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Approved. November 10, 1994

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 63

[AD-FRL-5116-5]

RIN 2060-AD93

National Emission Standards for Hazardous Air Pollutants for Source Categories: Gasoline Distribution (Stage I)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The final rule provided in this document is a national emission standard(s) for hazardous air pollutants (NESHAP) for bulk gasoline terminals and pipeline breakout stations pursuant to section 112 of the Clean Air Act as amended in 1990 (the Act). On February 8, 1994, EPA proposed a NESHAP for the gasoline distribution source category. On August 19, 1994, the EPA also published supplementary data and recommendations on the level of control for gasoline cargo tanks. This document announces the EPA's final decisions on the rule.

This final rule requires sources to achieve emission limits reflecting application of the maximum achievable control technology (MACT) consistent with section 112(d) of the Act. The rule regulates all hazardous air pollutants (HAP's) identified in the Act's list of 189 HAP's that are emitted from new and existing bulk gasoline terminals and pipeline breakout stations that are major sources of HAP's or are located at plant sites that are major sources of HAP's.

DATES: *Effective Date.* December 14, 1994.

Judicial Review. Under section 307(b)(1) of the Act, judicial review of NESHAP is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this final rule. Under section 307(b)(2) of the Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by the EPA to enforce these requirements.

ADDRESSES: *Docket.* Docket No. A-92-38, containing information considered by the EPA in developing the promulgated standards, is available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday including all non-Government holidays, at the EPA s Air and Radiation Docket and Information Center, room M1500, U.S. Environmental Protection Agency 401 M Street, SW., Washington, DC 20460; telephone (202) 260-7548. A reasonable fee may be charged for copying.

Background Information Document The background information document (BID) for the promulgated standards may be obtained as supplies permit from the U.S. Environmental Protection Agency Library (MD-35), Research Triangle Park, North Carolina 27711, telephone (919) 541-2777 or from the U.S. Department of Commerce, National Technical Information Service (NTIS), Springfield, Virginia 22161, telephone (703) 487-4650. Please refer to "Gasoline Distribution Industry (Stage I)—Background Information for Promulgated Standards" (EPA-453/R-94-002b). The BID contains. (1) a summary of the public comments made on the proposed standards and the EPA's responses to the comments, and (2) a summary of the revisions made to the regulatory analysis presented at proposal. Electronic versions of the BID as well as this preamble and final rule are available for download from the EPA's Technology Transfer Network (TTN), a network of electronic bulletin boards developed and operated by the Office of Air Quality Planning and Standards. The TTN provides information and technology exchange in various areas of air pollution control The service is free, except for the cost of a phone call. Dial (919) 541-5742 for up to a 14,400 bits per second (bps) modem. If more information on TTN is needed, contact the systems operator at (919) 541-5384.

FOR FURTHER INFORMATION CONTACT: For general and technical information concerning the final rule, contact Mr. Stephen Shedd, Waste and Chemical Processes Group, Emission Standards Division (MD-13), U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711, telephone (919) 541-5397 For information regarding the economic impacts of the rule, contact Mr. Scott Mathias, Innovative Strategies and Economics Group, Air Quality Strategies and Standards Division, at the above address; telephone (919) 541-5310. For information regarding the test methods and procedures referenced in the rule, contact Mr Roy Huntley Emission Inventory and Factors Group, Emissions, Monitoring and Analysis Division, at the above address; telephone (919) 541-1060.

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows.

I. Applicability

The final rule is applicable to all existing and new bulk gasoline terminals and pipeline breakout stations that are major sources of HAP's or are located at plant sites that are major sources. Major source facilities that are subject to this rule must install and operate the control equipment and implement the work practices required in the rule Section 112(a) of the Act defines major source as a source, or group of sources, located within a contiguous area and under common control that emits or has the potential to emit, considering controls, 10 tons per year (tpy) or more of any individual HAP or 25 tpy or more of any combination of HAP's Area sources are stationary sources that do not qualify as "major The term "affected source" as used in this rule means the total of all HAP emission points at each bulk gasoline terminal or pipeline breakout station that is subject to the rule

To determine the applicability of this rule to facilities that are within a contiguous area of other HAP-emitting emission sources that are not part of the source category covered by this rule, the owner or operator must determine whether the plant site as a whole is a major source. A formal HAP emissions inventory must be used to determine if total HAP emissions from all HAP emission sources at the plant site meets the definition of a major source. To determine the applicability of this rule to facilities that are not contiguous with other HAP-emitting emission sources (i.e., to stand-alone bulk gasoline terminals or pipeline breakout station facilities), the owner or operator may use the emissions screening equations in the rule, which are intended to identify clearly nonmajor (area) sources, or conduct a formal HAP emissions inventory

Certain assumptions used by all nonmajor sources in the emission screening equations will become enforceable limitations on the facility's operations under this rule. These enforceable limitations include, type of gasoline used, type and number of storage vessels, limit on gasoline throughput, level of cargo tank vapor-tightness, and number of valves, pumps, connectors, loading arm valves, and open-ended lines in gasoline service. Federally enforceable limitations must be established outside the provisions of this rule, for facilities using the emissions inventory for determination of their major source status, and for some parameters used by facilities in the emission screening equation. The vapor processor outlet emission limit for cargo tank emissions and minimum efficiency for fixed roof storage vessel emissions are the federally enforceable limitations that must be established outside the provisions of this rule to be used in the emission screening equations. Facilities using the emission screening equations in the rule are required to record their assumptions and calculations, notify the Administrator that the facility is using the screening equations and provide the results of the calculations, and operate the facility in a manner not to exceed the operational parameters used in the calculations. Larger facilities (those that, in and of themselves, have HAP emissions over 50 percent of the major source emissions thresholds above and use the emissions screening equations in the rule) are additionally required to submit to the Administrator for approval their assumptions and calculations, maintain records to document the parameters have not been exceeded, and submit an annual certification that the operational parameters established for the facility have not been exceeded.

II. Summary of Major Changes Since Proposal

On February 8, 1994 (59 FR 5868), the EPA proposed NESHAP for all major source bulk gasoline terminals and pipeline breakout stations and provided notice of a public hearing on the proposal. A public hearing was held on March 10, 1994, and the 60-day comment period ended on April 11, 1994. On August 19, 1994 (59 FR 42788), the EPA published an announcement of the availability of supplemental information pertaining to the level of control and test procedures for cargo tank leakage, and established a comment period for this information. Public comments received in response to the proposal and the supplemental notice have been considered in this final rulemaking action.

In response to comments received on the proposed standards, changes have been made in developing the final rule. While several of these are clarifying changes designed to make the Agency's intent clearer, a number of them are significant changes to the proposed control requirements of the standards. Substantive changes made since proposal are described in the following sections. The Agency's responses to public comments that are not addressed in this preamble and the revised analysis for the final rule are contained in the BID for this final rulemaking (see **ADDRESSES** section of this document).

A. Applicability

The constants in the proposed emission estimation screening equations have been modified based on lower emission factors for leakage emissions from tank trucks and equipment components. In addition, the storage vessel constants have been recalculated using the current EPA emission equations (publication AP–42, Section 12) to estimate evaporative emissions from the storage of gasoline. Finally an adjustment factor has been added to each equation to account for facilities that do not handle any reformulated or oxygenated gasoline containing methyl tert-butyl ether (MTBE).

For the purposes of this rulemaking and under certain conditions, the EPA has determined that a bulk gasoline terminal or pipeline breakout station facility's "potential to emit" (PTE) may be based on certain operating limitations that are made enforceable under this rule. These limitations would be established in the range between actual and maximum design conditions based on emission screening equations provided in the rule. If a facility's operation (e.g., gasoline throughput) exceeds these limitations or if a facility fails to maintain records or report as required in this final rule, it will be considered to be in violation of the rule.

B. Level of Control

The proposed leak detection and repair (LDAR) requirements for controlling equipment leaks have been replaced with a visual inspection program. Instrument leak detection and repair will be an available alternative rather than the basis of the final rule Both new and existing major sources are required to perform a visual leak inspection of their equipment on a monthly basis.

At proposal, the "floor," or minimum level of control for gasoline storage vessels at existing facilities was determined to be the requirements in 40 CFR part 60, subpart Kb, the new source performance standards (NSPS subpart Kb) which apply to new volatile organic liquid storage vessels. Based on the revised analysis, a new floor for storage vessels has been determined. Only the storage vessel floating roof closure device or "rim seal" requirements in the NSPS subpart Kb are now considered to be the floor for existing storage vessels. Gasketed "fittings" (such as hatch covers, vents, drains, etc.), which are also an NSPS subpart Kb requirement, are not now considered to be a part of the floor for this rule. However, in the final rule gasketed fittings are required to be installed on existing external floating roof storage tanks that do not meet the NSPS subpart Kb rim seal requirement, as of today's date.

The floor level of control and the control requirements for leakage from controlled cargo tanks (tank trucks and railcars) at existing and new major source bulk terminals have been changed so that cargo tanks must annually pass a certification test with a 25 mm (1 inch) of water pressure decay limit [in 5 minutes, after pressurization to +460 mm (+18 inches) of water column and then evacuation to −150 mm (−6 inches) of water] instead of the 75 mm (3 inch) of water pressure decay proposed limit. In addition, cargo tank owners and operators are required to annually perform a pressure test of the cargo tank's internal vapor valve and to be able to meet a 63 mm (2.5 inch) pressure change limit at any time. Test procedures to be used in performing these tests are added to the final rule. At proposal, new bulk gasoline terminals were required to install and operate a vacuum assist vapor collection system to minimize cargo tank leakage. The requirement for vacuum assist has been replaced with the same leak testing requirements described above for cargo tanks that load at existing facilities.

III. Significant Comments and Changes

Comments on the proposed standards and the supplemental notice were received from industry State and local air pollution control agencies, trade associations, an environmental group, and a U.S. Government agency A detailed discussion of comments and the EPA's responses can be found in the promulgation BID, which is referred to in the **ADDRESSES** section of this document. The major comments, responses, and changes made to the rule since proposal are discussed below.

A. Applicability Determination

1. Screening Equations

Several commenters felt that the EPA did not fully explain or support the development of the proposed emission estimation screening equations. As a result, these two equations were characterized by some commenters as arbitrary. One commenter who had experience preparing emissions inventories for bulk gasoline terminals in Texas pointed out that, for several terminals that do not exceed the 10/25 tons of HAP's per year threshold, the screening equation incorrectly indicates that many of these terminals emit greater than 10/25 tons of HAP's.

The development of the screening equations was discussed in the preamble to the proposed standards. This development was explained in more detail in a memorandum that was included at proposal in the rulemaking docket (item II–B–23), and has been updated and included in the final docket. These equations were not arbitrary, but were developed specifically to identify facilities that have the potential to emit (PTE) less than 10/25 tons per year of HAP and to reduce the amount of effort needed to perform applicability determinations. However, if a facility has other HAP emission sources not considered in the equation, the equation will under-predict emissions and cannot be used to determine if the facility is a major source. Some commenters expressed support for the use of screening equations as an aid in determining rule applicability but most of them had suggestions for revising the equations to make them more accurate and useful. In response to all of these comments, the equations have been retained in the rule but have been revised to accommodate the concerns of commenters and to make them more accurate in their function as a screening tool. These modifications and the new equations are discussed in detail in the responses to the following comments.

Some commenters suggested that, instead of using "worst-case" HAP-emitting gasolines to derive the constants in the equations, the Agency should use average parameters to promote consistency between the equations and the rule. Also, the EPA should include an adjustment factor for facilities that do not handle gasoline oxygenated with MTBE.

At proposal, the EPA developed the screening equations based on a HAP to VOC ratio that was determined to represent the average MTBE content in reformulated and oxygenated gasolines, and not the "worst-case" ratio. In the gasoline composition analyses that were available to the Agency before proposal, the MTBE content in gasoline ranged from 11.8 to 16.3 percent. Based on these data, the EPA made an assumption that the average MTBE content of reformulated and oxygenated gasolines was 11.9 percent, which is slightly higher than the lowest percentage found in the data. In addition, the EPA assumed that most facilities that handle higher MTBE content oxygenated gasolines would also handle the lower MTBE content reformulated gasolines. This approach is consistent with the Agency's intent to avoid underestimating emissions in this screening process, which could allow a major source to be deemed an area source and thus improperly escape applicability of this rule. Facilities in any case will have the opportunity to perform a full emissions inventory in order to make a more accurate determination of their status.

The EPA agrees that the proposed emission factors overestimate HAP emissions from facilities handling gasoline without MTBE. As a result, an adjustment factor has been included in the screening equations for facilities in this situation. Facilities that handle, or anticipate handling, any oxygenated or reformulated gasoline containing MTBE as a component will not use the adjustment factor in performing the calculations.

Several commenters felt the EPA's assumption that annually certified and tested tank trucks with vapor control lose 10 percent of the displaced vapors through leakage while loading is too high. The EPA has reevaluated the basis for its assumption that tank trucks in an annual test program lose 10 percent of the displaced vapors as leakage emissions. The EPA has calculated a new leakage rate that is much lower than the proposed figure, and this calculation is discussed in Section III.D.1 of this notice.

Commenters stated that fixed-roof storage vessels connected to a vapor control device emit virtually no HAP's and that a term should be added to represent and quantify the low emission levels from such controlled tanks. The EPA agrees with the commenters and has added a new expression, (1–CE), to both screening equations The term "CE" represents the control efficiency of the control device used to process vapors from the fixed-roof tank. The value of CE must be documented by the facility as meeting the definition of federally enforceable in subpart A of 40 CFR part 63 (General Provisions). If the facility is not controlling emissions from its fixed-roof tanks using a vapor control device, a value of zero will be entered for the term "CE."

Several commenters felt that the emission factors used for pump seals and valves were too high, based on recent data collected at marketing facilities. The EPA has evaluated the new data and agrees with this comment. The emission factors for pump seals and valves have been revised as discussed under Section III.B.1 of this notice.

Commenters felt that the equations should provide emission credits for facilities that have implemented an instrument LDAR program or vacuum assist vapor collection. Data provided by industry show that the use of visual inspection programs is just as effective as the use of instrument LDAR in identifying equipment leaks at marketing terminals and breakout stations, as discussed further in Section III.B.2 of this notice. As a result, the EPA will not grant credits to facilities that currently use an LDAR program. The EPA has decided to not require vacuum assist as explained in Section III.D.2.a of this notice, due to Agency concerns about the control effectiveness of vacuum assist technology at bulk terminal loading racks. As a result, the EPA also will not provide emission credits for any facility using vacuum assist technology

One commenter stated that emission standards or limitations more stringent than the Federal NSPS (40 CFR part 60, subpart XX) limit (35 mg/liter) should be recognized. The term "EF" in the screening equation for bulk terminals applies to any federally enforceable emission standard in effect for the vapor processor The concept of "federally enforceable," defined in § 63.2, allows emission standards or limitations more stringent than the NSPS limit.

One commenter believed that the screening equations should be modified to account for storage vessels that store MTBE for infrequent periods and durations. The EPA does not intend to regulate under this rule storage vessels that store only MTBE or any other gasoline component or additive All the other non-gasoline liquids such as MTBE will be studied for regulation under the forthcoming NESHAP source category of "Non-Gasoline Liquid Distribution under section 112 of the Act.

Commenters requested guidance on how to estimate emissions from "swing" tanks, which store gasoline only part of the time. In keeping with the intent of these equations as an emission estimation screening tool, the EPA has made the simplifying assumption that vessels storing gasoline for any period or periods during a year will be assumed to store gasoline year round. As a result, the emissions from "swing" tanks will be estimated in the same way as for tanks that store gasoline on a continuous basis. Owners and operators should use the emissions inventory approach, as specified in § 63.420(a)(2) and (b)(2), if these assumptions lead to a significant overestimation of HAP emissions at their facility

2. Emissions Inventory

As a supplement to the emission estimation screening equations, § 63.420(a)(2) and (b)(2) of the proposed rule exempted those facilities "for which the owner or operator has documented to the Administrator's satisfaction that the facility is not a major source as defined in section 112(a)(1) of the Clean Air Act." The proposal preamble on page 5877 indicated that an "emissions audit" would have to be performed to satisfy these provisions. One commenter felt that the rule provisions should specifically state that the estimation of emissions for the applicability determination is to be accomplished by means of an emissions audit, as was stated in the preamble. Several other commenters found the term "emissions audit" confusing, and questioned what the EPA would consider acceptable for demonstrating applicability Some suggested that the familiar term emission inventory" be substituted because emission inventories are common requirements and procedures are in place under many State programs. Others requested that the EPA define or provide an approved methodology for conducting the emissions audit. One commenter said that the public should have an opportunity to comment on this guidance prior to this rule being promulgated. One commenter thought that the EPA should eliminate the requirement that a source determine its applicability status by means of an emissions audit. They felt such a requirement is unnecessary and contrary to prohibitions in Executive Order 12866 since major sources, which are subject to part 70 permitting, are already required to determine their applicable regulatory requirements and identify them in their permit applications.

