### § 203.88 What is in a production report?

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

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

(b) Production drive mechanisms for each reservoir.

### § 203.89 What is in a deep water cost report?

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

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

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

(1) Platform well drilling and average depth;

(2) Platform well completion;

(3) Subsea well drilling and average depth;

(4) Subsea well completion;

(5) Production system (platform); and

(6) Flowline fabrication and installation.

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

(1) Operation;

(2) Equipment; and

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

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

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

(2) Trunkline and tieback lines; and

(3) Gas plant processing for natural gas liquids.

(e) Abandonment costs, based on historical costs, engineering estimates, or analogous projects. You should provide the costs to plug and abandon only wells and to remove only production systems for which you have not incurred costs as of the time of application submission. You should also include a point estimate or distribution of prospective salvage value for all potentially reusable facilities and materials, along with the source and an explanation of the figures provided.

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

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

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

(1) Expenses before first discovery on the field;

(2) Cash bonuses;

(3) Fees for royalty relief applications;

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

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

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

(9) Fines or penalties; and

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

### § 203.90 What is in a fabricator's confirmation report?

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

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

(b) A letter from the contractor building the system to the MMS's GOM Regional Supervisor—Production and Development, certifying when construction started on your system; and

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

### § 203.91 What is in a post-production development report?

For each cost category in the deep water cost report, you must compare actual costs up to the date when production starts to your planned pre-production costs. If your application included more than one development scenario, you need to compare actual costs with those in your scenario of most likely development. Keep supporting records for these costs and make them available to us on request.

[FR Doc. 98–842 Filed 1–15–98; 8:45 am]
BILLING CODE 4310–MR–P

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## DEPARTMENT OF THE INTERIOR

## Minerals Management Service

## 30 CFR Part 260

**RIN 1010–AC14**

## Royalty Relief for New Leases in Deep Water

**AGENCY:** Minerals Management Service (MMS), Interior.

**ACTION:** Final rule.

**SUMMARY:** The Secretary of the Interior is authorized to offer Outer Continental Shelf (OCS) tracts in parts of the Gulf of Mexico for lease with suspension of royalties for a volume, value, or period of production. This applies to tracts in water depths of 200 meters or more. This final rule specifies the royalty-suspension terms for lease sales using this bidding system.

**DATES:** This final rule is effective February 17, 1998.

**FOR FURTHER INFORMATION CONTACT:** Walter Cruickshank, Chief, Washington Division, Office of Policy and Management Improvement, at (202) 208–3822.

**SUPPLEMENTARY INFORMATION:**

## I. Background

*Legislative*

On November 28, 1995, President Clinton signed Public Law 104–58, which included the Outer Continental Shelf Deep Water Royalty Relief Act (''Act''). The Act contains four major provisions concerning new and existing leases. New leases are tracts leased during a sale held after the Act's enactment on November 28, 1995. Existing leases are all other leases.

First, section 302 of the Act clarifies the Secretary's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases to promote development, increase production, and encourage production of marginal resources on producing or non-producing leases. This provision applies only to leases in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Second, section 302 also provides that ''new production'' from existing leases in deep water (water at least 200 meters deep) qualifies for royalty suspensions if the Secretary determines that the new production would not be economic without royalty relief. The Act defines ''new production'' as production (1) From a lease from which no royalties are due on production, other than test production, before the date of the enactment of the Outer Continental Shelf Deep Water Royalty Relief Act; or (2) resulting from lease development activities under a Development Operations Coordination Document (DOCD), or supplement thereto that would expand production significantly beyond the level anticipated in the DOCD approved by the Secretary after the date of the Act. The Secretary must determine the appropriate royalty-suspension volume on a case-by-case basis, subject to specified minimums for leases not in production before the date of enactment. This provision also applies only to leases in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Third, section 303 establishes a new bidding system that allows the Secretary to offer tracts with royalty suspensions for a period, volume, or value the Secretary determines.

