[6560-50-P]

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 63

[EPA-HQ-OAR-2003-0146; FRL-   ]

RIN 2060-AO55

National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the national emission standards for petroleum refineries to address the risk remaining after application of the 1995 hazardous air pollution standards and to fulfill the requirement for EPA to review every 8 years the developments in practices, processes, and control technologies. This action also amends the national emission standards for petroleum refineries to add maximum achievable control technology standards for heat exchange systems. Finally, this action amends the general provisions cross reference table.

DATES: The final amendments are effective on [INSERT DATE OF PUBLICATION]. The incorporation by reference of certain publications listed in the final rule amendments is approved by the Director of the Federal Register as of [INSERT DATE OF PUBLICATION].

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2003-0146. All documents in the docket are listed in the www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in www.regulations.gov or in hard copy at the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Residual Risk Standards Docket, Environmental Protection Agency, EPA West Building, Room 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air and Radiation Docket is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Lucas, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Coatings and Chemicals Group (E143-01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-0884; fax number (919) 541-0246; e-mail address: lucas.bob@epa.gov.

SUPPLEMENTARY INFORMATION:

The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

The regulated category and entities potentially affected by this final action include:

Category	NAICS[1] code	Examples of regulated entities
Industry . . .	324110	Petroleum refineries located at a major source that are subject to 40 CFR part 63, subpart CC.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this final rule. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in 40 CFR 63.640 of subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries). If you have any questions regarding the applicability of this action to a particular entity, contact either the air permit authority for the entity or your EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web through the Technology Transfer Network (TTN). Following signature, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: http://www.epa.gov/ttn/oarpg/. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by [INSERT DATE 60 DAYS FROM DATE OF PUBLICATION]. Under section 307(d)(7)(B) of the CAA, only an objection to these final rules that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

II. Background Information

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, after EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) calls for us to promulgate national emission standards for hazardous air pollutants (NESHAP) for those sources. For "major sources" that emit or have the potential to emit any single HAP at a rate of

10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year, these technology-based standards must reflect the maximum reductions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

For MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as floor requirements. See CAA section 112(d)(3). Specifically, for new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. The EPA is then required to review these technology-based standards and to revise them “as necessary (taking into account developments in practices, processes, and control technologies)” no less frequently than every 8 years, under CAA section 112(d)(6).

To address the first stage, we published the final MACT standards for petroleum refineries (40 CFR part 63, subpart CC) on August 18, 1995 (60 FR 43620). These standards are commonly referred to as the “Refinery MACT 1” standards because certain process vents were excluded from this source category and subsequently regulated under a second MACT standard specific to these petroleum refinery process vents (40 CFR part 63, subpart UUU, referred to as “Refinery MACT 2”).

The second stage in standard-setting focuses on reducing any remaining “residual” risk according to CAA section 112(f). This provision requires, first, that EPA prepare a Report to Congress discussing (among other things) methods of calculating risk posed (or potentially posed) by sources after implementation of the MACT standards, the public health significance of those risks, the means and costs of controlling them, actual health effects to persons in proximity of emitting sources, and recommendations as to legislation regarding such remaining risk. EPA prepared and submitted this report (Residual Risk Report to Congress, EPA–453/R–99–001) in March

1999. Congress did not act in response to the report, thereby triggering EPA’s obligation under CAA section 112(f)(2) to analyze and address residual risk.

CAA section 112(f)(2) requires us to determine for source categories subject to CAA section 112(d) MACT standards whether the emissions limitations provide an ample margin of safety to protect public health. If the MACT standards for HAP “classified as a known, probable, or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than 1-in-1 million,” EPA must promulgate regulations that provide an ample margin of safety to protect public health. The EPA must also adopt more stringent standards if necessary to prevent an adverse environmental effect [1], but must consider cost, energy, safety, and other relevant factors in doing so. Section 112(f)(2) of the CAA expressly preserves our use of a two-step process for developing standards to address any residual risk and our interpretation of “ample margin of safety” developed in the National Emission Standards for Hazardous Air Pollutants: Benzene Emissions from Maleic

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[1] “Adverse environmental effect” is defined in CAA section 112(a)(7) as any significant and widespread adverse effect, which may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas.

Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants (Benzene NESHAP) (54 FR 38044, September 14, 1989).

The first step in this process is the determination of acceptable risk. The second step provides for an ample margin of safety to protect public health, which is the level at which the standards are set (unless a more stringent standard is required to prevent an adverse environmental effect after the consideration of costs, energy, safety, and other relevant factors).

The terms “individual most exposed,” “acceptable level,” and “ample margin of safety” are not specifically defined in the CAA. However, CAA section 112(f)(2)(B) directs us to use the interpretation set out in the Benzene NESHAP. See also, A Legislative History of the Clean Air Act Amendments of 1990, volume 1, p. 877 (Senate debate on Conference Report). We notified Congress in the Residual Risk Report to Congress that we intended to use the Benzene NESHAP approach in making CAA section 112(f) residual risk determinations (EPA-453/R-99-001, p. ES-11).

In the Benzene NESHAP, we stated as an overall objective:

> . . . in protecting public health with an ample margin of safety, we strive to provide maximum feasible protection against risks to health from hazardous air pollutants by (1) protecting the greatest number of

> persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million; and (2) limiting to no higher than approximately 1-in-10 thousand [i.e., 100-in-1 million] the estimated risk that a person living near a facility would have if he or she were exposed to the maximum pollutant concentrations for 70 years.

The Agency also stated that, “The EPA also considers incidence (the number of persons estimated to suffer cancer or other serious health effects as a result of exposure to a pollutant) to be an important measure of the health risk to the exposed population. Incidence measures the extent of health risk to the exposed population as a whole, by providing an estimate of the occurrence of cancer or other serious health effects in the exposed population.” The Agency went on to conclude that “estimated incidence would be weighed along with other health risk information in judging acceptability.”[2] As explained more fully in our Residual Risk Report to Congress, EPA does not define “rigid line[s] of acceptability,” but considers rather broad objectives to be weighed with a series of

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[2] In the Benzene NESHAP decision, the Agency considered the same risk measures in the “acceptability” analysis as in the “margin of safety” analysis, stating: “In the ample margin decision, the Agency again considers all of the health risk and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level of control will also be considered, including costs and economic impacts of controls, technological feasibility, uncertainties, and any other relevant factors. Considering all of these factors, the Agency will establish the standard at a level that provides an ample margin of safety to protect the public health, as required by section 112.”

other health measures and factors (EPA-453/R-99-001, p. ES-11).

The determination of what represents an “acceptable” risk is based on a judgment of “what risks are acceptable in the world in which we live” (54 FR 38045, quoting the Vinyl Chloride decision at 824 F.2d 1165) recognizing that our world is not risk-free.

In the Benzene NESHAP, we stated that “EPA will generally presume that if the risk to [the maximum exposed] individual is no higher than approximately 1-in-10 thousand, that risk level is considered acceptable.” We discussed the maximum individual lifetime cancer risk as being “the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years.” We explained that this measure of risk “is an estimate of the upper bound of risk based on conservative assumptions, such as continuous exposure for 24 hours per day for 70 years.” We acknowledge that maximum individual lifetime cancer risk “does not necessarily reflect the true risk, but displays a conservative risk level which is an upper bound that is unlikely to be exceeded.”

Understanding that there are both benefits and limitations to using maximum individual lifetime cancer risk as a metric for determining acceptability, we acknowledged in the 1989 Benzene

NESHAP that “consideration of maximum individual risk . . . must take into account the strengths and weaknesses of this measure of risk.” Consequently, the presumptive risk level of 100-in-1 million (1-in-10 thousand) provides a benchmark for judging the acceptability of maximum individual lifetime cancer risk, but does not constitute a rigid line for making that determination.