In describing the formal means of documenting a facility's major or area source status as an "emissions audit" in the proposal preamble, the EPA was referring to a calculation of a facility's potential to emit HAP considering federally enforceable controls. Such calculations are similar to those already being prepared under many existing Federal and State control programs. Therefore, the intent of the Agency was in accord with the thoughts of the commenters. The discussion in the preamble and the requirements in the final rule are intended to clarify and simplify compliance with the rule and are not known to be contrary to provisions of the part 70 permitting requirements. The EPA feels that guidance on performing HAP emissions inventories is not needed since the preparation of such inventories is standard practice. The activities undertaken in response to part 70 requirements are applicable and may relieve the majority of the burden of fulfilling this inventory.

3. Potential to Emit

One commenter felt that the rule was not clear in explaining whether a facility's major source applicability is determined from "potential to emit" (PTE) or actual emissions and asked for clarification. Several commenters who interpreted the rule to indicate that PTE should be used expressed disagreement with the EPA, and believed that basing major source applicability on a source's PTE would draw into the regulation many more sources than the EPA has anticipated. They said the EPA should recognize that there are inherent limits in the operational parameters (throughput, etc.) of gasoline distribution facilities, and major source determination should be based on a source's actual emissions or at least a more reasonable gasoline loading potential. The American Petroleum Institute (API) recommended a scheme for categorizing facilities based on actual emission rates that they felt would alleviate the "potentially drastic consequences" of applying the PTE definition. These categories are: I—actual emissions exceed the major source threshold (10/25 tpy), so the source is subject to all provisions of the rule; II—actual emissions are greater than 80 percent but less than 100 percent of the major source amounts. The facility would have to certify its area source status by obtaining a permit with enforceable limits, submit annual certification of emission rates, and notify the EPA of any change that could increase HAP emissions; III—actual emissions are greater than 50 percent but less than or equal to 80 percent of the major source definition. The facility would have to submit annual certification and provide notification of any change; IV—actual emissions are 50 percent or less of the major source cutoffs. This facility would only have to provide notification of any changes affecting emissions. Another commenter suggested that applicability should be based on a combination of the potential to emit of the vapor recovery system and the actual emissions of the storage vessel rim seals and fittings using the EPA's current emission factors.

At proposal, the EPA did not use the term PTE in the preamble discussion or in the proposed rule. However, the proposed rule and discussion in the preamble did reference the General Provisions (40 CFR part 63, subpart A), which includes a definition for PTE. This definition is as follows:

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

Terminals and breakout stations have many limitations that affect emissions and some of these can vary according to gasoline demand. Industry provided data showing many methods to calculate maximum capacity including total tank storage capacity loading rack pumping capacity feeder pipeline pumping rate, etc. Each of these methods of calculating capacity results in different and conflicting PTE results. The EPA has decided to provide an approach in the final rule that provides the facility an opportunity to set some operational and physical limitations that best fit its own operation only if all the HAP emitted are from affected gasoline operations. The EPA considered allowing gasoline terminals and pipeline breakout stations emitting additional HAP emissions from non-gasoline sources at the plant site to use this approach. However, the EPA believes covering all situations and other source categories under this rule would be too complex and uncertain. Therefore, those sources would have to obtain enforceable conditions and limitations outside the provisions of this rule.

Under this approach for plant sites emitting HAP only from affected gasoline operations, the bulk gasoline terminal or pipeline breakout station facility can establish its potential to emit through a combination of operational and physical limitations that are otherwise federally enforceable outside the context of this rule or that are made enforceable through compliance with parameters included in the screening equations in this rule. Examples of allowable federally enforceable limitations and conditions are provided in the definitions section of the General Provisions (§ 63.2). Examples of limitations at bulk terminals and pipeline stations that are required to meet the definition of federally enforceable outside the context of this rule are emission limits on vapor processors that process emissions from storage vessels and cargo tanks. Recordkeeping and reporting requirements will be used to monitor compliance with all limitations. Thus, the final rule allows the facility to limit PTE by complying with the approved values of the physical or operational parameters contained in the emission screening equations, such as maximum throughput. This provides the facility the most flexibility in operations without overestimating PTE.

The proposed rule required facilities to either use a specific emission estimation screening equation or prepare an inventory of emissions to determine their emissions for determination of major or area source status. The proposal allowed area source facilities to report their applicability findings and calculations in their initial notifications to the Agency [required under § 63.9(b)]. After review and acceptance by the Agency, the facility would have been considered an area source and would not be subject to the control requirements of the rule. Changes to the final rule establish certain facility parameters used in the emission screening equation as new "physical or operational limitation[s] on the capacity of the stationary source to emit a pollutant. Upon request, the owner or operator of the bulk gasoline terminal or pipeline breakout station will be responsible for demonstrating compliance with the facility's applicability determination, including all assumptions, limitations, and parameters used to calculate potential to emit HAP

To monitor these limitations, certain facilities are required in the final rule to annually certify that these facility parameters are not being exceeded. It would be burdensome and unnecessary for all facilities below the emissions threshold for major sources to provide detailed reports and records, and annually certify that changes have not occurred. As suggested in the API comments, only facilities within 50 percent of the emissions threshold for major sources will be required to submit a detailed report of these calculations and assumptions used in the calculations in an initial report, and then provide annual certification that the established facility parameters are not being exceeded. The remaining facilities will need to retain a record at the facility of these calculations and notify the Administrator of the use and results of the emission screening equation. These records would remain at the facility for inspection by the Administrator If the PTE "limitations" are exceeded or if the facility fails to keep records or report as required, the facility will be in violation of this rule and may in some cases be considered a major source and be subject to the emission standards of this rule.

The final rule also requires the reports submitted containing those limitations and certifications to be approved by the Administrator and made available for public inspection. The notifications and reports documenting those limitations must be submitted within 1 year of today's date to the Administrator. The final rule allows facilities to change these parameters after submittal of the revised calculations and approval by the Administrator.

If the facility becomes an area (nonmajor) source by complying with the PTE enforceable limitations and conditions established under this final rule, then the emission control requirements of this rule would not apply. Furthermore, for purposes of section 112 of the Act, it would not be a regulated area source that would be required to have an operating permit under 40 CFR part 70. In other words, being subject to the PTE limitations in this rule does not in and of itself make the facility subject to 40 CFR part 70. However, there may be other reasons that the stationary source is required to comply with 40 CFR part 70.

The EPA believes the mechanisms provided in this rule for limiting PTE provide adequate safeguards for this source category However, the EPA is still evaluating whether the general approach taken in this rule will be appropriate for other source categories.

4. Refinery Bulk Terminals

One commenter requested that, for bulk terminals contiguous to refineries, the EPA clearly define the separation between terminal storage tanks and refinery storage tanks. These terminals are usually fed from tanks located within the refinery itself, often thousands of feet from the terminal. Refinery tanks will be regulated by the NESHAP for petroleum refineries (proposed at 59 FR 36130, July 15, 1994). The commenter felt that tanks not located at the terminal itself should be considered part of the refinery for the purposes of regulation.

Several commenters were of the opinion that the EPA should distinguish the association and applicability of the gasoline distribution MACT rule from the refinery MACT rule currently under development. Many commenters believe that only cargo tank loading racks and cargo tank leakage should be regulated at terminals that are "contiguous to" refineries, and that tankage and equipment leakage emissions should be regulated under the refinery MACT rule One suggested method to distinguish whether facilities are subject to the refinery rule or the gasoline distribution rule is to consult the applicable Standard Industrial Classification (SIC) codes already assigned to these facilities.

Terminals and pipeline facilities contiguous to refineries are of two types. First, there are terminals and pipeline facilities that are located within a contiguous area and under common control, but are managed by the "marketing" or "distribution" departments, though they are located on the same property as a refinery The other type are terminals and pipeline facilities located among the refinery process units and storage tanks and managed by the "refinery" management departments. SIC codes are assigned and are currently being used by these facilities to distinguish between equipment. Industry commenters expressed a need to retain this separation because they often have separate management for maintenance, capital improvements, personnel, and operation of the assigned equipment. This separation would keep the management of the air pollution control equipment under the same management structure as the surrounding process equipment. The Agency agrees with the commenters that maintaining this structure would be beneficial, because it will increase the management of proper operation and maintenance of the control equipment, decrease compliance costs, and improve the reporting and recordkeeping and enforcement of this rule.

Since a final rule cannot refer to another standard that has not been promulgated as a final rule, this change is not incorporated into the final gasoline distribution rule. The Agency however, plans to carry out this change by modifying this rule at the promulgation of the refinery MACT standards. The proposed refinery MACT standards contain different requirements for equipment leaks and compliance schedules for storage tanks. The Agency will assess the differences between these two rules after it considers public comments on the refinery MACT proposal and develops the final refinery MACT standards. Meanwhile, all provisions of this gasoline distribution rule will be implemented as they are being promulgated here, since there are no requirements in this rule that must be implemented before the scheduled promulgation of the refinery MACT standards. Independent of the SIC code designation decision discussed above, the EPA will make a decision in the refinery MACT rule on the use of emission trading or averaging between the collocated gasoline distribution and refinery sources.

B. Equipment Leak Requirements

1 Emission Factors

Several commenters strongly objected to the EPA's use of 1980 refinery data to estimate emissions from equipment (pumps, valves, etc.) at bulk terminals and pipeline breakout stations. These commenters were in support of using the new API data gathered at several bulk terminals. These data indicate that leakage from bulk terminal and breakout station equipment is very small and that the refinery emission factors overestimate these emissions greatly The commenters pointed out that the EPA s use of the higher factors would lead to incorrect calculations of applicability status and baseline emissions.

At proposal, the EPA used the refinery equipment emission factors in publication AP–42, Section 9.1, Petroleum Refining, to estimate emissions from equipment components at marketing terminals and pipeline breakout stations. The API supplied new data which indicated that corresponding emission factors for marketing terminals and breakout stations are over 99 percent lower The EPA has reviewed the data submitted by API. In May 1994, the EPA released a draft report containing new correlation equations for marketing facilities using the API data. The Agency is still reviewing and analyzing the API data to determine new EPA emission factors. For the purposes of this analysis and completion of this final rule, API's suggested emission factors are being used because in our judgement these new factors better reflect emissions from this source category than the 1980 refinery data. The EPA intends to issue new EPA emission factors in the near future.

2. Control Level

Several commenters expressed disagreement with the proposal to require a leak detection and repair (LDAR) program at bulk terminals and breakout stations, stating that the emissions from equipment leaks are much smaller than the EPA had estimated. Consequently the commenters considered the EPA s estimated emission reductions due to an LDAR program to be greatly overstated. As a result, the cost effectiveness of such a program would be very poor. In lieu of an LDAR program, many commenters felt that a mandatory visual inspection program (similar to existing programs at many terminals) would be more appropriate. The API performed a leak rate survey at bulk terminals, including both terminals where an LDAR program was in effect and terminals that were not carrying out a formal LDAR program. The API's conclusion was that there was no statistically significant difference in the leak rates found at the two groups of terminals. The commenters concluded that LDAR programs are more appropriate for refineries, where the equipment handles fluids at higher temperatures and pressures.

Before proposal of this MACT regulation, the EPA learned that few existing terminals and pipeline breakout stations (less than 1 percent) routinely use a portable organic vapor analyzer (OVA) to carry out LDAR programs on their gasoline handling equipment. As a result, the "floor" for control of equipment leaks at existing terminals was found to be periodic visual inspections (no formal, federally enforceable inspection program). A monthly LDAR program using an OVA was determined to be in practice at a few terminals associated with refineries and therefore was determined to be the floor for equipment at new terminals and breakout stations. As stated earlier, the EPA in the proposal analysis used the refinery emission factors in AP–42 to calculate baseline emissions from equipment leaks at existing facilities and analyzed LDAR as an "above the floor" option. The EPA found LDAR to be cost effective; however, the Agency noted that there were industry concerns with the refinery factors and thus did not select the higher emission reduction alternative (monthly instead of quarterly LDAR). As discussed above, after reviewing equipment leak data submitted by API, the EPA agrees that the equipment leak factors at marketing terminals are much lower than the refinery factors, resulting in much lower potential emission reductions due to an LDAR program. As a result of this determination, the cost effectiveness of a formal instrument LDAR program has been found to be much less favorable for gasoline marketing facilities.

The new gasoline distribution equipment leak data submitted by API showed only a slight difference (0.2 percent) between emission factors at facilities performing periodic LDAR (with an instrument) and facilities with a periodic visual program. Based on its review of these data, the EPA agrees with API's assessment that this difference is statistically insignificant. Therefore, the EPA is in agreement with the majority of commenters that periodic visual inspection and LDAR programs achieve essentially equal emission reductions for these facilities.

Industry submitted survey information that 81 percent of terminal facilities are implementing some type of periodic visual inspection program. The survey data did not show the frequency of visual inspections, but API has stated that current industry periodic visual programs range in frequency from daily to quarterly The API suggested a quarterly program and provided language to make it enforceable and verifiable through recordkeeping. The program suggested by API included: (1) A quarterly determination of leaks by visual, audible, and olfactory inspection of pumps and valves; (2) a log book listing all of the equipment in gasoline service; (3) note all non-inspected equipment; (4) if a leak is detected, repair as soon as practical (considering safety); if the leak cannot be repaired immediately then the leak must be repaired or the equipment replaced within 15 calendar days, unless not practical for reasons stated in the log book or, when possible, use of the leaking equipment is to be suspended; (5) annual checks of log book by facility supervisor; and (6) quarterly logs and records of annual checks retained for 5 years and accessible for inspection within 3 business days.

The NSPS for bulk gasoline terminals [40 CFR part 60, subpart XX, § 60.502(j)] requires monthly inspection of loading racks as follows:

> (j) Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For the purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

The visual inspection program in the final rule is similar to these NSPS provisions; however, the provisions have been expanded based on suggestions of the commenters and certain requirements in existing Federal LDAR regulations. As in the NSPS, a monthly inspection using sight, sound, and smell is required. Each detection of a leak is to be recorded in a log book. Leaks must be repaired as soon as practicable, but with the first attempt at repair made no later than 5 calendar days after detection, and repair completed within 15 days after detection. Delay of repair is allowed upon demonstration to the EPA that timely repair is not feasible. Full records of each inspection are required, including for each leak a record of the date of detection, nature of the leak and detection method, dates of repair attempts and methods used, and details of any delays of repairs.

The final rule contains a requirement for both new and existing facilities to perform a visual inspection of equipment on a monthly basis because it is achieved in practice on the same and similar equipment under the 40 CFR part 60, subpart XX requirements as described above and at some facilities that are covered under monthly LDAR programs in response to 40 CFR part 60, subparts VV and GGG, and 40 CFR part 61, subparts J and V As noted earlier, the emission reductions resulting from these visual inspection programs have not been established, so the emission benefits cannot be quantified other than to say that periodic inspections ensure low emission levels. The national annual cost for monthly visual inspections under this final rule is estimated to be $43,000.

C. Storage Vessel Requirements

1. Control Level

Several commenters claimed that the discussion in the proposal concerning the "floor" level of control for storage vessels was inadequate and unclear. The EPA s conclusion was that the NSPS requirements of 40 CFR part 60, subpart Kb (NSPS subpart Kb) constituted the floor for storage vessels at existing sources. One commenter stated that the EPA had not performed an adequate evaluation to establish the floating roof rim seal requirements of NSPS subpart Kb as the floor. Several other commenters believed that the EPA had demonstrated that NSPS subpart Kb's rim seal requirements are the floor for existing sources, but not the additional NSPS subpart Kb requirement to control the roof deck fittings. At proposal, the EPA required gasoline storage vessels at existing facilities to meet all of the control requirements in NSPS subpart Kb. Subpart Kb specifies closure devices between the wall of the storage vessel and the edge of the floating roof ("rim seals"), and the installation of gaskets on specified lids and other openings in the floating deck ("controlled fittings"). The EPA also proposed these same requirements as the floor for new facilities. Subpart Kb is the most recent (1984) new source performance standard applicable to all new, modified, and reconstructed volatile organic liquid storage vessels (including gasoline liquid storage vessels).

