41, 203.43, 203.44, and 203.47, you must apply the royalty suspension volumes prescribed in § 203.41 to the earliest gas production:

(1) Occurring on and after the later of March 1, 2004 or the date that the first qualified well that earns your lease the royalty suspension volume begins production (other than test production);

(2) From all qualified wells, regardless of their depth, on your lease for which you have met the requirements in § 203.43, up to the aggregate royalty suspension volume earned by your lease.

Example to paragraph (a): You began drilling an original well that was a qualified well with a perforated interval the top of which is 18,200 feet TVD SS on May 1, 2003 and it began producing on September 1, 2003. You subsequently drilled two more original wells that are qualified wells with a perforated interval the tops of which are 16,600 feet TVD SS. The first well earned a royalty suspension volume of 25 BCF. You must apply the royalty suspension volume each month beginning on March 1, 2004 to production from all three wells until the 25 BCF royalty suspension volume is fully utilized.

(b) This paragraph applies to any lease all or part of which is within an MMS-approved unit. If your lease has a qualified well, a share of the production from all the qualified wells in the unit participating area will be allocated to your lease each month according to the participating area percentages. Subject to the requirements of §§ 203.40, 203.41, 203.43, 203.44, and 203.47, you must apply the royalty suspension volume to the earliest gas production occurring on and after the later of March 1, 2004 or the date that the first qualified well that earns your lease the royalty suspension volume begins production (other than test production):

(1) From all qualified wells on the non-unitized area of your lease and

(2) Allocated to your lease from qualified wells on unitized areas of your lease and other leases in the unit under an MMS-approved unit agreement. That allocated share does not increase the royalty suspension volume for your lease. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

Example to paragraph (b): The east half of your lease A is unitized with all of lease B. There is one qualified well on the non-unitized portion of lease A, one qualified well on the unitized portion of lease A and a qualified well on lease B. The participating area percentages allocate 32 percent of production from both of the unit qualified wells to lease A and 68 percent to lease B. If the non-unitized qualified well on lease A produces 12,000 MCF and the unitized qualified well on lease A produces 15,000 MCF, and the qualified well on lease B produces 10,000 MCF, then the production volume from and allocated to lease A to which the lease A royalty suspension volume applies is 20,000 MCF [12,000 + (15,000 + 10,000)(32 percent)]. The production volume allocated to lease B to which the lease B royalty suspension volume applies is 17,000 MCF [(15,000 + 10,000)(68 percent)].

(c) Unused royalty suspension volume transfers to a successor lessee and expires with the lease.

(d) You may not apply the royalty suspension volume allowed under § 203.41:

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

(2) To production from a deep well that commenced drilling before March 26, 2003; or

(3) To production from a deep well on any other lease, except as provided in paragraph (b) of this section.

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

(f) No royalty suspension volume may be applied to any liquid hydrocarbon (oil and condensate) volumes.

§ 203.43 What administrative steps must I take to use the royalty suspension volume?

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

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

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

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

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

(d) If you produced from a qualified well before March 1, 2004, you must provide the information in paragraph (b) of this section no later than June 1, 2004.

(e) If you cannot produce from a well that otherwise meets the criteria for a qualified well before March 1, 2009, the MMS Regional Supervisor for Production and Development may extend the deadline for beginning production for up to 1 year, based on the circumstances of the particular well involved, provided you demonstrate that:

(1) The delay occurred after reaching total depth in your well;

(2) Production (other than test production) was expected to begin before March 1, 2009; and

(3) The delay in beginning production is for reasons beyond your control, including but not limited to adverse weather and unavoidable accidents.

§ 203.44 If I drill a certified unsuccessful well, what royalty relief will my lease earn?

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

(a) If you drill a certified unsuccessful well and you satisfy the administrative requirements of § 203.46 and subject to the price conditions in § 203.47, you earn a royalty suspension supplement shown in the following table (in billions of cubic feet of gas equivalent (BCFE) or in thousands of cubic feet of gas equivalent (MCFE)) applicable to oil and gas production as prescribed in § 204.45:

If you have a certified unsuccessful well that is . . .	Then, you earn a royalty suspension supplement on this volume of oil and gas production as prescribed in this section and § 203.45:
(1) An original well and your lease has not produced gas or oil from a deep well.	5 BCFE.
(2) A sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has not produced gas or oil from a deep well.	0.8 BCFE plus 120 MCFE times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 5 BCFE.
(3) An original well or a sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS.	2 BCFE.

(b) We will suspend royalties on oil and gas volumes produced on or after March 1, 2004 reported on the Oil and Gas Operations Report, Part A (OGOR–A) for your lease under 30 CFR 216.53, as and to the extent prescribed in § 203.45. All oil and gas production reported on the OGOR–A, including production that is not subject to royalty (except for production to which a royalty suspension volume under §§ 203.41 and 203.42 applies), counts toward the lease royalty suspension supplement.

Example 1. If you drill a certified unsuccessful well that is an original well to a target 19,000 feet TVD SS, you earn a royalty suspension supplement of 5 BCFE of gas and oil production if your lease has not previously produced from a deep well, or you earn a royalty suspension supplement of 2 BCFE of gas and oil production if your lease has previously produced from a deep well with a perforated interval from 15,000 to less than 18,000 feet TVD SS, as prescribed in § 203.45.