Fourth, section 304 provides that all tracts offered within 5 years of the date of enactment in deep water (water at least 200 meters deep) in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude, must be offered under the new bidding system. The following minimum volumes of production are not subject to a royalty obligation:

- 17.5 million barrels of oil equivalent (MMBOE) for leases in 200 to 400 meters of water;
- 52.5 MMBOE for leases in 400 to 800 meters of water; and
- 87.5 MMBOE for leases in more than 800 meters.

*Regulatory*

On February 2, 1996, we published a final rule modifying the regulations governing the bidding systems we use to offer OCS tracts for lease (61 FR 3800). New § 260.110(a)(7) implements the new bidding system under section 303 of the Act.

We published an advance notice of proposed rulemaking (ANPR) in the **Federal Register** on February 23, 1996 (61 FR 6958), and informed the public of our intent to develop comprehensive regulations implementing the Act. The ANPR sought comments and recommendations to assist us in that process. In addition, we conducted a public meeting in New Orleans on March 12–13, 1996, about the matters the ANPR addressed.

On March 25, 1996, we published an interim final rule in the **Federal Register** (61 FR 12022) specifying the royalty-suspension terms under which the Secretary would make tracts available under the bidding system requirements of sections 303 and 304 of the Act. We issued an interim final rule, in part, because we needed royalty relief rules in place before the lease sale held on April 24, 1996. However, in the interim final rule we asked for comments on any of the provisions and stated that we would consider those comments and issue a final rule. This final rule now modifies some of the provisions in the March 25, 1996, interim final rule.

On May 31, 1996, we published another interim final rule in the **Federal Register** (61 FR 27263) implementing section 302 of the Act. The interim final rule established the terms and conditions under which the Minerals Management Service (MMS) would suspend royalty payments on certain deep water leases issued as a result of a lease sale held before November 28, 1995. (The rule also contained provisions dealing with royalty relief on producing leases under the authority granted the Secretary by the OCS Lands Act.) We again asked for comments that we would consider before issuing a final rule.

Simultaneous with the publication of this rule, we are issuing another final rule (RIN 1010–AC13) to replace the interim final rule implementing section 302 of the Act. The final rule will revise 30 CFR 203 to establish conditions for suspension of royalty payments on certain deep water leases issued as a result of lease sales held before November 28, 1995.

## II. Responses to Comments

One respondent—Exxon Exploration Company (Exxon)—submitted comments on the Interim Final Rule for Deep Water Royalty Relief for New Leases, issued March 25, 1996.

Exxon disagreed with our definition of the term ''Field'' (§ 260.102). Exxon said that our definition could be applied in such a way as to place unrelated and widely separated reservoirs within the same field. Exxon offered an alternative definition that it said provides for the creation of fields based on geology by allowing the inclusion of separate reservoirs in the same field when there is a meaningful geologic relationship between those reservoirs and avoids inclusion of reservoirs when such a relationship does not exist.

Exxon offered this alternative definition:

> ''Field means an area consisting of a single hydrocarbon reservoir or multiple hydrocarbon reservoirs all grouped on or related to same local geologic feature or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata. Separate reservoirs would be considered to constitute separate fields if significant lateral separation exists and/or they are controlled by separate trapping mechanisms. Reservoirs vertically separated by a significant interval of nonproductive strata may be considered as separate fields when their reservoir quality, fluid content, drive mechanisms, and trapping mechanisms are sufficiently different to support such a determination.''

Except for a minor editorial change, we have decided to leave the definition of ''Field'' unchanged from the interim final rule for the following reasons:

- The definition in the interim final rule is similar to, or consistent with, standard definitions used in industry and government, including the American Petroleum Institute, the National Petroleum Council, and the Department of Energy's Energy Information Administration.
- We do not segregate reservoirs vertically since the reservoirs are developed from the same platforms and use the same infrastructure. Affected lessees/operators typically make development decisions based on a primary objective(s) knowing that secondary targets exist which they will pursue subsequently.
- Reservoir quality, fluid content, and drive mechanisms are not appropriate determinants for field designations. These factors are reservoir performance/recovery issues. Indeed, such information is rarely available to MMS at the time field determinations are made. We have not considered these factors in our past field designations and their inclusion now would complicate the process significantly and lead to too much subjectivity.
- Elements of the alternative definition, e.g., ''a significant interval of nonproductive strata'' and ''significant lateral separation'' would be difficult to define and even more difficult to apply consistently.