The Agency also explained in the 1989 Benzene NESHAP the following: “In establishing a presumption for MIR, rather than rigid line for acceptability, the Agency intends to weigh it with a series of other health measures and factors. These include the overall incidence of cancer or other serious health effects within the exposed population, the numbers of persons exposed within each individual lifetime risk range and associated incidence within, typically, a 50 kilometer (km) exposure radius around facilities, the science policy assumptions and estimation uncertainties associated with the risk measures, weight of the scientific evidence for human health effects, other quantified or unquantified health effects, effects due to co-location of facilities, and co-emission of pollutants.”

In some cases, these health measures and factors taken together may provide a more realistic description of the magnitude of risk in the exposed population than that provided by maximum individual lifetime cancer risk alone.

We are required by a Consent Decree to issue the results of our CAA section 112(d)(6) 8-year review by January 16, 2009. The Consent Decree also requires EPA to consider and address the application of the NESHAP general provisions in 40 CFR part 63, subpart A to the existing Refinery MACT 1 rule (subpart CC). In developing this rule, we first issued an advanced notice of proposed rulemaking (ANPR) on March 29, 2007. The purpose of the ANPR, which covered the sources subject to the Refinery MACT 1 rule and other source categories, was to solicit additional emissions data and any corrections to the data we already had. We issued an initial proposed rule for the petroleum refineries subject to the Refinery MACT 1 on September 4, 2007, and held a public hearing in Houston, Texas on November 27, 2007. In response to public comments on the initial proposal, we collected additional information and revised our impact analyses. Based on the results of these additional analyses, we issued a supplemental proposal on November 10, 2008, that established a new MACT floor for heat exchange systems and proposed an additional option under the residual risk and technology review (RTR) for storage vessels. A public hearing for the supplemental proposal was held in Research Triangle Park, North Carolina on November 25, 2008. We are now taking final action to perform the RTR of the Refinery MACT 1 standards (40 CFR part 63, subpart CC).

III. Summary of Final Amendments to NESHAP for Petroleum Refineries

A. What requirements for Group 1 storage vessels are we promulgating pursuant to CAA sections 112(f)(2) and (d)(6)?

EPA proposed three regulatory options for storage vessels: Option 1 would require no revisions to the Refinery MACT 1 rule; Option 2 would add the requirements in 40 CFR 63.119(c)(2)(ix) and (x) for slotted guide poles on existing external floating roof (EFR) storage vessels (40 CFR part 63, subpart CC currently provides an exemption from these requirements for existing storage vessels); and Option 3, which was proposed in the supplemental proposal, was intended to require all Group 1 EFR storage vessels to meet the requirements of 40 CFR part 63, subpart WW. The subpart WW requirements include the requirements for fitting controls on slotted guide poles as well as additional requirements for fittings for unslotted guide poles and other openings on EFR storage vessels (this option is referred to as “fitting controls” for the remainder of this preamble).

Based on our review of public comments, we are adopting Option 3 and finalizing requirements for Group 1 EFR storage vessels to meet the requirements in 40 CFR part 63, subpart WW. The final standards also include the inspection, recordkeeping, and reporting requirements set forth in 40 CFR part 63, subpart WW to account for the additional requirements for fitting controls for EFR storage vessels. Internal floating roof (IFR) storage vessels are not required to install guide pole controls or other fitting controls.

Based on our technology review under CAA section 112(d)(6), we are revising the NESHAP to include the complete set of EFR storage vessel fitting control requirements. We opted to cross-reference 40 CFR part 63, subpart WW for the fitting control requirements, rather than retaining the cross reference to the storage vessel requirements in the HON (40 CFR part 63, subpart G) because subpart WW provides clearer language for the fitting controls.