Regarding the comments concerning the floor determination for rim seal requirements for existing sources, the EPA continues to maintain its previous conclusion that the NSPS subpart Kb rim seal requirements are the floor for storage vessels at gasoline distribution facilities as proposed and presented in the proposal notice (February 8, 1994, 59 FR 5868) and further discussed in the promulgation BID. The EPA believes it did perform a proper evaluation, and the commenter did not provide any data or information to support a change in the finding that NSPS subpart Kb rim seals are the floor level of control.

The EPA, however, does agree with the commenters' statements that the discussion in the proposal preamble did not support the NSPS subpart Kb fitting control requirements set in 1984 for new tanks as part of the floor for storage vessels at existing facilities. The EPA did not have access to any data regarding the number of gasoline storage vessels that are equipped with controlled fittings. The commenters also did not provide any data or information on the number of storage vessels with or without fitting controls for these subcategories. Information obtained in the tank survey conducted for the refinery MACT standards was inconclusive regarding the use of controlled fittings on storage vessels. As a result, the EPA has no data to support the conclusion that controls on tank fittings are part of the floor for existing sources. Therefore, the EPA has determined the existing source MACT floor for fittings as "uncontrolled.

The Agency has considered controlled fitting requirements as an option providing the maximum degree of reduction in HAP emissions ("above the floor") as required by the Act. The Administrator is required under section 112(d) to set emission standards for new and existing sources of HAP that require the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any nonair quality health and environmental impacts, and energy requirements. New tanks at new or existing facilities since 1984 are meeting the deck fitting control requirements in 40 CFR part 60, subpart Kb and, therefore, these requirements are achievable. Controlling fittings to that level is also considered the maximum degree of emission reduction.

Emission reductions and costs for controlled fittings were analyzed on both a per model storage vessel and a nationwide basis using two typical size and throughput vessels, and different potential HAP contents in gasoline. Additionally installation of controlled fittings on many tanks requires degassing and cleaning of the tanks. Industry reports that storage vessels are degassed and cleaned at least every 10 years for safety inspections and requested that the Agency require all retrofits (fittings and rim seals) on storage tanks to occur simultaneously Therefore, the new analysis included two options, with and without degassing and cleaning costs. If fitting controls were required within 3 years of today's date, the cost impact for this standard would include the degassing and cleaning costs along with the cost of controlled fittings if a tank's routine safety inspection would not have occurred during that 3-year time period. The option of waiting until the next routine tank degassing and cleaning would avoid the additional costs of cleaning and degassing as an impact of this standard since the activity would have occurred anyway. A discussion and presentation of the model tank analysis of fitting controls are included in Appendix B of the promulgation BID

Installing controlled fittings on floating roof tanks, without degassing and cleaning costs, would result in a cost savings due to the value of gasoline vapor prevented from evaporating through openings in the floating roof deck. The capital costs of installing deck fitting controls on the model tanks, without the cost of degassing and cleaning of the tanks, ranged in the analysis from $1,200 to $2,800, annualized costs ranged from a savings to a cost of $340 per year, and the cost effectiveness ranged from a savings to a cost of $7,500 per megagram of HAP reduced. When controlled deck fitting installation costs included degassing and cleaning costs, the capital costs ranged from $21,000 to $67,000, annualized costs ranged from $4,000 to $14,000 per year, and the cost effectiveness ranged from $25,000 to $300,000 per megagram of HAP reduced. Calculation of product price increases under either option showed them to be insignificant (less than 0.05

cent per gallon). In conclusion, installing controlled deck fittings is significantly less costly if it can be done at the next scheduled tank degassing and cleaning.

The Agency has decided to require installation of controlled deck fittings on each existing external floating roof storage tank that is required to be degassed and taken out of service for the purpose of replacing or upgrading rim seals to meet 40 CFR 60, subpart Kb requirements. Since these tanks must be degassed and cleaned and have plant maintenance personnel on site, it is reasonable to require installation of the fitting controls at the same time. A national impact analysis was performed on this requirement. Table D–1 in Appendix D of the promulgation BID presents the results of the national analysis on storage tanks and other emission sources at bulk terminals and pipeline breakout stations. Installing fitting controls on external floating roof tanks is estimated to reduce 66 megagrams per year of HAP at an annualized cost savings of $93,000.

The cost analyses show that installing controlled fittings when installing or replacing rim seals on existing external floating roof tanks involves a small capital cost (approximately $2,000 per tank), with an annualized cost savings, and insignificant change in gasoline prices. Given these low costs and the simplicity of these control measures when tanks are otherwise out of service, the EPA has concluded that fitting controls are practical and affordable for existing external floating roof storage tanks. These controls also prevent pollution and conserve energy by preventing liquid gasoline from evaporating. Having given full consideration to the directives in the Act, the Administrator is requiring gasoline storage vessels at existing facilities to control the deck fittings when replacing or installing rim seals on external floating roof storage tanks to comply with the requirements in this final rule. Given the small national HAP emission reduction, the Agency has decided not to require fitting controls on existing internal floating roof storage tanks. While the EPA is not at this time requiring these controls nationally on internal floating roofs, the EPA encourages industry to consider the installation of these controls on a case-by-case basis. All new storage tanks at both new and existing facilities are already required under NSPS requirements of 40 CFR part 60, subpart Kb to install these same fitting controls. Those NSPS requirements are cross-referenced and are therefore part of today s final rule. This level of control for roof deck fittings for new sources and for existing external floating roof tanks upgrading to rim seal requirements under this rule, is the same level as proposed on February 8, 1994. The storage vessel compliance period is discussed and analyzed in the next section.

While this final rule does not require fitting controls for existing internal floating roof storage tanks or the existing external floating roof storage tanks currently meeting the rim seal requirements in this rule, the Agency believes it is appropriate and recommends the inspection, repair, and upgrading of gasketing materials on fittings in the tank roof when any storage tank is taken out of service. It is a major part of the normal safety and maintenance procedure to inspect, repair, and upgrade the physical and mechanical condition of all the tank components. Additionally requiring fittings to be installed on all tanks will reduce additional air toxics and volatile organic compounds, and will upgrade all tanks to the same level of control. An effective mechanism to get controlled fittings in place on all tanks is the combination of this rule, the air toxics programs under section 112(l) of the Act, and the national ambient air quality programs for control of ambient ozone under the Act. The EPA recommends that State and local air pollution control agencies pursue implementation of fitting controls on the remaining tanks under those programs.

2. Compliance Period

Several commenters said that the proposed 3-year compliance period for storage tanks is unreasonable and is more stringent than the compliance schedule in other Federal regulations. To install the required controls, tanks would have to be taken out of service, cleaned, and degassed. Requiring all storage tanks to comply in a 3-year period could potentially disrupt the nation s gasoline supply causing a gasoline shortage, especially in light of the new reformulated/oxygenated fuel requirements. One commenter stated that limited contractor resources could make the schedule logistically unworkable. Additionally the cleaning and degassing of a storage tank creates an air emissions event that in many cases will exceed the emission reductions resulting from the new controls (e.g., the retrofit of an internal floating roof tank already meeting 40 CFR part 60, subpart Ka rim seal requirements) One commenter stated that the EPA must perform a cost effectiveness analysis to support a 3-year compliance date. All of the commenters suggested that the EPA relax the compliance schedule and allow storage tank owners and operators to comply at the next scheduled tank inspection or within 10 years, whichever comes first. One of the commenters felt that a 10-year period is an integral part of the floor for existing sources. This commenter recommended that, should the EPA not allow up to 10 years for compliance for all tanks currently equipped with floating roofs, at a minimum internal floating roof tanks currently meeting NSPS subpart Ka requirements should be provided a compliance period up to 10 years, or the next regular inspection cycle, whichever occurs first.

Section 112(i)(3) of the Act requires the Administrator to establish a compliance date which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date (promulgation) of the standards. In addition, the Administrator (or a State with a program approved under title V) may issue a permit which grants up to a 1-year extension to comply with the standards if an additional period is necessary for installation of controls. However, some commenters suggest that taking a tank out of service before its normal cleaning and inspection schedule to comply with the regulation may generate more emissions than the added controls would reduce or control in the 3-year period.

To determine whether any tanks should be allowed an extension of the compliance time to achieve the maximum degree of reduction in emissions of HAP the EPA compared the emission reductions achieved by the controls (i.e., rim seals and fittings controls) to the emissions generated from degassing and cleaning of fixed-roof and internal and external floating roof tanks for various tank diameters and gasoline turnover rates. The results of this analysis showed that additional degassing and cleaning emissions do not exceed the emission reductions from tanks complying with this final rule within the required 3-year compliance period. The analysis did show net emissions increases for some very large tanks either installing secondary seals without installing fitting controls, or installing fitting controls alone. However, these final standards require a facility to install fitting controls when installing secondary rim seals, and no tanks are required to install fitting controls alone. A complete discussion of this analysis of emissions generated from tank cleaning and degassing is presented in Appendix B of the promulgation BID

D. Cargo Tank Requirements

1. Emission Factors

Several commenters stated that the EPA s assumption at proposal that tank trucks that have passed the EPA Method 27 annual vapor tightness test leak 10 percent of their emissions during controlled loading is outdated and inaccurate. Consequently, the baseline emissions calculated for tank trucks are grossly overstated. New data suggest that very few tank trucks leak due to today s better construction standards and the test requirements in effect under current Federal and State rules. One commenter provided calculations indicating that, under the proposed pressure decay standard (which is the same as the 40 CFR part 60, subpart XX NSPS requirement), a typical controlled tank truck would have a leakage emission factor for loading of 5.6 mg/liter (at the allowable maximum of 18 in. H_2O backpressure). Another commenter estimated, on the basis of test failure rate data from the Bay Area Air Quality Management District (BAAQMD) and several oil companies, that the overall average leak rate is 0.88 percent of the total volume of vapors displaced during the loading of tank trucks connected to a vapor recovery system.

The EPA's estimate of 10 percent vapor leakage from emission sources in tank trucks while loading at controlled loading racks was based on data collected in 1978 on 27 tank trucks in California. These tank trucks were under a State requirement to be certified annually in a vapor tightness test, and time periods ranging from 4 days to a full year had elapsed since the last certification test for these trucks. The volume losses among the trucks varied from 0.1 to 35.8 percent, with the average leakage being about 10 percent. The data from these tests were further described, and the 10 percent figure derived, in the BID for the proposed NSPS for bulk gasoline terminals (docket item II–A–14).

The commenter who supplied the 0.88 percent overall leakage estimate relied upon vapor volume loss data for individual tank trucks reported in the 1978 study and combined these data with test failure rate data from the BAAQMD (pressure test data) and from several oil companies (combustible gas detector results gathered during loading rack performance tests). Based on an assumption that a leak definition of 10,000 ppm is equivalent to a 1 percent loss of vapors through leakage, the commenter determined that the average leak rate for tanks with leakage rates over 1 percent ("failing" tanks) was 12.1 percent, while the average leak rate for the remaining, "passing" tanks was 0.5 percent. On the basis of the failure rate data, the overall failure rate during 1989 to 1994 was found to be 3.3 percent. Combining the average leak rate figures with these failure prevalence data, the commenter arrived at the overall leak rate for all tank trucks of 0.88 percent.

The EPA recognizes and agrees with the commenter that the available data indicate that overall vapor leakage rates from tank trucks subject to a regular test and repair program using the pressure decay procedure have been reduced over the past 16 years. However, the use of concentration data to estimate a volume leakage rate, as the commenter has done, is uncertain. In addition, neither the EPA nor industry have access to current data for several areas throughout the country that would allow a national average calculation of this volume leakage to be made. Therefore, any numerical result derived from the existing data would be at best a broad estimate, which would not account for the full range of truck ages, ownership scenarios, and local control programs.

In spite of these limitations, the EPA has made an estimate which it feels more closely reflects actual overall emissions under a vapor-tight cargo tank program than the emission factor used for the proposal. The Agency's new emission factor, 0.8 percent of the total vapors displaced or 8 mg of VOC/liter, is based on the use of a volume loss equation found in Appendix C of the tank truck CTG (EPA–450/2–78–051) combined with the test failure rate data submitted by the commenter and measured leakage from trucks that failed the test. This new emission factor represents the emissions after control to the level of today's final standards as discussed in the following sections. The promulgation BID, Appendix A presents more details on the calculation of this emission factor

2. Control Level

a. Vacuum assist vapor collection. Many commenters expressed opposition to the proposal to require use of "vacuum assist" technology at new bulk terminal loading racks. Most of the commenters felt that annual vapor tightness testing is adequate to control tank truck leakage emissions. Some commenters expressed safety concerns; e.g., the potential for fires and tank truck implosion. One of them said that internal tank vacuums can (and already do) damage the internal compartment heads of tank trucks by reversing those heads and weakening the tank's outer shell, which compromises product retention capability Several do not believe that vacuum assist technology has been demonstrated as "achievable in practice." The technology has been used in only one State (Texas) and has not been tested under various climatic conditions, such as combined low temperatures and high humidity levels. Others believe that the complexity of the loading system would increase. Also, due to rapid fluctuations in gasoline flow rates and the requirement to maintain a vacuum at all times during loading, nuisance shutdowns of the loading operation could be a problem. One commenter said that such a system may adversely affect the efficiency of the vapor control device because air can leak into the vapor collection system and dilute the inlet VOC concentration. Another commenter felt that volatilization of fuel in the cargo tank would be increased due to the vacuum, sending more vapors to the control device. This would require a larger device which may have greater emissions, and more solid waste impact for the case of a carbon system. One commenter said that vacuum assist systems will increase electrical power consumption 15 to 400 percent depending on the type of emission control device used. Others said that vacuum assist is unnecessary because tank trucks do not leak enough during loading to justify vacuum assist as a means of reducing the losses. Recent API data show that tank truck leakage has been significantly reduced since the EPA study performed in 1978. Three commenters said that the system addresses losses from the tank truck only while loading at the terminal and not while in transit or while operating at bulk plants and service stations. Other commenters said that vacuum assist is very expensive and not cost effective.

The vacuum assist system was proposed for new source bulk terminals to control HAP emissions due to vapor leaks from cargo tanks during gasoline loading operations. This system creates a negative pressure in the vapor collection system during loading to ensure that vapors will not be forced out into the air through any leakage points. The proposal rationale was based on the following information. Vacuum assist systems are in use at a few bulk gasoline terminals (in addition to the annual vapor tightness test for truck tanks) in Texas, so it meets the Act requirement to consider the best controlled similar source in establishing the floor level of control for new terminals. Since less than 1 percent of terminals use this vacuum assist system, it is not considered the floor for cargo tank leakage at existing terminals. Annual vapor tightness testing of cargo tanks was considered at proposal to be the floor for existing terminals (this floor determination has been modified on the basis of public comments; see 59 FR 42788, August 19, 1994). Based on field tests in the late 1970's, an annual vapor tightness testing program was estimated to reduce the leakage rate from baseline levels at 30 percent leakage to about 10 percent leakage. The vacuum assist system was estimated to reduce the 10 percent leakage rate under the annual vapor tightness test program by nearly 100 percent.

Industry sources had expressed concerns before proposal regarding the operational reliability of a vacuum assist system, especially under extreme cold weather conditions. Those commenters also believed that the system could present a safety hazard if excess negative pressures were developed within a tank truck fuel compartment. To the Agency s knowledge, the systems in operation have not experienced any significant problems, and one of the systems has been operating for over 3 years. These systems contain safety pressure relief devices in combination with the pressure-vacuum vents already installed on each tank truck compartment. However, safety concerns are important to the Agency. The Agency specifically requested comment at proposal, including technical documentation and data where available, on the reliability effectiveness, safety aspects, and any other issue concerning vacuum producing equipment for bulk terminal vapor collection systems. No technical documentation or data on installed systems was provided during the comment period.

As discussed above in Section III.D.1, the leakage emission factor for controlled cargo tanks under an annual vapor tightness program was adjusted to reflect current data on the frequency with which cargo tanks pass the test on the first attempt. Emissions lost from cargo tanks under test programs with a pressure decay limit of 3 in. H_2O are now estimated to be 1.3 percent of total vapor displaced during loading operations (just under 99 percent collection efficiency). In California, where an annual pressure decay limit of 1 inch of water is in effect, the emission losses during loading are estimated at 0.8 percent (slightly over 99 percent collection). The corresponding HAP emission factors are 0.4 and 1.3 mg/liter of HAP for normal and oxygenated gasolines, respectively At proposal, the leakage emission rate was estimated to be a 10 percent loss (90 percent collection efficiency). Thus, while vacuum assist systems were previously thought to have the potential to capture an additional 10 percent of the loading emissions, they now appear to have the potential to capture about 1 percent.