We recognize industry's concerns about field designations. This rule establishes, as discussed below, a process whereby lessees may appeal field designations to the Director, MMS.

Other steps include:

- The MMS *Field Naming Handbook*, which explains our methodology for designating fields, is available on the Internet (www.mms.gov). The Gulf of Mexico Region will entertain suggestions for improvements in the methodology.

• We will elevate the level at which we make field definition decisions in the Gulf of Mexico Region. The Chief, Reserves Section, Office of Resource Evaluation, will make these determinations after a lease has a well into the field qualified as producible.

• As part of the field designation process, affected lessees/operators will have the chance to review and discuss the field designation with Gulf of Mexico Region personnel before MMS makes a final decision.

## III. Summary of Modifications to the Interim Final Rule

As discussed below, we have modified the interim final rule to:

• Allow for appeals of field designations;

• Clarify when the cumulative royalty-suspension volume ends;

• Describe how MMS will establish and allocate royalty-suspension volume in fields that have a combination of *eligible* leases and leases that are granted a royalty-suspension volume under section 302 of the Act; and

• Eliminate the reference to a pressure base standard in the provision for the conversion of natural gas to oil equivalency (§ 260.110(d)(14)). The rule now indicates you must measure that natural gas in accordance with the procedures set forth in 30 CFR 250, subpart L.

1. We have added a new provision (§ 260.110(d)(2)) establishing that you or any other affected lessees may appeal to the Director the decision designating your lease as part of a field. The Director's decision is a final agency action subject to judicial review.

2. The preamble to the interim final rule indicated that a royalty-suspension volume would continue until the end of the month in which cumulative production from *eligible* leases in the field reached the royalty-suspension volume for the field. The interim final rule itself did not include this provision. This final rule now includes a provision (§ 260.110(d)(10)) that a royalty-suspension volume will continue through the end of the month in which cumulative production from leases in the field entitled to share the royalty-suspension volume reaches that volume. The purpose of this provision is to avoid the complications that would occur for royalty payors if the royalty rate changed in the middle of the month.

3. We have modified § 260.110(d)(9) and added a new § 260.110(d)(10) to describe how MMS will establish and allocate royalty-suspension volumes in fields having a combination of pre-Act and *eligible* leases. (Pre-Act leases are defined as OCS leases issued as a result of a sale held before November 28, 1995; in a water depth of at least 200 meters; and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude. See 30 CFR 203.60 through 203.80). The provisions are necessary to account for and ensure consistency with the deep water royalty relief rules for pre-Act leases (§ 203.60). We published the interim final rule for pre-Act leases on May 31, 1996 (61 FR 27263), after publication of the interim final rule for new leases in deep water on March 25, 1996.

We have added wording in § 260.110(d)(9) for cases where an *eligible* lease is added to a field that includes pre-Act leases granted a royalty-suspension volume under section 302 of the Act. This rule provides that the addition of the *eligible* lease will not change the field's established royalty-suspension volume. The added lease(s) may share in the suspension volume even if the volume is more than the *eligible* lease would qualify for based on its water depth.

The new § 260.110(d)(10) describes a case where pre-Act leases in a field that includes *eligible* leases apply for and receive a royalty-suspension volume larger than the suspension volume established for the field by the *eligible* leases. This rule provides that the *eligible* leases may share in the larger suspension volume to the extent of their actual production until cumulative production by all lessees equals the royalty-suspension volume.

4. This final rule states that lessees must measure natural gas in accordance with 30 CFR 250, Subpart L. We have eliminated the specific measurement procedures from the interim final rule because a forthcoming final rule will change those procedures.

## IV. Administrative Matters

*Executive Order (E.O.) 12866*

This rule is a significant rule under E.O. 12866 due to novel policy issues arising out of legal mandates. You may obtain a copy of the determination from MMS. The Office of Management and Budget (OMB) has reviewed this rule.