The final amendments to the Group 1 storage vessel requirements reduce HAP emissions and risks beyond the current MACT standard using controls that are technically and economically feasible. We estimate that these controls will reduce HAP emissions by 1,650 tons per year (ton/yr), will reduce the number of people at cancer risk greater than 1-in-1 million by 40,000 individuals, and will reduce cancer incidence by 0.003 – 0.004 cases per year (i.e., prevent one cancer case every 300 years). In addition, the amendments to the Group 1 storage vessel requirements will provide an additional health and environmental benefit by reducing emissions of volatile organic compounds (VOC) by 14,800 ton/yr. Reducing VOC emissions may reduce ambient concentrations of ozone and may also reduce ambient concentrations of fine particulate matter. The annualized cost impacts of these final amendments to the Group 1 storage vessel requirements are estimated to be a cost savings of $6.3 million. Our economic analysis entitled “Economic Impact and Small Business Analysis for Petroleum Refinery NESHAP – Residual Risk and Technology Review – Final Rulemaking”, which has been placed in the docket, indicates that this cost savings will have little impact on the output of petroleum products. See Section V of this preamble for further details supporting these requirements.

B. What are the requirements pursuant to CAA sections 112(f)(2) and (d)(6) for EBU used to treat Group 1 wastewater streams?

EPA proposed two regulatory options for enhanced biological units (EBU): Option 1 would require no revisions to the Refinery MACT 1 rule and Option 2 for EBU would revise the wastewater provisions in the Refinery MACT 1 rule to add a specific performance standard and monitoring requirement for EBU. We selected Option 1 and are finalizing no amendments for the EBU at this time because we have determined that the existing Refinery MACT 1 requirements for wastewater provide an ample margin of safety to protect public health and prevent an adverse environmental effect, and that there have been no advances in practices, processes, and control technologies to warrant additional requirements. For more detail regarding our conclusions that the existing standards provide an ample margin of safety and that it is not necessary to mandate additional controls under CAA section 112(d)(6), see the Response to Comment section, below.

C. What requirements for heat exchange systems are we promulgating pursuant to CAA sections 112(d)(2) and (f)(2)?

On September 4, 2007, we proposed, under CAA section 112(d)(2) and (f)(2), two options for work practice standards for cooling towers: Option 1 was proposed based on our initial assessment of the MACT floor and Option 2 was a beyond-the-floor option. These options would require the owner or operator of a new or existing source to monitor for leaks in the cooling tower return lines from heat exchangers in organic HAP service (i.e., lines that contain or contact fluids with 5 percent by weight or greater of total organic HAP listed in Table 1 of the rule) and, where leaks are detected, to repair such leaks within a specified period of time.

On November 10, 2008, we issued a supplemental proposal that significantly modified the proposed monitoring methods, leak definitions, and corrective action timeframe based on a revised MACT floor and beyond-the-floor analysis. In the supplemental proposal, we also redefined the requirements in terms of heat exchange systems to include the heat exchangers, for which corrective actions are targeted, as part of the source and to specifically address once-through cooling systems.

After considering public comments, for purposes of establishing MACT under CAA section 112(d)(2), we have selected the MACT floor requirements specified in the supplemental proposal for heat exchange systems in organic HAP service at petroleum refineries. We rejected the beyond-the-floor option because it is not cost-effective. In addition, for purposes of our residual risk review under CAA section 112(f)(2), we are concluding that these MACT floor requirements provide an ample margin of safety to protect public health and prevent an adverse environmental effect. In making this decision we are rejecting additional controls because the controls are not cost effective and the risk reduction is minimal.