The EPA shares commenters concerns that the emission control achieved with the vacuum assist system is uncertain. The Agency s uncertainty centers on the system s effectiveness in accurately maintaining a slight vacuum to collect a small leak (1 percent of the volume displaced to the collection system) while handling the variability of flows and pressures and limiting the ingestion of air into the system to a degree where it does not affect the control effectiveness of the processor The vapor volume collected by the system and internal pressures within the vapor collection system vary widely throughout the day Each cargo tank loading and displacing vapors influences the pressures and flows in the system. Terminals operate on demand, just like gasoline service stations. The number of tanks loading at any given time varies from none, to a few to 10 or more tanks. Additionally vapor processor control efficiency may be adversely influenced by increased amounts of air sent to the control system. A vacuum assist system draws additional air into the system. Even small malfunctions in the system would be likely to increase emissions above the 1 percent control target. Finally the Agency agrees that it lacks sufficient information to determine whether conditions outside of Texas may affect the control performance of vacuum assist methods.

The proposal of vacuum assist was based on the minimum baseline (floor) at which standards may be set. Under section 112(d)(3) of the Act, the floor for new sources

> shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator

The Administrator has determined that emission control is not being achieved in practice given the technical uncertainties about achieving emission reduction from this source as discussed in the previous paragraph. Consequently the proposed vacuum assist requirement for new bulk terminals has been deleted from the final rule.

b. Vapor tightness standards. Two commenters recommended during the proposal's comment period that the EPA implement the cargo tank vapor tightness program in effect within the State of California since 1977 The California standard requires annual certification that cargo tanks meet 5-minute pressure and vacuum decay standards of 1 inch of water column (in H_2O). Based on a BAAQMD survey of 200 tank truck owners which quantified actual pressure change values, California is proposing to lower this annual standard to 0.5 in. H_2O. In addition, the same commenters recommended that the EPA apply the California year-round standard of 2.5 in H_2O pressure loss in 5 minutes. The EPA published a supplemental **Federal Register** notice (59 FR 42788, August 19, 1994) and opened a comment period for consideration of the existing California standards as the level of control for new and existing sources in the final MACT rule. The following comments were received on the floor determination and on the level of control that is appropriate for controlling cargo tank leakage. The promulgation BID summarizes additional comments and responses to comments received on the proposal and supplemental notice.

Five commenters felt that the existing California standards should be specified for cargo tanks at new sources, but would be inappropriate for existing sources. These commenters based their opinion on the conclusion that the EPA had inappropriately based its floor determination on California s gasoline throughput, or number of tank trucks operating in the State. They felt that, since the legal responsibility for compliance would be on the terminal owner or operator, the basis should be the number of terminals in California. One commenter said that this figure is 71, out of a total of 1,125 terminals nationwide (6.3 percent). Since this value is less than the required 12 percent, applying this control level to existing sources would be an "above the floor option. Thus, a cost effectiveness analysis should be provided to justify the California standards as the existing source floor. Another commenter stated that the California Highway Patrol, which monitors California s tank testing program, does not include vapor tightness testing in its 44-point program for inspecting out-of-State cargo tanks. The commenter felt that this issue could impact the foundation upon which the EPA had reopened the proposal action. Two commenters favored incorporation of the California standards for both new and existing sources.

Several commenters responded to the EPA s request for comments on whether the level of control for cargo tanks at new and existing facilities should be based on the existing or the proposed

California standards. Commenters were unanimous in asserting that only the existing, and not the proposed, California standards should be considered. Two of the commenters felt that BAAQMD's survey of 200 tank truck owners was not sufficiently representative to indicate that the more stringent proposed standards should be applied. Another commenter said the proposed requirements should not be adopted because: (1) the testing in the survey has not been properly peer reviewed, (2) the proposal has yet to be adopted by the California Air Resources Board (ARB), and (3) there is no conclusive demonstration of any significant emissions difference between the current and proposed standards. Two other commenters echoed that there is no basis for considering the more stringent standards because the effect on tank truck emissions is unknown. Finally, one commenter requested that the EPA consider the proposed California standards for new and existing facilities, feeling that this would standardize regulations nationwide and result in lower costs for equipment and remove some burden from the California ARB.

The California ARB and the California air pollution control districts have been implementing tank truck leakage standards since the late 1970's. Currently, all tank trucks transporting gasoline in California, including tank trucks from neighboring States that operate in California, must meet the California standards and are checked by the California air pollution control districts. In summary, they include three major standards: an annual certification, a year-round standard for the tank and its vapor piping and hoses, and a year-round pressure standard for the tank truck's internal vapor valve. The annual certification standards include initially pressurizing and later evacuating the tank and associated vapor piping and hoses to 18 in. H_2O and to 6 in. H_2O, respectively. In 5 minutes the allowable pressure change may be no more than the values shown in Table 1. Further details on the performance requirements and test procedures used in the California program were discussed at 59 FR 42788 The EPA's Control Techniques Guideline (CTG) document and NSPS, subpart XX contain annual pressure and vacuum test levels of initial pressures and test duration which are the same as California's. However, a less stringent pressure change of 75 mm of water column (3 in. H_2O) is allowed for all tank trucks under the NSPS, the CTG, and the proposal.

TABLE 1 —ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change in 5 minutes, mm H_2O (in. H_2O)	Allowable pressure change in 5 minutes at any time, mm H_2O (in. H_2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

In the August 19, 1994 supplemental notice, the EPA stated that the gasoline throughput in California accounts for nearly 12 percent of the national gasoline consumption (13.46 out of 117.9 billion gallons per year). Essentially all of this gasoline would be transported by tank trucks, which include both California and out-of-State cargo tanks, all of which are subject to the State's vapor tightness standards. For this reason, it was assumed that about 12 percent of the national tank truck population is under a requirement for annual certification and periodic testing in accordance with the California vapor tightness standards. On the basis of public comments, however, the EPA has examined the effect of considering the number of terminals in California on the floor determination. As pointed out by one of the commenters, California terminals account for 6.3 percent of the national total. In determining the floor for existing sources, the EPA looks at emission limitations achieved by each of the best performing 12 percent of existing sources, and averages those limitations (59 FR 29196). In this case, the "best performing" cargo tanks are presumed to be those subject to the most stringent vapor tightness standards. The Agency interprets "average" to mean a measure of central tendency such as the arithmetic mean, mode, or median. It can be seen here that on the basis of the number of terminal facilities, the California standards meet this test by constituting certainly the 94th percentile or median, and mode. Therefore, even when the number of terminals is used in the floor determination, the existing California standards constitute the floor level of control for cargo tanks at existing bulk terminals affected by the final MACT standards. As proposed and discussed in the promulgation BID, it has also been determined that the same tests can be applied to railcars since they are similar sources. Therefore, the final rule incorporates the existing California standards for cargo tanks (tank trucks and railcars) loading at existing and new facilities.

Commenters had several concerns on the level of control for cargo tanks. In the supplemental notice, the EPA had discussed promulgating cargo tank leakage control levels based either on the existing or the proposed California certification annual leak rate, 1 in. H_2O or 0.5 in. H_2O pressure change, respectively. Some commenters questioned the data collected on the number of tank trucks meeting the lower proposed California standard as not representative, not peer reviewed, and not providing a conclusive demonstration of increased emission reduction. Also, some commenters were concerned that the proposed standards based on those data have not at this time been adopted by the California ARB. The EPA shares the commenters' concerns and is reluctant to move forward and recommend a final standard based on data the California ARB has not acted on by adopting and implementing the standards that have been proposed within the State. Thus, the Agency is setting the level of cargo tank leak standards for new and existing facilities on the basis of the existing California standards.

E. Continuous Monitoring

One commenter stressed that, while continuously monitoring a key operating parameter of a vapor processing device may serve as a guide to warn of potential problems and to gauge efficient operation, such monitoring would not be sufficient to assure compliance with the pertinent emission standard. This commenter and others were concerned that a value of the monitored process variable could be selected that is more stringent than necessary to indicate compliance with the proposed 10 mg/liter emission standard. They felt that requiring a facility to continuously maintain a parameter value determined during an initial performance test to maintain compliance and then consider the facility out of compliance if it exceeds that value would be unfair. It is highly probable that during an initial performance test the vapor control device while operating at a particular value will perform much better than the emission limit. One commenter said that, as an example, thermally controlled combustion systems do not require elevated temperatures all of the time to achieve 10 mg/liter. The commenter recommended that, for these units, a single high temperature value should not be set because assist fuel gas consumption would be very high and the unit would be made to operate at control efficiencies substantially higher than the standard.

One commenter suggested that facilities be allowed to use an extrapolative method to predict the operating parameter value at the regulated emission standard based upon the operating parameter value associated with the lower emission level recorded during the performance test. Such an allowance is needed because it is usually not possible to operate a vapor processing system at maximum design conditions. Another commenter recommended that the operating parameter value be set by the least stringent parameter value obtained during the test while the unit is in compliance with the standard.

Section 114(a)(3) of the Act requires enhanced monitoring and compliance certification of all major stationary sources. The annual compliance certifications certify whether compliance has been continuous or intermittent. Enhanced monitoring shall be capable of detecting deviations from each applicable emission limit or standard with sufficient representativeness, accuracy precision, reliability frequency and timeliness to determine if compliance is continuous during a reporting period. The monitoring in this regulation satisfies the requirements of enhanced monitoring.

The required performance test is a minimum of 6 hours in duration, with outlet organic concentration and flow rate data recorded every 5 minutes. While it seems reasonable to base the selection of the parameter range or limit on a 6-hour period to be consistent with the length of the test (as the Agency did at proposal), the Agency has decided this is too long a period to calculate a meaningful average on a continuous basis. One commenter requested that the EPA consider using an extrapolative method (not specified by commenter), using a single high temperature, or setting the parameter based on data just meeting the 10 mg/liter standard. As noted at proposal, the EPA proposed that a site-specific monitoring parameter value be used to account for the different types and designs of control equipment available and the site-specific facility operating conditions. The proposal required a performance test recording 5-minute readings of outlet concentrations and flow rates while continuously recording the specified parameter values. An engineering assessment of those data, along with the manufacturer's recommendations, could be used to find the appropriate parameter value, monitoring frequency and averaging time that is equivalent to the emission standard. This approach, which is incorporated into the final rule, is the most straightforward way of accounting for both the emission standard and the variability of the control equipment design and facility operations. Under this approach, the Agency is allowing some latitude for the method by which the parameter range of the "not to exceed" limit is developed under the final standards. The engineering assessment and manufacturer's recommendations must be documented (recorded in facility files) and reported to the Administrator for approval.

IV Summary of the Final Rule

The final rule will be codified under part 63 of title 40 of the Code of Federal Regulations (CFR). The General Provisions of part 63 (59 FR 12408, March 16, 1994) are located in subpart A and codify procedures and criteria to implement emission standards for stationary sources that emit one or more HAP's, and provide general information and requirements that apply under the section 112 NESHAP promulgated under the Act. The applicability of the General Provisions to affected sources is clarified in subpart R, Table 1, General Provisions Applicability

A. Sources Covered

Sources in the gasoline distribution category are a combination of major sources and area sources. Some pipeline breakout stations and bulk gasoline terminals have been determined to be major sources, since gasoline operations at the larger breakout stations and terminals may have the potential to emit either 10 tpy or greater of an individual HAP (e.g., hexane or MTBE) or 25 tpy or greater of a combination of HAP's, or they are contiguous with a major source plant site that contains additional HAP emission sources other than the affected gasoline operations. For purposes of this final rulemaking, the Agency is requiring that pipeline breakout stations and bulk gasoline terminals that are major sources on their own or are contiguous with a major source plant site be regulated under maximum achievable control technology (MACT) standards. The term "affected source means the total of all HAP emission points at a subject bulk gasoline terminal or pipeline breakout station In addition to affected sources, some nonmajor pipeline breakout stations and bulk gasoline terminals will be subject to modest recordkeeping and reporting requirements to monitor their potential to emit HAP's. The following is a summary of the methods used to determine applicability of the final rule

1. Applicability Determination

The final emission standards apply to all pipeline breakout stations and bulk gasoline terminals that themselves are major sources of HAP's or are located at plant sites that are major sources of HAP's. The standards provide two ways to determine whether a facility's potential to emit (PTE) HAP's may make it a major source. They are:

(1) The appropriate emission equation listed in § 63.420 is used (under specified conditions) to "screen the facility for its potential HAP emissions or (2) the owner or operator provides documentation to the Administrator of the facility's PTE by completing an emissions inventory for the facility

The screening equations in the rule are only allowed to be used at facilities that only emit HAP from gasoline operations. Certain assumptions used by all nonmajor sources in the emission screening equations will become enforceable limitations on the facility's operations under this rule Federally enforceable limitations must be established outside the provisions of this rule, for facilities using the emission inventory for determination of their major source status, and for some parameters used by facilities in the emission screening equation. Facilities using the emission screening equations in the rule are required to record their assumptions and calculations, notify the Administrator that the facility is using the screening equations and provide the results of the calculations, and operate the facility in a manner not to exceed the operational parameters used in the calculations. Larger facilities (those that, in and of themselves, have HAP emissions over 50 percent of the major source emissions thresholds above and use the emission screening equations in the rule) are additionally required to submit to the Administrator for approval their assumptions and calculations, maintain records to document the parameters have not been exceeded, and submit an annual certification that the operational parameters established for the facility have not been exceeded. However, these nonmajor sources are not subject to any of the control requirements of this final rule. The need for and level of reporting and recordkeeping procedures for facilities using emission inventories to demonstrate nonmajor source status are established when federally enforceable limits were set for those facilities. All facilities (major and nonmajor) upon request by the Administrator or delegated State must demonstrate compliance with the applicability determination.

2. Emission Points Covered

Emission points affected under the final standards at bulk gasoline terminals are storage vessels that contain or have the potential to contain gasoline, leaks from the piping system and equipment that handle gasoline or gasoline vapors, loading racks that load gasoline into cargo tanks (tank trucks or railcars), and gasoline vapor leakage from sealed cargo tanks during loading. Emission points affected under the final standards at pipeline breakout stations are individual storage vessels that contain or have the potential to contain gasoline, and equipment leaks from the entire breakout station piping system that handles gasoline

B. Standards for Sources

The final rule specifies an equipment standard for storage vessels at affected bulk gasoline terminals and pipeline breakout stations. The final existing storage vessel provisions require that external floating roof storage vessels not already meeting the NSPS subpart Kb rim seal specifications comply within 3 years to meet the full NSPS subpart Kb specifications (both rim seal and controlled fitting requirements, and reporting and recordkeeping requirements). Any existing storage vessel currently meeting only the rim seal requirements of NSPS subpart Kb is not required to install additional equipment, but must meet the rim seal monitoring, reporting, and recordkeeping requirements. New, modified, or reconstructed storage vessels at existing and new affected sources must comply with the NSPS subpart Kb requirements at startup (as required under the NSPS).

Additionally, the rule specifies an emission limit standard of 10 milligrams (mg) of total organic compounds (TOC) per liter of gasoline loaded (10 mg TOC/liter) for the process stream outlet of control devices and continuous compliance monitoring of certain operating parameters of control devices installed at the cargo tank loading racks of new and existing affected bulk gasoline terminals. Operating the control device in a manner that exceeds or fails to maintain, as appropriate, the monitored operating parameter value established during the emission performance test is an exceedance and constitutes a violation of the emission limit standard.

The Agency is also requiring equipment and performance standards for all cargo tanks loading gasoline at existing and new affected bulk gasoline terminals. Cargo tanks loading at these facilities are required to pass an annual vapor tightness test, and are subject to a vapor tightness standard and test procedures for the tank, vapor piping, and hoses, and a pressure standard for the internal vapor valve at any time. Although the cargo tanks are subject to the "year-round" vapor tightness standard, facility owners and operators are not required to test them at specified intervals. However, as under the NSPS subpart XX, owners and operators will be required to maintain certain records on the vapor-tight status of gasoline cargo tanks and to take steps to assure that nonvapor-tight cargo tanks will not be reloaded until vapor tightness documentation has been obtained.