*Regulatory Flexibility Act*

The Department of the Interior (DOI) has determined that the primary impact of this rule, i.e., royalty relief to spur deep water oil and gas development, may have a significant effect on small entities although we can't estimate their number at this time. The number of small entities affected will depend on how many of them acquire leases that meet the statutory and regulatory criteria for royalty relief at lease sales between November 28, 1995, and November 28, 2000.

Exploration and development activities in the deep water areas of the Gulf of Mexico have traditionally been conducted by the major oil companies because of the expertise and financial resources required. ''Small entities'' (classified by the Small Business Administration as oil and gas producers with fewer than 500 employees) are increasingly active on the OCS, including in deep water, and we expect that trend to continue. The only firm to whom we have granted royalty relief so far under section 302 of the Act is a small entity.

In any case, this rule will have positive impacts on OCS oil and gas companies, large or small. Royalty relief in the form of a royalty-suspension volume is automatically established for leases that meet the statutory and regulatory criteria. No applications or special reports are necessary.

The beneficial effect of this relief on companies' financial operations will be substantial. Once we determine that a lease is *eligible* for a royalty-suspension volume, the value of that relief may range from tens of millions of dollars to over $100 million. The suspensions will allow companies to recover more of their investment costs before paying royalties, which may allow greater opportunity for small companies to operate in deep water.

This rule also will have a very positive impact on small entities. Constructing and equipping the platforms and other infrastructure associated with deep water development are huge projects that involve not only large companies but numerous small businesses nationwide as well. Once the platforms are operational, other small businesses will provide supplies and services.

*Paperwork Reduction Act*

This rule contains no reporting and recordkeeping requirements subject to the Paperwork Reduction Act of 1995.

*Takings Implication Assessment*

DOI certifies that this rule does not represent a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment prepared pursuant to E.O. 12630, Governmental Actions and Interference with

Constitutionally Protected Property Rights, is not required.

*Unfunded Mandates Reform Act of 1995*

DOI has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this final rule will not impose a cost of $100 million or more in any given year on State, local, and tribal governments, or the private sector.

*E.O. 12988*

DOI has certified to OMB that this regulation meets the applicable standards provided in section 3(b)(2) of E.O. 12988.

*National Environmental Policy Act*

We examined this rulemaking and have determined that this rule does not constitute a major Federal action significantly affecting the quality of the human environment pursuant to Section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)).

**List of Subjects in 30 CFR Part 260**

Continental shelf, Government contracts, Minerals royalties, Oil and gas exploration, Public lands—mineral resources.

Dated: September 22, 1997.

**Sylvia V. Baca,**

*Assistant Secretary, Land and Minerals Management.*

For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 30 CFR part 260, as follows:

## PART 260—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

1. The authority citation for part 260 continues to read as follows:

**Authority:** 43 U.S.C. 1331 and 1337.

2. In § 260.102, the definitions for ''Eligible lease'' and ''Field'' are revised to read as follows:

### § 260.102 Definitions.

* * * * *

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

*Field* means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. Two or more reservoirs may be in a field, separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

* * * * *

3. In § 260.110, paragraph (d) is revised to read as follows:

### § 260.110 Bidding systems.

* * * * *

(d) This paragraph explains how the royalty-suspension volumes in section 304 of the Outer Continental Shelf Deep Water Royalty Relief Act, Public Law 104–58, apply to *eligible* leases. For purposes of this paragraph, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter do not count against royalty-suspension volumes. Also, for the purposes of this paragraph, production includes volumes allocated to a lease under an approved unit agreement.

(1) Your *eligible* lease may receive a royalty-suspension volume only if your lease is in a field where no current lease produced oil or gas (other than test production) before November 28, 1995. Paragraph (d) of this section applies only to *eligible* leases in fields that meet this condition.

(2) We will assign your lease to an existing field or designate a new field and will notify you and other affected lessees of that assignment. Within 15 days of that notification, you or any of the other affected lessees may file a written request with the Director, MMS, for reconsideration accompanied by a statement of reasons. The Director will respond in writing either affirming or reversing the assignment decision. The Director's decision is final for the Department and is not subject to appeal to the Interior Board of Land Appeals under 30 CFR part 290 and 43 CFR part 4.