Example 2. If you drill a certified unsuccessful well that is a sidetrack that reaches a target 19,000 feet TVD SS, that has a sidetrack measured depth of 12,545 feet, and your lease has not produced gas or oil from any deep well, we round the distance to 12,500 feet and you earn a royalty suspension supplement of 2.3 BCFE of gas and oil production as prescribed in § 203.45.

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

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

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

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

(e) If the same wellbore that earns a royalty suspension supplement as a certified unsuccessful well later produces from a perforated interval the top of which is 15,000 feet TVD SS or deeper before March 1, 2009, it will become a qualified well subject to the following conditions:

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

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

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

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

§ 203.45 To which production do I apply the royalty suspension supplements from drilling one or two certified unsuccessful wells on my lease?

(a) Subject to the requirements of §§ 203.40, 203.42, 203.44, 203.46 and 203.47, you must apply royalty suspension supplements in § 203.44 to the earliest oil and gas production:

(1) Occurring on and after the day you file the information under § 203.46(b),

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

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

Example to paragraph (b):

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

(c) If you have no current production on which to apply the royalty suspension supplement allowed under § 203.44, your royalty suspension supplement applies to the earliest subsequent production of gas and oil from, or allocated under an MMS-approved unit agreement to, your lease.

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

(e) You may not apply the royalty suspension supplement allowed under § 203.44 to production from any other lease, except for production allocated to your lease from an MMS-approved unit agreement. If your certified unsuccessful well is on a lease subject to an MMS-approved unit agreement, the lessees of other leases in the unit may not apply any portion of the royalty suspension supplement for your lease to production from the other leases in the unit.

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

§ 203.46 What administrative steps do I take to obtain and use the royalty suspension supplement?

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

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

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

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

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

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

(c) If you commenced drilling a well that otherwise meets the criteria for a certified unsuccessful well on or after March 26, 2003, and finished it before March 1, 2004, provide the information in paragraph (b) of this section no later than June 1, 2004.

§ 203.47 Do I keep royalty relief if prices rise significantly?

(a) You must pay royalties on all gas and oil production for which royalty suspension volume or royalty suspension supplement otherwise would be allowed under §§ 203.40 through 203.46 for any calendar year when the average daily closing NYMEX natural gas price exceeds the threshold of $9.34 per MMBtu, adjusted annually after year 2004 for inflation. The threshold price for any calendar year after 2004 is found by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product as published by the Department of Commerce changed during the calendar year.

(b) You must pay any royalty due under this paragraph, plus late payment interest from the end of the month after the month of production until the date of payment under 30 CFR 218.54, no later than 90 days after the end of the calendar year for which you owe royalty.

(c) Production volumes on which you must pay royalty under this section count as part of your royalty suspension volumes and royalty suspension supplements.

§ 203.48 May I substitute the deep gas drilling provisions in § 203.0 and §§ 203.40 through 203.47 for the deep gas royalty relief provided in my lease terms?

(a) You may exercise an option to replace the applicable lease terms for royalty relief related to deep-well drilling with those in § 203.0 and §§ 203.40 through 203.47 if you have a lease issued with royalty relief provisions for deep-well drilling. Such leases:

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

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

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

(c) Once you exercise the option under paragraph (a) of this section, you are subject to all the activity, timing, and administrative requirements pertaining to deep gas royalty relief as specified in §§ 203.40 through 203.47.

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

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 131

[FRL–7613–2]

Water Quality Standards for Puerto Rico

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating designated uses and associated water quality criteria for six waterbodies and an area of coastal waters known as the *coastal ring* in the Commonwealth of Puerto Rico. These waterbodies are: Mayaguez Bay (from Punta Guanajibo to Punta Algarrobo); Yabucoa Port (from Punta Icacos to Punta Yeguas); Guayanilla and Tallaboa Bays (from Cayo Parguera to Punta Verraco); Ponce Port (from Punta Carenero to Punta Cuchara) and San Juan Port (from the mouth of Río Bayamón to Punta El Morro), as well as the area of coastal waters known as the coastal ring, defined as all coastal waters from 500 meters seaward to a maximum of three miles seaward. Through this promulgation, the Federally designated use of primary contact recreation and the associated water quality criteria are added to the Commonwealth's designated uses for the previously referenced embayments and the coastal ring (referred to collectively in this preamble as the ''Subject Waterbodies'').

DATES: This regulation is effective March 26, 2004.

ADDRESSES: The public record for this rulemaking has been established, is located at EPA Region 2, 290 Broadway, New York, New York 10007, and Carribean Environmental Protection Division, U.S. EPA Region 2, 1492 Ponce De Leon Avenue, Suite 417, Santurce, Puerto Rico 00907, and can be viewed between 9 a.m. and 3:30 p.m. at both locations.

FOR FURTHER INFORMATION CONTACT: For information concerning today's final rule, contact Wayne Jackson, U.S. EPA Region 2, Division of Environmental Planning and Protection, 290 Broadway, New York, New York 10007 (telephone: 212–637–3807 or e-mail: *jackson.wayne@epa.gov*) or Claudia Fabiano, U.S. EPA Headquarters, Office of Science and Technology, 1200 Pennsylvania Avenue NW., Mail Code 4305T, Washington, DC 20460 (telephone: 202–566–0446 or e-mail: *fabiano.claudia@epa.gov*).

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I. General Information

A. Who Is Potentially Affected by This Rule?

Citizens concerned with water quality in Puerto Rico may be interested in this rulemaking. Facilities discharging pollutants to certain waters of the United States in Puerto Rico could be indirectly affected by this rulemaking since water quality standards are used in determining water quality-based National Pollutant Discharge