New and existing affected bulk gasoline terminals and pipeline breakout stations are required to perform a monthly visual (sight, sound, and smell) inspection of all pumps, valves, and other equipment components in gasoline liquid or vapor service and to maintain records of these inspections. When a leak is identified, the owner or operator must record the presence of the leak, and then has 5 calendar days in which to make an initial repair attempt and 15 calendar days in which to complete the repair. Any leaks for which repair is not attempted within 5 days or completed within 15 days must be reported as excess emissions. The final rule also includes a housekeeping provision requiring spills and open sources of gasoline vapor emissions to be minimized, and for spills to be cleaned up as quickly as possible.

C. Effective Date for Compliance

Section 112(i)(3)(A) of the Act requires compliance by existing sources as expeditiously as practicable, but in no event later than 3 years after rule promulgation (today's date), notwithstanding the provisions of sections 112(i) (1) and (2). New affected facilities are required to comply with all provisions of the standards upon startup.

D. Compliance Extensions

Section 112(i)(3)(B) of the Act allows the Administrator (or a State with a program approved under title V) to grant existing sources an extension of compliance of up to 1 year, upon application by an owner or operator of an affected facility, if such time period is necessary for the installation of controls.

Under the early reduction provisions of section 112(i)(5), existing sources may be granted a 6-year extension of compliance with an otherwise applicable section 112(d) standard (MACT standard) upon demonstration by the owner or operator of the source that HAP emissions have been reduced by 90 percent or more prior to February 8, 1994 (the proposal date of this rule), or the source made an enforceable commitment to achieve such reduction prior to January 1, 1994. The general notice governing early reduction compliance extensions was published in the **Federal Register** on June 13, 1991 (56 FR 27338).

E. Compliance Testing and Monitoring

The tests required under the final standards include initial performance testing of the bulk terminal vapor processing system, vapor leak monitoring and repair of the vapor collection system before each performance test, and annual vapor tightness testing of gasoline cargo tanks. In addition, gasoline cargo tank owners and operators are subject to test procedures to determine compliance with year-round leak rate requirements on cargo tanks, vapor collection systems, and internal vapor valves. Storage vessels at bulk terminals and pipeline stations require periodic visual inspections and/or seal gap measurements. Continuous monitoring of an operating parameter is required for vapor processing systems to ensure continuous compliance with the 10 mg TOC/liter emission limit.

Sehedule for performance testing is provided in § 63.7 of the General Provisions. The initial performance test is required 180 days after the effective date of the standards or after initial startup for a new facility or 180 days after the compliance date specified for an existing facility.

Methods 2A, 2B, 25A, and 25B in appendix A of 40 CFR part 60 are specified for measurement of total organic compound emissions from the vapor collection and processing systems. Due to the inherent inability to measure mass emissions from elevated flares (an elevated flare's flame is open to the atmosphere and therefore the emissions cannot be routed through stacks), these test methods are not applicable. Therefore, the Agency has established performance requirements for flares. These performance requirements, including a limitation on visible emissions, are provided in § 63.11(b), which specifies the use of Method 22 for determining visible emissions from flares.

Before each performance test on the vapor processing system, the owner or operator is required to use Method 21 to monitor potential leak sources in the terminal's vapor collection system during the loading of a gasoline cargo tank. Any leaks from the vapor collection and processing systems must be repaired before the performance test is conducted.

The final emission standards include continuous monitoring of an operating parameter as a requirement for vapor processing systems to ensure continuous compliance with the 10 mg TOC/liter emission limit. The vapor processing system's operating parameter "value, monitoring frequency and averaging time are to be established based on data collected in performance tests of the vapor processor. The facility documents and reports their recommended value, monitoring frequency and averaging time to the Administrator for approval. Exceeding or failing to maintain, as appropriate, the approved operating parameter value will constitute a violation of the emission limit standard. The standards also require the maintenance and repair of the system necessary to maintain the parameter value and documentation of any exceedances in a quarterly excess emissions report to the Administrator. The parameters that may be monitored include organic compounds concentration for carbon adsorption and refrigeration condenser systems, and combustion or condenser temperature for thermal oxidation and refrigeration condenser systems. An owner or operator may substitute an alternative parameter or vapor processor type upon the approval of the Administrator.

Each gasoline cargo tank loading at an affected bulk terminal is required to undergo an annual certification test by following the procedures in Method 27 of 40 CFR part 60, appendix A, which is entitled "Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test. Method 27 tests the vapor tightness of the cargo tank (or compartment) under two conditions, positive pressure and negative pressure (vacuum). The procedure for testing the cargo tank for vapor tightness is as follows. The cargo tank is sealed and pressurized to 460 mm H_2O (18 in. H_2O), gauge. [If conducting a vacuum test, the cargo tank (or compartment) is evacuated to 150 mm H_2O (6.0 in. H_2O), gauge.] The source of pressure is removed, the cargo tank is sealed, and then the pressure in the tank is recorded at the end of 5 minutes. The actual change in pressure (or vacuum) after 5 minutes is compared to the maximum change allowed in the regulation.

The annual certification test also consists, in addition to the procedures in Method 27 of a leak test of the tank s internal vapor valve. A summary of these procedures, which are detailed in § 63.425(e)(2), is as follows. The cargo tank is repressurized and the leak rate across the internal vapor valve is measured after 5 minutes. This value is compared to the maximum allowable 5-minute pressure change to determine the vapor tightness of the valve.

In addition to the annual tests, cargo tanks are subject at any time to a leak detection test as described in § 63.425(f) using Method 21, and may also be subject to other procedures as discussed below. Method 21 is also in 40 CFR part 60, appendix A, and is entitled "Determination of Volatile Organic Compounds Leaks. The principle of Method 21 is that organic vapors cause a positive response in a variety of portable hand-held detectors. Thus, a positive detector response indicates the presence of a source of emissions (leak). During a Method 21 test, the tester holds the probe 3 cm (1 inch) from the sources of possible leaks. Any organic vapor concentration in excess of 21,000 ppm as propane is an indication of a leak. If leaks are found, the cargo tank must be repaired and must pass the following tests before it can be reloaded at the facility

Cargo tanks are subject at any time to being tested for vapor tightness using the test procedures in § 63.425(g), referred to as the nitrogen pressure decay field test, and may also be subject to the procedures discussed below. A summary of this test, which includes procedures for the cargo tank and the internal vapor valve, is as follows. The headspace of a cargo tank that has been filled is pressurized to a pressure of 460 mm H_2O (18.0 in. H_2O), gauge with nitrogen gas. Vapor tightness is determined by measuring the pressure decay if any over time and comparing the pressure decay to the maximum allowable calculated value, which is determined using procedures described in § 63.425(g). If the pressure decay exceeds the maximum allowable value, the cargo tank must be repaired and must pass the procedure below.

Cargo tanks are also subject at any time to a test of vapor tightness using the test procedures in § 63.425(h). These procedures are similar to the procedures in § 63.425(e) except that only the positive pressure test is conducted and the acceptance criteria are less stringent.

F Recordkeeping and Reporting

The final standards require four types of reports: initial notification, notification of compliance status, periodic reports, and other reports.

The initial notification report (§ 63.9(b)) apprises the regulatory authority of the results of the applicability determination for existing sources or of the intent to construct for new sources. This report also includes a statement as to whether the facility can achieve compliance by the required compliance date. The initial notification report under this rule is required to be submitted not later than 1 year from today's date.

The notification of compliance status (§ 63.9(h))demonstrates that compliance has been achieved. This report lists the methods used to determine compliance, the results of the initial performance test and the continuous monitoring system (CMS) performance evaluation, which include a description of the continuous monitoring program and supporting data for the monitored operating parameter value for the vapor processor, and a list of equipment subject to the standard.

Periodic reports to the Administrator are required on a semiannual basis. These reports will include loadings of gasoline cargo tanks for which vapor tightness documentation was not on file at the facility reports of storage vessel control systems and inspections, and the excess emissions and CMS performance report and/or summary report required under § 63.10(e)(3). Excess emissions and continuous monitoring reports are also required to be submitted quarterly if a listed exceedance has occurred. Procedures have been established in § 63.10(e)(3) to reduce the reporting frequency once exceedances no longer occur. Excess emissions and continuous monitoring exceedances reported quarterly will include exceedances or failures to maintain the monitored operating parameter value, failures to take steps to assure that a nonvapor-tight gasoline cargo tank will not be reloaded at the facility before vapor tightness documentation is obtained, reloadings of such gasoline cargo tanks, and equipment leaks for which repair is not attempted within 5 days or completed within 15 days.

Certain additional reporting is occasionally necessary because a short-term response may be needed from the reviewing authority For example, the Administrator may request more frequent reports of the monitored operating parameter or visual inspection data if it is deemed necessary to ensure compliance with the standard.

Records, reports, and notifications required under the final standards must be available for inspection for 5 years, in accordance with § 63.10(b). The records include the applicability determination for all bulk terminals and pipeline breakout stations, regardless of their size and the outcome of the determination. For affected sources, the records also include (but are not limited to) gasoline cargo tank vapor tightness test results, as well as CMS monitoring data from the vapor processor. Records from the visual inspection program and storage vessel inspections, and records of startups, shutdowns, and malfunctions of the vapor processor are required to ensure that the controls in place are continuing to be effective. Section 63.10(b) allows the records to be retained at the facility for 2 years and off site for the remaining 3 years.

All pipeline breakout stations and bulk gasoline terminals using the emission screening equations will have additional modest recordkeeping and reporting requirements to monitor their potential to emit HAP's. Only facilities that are within 50 percent of the major source criteria, as determined from using the appropriate emission screening equation, must report the calculations and support information for their nonmajor source determination. Once this determination is approved by the Administrator, the source must keep records and certify annually that it has continued to not exceed any of the enforceable operating limitations contained in its most recent applicability determination. That report of calculations and assumptions must be submitted to the Administrator by the owner or operator within 1 year of the date of today's notice. Nonmajor sources using the screening equations with HAP emissions under the 50 percent threshold must keep records of their determination for possible inspection by the Administrator, operate the facility in a manner not to exceed the parameters used in the equation, and notify the Administrator of the use and the results of the emission screening equation. That notification must be submitted to the Administrator by the owner or operator within 1 year of the date of today's notice. The owner or operator is also required to demonstrate, upon request, compliance with the facility operating limits used in the applicability determination.

V Administrative Requirements

A. Docket

The docket is an organized and complete file of all of the information submitted to or otherwise considered by the EPA in the development of this rulemaking. The principal purposes of the docket are: (1) To allow interested parties to readily identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review (except for interagency review materials) (section 307(d)(7)(A) of the Act).

B. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether a regulation is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The criteria set forth in section 1 of the Order for determining whether a regulation is a significant rule are as follows:

(1) Is likely to have an annual effect on the economy of $100 million or more, or adversely and materially affect a sector of the economy, productivity competition, jobs, the environment, public health or safety or State, local, or tribal government communities;

(2) Is likely to create a serious inconsistency or otherwise interfere with an action taken or planned by another agency·

(3) Is likely to materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Is likely to raise novel or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined to treat this action as a "significant regulatory action" within the meaning of the Executive Order. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the docket listed at the beginning of this notice under ADDRESSES. The docket is available for public inspection at the Agency's Air Docket Section, which is listed in the ADDRESSES section of this preamble

C. Paperwork Reduction Act

The information collection requirements in this rule have been approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and have been assigned OMB control number 2060–0325. An Information Collection Request document has been prepared by the EPA (ICR No. 1659.02) to reflect the changed information requirements of the final rule and has been submitted to OMB for review A copy may be obtained from Ms. Sandy Farmer, Information Policy Branch, Environmental Protection Agency 401 M Street SW (mail code 2136), Washington, DC 20460, or by calling (202) 260–2740.

This collection of information has an estimated annual reporting burden averaging 155 hours per bulk gasoline terminal respondent and 45 hours per pipeline breakout station respondent. Similarly the estimated annual recordkeeping burden is approximately 125 hours per bulk gasoline terminal respondent and 20 hours per pipeline breakout station respondent. These estimates include time for reviewing instructions, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Chief, Information Policy Branch, Environmental Protection Agency 401 M Street SW., (mail code 2136); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked Attention: Desk Officer for EPA.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.) requires the EPA to consider potential impacts of regulations on small business "entities. If a preliminary analysis indicates that a regulation would have a significant economic impact on a substantial number of small entities, a regulatory flexibility analysis must be prepared. However, regulatory alternatives that would alleviate the potential impact of the standards on directly affected companies were not selected because the Act requires all facilities that are members of a category or subcategory of major sources to meet, at a minimum, the requirements of the MACT floor.

For the affected industry sectors, the Small Business Administration s definition of small business is independently owned companies with 100 or fewer employees. The promulgated standards directly impact small companies owning bulk gasoline terminals and pipeline breakout stations. Also, due to downstream wholesale gasoline price increases, the promulgated standards will indirectly impact small companies owning gasoline bulk plants and gasoline service stations.

A definitive estimate of the number of small businesses that will be directly or indirectly affected by the promulgated standards could not be feasibly obtained because of the lack of data related to the extent of vertical integration in the gasoline distribution chain. However, the EPA believes that a maximum of 56 percent of all bulk gasoline terminals are owned by small companies. Potentially up to 99 percent of the indirectly affected gasoline bulk plants and service stations are owned by small companies. The actual percentage of small companies in these sectors, especially the bulk gasoline terminal sector, is projected to be much smaller due to vertical integration with petroleum refiners. No estimate has been made of the percentage of pipeline breakout stations owned by small companies, but since they are typically affiliated with petroleum refiners, the percentage is projected to be small.

The EPA believes that the promulgated regulation will not result in financial impacts that significantly or differentially stress affected small companies. The per unit compliance cost differentials between large throughput and small throughput facilities are minor. Small facilities are likely to be serving small or specialized markets, which makes it unlikely that the minor differential in unit control costs between large throughput and small throughput facilities will seriously affect the competitive position of small companies, even assuming that small companies own small facilities.

E. Regulatory Review

In accordance with sections 112(d)(6) and 112(f)(2) of the Act, this regulation will be reviewed within 8 years from the date of promulgation. This review may include an assessment of such factors as evaluation of the residual health risk, any overlap with other programs, the existence of alternative methods of control, enforceability improvements in emission control technology and health data, and the recordkeeping and reporting requirements.

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Petroleum bulk stations and terminals, Reporting and recordkeeping requirements.

Dated: November 23, 1994.

Carol M. Browner,

Administrator.

For reasons set out in the preamble, parts 9 and 63 of title 40, chapter I, of the Code of Federal Regulations are amended as follows:

PART 9—[AMENDED]

1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135 *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.*, 1311, 1313d, 1314, 1321, 1326, 1330, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR 1971–1975 Comp., p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657 11023, 11048.

2. Section 9.1 is amended by adding a new entry to the table under the indicated heading in numerical order to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

40 CFR citation	OMB control No.
National Emission Standards for Hazardous Air Pollutants for Source Categories.	
63.420	2060–0325
63.422–63.428	2060–0325

PART 63—[AMENDED]

3. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

4. Part 63 is amended by adding a new subpart R to read as follows:

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

Sec.

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

§ 63.420 Applicability.

(a) The affected source to which the provisions of this subpart apply is each bulk gasoline terminal, except those bulk gasoline terminals:

(1) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_T, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$$E_T = CF\,[0.59\,(T_F)\,(1-CE) + 0.17\,(T_E) + 0.08\,(T_{ES}) + 0.038\,(T_I) + 8.5 \times 10^{-6}\,(C) + KQ]$$

where:

E_T = emissions screening factor for bulk gasoline terminals;

CF = 0.161 for bulk gasoline terminals that do not handle any reformulated or oxygenated gasoline containing methyl tert-butyl ether (MTBE), *OR*

CF = 1.0 for bulk gasoline terminals that handle reformulated or oxygenated gasoline containing MTBE,

CE = federally enforceable control efficiency of the vapor processing system used to control emissions from fixed-roof gasoline storage vessels [value should be added in decimal form (percent divided by 100)];

T_F = total number of fixed-roof gasoline storage vessels without an internal floating roof;

T_E = total number of external floating roof gasoline storage vessels with only primary seals;

T_{ES} = total number of external floating roof gasoline storage vessels with primary and secondary seals;

T_I = total number of fixed-roof gasoline storage vessels with an internal floating roof;

C = number of valves, pumps, connectors, loading arm valves, and open-ended lines in gasoline service;

Q = federally enforceable gasoline throughput limit or gasoline throughput limit in compliance with paragraphs (c), (d), and (f) of this section (liters/day);

K = 4.52×10^{-6} for bulk gasoline terminals with uncontrolled loading racks (no vapor collection and processing systems), *OR*

K = $(4.5 \times 10^{-9})(EF + L)$ for bulk gasoline terminals with controlled loading racks (loading racks that have vapor collection and processing systems installed on the emission stream);

EF = federally enforceable emission standard for the vapor processor outlet emissions (mg of total organic compounds per liter of gasoline loaded);

L = 13 mg/l for gasoline cargo tanks meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in § 60.501 of this chapter, *OR*

L = 304 mg/l for gasoline cargo tanks not meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in § 60.501 of this chapter; or

(2) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in § 63.2 of subpart A of this part.