(3) The Final Notice of Sale will specify the water depth for each *eligible* lease. Our determination of water depth for each lease is final once we issue the lease. The Notice also will specify the royalty-suspension volume applicable to each water depth. The minimum royalty-suspension volumes for fields are:

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

(ii) 52.5 MMBOE in 400 to 800 meters of water; and

(iii) 87.5 MMBOE in more than 800 meters of water.

(4) When production (other than test production) first occurs from any of the *eligible* leases in a field, we will determine what royalty-suspension volume applies to the *eligible* lease(s) in that field. The determination is based on the royalty-suspension volumes specified in paragraph (d)(3) of this section.

(5) If a new field consists of *eligible* leases in different water depth categories, the royalty-suspension volume associated with the deepest *eligible* lease applies.

(6) If your *eligible* lease is the only *eligible* lease in a field, you do not owe royalty on the production from your lease up to the applicable royalty-suspension volume.

(7) If a field consists of more than one *eligible* lease, payment of royalties on the *eligible* leases' initial production is suspended until their cumulative production equals the field's established royalty-suspension volume. The royalty-suspension volume for each *eligible* lease is equal to each lease's actual production (or production allocated under an approved unit agreement) until the field's established royalty-suspension volume is reached.

(8) If an *eligible* lease is added to a field that has an established royalty-suspension volume as the result of an approved application for royalty relief submitted under 30 CFR part 203 or as the result of one or more *eligible* leases having been assigned previously to the field, the field's royalty-suspension volume will not change even if the added lease is in deeper water. If a royalty-suspension volume has been granted under 30 CFR part 203 that is larger than the minimum specified for that water depth, the added *eligible* lease may share in the larger suspension volume. The lease may receive a royalty-suspension volume only to the extent of its production before the cumulative production from all leases in the field entitled to share in the suspension volume equals the field's previously established royalty-suspension volume.

(9) If a pre-Act lease(s) receives a royalty-suspension volume under 30 CFR part 203 for a field that already has a royalty-suspension volume due to *eligible* leases, then the *eligible* and pre-Act leases will share a single royalty-suspension volume. (Pre-Act leases are OCS leases issued as a result of a sale held before November 28, 1995; in a water depth of at least 200 meters; and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude. See 30 CFR part 203). The field's royalty-suspension volume will be the larger of the volume for the *eligible* leases or the volume MMS grants in response to the pre-Act leases' application. The suspension volume for each lease will be its actual production from the field until cumulative production from all leases in the field equals the suspension volume.

(10) A royalty-suspension volume will continue through the end of the month in which cumulative production from leases in a field entitled to share the royalty-suspension volume reaches that volume.

(11) If we reassign a well on an *eligible* lease to another field, the past production from that well will count toward the royalty-suspension volume, if any, specified for the field to which it is reassigned. The past production will not count toward the royalty suspension volume, if any, for the field from which it was reassigned.

(12) You may receive a royalty-suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. A field that lies on both sides of this meridian will receive a royalty-suspension volume only for those *eligible* leases lying entirely west of the meridian.

(13) Your lease may obtain more than one royalty-suspension volume. If a new field is discovered on your *eligible* lease that already benefits from the royalty-suspension volume for another field, production from that new field receives a separate royalty suspension.

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

[FR Doc. 98–843 Filed 1–15–98; 8:45 am]

**BILLING CODE 4310–MR–P**

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 63

**[FRL–5950–4]**

### National Emission Standards for Gasoline Distribution Facilities; Bulk Gasoline Terminals and Pipeline Breakout Stations

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Notice of limited exclusion for gasoline distribution facilities.

**SUMMARY:** The EPA publishes today notification of a limited exclusion from applicability for gasoline distribution facilities that would be, but for this action, subject to the air toxic provisions of 40 CFR part 63, subpart R, the National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

**DATES:** This policy took effect on December 12, 1997, the day that the attached letter detailing this policy was signed. Petitions for review of this determination must be filed on or before March 17, 1998 in accordance with the provisions of section 307(b)(1) of the Clean Air Act (CAA).

**ADDRESSES:** The related material in support of this policy may be examined during normal business hours at the United States Environmental Protection Agency, Office of Enforcement and Compliance Assurance, Air Enforcement Division, Ariel Rios Building, Room 1119, 12th and Pennsylvania Ave., NW, Washington, DC 20004.