(b) The affected source to which the provisions of this subpart apply is each pipeline breakout station, except those pipeline breakout stations:

(1) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_P, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$$E_P = CF\,[\,6.7\,(T_F)\,(1-CE) + 0.21\,(T_E) + 0.093\,(T_{ES}) + 0.1\,(T_I) + 5.31 \times 10^{-6}\,(C)\,]$$

where:

E_P = emissions screening factor for pipeline breakout stations, and

the definitions for CF T_F, CE, T_E, T_{ES}, T_I, and C are the same as provided in paragraph (a)(1) of this section; or

(2) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in § 63.2 of subpart A of this part.

(c) A facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 1.0 but greater than or equal to 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section, and approved by the Administrator, is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(i).

(d) A facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(j).

(e) The provisions of paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability to bulk gasoline terminals or pipeline breakout stations that are either:

(1) Located within a contiguous area and under common control with another bulk gasoline terminal or pipeline breakout station, or

(2) Located within a contiguous area and under common control with other sources not specified in paragraphs (a)(1) or (b)(1) of this section, that emit or have the potential to emit a hazardous air pollutant.

(f) Upon request by the Administrator, the owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of any paragraphs in this section shall demonstrate compliance with those paragraphs.

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of 40 CFR part 60, subpart Kb or XX of this chapter shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility.

(h) Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station is subject to the provisions of 40 CFR part 63, subpart A—General Provisions, as indicated in Table 1.

§ 63.421 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act; in subparts A, K, Ka, Kb, and XX of part 60 of this chapter; or in subpart A of this part. All terms defined in both subpart A of part 60 of this chapter and subpart A of this part shall have the meaning given in subpart A of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Controlled loading rack, for the purposes of § 63.420, means a loading rack equipped with vapor collection and processing systems that reduce displaced vapor emissions to no more than 80 milligrams of total organic compounds per liter of gasoline loaded, as measured using the test methods and procedures in § 60.503 (a) through (c) of this chapter.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in the gasoline liquid transfer and vapor collection systems. This definition also includes the entire vapor processing system except the exhaust port(s) or stack(s).

Gasoline cargo tank means a delivery tank truck or railcar which is loading gasoline or which has loaded gasoline on the immediately previous load.

In gasoline service means that a piece of equipment is used in a system that transfers gasoline or gasoline vapors.

Operating parameter value means a value for an operating or emission parameter of the vapor processing system (e.g., temperature) which, if maintained continuously by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with the applicable emission standard. The operating parameter value is determined using the procedures outlined in § 63.425(b).

Oxygenated gasoline means the same as defined in 40 CFR 80.2(rr).

Pipeline breakout station means a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

Reformulated gasoline means the same as defined in 40 CFR 80.2(ee).

Uncontrolled loading rack means a loading rack used to load gasoline cargo tanks that is not a controlled loading rack.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 63.425(e), and which is subject at all times to the test requirements in § 63.425 (f), (g), and (h).

Volatile organic liquid (VOL) means, for the purposes of this subpart, gasoline.

§ 63.422 Standards: Loading racks.

(a) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in § 60.502 of this chapter except for paragraphs (b), (c), and (j) of that section. For purposes of this section, the term "affected facility" used in § 60.502 of this chapter means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.

(b) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded. Each owner or operator shall comply as expeditiously as practicable, but no later than December 15, 1997 at existing facilities and upon startup for new facilities.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with § 60.502(e) of this chapter as follows:

(1) For the purposes of this section, the term "tank truck" as used in § 60.502(e) of this chapter means "cargo tank."

(2) Section 60.502(e)(5) of this chapter is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(i) The gasoline cargo tank meets the applicable test requirements in § 63.425(e);

(ii) For each gasoline cargo tank failing the test in § 63.425 (f) or (g) at the facility the cargo tank either:

(A) Before repair work is performed on the cargo tank, meets the test requirements in § 63.425 (g) or (h), or

(B) After repair work is performed on the cargo tank before or during the tests in § 63.425 (g) or (h), subsequently passes the annual certification test described in § 63.425(e).

§ 63.423 Standards: Storage vessels.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in § 60.112b(a) (1) through (4) of this chapter, except for the requirements in §§ 60.112b(a)(1) (iv) through (ix) and 60.112b(a)(2)(ii) of this chapter.

(b) Each owner or operator shall equip each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in § 60.112b(a)(2)(ii) of this chapter if such storage vessel does not currently meet the requirements in paragraph (a) of this section.

(c) Each gasoline storage vessel at existing bulk gasoline terminals and pipeline breakout stations shall be in compliance with the requirements in paragraphs (a) and (b) of this section as expeditiously as practicable, but no later than December 15, 1997 At new bulk gasoline terminals and pipeline breakout stations, compliance shall be achieved upon startup.

§ 63.424 Standards: Equipment leaks.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service. For this inspection, detection methods incorporating sight, sound, and smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank.

(b) A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(c) Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (d) of this section.

(d) Delay of repair of leaking equipment will be allowed upon a demonstration to the Administrator that repair within 15 days is not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed.

(e) Initial compliance with the requirements in paragraphs (a) through (d) of this section shall be achieved by existing sources as expeditiously as practicable, but no later than December 14, 1995. For new sources, initial compliance shall be achieved upon startup.

(f) As an alternative to compliance with the provisions in paragraphs (a) through (d) of this section, owners or operators may implement an instrument leak monitoring program that has been demonstrated to the Administrator as at least equivalent.

(g) Owners and operators shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

§ 63.425 Test methods and procedures.

(a) Each owner or operator subject to the emission standard in § 63.422(b) or § 60.112b(a)(3)(ii) of this chapter shall conduct a performance test on the vapor processing system according to the test methods and procedures in § 60.503, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under § 60.503(b). If a flare is used to control emissions, and emissions from this device cannot be measured using these methods and procedures, the provisions of § 63.11(b) shall apply

(b) For each performance test conducted under paragraph (a) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

(1) During the performance test, continuously record the operating parameter under § 63.427(a);

(2) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

(3) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency and averaging time demonstrate continuous

compliance with the emission standard in § 63.422(b) or § 60.112b(a)(3)(ii) of this chapter.

(c) For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test.

(d) The owner or operator of each gasoline storage vessel subject to the provisions of § 63.423 shall comply with § 60.113b of this chapter. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (b) of this section.

(e) Annual certification test. The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27 appendix A, 40 CFR part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm H_2O (18 in. H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are as shown in the second column of Table 2 of this paragraph.

TABLE 2.—ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change (Δp, Δv) in 5 minutes, mm H_2O (in. H_2O)	Allowable pressure change (Δp) in 5 minutes at any time, mm H_2O (in. H_2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

(2) Pressure test of the cargo tank s internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this section, use the procedures in Method 27 to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge. Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

(f) Leak detection test. The leak detection test shall be performed using Method 21, appendix A, 40 CFR part 60, except omit section 4.3.2 of Method 21. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph.

(1) The leak definition shall be 21,000 ppm as propane. Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

(2) In addition to the procedures in Method 21, include the following procedures:

(i) Perform the test on each compartment during loading of that compartment or while the compartment is still under pressure.

(ii) To eliminate a positive instrument drift, the dwell time for each leak detection shall not exceed two times the instrument response time. Purge the instrument with ambient air between each leak detection. The duration of the purge shall be in excess of two instrument response times.

(iii) Attempt to block the wind from the area being monitored. Record the highest detector reading and location for each leak.

(g) Nitrogen pressure decay field test. For those cargo tanks with manifolded product lines, this test procedure shall be conducted on each compartment.

(1) Record the cargo tank capacity Upon completion of the loading operation, record the total volume loaded. Seal the cargo tank vapor collection system at the vapor coupler. The sealing apparatus shall have a pressure tap. Open the internal vapor valve(s) of the cargo tank and record the initial headspace pressure. Reduce or increase, as necessary, the initial headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge by releasing pressure or by adding commercial grade nitrogen gas from a high pressure cylinder capable of maintaining a pressure of 2,000 psig.

(i) The cylinder shall be equipped with a compatible two-stage regulator with a relief valve and a flow control metering valve. The flow rate of the nitrogen shall be no less than 2 cfm. The maximum allowable time to pressurize cargo tanks with headspace volumes of 1,000 gallons or less to the appropriate pressure is 4 minutes. For cargo tanks with a headspace of greater than 1,000 gallons, use as a maximum allowable time to pressurize 4 minutes or the result from the equation below, whichever is greater.

$$T = V_h \times 0.004$$

where:

T = maximum allowable time to pressurize the cargo tank, min;

V_h = cargo tank headspace volume during testing, gal.

(2) It is recommended that after the cargo tank headspace pressure reaches approximately 460 mm H_2O (18 in. H_2O), gauge, a fine adjust valve be used to adjust the headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge for the next 30 ± 5 seconds.

(3) Reseal the cargo tank vapor collection system and record the headspace pressure after 1 minute. The measured headspace pressure after 1 minute shall be greater than the minimum allowable final headspace pressure (PF) as calculated from the following equation:

$$P_F = \left(\frac{N}{18.0}\right)^{\frac{V_s}{5 \times V_k}}$$

where:

P_f = minimum allowable final headspace pressure, in. H_2O, gauge;

V = total cargo tank shell capacity, gal;

V_h = cargo tank headspace volume after loading, gal;

18.0 = initial pressure at start of test, in. H_2O, gauge;

N = 5-minute continuous performance standard at any time from the third column of Table 2 of § 63.425(e)(i), in. H_2O.

(4) Conduct the internal vapor valve portion of this test by repressurizing the cargo tank headspace with nitrogen to 460 mm H_2O (18 in. H_2O), gauge. Close the internal vapor valve(s), wait for 30 ± 5 seconds, then relieve the pressure downstream of the vapor valve in the vapor collection system to atmospheric pressure. Wait 15 seconds, then reseal the vapor collection system. Measure and record the pressure every minute for 5 minutes. Within 5 seconds of the pressure measurement at the end of 5 minutes, open the vapor valve and record the headspace pressure as the "final pressure."

(5) If the decrease in pressure in the vapor collection system is less than at least one of the interval pressure change values in Table 3 of this paragraph, or if the final pressure is equal to or greater than 20 percent of the 1-minute final headspace pressure determined in the test in paragraph (g)(3) of this section, then the cargo tank is considered to be a vapor-tight gasoline cargo tank.

TABLE 3.—PRESSURE CHANGE FOR INTERNAL VAPOR VALVE TEST

Time interval	Interval pressure change, mm H_2O (in. H_2O)
After 1 minute	28 (1.1)
After 2 minutes	56 (2.2)
After 3 minutes	84 (3.3)
After 4 minutes	112 (4.4)
After 5 minutes	140 (5.5)

(h) Continuous performance pressure decay test. The continuous performance pressure decay test shall be performed using Method 27 appendix A, 40 CFR Part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2O), gauge. The maximum allowable 5-minute pressure change (Δp) which shall be met at any time is shown in the third column of Table 2 of § 63.425(e)(1).

§ 63.426 Alternative means of emission limitation.

For determining the acceptability of alternative means of emission limitation for storage vessels under § 63.423, the provisions of § 60.114b of this chapter apply

§ 63.427 Continuous monitoring.

(a) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section, except as allowed in paragraph (a)(5) of this section.

(1) Where a carbon adsorption system is used, a continuous emission monitoring system (CEMS) capable of measuring organic compound concentration shall be installed in the exhaust air stream.

(2) Where a refrigeration condenser system is used, a continuous parameter monitoring system (CPMS) capable of measuring temperature shall be installed immediately downstream from the outlet to the condenser section. Alternatively a CEMS capable of measuring organic compound concentration may be installed in the exhaust air stream.

(3) Where a thermal oxidation system is used, a CPMS capable of measuring temperature shall be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs.

(4) Where a flare is used, a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple, shall be installed in proximity to the pilot light to indicate the presence of a flame.

(5) Monitoring an alternative operating parameter or a parameter of a vapor processing system other than those listed in this paragraph will be allowed upon demonstrating to the Administrator's satisfaction that the alternative parameter demonstrates continuous compliance with the emission standard in § 63.422(b) or § 60.112b(a)(3)(ii) of this chapter.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described in paragraphs (a)(1) and (a)(2) of this section, or to go below the operating parameter value for the parameter described in paragraph (a)(3) of this section, and established using the procedures in § 63.425(b). In cases where an alternative parameter pursuant to paragraph (a)(5) of this section is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below as appropriate, the alternative operating parameter value. Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as specified above, shall constitute a violation of the emission standard in § 63.422(b).

(c) Each owner or operator of gasoline storage vessels subject to the provisions of § 63.423 shall comply with the monitoring requirements in § 60.116b of this chapter, except records shall be kept for at least 5 years. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (a) of this section.

§ 63.428 Reporting and recordkeeping.

(a) The initial notifications required for existing facilities under § 63.9(b)(2) shall be submitted not later than 1 year after a facility becomes subject to the provisions of this subpart.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as follows:

(1) Annual certification testing performed under § 63.425(e); and

(2) Continuous performance testing performed at any time at that facility under § 63.425 (f), (g), and (h).

(3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:

(i) Name of test:

Annual Certification Test—Method 27 (§ 63.425(e)(1)),
Annual Certification Test—Internal Vapor Valve (§ 63.425(e)(2)),
Leak Detection Test (§ 63.425(f)),
Nitrogen Pressure Decay Field Test (§ 63.425(g)), or
Continuous Performance Pressure Decay Test (§ 63.425(h)).

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number

(iv) Test location and date.

(v) Tester name and signature.

(vi) Witnessing inspector, if any Name, signature, and affiliation.

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: Pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument and leak definition.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under § 63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have

occurred or, alternatively shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the notification of compliance status required under § 63.9(h):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under § 63.425(b); and

(ii) The following information when using a flare under provisions of § 63.11(b) to comply with § 63.422(b):

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and

(B) All visible emissions readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under § 63.425(a).

(3) If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in § 63.427(a), the owner or operator shall submit a description of planned reporting and recordkeeping procedures. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application.

(d) Each owner or operator of storage vessels subject to the provisions of this subpart shall keep records and furnish reports as specified in § 60.115b of this chapter, except records shall be kept for at least 5 years.

(e) Each owner or operator complying with the provisions of § 63.424 (a) through (d) shall record the following information in the log book for each leak that is detected:

(1) The equipment type and identification number;

(2) The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell);

(3) The date the leak was detected and the date of each attempt to repair the leak,

(4) Repair methods applied in each attempt to repair the leak,

(5) "Repair delayed" and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak,

(6) The expected date of successful repair of the leak if the leak is not repaired within 15 days, and

(7) The date of successful repair of the leak.

(f) Each owner or operator subject to the provisions of § 63 424 shall report to the Administrator a description of the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under § 63.424(f), the report shall contain a full description of the program.

(1) In the case of an existing source or a new source that has an initial startup date before the effective date, the report shall be submitted with the initial notifications required under paragraph (a) of this section, unless an extension of compliance is granted under § 63.6(i). If an extension of compliance is granted, the report shall be submitted on a date scheduled by the Administrator.

(2) In the case of new sources that did not have an initial startup date before the effective date, the report shall be submitted with the application for approval of construction, as described in § 63.5(d).

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual report to the Administrator the following information:

(1) Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility;

(2) Periodic reports required under paragraph (d) of this section; and

(3) The number of equipment leaks not repaired within 5 days after detection.

(h) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in the excess emissions report to the Administrator required under § 63.10(e)(3) the following information:

(1) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under § 63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(2) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

(3) Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with § 63.422(c)(2).

(4) For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:

(i) The date on which the leak was detected;

(ii) The date of each attempt to repair the leak;

(iii) The reasons for the delay of repair; and

(iv) The date of successful repair.

(i) Each owner or operator of a facility meeting the criteria in § 63.420(c) shall perform the requirements of this paragraph (i), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 14, 1995 for existing facilities, within 30 days for existing facilities subject to § 63.420(c) after December 14, 1995 or at startup for new facilities the methods, procedures, and assumptions supporting the calculations for determining criteria in § 63.420(c);

(2) Maintain records to document that the facility parameters established under § 63.420(c) have not been exceeded; and

(3) Report annually to the Administrator that the facility parameters established under § 63.420(c) have not been exceeded.

(4) At any time following the notification required under paragraph (i)(1) of this section and approval by the Administrator of the facility parameters, and prior to any of the parameters being exceeded, the owner or operator may submit a report to request modification of any facility parameter to the Administrator for approval. Each such request shall document any expected HAP emission change resulting from the change in parameter.

(j) Each owner or operator of a facility meeting the criteria in § 63.420(d) shall perform the requirements of this paragraph (j), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 14, 1995 for existing facilities, within 30 days for existing facilities subject to § 63.420(d) after December 14, 1995 or at startup for new facilities the use of the emission screening equations in § 63.420(a)(1) or (b)(1) and the calculated value of E_T or E_P,

(2) Maintain a record of the calculations in § 63.420 (a)(1) or (b)(1), including methods, procedures, and assumptions supporting the calculations for determining criteria in § 63.420(d); and

(3) At any time following the notification required under paragraph (j)(1) of this section, and prior to any of

the parameters being exceeded, the owner or operator may notify the Administrator of modifications to the facility parameters. Each such notification shall document any expected HAP emission change resulting from the change in parameter.

§ 63.429 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(l) of the Act, the authority contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) The authority conferred in § 63.426 and § 63.427(a)(5) will not be delegated to any State.

TABLE 1 TO SUBPART R—GENERAL PROVISIONS APPLICABILITY TO SUBPART R

Reference	Applies to subpart R	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	Yes	
63.1(a)(5)	No	Section reserved
63.1(a)(6)(8)	Yes	
63.1(a)(9)	No	Section reserved
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12))–(a)(14)	Yes	
63.1(b)(1)	No	Subpart R specifies applicability in § 63.420
63.1(b)(2)	Yes	
63.1(b)(3)	No	Subpart R specifies reporting and recordkeeping for some large area sources in § 63.428
63.1(c)(1)	Yes	
63.1(c)(2)	Yes	Some small sources are not subject to subpart R
63.1(c)(3)	No	Section reserved
63.1(c)(4)	Yes	
63.1(c)(5)	Yes	
63.1(d)	No	Section reserved
63.1(e)	Yes	
63.2	Yes	Additional definitions in § 63.421
63.3(a)–(c)	Yes	
63.4(a)(1)–(a)(3)	Yes	
63.4(a)(4)	No	Section reserved
63.4(a)(5)	Yes	
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)(1)	Yes	
63.5(a)(2)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Section reserved
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	
63.5(b)(5)	Yes	
63.5(b)(6)	Yes	
63.5(c)	No	Section reserved
63.5(d)(1)	Yes	
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)(1)	Yes	
63.5(f)(2)	Yes	
63.6(a)	Yes	
63.6(b)(1)	Yes	
63.6(b)(2)	Yes	
63.6(b)(3)	Yes	
63.6(b)(4)	Yes	
63.6(b)(5)	Yes	
63.6(b)(6)	No	Section reserved
63.6(b)(7)	Yes	
63.6(c)(1)	No	Subpart R specifies the compliance date
63.6(c)(2)	Yes	
63.6(c)(3)–(c)(4)	No	Sections reserved
63.6(c)(5)	Yes	
63.6(d)	No	Section reserved
63.6(e)	Yes	
63.6(f)(1)	Yes	

TABLE 1 TO SUBPART R—GENERAL PROVISIONS APPLICABILITY TO SUBPART R—Continued

Reference	Applies to subpart R	Comment
63.6(f)(2)	Yes	
63.6(f)(3)	Yes	
63.6(g)	Yes	
63.6(h)	No	Subpart R does not require COMS
63.6(i)(1)–(i)(14)	Yes	
63.6(i)(15)	No	Section reserved
63.6(i)(16)	Yes	
63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)	Yes	
63.7(a)(3)	Yes	
63.7(b)	Yes	
63.7(c)	Yes	
63.7(d)	Yes	
63.7(e)(1)	Yes	
63.7(e)(2)	Yes	
63.7(e)(3)	Yes	
63.7(e)(4)	Yes	
63.7(f)	Yes	
63.7(g)	Yes	
63.7(h)	Yes	
63.8(a)(1)	Yes	
63.8(a)(2)	Yes	
63.8(a)(3)	No	Section reserved
63.8(a)(4)	Yes	
63.8(b)(1)	Yes	
63.8(b)(2)	Yes	
63.8(b)(3)	Yes	
63.8(c)(1)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	
63.8(c)(4)	Yes	
63.8(c)(5)	No	Subpart R does not require COMS
63.8(c)(6)–(c)(8)	Yes	
63.8(d)	Yes	
63.8(e)	Yes	
63.8(f)(1)–(f)(5)	Yes	
63.8(f)(6)	Yes	
63.8(g)	Yes	
63.9(a)	Yes	
63.9(b)(1)	Yes	
63.9(b)(2)	No	§ 63.428(a) specifies 1-year initial notification requirement
63.9(b)(3)	Yes	
63.9(b)(4)	Yes	
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	Yes	
63.9(f)	Yes	
63.9(g)	Yes	
63.9(h)(1)–(h)(3)	Yes	
63.9(h)(4)	No	Section reserved
63.9(h)(5)–(h)(6)	Yes	
63.9(i)	Yes	
63.9(j)	Yes	
63.10(a)	Yes	
63.10(b)(1)	Yes	
63.10(b)(2)	Yes	
63.10(b)(3)	Yes	
63.10(c)(1)	Yes	
63.10(c)(2)–(c)(4)	No	Sections reserved
63.10(c)(5)–(c)(8)	Yes	
63.10(c)(9)	No	Section reserved
63.10(c)(5)–(c)(8)	Yes	

TABLE 3.—GENERAL PROVISIONS APPLICABILITY TO SUBPARTS F G, AND H (CONCLUDED)

Reference	Applies to subpart R	Comment
63.10(d)(1)	Yes	
63.10(d)(2)	Yes	
63.10(d)(3)	Yes	
63.10(d)(4)	Yes	
63.10(d)(5)	Yes	
63.10(e)	Yes	
63.10(f)	Yes	
63.11(a)–(b)	Yes	
63.12(a)–(c)	Yes	
63.13(a)–(c)	Yes	
63.14(a)–(b)	Yes	
63.15(a)–(b)	Yes	

[FR Doc. 94-30402 Filed 12-13-94; 8:45 am]
BILLING CODE 6560-50-P

40 CFR Part 52

[UT4-1-6465 and UT2-1-6694; FRL-5119-1]

Approval and Promulgation of State Implementation Plans: Utah; Stack Height Analyses and Regulations and SO_2 Nonattainment Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, EPA is approving two revisions to the Utah State Implementation Plan (SIP): Section 16, Stack Height Demonstration, and Section 9, Part B, Sulfur Dioxide. Sections 16 and 9 were submitted by the Governor of Utah in letters dated December 23, 1991, and May 15, 1992, respectively. The revisions to Section 16 were to address the stack-height demonstration requirements for the Kennecott Minerals Company Smelter near Magna, Utah. Minor corrections to the other stacks in the State were also made. Section 9, Part B was revised to be consistent with Section 16. Prior to the revision, the SO_2 attainment demonstration for Salt Lake County and portions of Tooele County was based on multipoint rollback emission rates at the Kennecott smelter. The PM_{10} SIP adopted for Salt Lake County in 1991 established significantly lower emission rates (which would meet the 24-hour National Ambient Air Quality Standard (NAAQS) for the smelter based on reasonable available control technology (RACT).) Section 16 and Section 9, Part B needed to be consistent with the PM_{10} SIP (the PM_{10} SIP is located in Section 9, Part A). In addition, Section 9 Part B was revised to include an analysis and the emission limitation that would demonstrate attainment of the 3-hour secondary NAAQS. General SO_2 regulations initially determined as deficient with respect to meeting the statewide SO_2 SIP requirements are also being approved.

EFFECTIVE DATE: January 13, 1995.

ADDRESSES: Copies of the documents relevant to this proposed action are available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at the following office: Environmental Protection Agency, Region VIII, Air Programs Branch, 999-18th Street, suite 500, Denver, Colorado 80202-2466.

FOR FURTHER INFORMATION CONTACT: Lee Hanley at (303) 293-1760.

SUPPLEMENTARY INFORMATION:

I. Background

A. Regulatory History and Regulatory Requirement for Stacks Greater Than GEP

On February 8, 1982 (47 FR 5864), EPA promulgated final regulations limiting stack height credits and other dispersion techniques as required by section 123 of the Clean Air Act (CAA) As a result of a court challenge, EPA promulgated revisions to the stack height regulations on July 8, 1985 (50 FR 27892). The revisions redefined a number of specific terms including "excessive concentrations," "dispersion techniques," "nearby," and other important concepts, and modified some of the bases for determining good engineering practice (GEP) stack height credit.

Subsequent to the July 8, 1985 promulgation, the stack height regulations were again challenged in *NRDC* v. *Thomas*, 838 F.2d 1224 (D.C. Cir. 1988). On January 22, 1988, the U.S Court of Appeals for the D.C. Circuit issued its decision affirming the regulations, for the most part, but remanding three provisions to the EPA for reconsideration. These are:

1. Grandfathering pre-October 11, 1983 within-formula stack height increases from demonstration requirements (40 CFR 51.100(kk)(2));

2. Dispersion credit for sources originally designed and constructed with merged or multiflue stacks (40 CFR 51.100(hh)(2)(ii)(A)); and

3. Grandfathering pre-1979 use of the refined H + 1.5L formula (40 CFR 51.100(ii)(2)).

However, none of these provisions is at issue here.

GEP has been established by the regulations to be the greater of: (1) 65 meters; (2) the height derived through application of one of two formulas which base GEP on the dimensions of nearby buildings; or (3) the height demonstration through a field study or fluid modeling demonstration to be necessary to avoid excessive concentrations of any air pollutant due to downwash, eddies, or wakes caused by the source itself or nearby buildings or terrain obstacles (40 CFR 51.100(ii)). Where EPA or a State finds that a source emission limit is affected by dispersion from a stack in excess of GEP the State must then model to establish an emission limit which will provide for attainment of the NAAQS when stack height credit is restricted to GEP

The reader is referred to 59 FR 18341, April 18, 1994, for additional information on the regulatory history and regulatory requirement for stacks greater than good engineering practice (GEP).

B. The 1981 and 1986 SIP Submittals

1 The 1981 SO_2 SIP Submittal

A Utah SO_2 SIP revision was submitted with a letter dated August 17 1981, by the Governor of Utah to address the attainment of the SO_2 NAAQS in Salt Lake County and portions of the nonattainment area in Tooele County Additional information was submitted by the State on December 7 1981, and January 25, 1983 On February 7 1983, the Governor submitted a request to redesignate all of Salt Lake County and the nonattainment portion of Tooele County to attainment On March 23, 1984 (49 FR 10926), EPA proposed to delay any action on the request to redesignate the area to attainment until final resolution of several issues. A detailed discussion of this SIP revision is contained in the March 23, 1984 notice of proposed rulemaking and should be used as a reference for additional information.

The control strategy for the 1981 SIP has several parts: (1) Emission limitations on several low-level stacks at the smelter (e.g., boilers and heat treaters); (2) reasonably available measures to control or eliminate fugitive emissions; and (3) cumulative emission limits for the main stack (see additional discussion on these emission limits in 2.b. below). The State's strategy was based upon measured ambient data in the lower elevation near the smelter. EPA identified the major deficiencies of the State analysis: (1) The State made no attempt to demonstrate the effects in the upper elevation (above 5600 feet in the Oquirrh Mountains); and (2) the database at the smelter was insufficient to be used reliably with the established emission limits, given the assumption in the development of the emission limits technique. Modeling analyses performed by the State and EPA to demonstrate attainment in the upper elevation were screening analyses only EPA concluded that dispersion modeling in this complex terrain was unreliable and that the only method that could be used for this determination was monitoring. The 1981 SO_2 SIP was conditionally approved on the assumption that the emission limits were consistent with federal 1985 stack height rules and, therefore, adequate for attainment of the SO_2 NAAQS. The redesignation of the area to attainment was denied. (50 FR 7059, February 20, 1985)

2. The May 2, 1986 GEP SIP Submittal

The Utah Stack Height SIP was submitted by the Governor with a letter dated May 2, 1986. The submittal included regulations to address: (1) GEP stack height credit and dispersion techniques; (2) a new Section 17 of the SIP that listed all existing stacks in Utah greater than 65 meters; and (3) a technical support document for Section 17 of the SIP The Kennecott Magna stack analyses were part of this submittal. Subsequent submittals to support the Kennecott analyses were received in letters dated October 6, 1986, December 3, 1986, November 13, 1987 and May 17 1988. The Kennecott smelter stack height credit was a significant component of the Utah SO_2 SIP emission limits conditionally approved on February 20, 1985

a Applicability of the NSPS Regulation The federal NSPS regulation for primary copper smelters applies to any such facility that commences construction or modification after October 16, 1974 (42 FR 37937 July 25, 1977 and 40 CFR 60 160). Modification generally means any physical or operational change which results in an increase in the emission rate to the atmosphere.

The Kennecott Magna smelter expansion/modification began in the early 1970s, with a commitment to the 1215-foot stack in 1973 and completion of the project in 1977 The modification of the acid plant system resulted in an increase from 60% sulfur capture to 86%, approximately a 65% reduction of sulfur emissions. Based on this information, EPA concluded that the 1970's Kennecott expansion/ modification did not subject the smelter to NSPS requirements.

b. Analyses on the 1986 Submittal The Kennecott stack height analyses were undertaken to comply with the July 8, 1985 stack height regulation, as well as the condition specified in the approval of the Utah SO_2 SIP The reader should refer to the February 2, 1985 final conditional approval (50 FR 7056) and March 23, 1984 proposed approval (49 FR 10946) **Federal Register** actions for additional information on the Utah SO_2 SIP

Kennecott originally had two 400-foot stacks (grandfathered stack heights) from which SO_2 emissions from the smelter were vented. The 1970's modification/expansion included the replacement of the 400-foot stacks with a single 1215-foot stack. The GEP formula height (H + 1.5 L), considering the nearby buildings, is 212.5 feet.

The initial Kennecott GEP demonstration was submitted on May 2, 1986, with subsequent submittals on October 6, 1986, December 3, 1986, November 13, 1987 and May 11, 1988. There are two basic parts to the Kennecott analyses: the GEP demonstration and BART analysis. The GEP demonstration consists of three subparts: the fluid modeling protocol, the fluid modeling results, and an evaluation of the fluid modeling results with respect to the stack height regulations. The BART analysis is performed if the source contends that the NSPS emission limits are infeasible Relevant factors for this analysis include: high cost-effectiveness ratio, excessive local community impact, excessive plant impact, and technological infeasibility. Kennecott provided responses to all the BART factors mentioned above. The cost-effectiveness ratio and technical infeasibility issues, however, were determined critical to this review because of their relationship to the emission limitations used in the GEP analyses

Since the Kennecott emissions, as established through Multi-point Rollback (MPR), were used in the 1981 SO_2 SIP EPA's primary concern, with the use of any emission rate in the demonstration of GEP is ensuring protection of the NAAQS (i.e., to protect health and welfare). The basic concept behind GEP is to prevent sources from using illegal dispersion techniques to avoid emissions controls.

Kennecott provided extensive data on its GEP analyses. The reader is referred to 53 FR 48942 for information on the GEP demonstration and BART analysis. To summarize, the GEP demonstration showed that the existing stack height of 1215-foot (370.4m) met the 40% criterion due to terrain effects and an exceedance of the NAAQS at MPR emission rates. (Discussion of the MPR emission rates for Kennecott can be found in 49 FR 10948, March 12, 1983, proposed rulemaking). MPR is a technique designed for sources with variable emission rates (e.g., smelters). MPR allows for a frequency distribution of emission rates which will permit extremely high emissions on rare occasions. The MPR methodology is constructed around the recognition that any control strategy will have a predictable probability of allowing a violation of the NAAQS. The MPR is based upon allowing a 26% probability of recording a violation (Additional information on MPR is found in Appendix A). The GEP demonstration satisfies the excessive concentration criteria in EPA s regulation if MPR reflects the proper emission rates. After review EPA concluded that Kennecott s analyses were acceptable, since Kennecott performed a fluid modeling study consistent with existing guidance and the study was approved by EPA.