**FOR FURTHER INFORMATION CONTACT:** Charles Garlow of the U.S. EPA, Air Enforcement Division (Mail Code 2242A), 401 M St SW, Washington, DC 20460, telephone (202) 564–1088.

**SUPPLEMENTARY INFORMATION:** On October 15, 1997, the American Petroleum Institute (API) requested relief from the applicability of the Gasoline Distribution National Emission Standard for Hazardous Air Pollutants (NESHAP) as the compliance date of December 15, 1997 was approaching. Certain members of the API trade association had timely applied for synthetic minor permits so as to qualify as area or minor sources not subject to the Gasoline Distribution MACT standard. However, state or local permitting authorities had, in many instances, not been able to process the otherwise-approvable applications before December 15, 1997. Since many states have a public comment period, it was apparent that these permits could not be issued prior to the compliance date even if every effort was made. Therefore, API asserted, through no fault of their members, they would be subject to the requirements of this NESHAP when they assumed they would not be, resulting in some sources potentially facing operational shutdowns or violation of the standard.

The EPA responded, as is detailed in the attached letter, by granting a time limited exclusion from applicability to those sources that notify the EPA that they have timely applied and have otherwise made good faith efforts to obtain the synthetic minor permits in question. Due to delays in publishing this document, sources wishing to avail themselves of this policy have until January 30, 1998, to notify EPA of their status, if they have not already done so.

In addition to publication of this document, US EPA has placed a copy of this policy letter on its Technology Transfer Network (TTN) bulletin board service and Website.

(Sec. 112, Clean Air Act (42 U.S.C. 7412))

**Bruce Buckheit,**

*Director, Air Enforcement Division.*

December 12, 1997.

Ms. Ellen Siegler,

*American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005–4070.*

Re: Gasoline Distribution MACT Standard.

Dear Ms. Siegler: The American Petroleum Institute recently approached the Environmental Protection Agency (EPA) seeking relief from the Gasoline Distribution Maximum Achievable Control Technology (MACT) standard for those facilities that timely sought permits limiting their potential to emit so as to qualify as area sources not covered by that standard. We were then informed that numerous facilities (through no fault of their own) have not yet been issued such permits by their permit issuing authorities. Under EPA's ''once in—always in'' policy, such facilities will become subject to the Gasoline Distribution MACT standard on that rule's compliance date (December 15, 1997).

As a general matter, we believe that it is the source's obligation to achieve compliance with the regulation as of the effective date of that regulation. Where, as here, the regulation provided 3 years to achieve compliance, we believe that sources that wish to avoid the imposition of major source obligations by seeking ''synthetic minor'' permits should do so shortly after the date of rule promulgation. Given the substantial workload imposed on permitting authorities by the Title III and Title V programs, those who wait until there is less than 1 year from the compliance date to submit their permit application should anticipate that there is a substantial risk, that they must bear, that the synthetic minor permit may not be issued in time. However, because this is an issue of first impression, and facilities may have relied in good faith on representations of permitting authorities that permits received within a shorter time frame would be processed by December 15, 1997, we have agreed to provide a limited enforcement discretion as set out below.

Based on the facts presented and subject to the terms, conditions and limitations outlined herein, we concluded that the EPA should and, therefore, will provide limited relief for certain facilities:

*Limited Exclusion*—EPA will not consider an otherwise covered facility to be subject to the Gasoline Distribution MACT standard (1) if the facility owner or operator filed a complete application with its appropriate permitting authority for a permit limiting its potential to emit so as to qualify as an area source not covered by that standard prior to June 15, 1997, and (2) if it identifies the facility to EPA not later than January 15, 1998. This limited exclusion is limited to a 90-day period and will expire on March 15, 1998.

*Conditional Extension*—If a facility has not yet received its permit by March 15, 1998, it will be subject to the Gasoline Distribution MACT standard as of this date *unless* such facility notifies EPA, prior to March 15, 1998, that an additional period of time is needed for good cause shown. If the facility has not yet received such permit and then certifies to