Application of the level of control required by NSPS would reduce the emissions of SO_2 at Kennecott during the stable process phase, but would not affect emission rates under startup, shutdown, malfunction, and upset conditions. This is because the NSPS emission rate is for normal operations and excludes such process conditions. MPR includes startup, shutdown, malfunction, and upset conditions. From the Kennecott assessment, considering only long-term averages, the cost portion is consistent with the tons of SO_2 reduction expected from similar NSPS applications. In the Kennecott BART analysis, the controlling emissions for the determination of GEP appear to be those under upset, start-up, shutdown, and malfunction. Therefore, while there would be no difference in the emission rates under these conditions as a result of meeting NSPS, there would be a substantial additional cost to control these emissions.

In summary the emissions at the smelter from startups, shutdowns, upsets, and malfunctions are included in the MPR emission limits and could be considered in the NAAQS attainment and GEP analyses. Application of NSPS technology will not affect these emission rates and will, therefore, result in no change in demonstrating GEP It may be possible to reduce annual emissions by requiring additional controls on the smelter, but such reduction would have no relevance to the limiting case for determination of GEP

Given the above discussion, EPA proposed to approve (53 FR 48942, December 5, 1988) the Kennecott analysis in the Utah GEP SIP submitted on May 2, 1986, with subsequent submittals on October 6, 1986, December 3, 1986, November 13, 1987 and May 17 1988. However, EPA's review was conducted under a specific assumption: That the emission rate(s) in the SO_2 SIP were sufficient to demonstrate attainment. That assumption followed another critical assumption: That Kennecott owned or controlled the lands in the upper elevation for which no monitoring data exist to demonstrate attainment of the NAAQS.

Only one comment was received in response to the December 5, 1988 **Federal Register** proposed approval of the Kennecott GEP demonstration. The comment was from Kennecott in support of this action. However, prior to publication of the proposed approval **Federal Register**, EPA did receive a letter from a landowner in the Oquirrh Mountains expressing concerns due to the lack of ambient monitoring in the nonattainment area. This was EPA's first documented information on public access in the nonattainment area other than the Kennecott operation. EPA proceeded to continue its evaluation of the State submittal and to publish its position on the GEP demonstration based on the State submittal, but initiated a reevaluation on land ownership above the 5600-ft. elevation in the Oquirrh Mountains. Documentation on the claim of land ownership, other than that of the Kennecott operations, was provided by Howard Haynes, Jr. in March 1989.

3. Utah 1981 SO_2 and 1986 GEP SIP Reassessment

Data from the Salt Lake County and Tooele County Assessor offices showed over 80 landowners in this nonattainment area. Kennecott, in its land ownership research, verified the list of landowners.

One of the critical assumptions of the conditional approval of the 1981 SO_2 SIP and the emission rate was Kennecott's ownership or control of those lands in the potential nonattainment area in the Oquirrh Mountains. The land ownership research revised the EPA's earlier assumptions on the adequacy of the 1981 SO_2 and the 1986 GEP Stack SIPs.

EPA entered into discussions with Kennecott and the State for resolution of these issues and attempted to outline the procedures for addressing the SO_2 and GEP SIPs. During these negotiations, the State was developing the PM_{10} SIP for Salt Lake County The Salt Lake County PM_{10} SIP development process identified SO_2 as a precursor for PM_{10}. (Precursors are secondary particles which are formed in the atmosphere from gases which are directly emitted by the source. Sulfates are one of the most common secondary particles in a PM_{10} nonattainment area and result from sulfur dioxide emissions.) The Kennecott smelter SO_2 emissions comprised ≈56% of the total (primary and secondary) PM_{10} emissions in Salt Lake County

The PM_{10} SIP was adopted by the State in August 1991 and submitted to EPA in November 1991. The reader is referred to 59 FR 35036, July 8, 1994, for information on the PM_{10} SIP The PM_{10} SIP required significant emission reduction for the Kennecott operations (refinery, concentrator, mine, power plant and smelter). The Kennecott smelter emission limits were reduced from 76,000 tpy or 18,000 lb/hr annual average (as allowed in the 1981 SO_2 and 1986 GEP SIPs) to ≈18,500 tpy (which includes fugitive emissions, and applies to the entire smelter). The 1981 SO_2 and 1986 GEP SIPs addressed emissions from smelter processing units and SO_2 collection and removal equipment vented to the smelter tall stack. They did not include fugitive emissions. For clarification, the 76,000 tpy was reduced to the 14,191 tpy limit on the 1215-foot stack for emissions from the smelter processing units and SO_2 collection and removal equipment.

D. The 1991 GEP and 1992 SO_2 SIP Submittals

Prior to the State's adoption of the PM_{10} SIP EPA discussed the uncertainties of finalizing the 1986 GEP SIP with the State and Kennecott. In a letter dated July 18, 1991, EPA clarified its position on the need for consistency within the Utah SIP with respect to emission limitations at the Kennecott smelter. EPA stated that it could not knowingly and legally proceed to approve a regulation and emission limitation that were no longer applicable, or a stack height demonstration analysis based on an obsolete regulation or emissions limitation.

In a letter dated December 23, 1991, the Governor of Utah submitted a revision to Section 16, Demonstration of GEP Stack Height, of the Utah SIP The 1991 submittal was received on December 30, 1991. On February 28, 1992, EPA advised the Governor of Utah that this submittal was administratively and technically complete in accordance with the Federal SIP completeness criteria.

The revisions to Section 16 specify the allowable emission limit for the 1215-foot main stack at 14,191 tons/year as derived in the PM_{10} SIP This emission limit is based on double contact acid plant technology (which is considered NSPS for the smelter acid plant tail gas), significant capture improvement of fugitive emissions, and improved operation and maintenance. The 1991 submittal also contained a reanalysis of other sources in the State for which stack heights above the de minimis level (65m) were previously reported. (These sources' stack heights were published in 54 FR 24334, June 7 1989.)

EPA found minor changes between the June 7 1989 **Federal Register** and the 1991 revision to Section 16 for the "actual" stack height of some sources. EPA is not concerned with these minor changes since they could be attributed to errors in rounding and the stack height changes are less than one foot. Listed below are the differences between the June 7 1989 **Federal Register** and the 1991 submittal:

Source	6/7/89 FR	1991 revision
Deseret Units 1 & 2	182.9 m	182 m
UP&L Hunter Units 1 & 2.	183.08 m	183 m
UP&L Hunter Unit 3	183.1 m	183 m*
UP&L Huntington Units 1 & 2.	182.93 m	183 m
IPP Units 1 & 2	216.46 m	216 m
Chevron USA HCC cracker.	1946*	1950**

*The State indicated very insignificant changes to these sources "calculated" GEP stack heights; the State has indicated that the "actual" height will be the enforceable stack height.

** Correction of grandfathered date.

The State's revised analyses are presented in the table below. Detailed documentation for these analyses and the corresponding EPA review is contained in the EPA technical support document and air compliance files, and the State files.

Source name	Stack height (M)	Allowable SO_2 emissions (ton-year)
Deseret Units 1&2	182	1,512
U.P.&L. Hunter Units 1&2.	183	4,347
U.P.&L. Hunter Unit 3.	183	1,283
U.P.&L. Huntington Units 1&2.	183	9,448
I.P.P Units 1&2	216	17,870
U.P.&L. Gadsby Units 1,2&3.	76.2	67.7+
Geneva Steel blast furnaces 1&2.	79.2	12.5+
Geneva Steel Coke blast furnace.	68.6	
Geneva Steel Coke Combustion 1–4.	76.2	102.8+
Kennecott Utah Copper Smelter Main Stack.	370	14,191+
Chevron USA HCC Cracker Cat. Dis.	88.4	66.7+
Chevron Research Air Heater.	69.8	0
Chevron Research Retort.	69.8	0+
Amax melt reactor	76.22	0
Amax electrolytics	76.22	0
Amax emergency off gas.	76.22	0
Amax spray dryers 1–3.	76.22	83
Phillips thermal cat. cracking.	80.8	3.5+
White River Shale Lift Pipes.	76.2	–
White River Elutriators.	76.2	–
White River Hydrogen Plant.	76.2	–
White River Power Plants.	76.2	–
White River Ball Heaters.	76.2	1,180.8*
Tosco Preheat Stacks.	95	–
Tosco Warm Ball Elutriators.	95	–
Tosco Process Shale Wetters.	95	1,166.6*

+SO_2 emissions derived from the PM_{10} SIP adopted August 14, 1991

*The total SO_2 emissions are given for these sources.

On May 15, 1992, the Governor of Utah submitted a revision to Section 9, Part B, Sulfur Dioxide, Utah SIP The revision was to address the 1990 CAA requirement that a SIP revision be submitted by May 15, 1992, for any area that did not have a fully approved SIP (the 1981 SO_2 SIP was only conditionally approved). The significant changes in this SIP revision from that of the 1981 submittal are as follows:

a. The MPR emission limitations and assumptions are removed and replaced with the emission limitation which can be achieved using the NSPS technology double contact acid plant, or the equivalent of NSPS. (NSPS is the presumptive norm for RACT for this facility.) The SO_2 SIP now references the same emission limitations as those stated in PM_{10} SIP

b. The SO_2 NAAQS are the 0.14 ppm, 24-hour primary standard, and the 0.5 ppm, 3-hour secondary standard. The 24-hour impact analysis was a rollback analysis which compared the smelter emissions in 1991 (PM_{10} SIP emission limitation) with 1979 emissions. The State had monitoring data showing attainment at Lake Point (an area originally defined as ambient air and owned by the Bureau of Land Management, but now owned by Kennecott) where exceedances were recorded. The Lake Point site could be considered representative of the closest point in the elevated terrain that would be impacted by the tall stack emissions. Demonstrating attainment at Lake Point would technically support the attainment elsewhere in the elevated terrain that is considered ambient air. The area considered ambient air in the elevated terrain is a significant distance downwind from Lake Point.

c. The PM_{10} SIP addressed, to some degree, the 3-hour impact. The PM_{10} SIP emission limitation was based on a 24-hour SO_2 limit; this emission limitation would be achieved through a given lb/hr calculated on a 6-hour average. The 24-hour limit was considered "controlling" for PM_{10} and SO_2 (i.e., the 24-hour limitation was believed to be the level of control necessary for PM_{10} attainment, as well as for the SO_2 attainment demonstration). The SO_2 SIP established a 3-hour limitation and verified that such limitation would protect the 3-hour NAAQS.

d. Section 4.2 of the Utah Air Conservation Regulations was revised to include a 24-hour averaging period for the sulfur content of coal, fuel oil, and fuel mixtures, and to specify the ASTM methods to be used to demonstrate compliance with the limitation and reporting requirement. (The previous rule specified a limit for the sulfur content of fuels, but did not specify an averaging time or specific ASTM methods.) Section 4.6 was also revised to include a 3-hour averaging time for Sulfur Burning Production Sulfuric Acid Plants.

e. Specific regulations which provided for special consideration (including malfunction provisions) on the smelter fluctuating operation are removed. Malfunction provisions for the Kennecott smelter operation are now the same as for any stationary source in Utah. This issue was addressed during the PM_{10} SIP development and is being approved under the PM_{10} SIP federal approval process. These regulation impacts were clarified in this SIP revision.

II. Final Action

This document makes final the action at 59 FR 18341, April 16, 1994. No adverse public comment was submitted with the proposed action. As a direct result, the Regional Administrator has reclassified this action from Table I to a Table III under the processing procedures established at 54 FR 2214, January 19, 1989.

The December 23, 1991 Section 16, Stack Height revision and the May 15, 1992 Section 9, Part B, SO_2 revision are consistent with other provisions in the State-wide SIP EPA is approving these revisions because they are consistent with EPA guidance for GEP stack height demonstration and the attainment demonstration for the SO_2 NAAQS. General SO_2 regulations initially determined as deficient with respect to meeting the statewide SO_2 SIP requirements are also being approved.

These revisions resolve EPA s concerns regarding ambient air attainment demonstration in the elevated terrain, and the enforceability issues related to the smelter operations. The previous emission limitations have been the subject of litigation filed by the Environmental Defense Fund. The legal actions have been stayed pending EPA final action on the past SIP revisions. The 1991 and 1992 revisions are believed to have settled the litigants' concerns about applying reasonable control technology and demonstrating attainment per the traditionally accepted federal requirements (i.e., application of RACT (double contact acid plant or the equivalent), monitoring demonstration, etc).

The May 15, 1992 submittal also contained an updated Appendix A.2.1 (Emission Limitations and Operating Practices for Davis and Salt Lake Counties). EPA is not acting on this part of the submittal since no information on the stationary source updates was provided with this submittal. In addition, EPA's review during the State's public hearing for the SO_2 SIP did not include information on these emission limitations.

Since State adoption of this SO_2 and Stack Height SIPs, the State has been finalizing the permit conditions for these SO_2 sources. EPA has advised the State on the need to ensure consistency with the State's permits and the federally enforceable SIP The State's permit program is in the federally approved SIP The final approval to the SO_2 and Stack Height SIPs will also make the emission limitations for these stationary sources federally enforceable. EPA is giving notice that should different emission limitations exist, EPA will enforce the more stringent of the two (or more) emission limitations. EPA must have assurance that the attainment demonstration of a nonattainment area plan is maintained. The less stringent emission limitation may not provide that assurance without a reanalysis of the attainment demonstration. It is, therefore, critical that the State maintain consistent emission limitations in the permits and in the federally approved nonattainment area plan and update the emission limitations section of these plans to ensure clarity and consistency in the Statewide SIP The tracking of this effort will be documented annually in the EPA/State Agreement.

Regulatory Process

Under the Regulatory Flexibility Act, 5 U.S.C. 600 et seq., EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, EPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over population of less than 50,000.

SIP approvals under section 110 and subchapter I, part D of the CAA do not create any new requirements, but simply approve requirements that the State is already imposing. Therefore, because the federal SIP-approval does not impose any new requirements, I certify that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the federal-state relationship under the CAA, preparation of a regulatory flexibility analysis would constitute federal inquiry into the economic reasonableness of state action. The CAA forbids EPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v *U.S. E.P.A* 427 U.S. 246, 256–66 (S.Ct 1976), 42 U.S.C. 7410(a)(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by February 13, 1995 Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see Section 307(b)(2)).

Executive Order 12866

The OMB has exempted these actions from review under Executive Order 12866.

List of Subjects in 40 CFR Part 52

Air pollution control, Environmental protection, Incorporation by reference, Reporting and recordkeeping requirements, Sulfur dioxide.

Note: Incorporation by reference of the State Implementation Plan for the State of Utah was approved by the Director of the Federal Register on July 1, 1982.

Dated: October 6, 1994.

Jack W. McGraw,

Acting Regional Administrator

Chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart TT—Utah

2. Section 52.2320 is amended by adding paragraph (c)(26) to read as follows:

§ 52.2320 Identification of plan.

(c) *

(26) The Governor of Utah submitted a Section 16, Stack Height Demonstration and Section 9, Part B, Sulfur Dioxide of the Utah State Implementation Plan (SIP) a letter dated December 23, 1991, and May 15, 1992; respectively. The Governor's submittal also included statewide SO_2 regulations

(i) Incorporation by reference.

(A) Utah State Implementation Plan, Section 16, effective December 16, 1991

(B) Utah State Implementation Plan, Section 9, Part B effective June 15, 1992

(C) Utah Air Conservation Regulations, R307-1-4. Emission Standards. changes to 4.2 Sulfur Content of Fuels and 4.6.2, effective June 15, 1992.

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BILLING CODE 6560-50-P

40 CFR Part 52

[CA 71-6-6615a; FRL-5114-9]

Approval and Promulgation of Implementation Plans; California State Implementation Plan Revision; Ventura County Air Pollution Control District

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is taking direct final action on revisions to the California State Implementation Plan. The revisions concern rules from the Ventura County Air Pollution Control District (VCAPCD). This approval action will incorporate these rules into the Federally approved SIP The intended effect of approving these rules is to regulate emissions of volatile organic compounds (VOCs) in accordance with the requirements of the Clean Air Act, as amended in 1990 (CAA or the Act). These rules control VOC emissions from gasoline transfer operations and from sumps, pits, ponds and well cellars during the production, gathering, separation, processing, and storage of crude oil or petroleum material. Thus, EPA is finalizing the approval of these revisions into the California SIP under provisions of the CAA regarding EPA action on SIP submittals, SIPs for national primary and secondary ambient air quality standards and plan requirements for nonattainment areas.

DATES: This action is effective on February 13, 1995 unless adverse or critical comments are received by January 13, 1995. If the effective date is delayed, a timely notice will be published in the **Federal Register**

ADDRESSES: Copies of the rules and EPA s evaluation report for each rule are