Under these selected requirements, owners and operators of heat exchange systems that are in organic HAP service at new and existing sources are required to conduct monthly sampling and analyses using the Texas Commission on Environmental Quality's (TCEQ) Modified El Paso method, Revision Number One, dated January 2003.[3] For existing sources, a leak is defined as 6.2 parts per million by volume (ppmv) total strippable VOC in the stripping gas collected via the Modified El Paso method. For new sources, a leak is defined as 3.1 ppmv total strippable VOC collected via the Modified El Paso method. The amendments require the repair of leaks in heat exchangers in organic HAP service within 45 days of the sampling event in which the leak is detected, unless a delay in repair is allowed. Delay in repair of the leak is allowed until the next shutdown if the repair of the leak requires the process unit served by the leaking heat exchanger to be shut down and the total strippable VOC concentration is less than 62 ppmv. Delay in repair of the leak is also allowed for up to 120 days if the total strippable VOC concentration is less than 62 ppmv and if critical parts or personnel are not available. The owner or operator is required to continue monthly monitoring and to repair the heat exchanger within 30 days if sampling results show that the leak exceeds 62 ppmv total strippable VOC.

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[3] "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources," Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14).

Sampling for leaks can be done for individual or combined heat exchangers. For heat exchange systems including a cooling tower, sampling can be conducted at the combined cooling tower inlet water location. Similarly, for once-through heat exchange systems, the sampling can be conducted after the heat exchanger water is combined and prior to discharge where it will be open to atmosphere. For both cooling tower and once-through heat exchange systems, sampling can be conducted at individual heat exchangers in the return or “exit” lines (i.e., water lines returning the water from the heat exchangers to the cooling tower or to the discharge point). That is, if the cooling tower or once-through system services multiple heat exchangers, the owner or operator may elect to monitor only the heat exchangers “in organic HAP service” or monitor at branch points that combine several heat exchanger exit lines, or monitor at the combined stream for the entire system. If a leak is detected (the measured VOC concentration exceeds the applicable leak definition) at the combined cooling tower inlet or once-through system, the owner or operator may either fix the leak (reduce the VOC concentration to less that the applicable leak definition) or sample heat exchanger exit lines for combinations of heat exchanger exit lines or sample each heat exchanger “in organic HAP service” as necessary to document that the leak is not originating from a heat exchanger “in organic HAP service.” If a leak is detected in an individual heat exchanger “in organic HAP service,” that leak must be repaired.

All new or existing refineries with a heat exchange system “in organic HAP service” are required to maintain records of all heat exchangers and which of those heat exchangers are in organic HAP service, the cooling towers and once-through systems associated with heat exchangers in organic HAP service, monthly monitoring results, and information for any delays in repair of a leak.

These requirements will apply to sources on a continuous basis, including periods of start-up, shut-down and malfunction (SSM). As provided in the response to comments below, properly operating heat exchangers will not leak HAP into the cooling water, so HAP will not be emitted from the cooling tower or once-through discharges. It is only when they malfunction (i.e., there are leaks) that there may be HAP emissions. The MACT standard for heat exchange units addresses these emissions. Furthermore, there are no HAP emissions associated with start-up and shutdown.

The requirements outlined above are based on the MACT floor determination. We evaluated the following beyond-the-floor options: having a leak definition of 3.1 ppmv for existing sources (beyond-the-floor option for existing sources) and requiring continuous monitoring (beyond-the-floor options for both new and existing sources). As described in our supplemental proposal, we determined that these beyond-the-floor options were not cost-effective and concluded that MACT was the floor level of control.

The final MACT requirements for heat exchange systems will reduce HAP emissions by 630 ton/yr. The maximum source category MIR remaining after implementation of MACT is 30-in-1 million, and the annual cancer incidence is estimated to be between 0.03 and 0.05 excess cancer cases per year. After implementation of heat exchange system MACT, there are an estimated 440,000 people exposed to risks exceeding 1-in-1 million for the source category. Additional controls for heat exchange systems would not reduce the maximum facility MIR and would reduce cancer incidence by approximately 0.0003 cases per year (i.e., prevent three cancer cases every 10,000 years) at an additional cost of over $600 million per cancer incidence avoided. As no individual is exposed to risks from petroleum refinery emissions exceeding 100-in-1 million after the implementation of MACT, and based on the risk reduction that would be achieved and the significant cost of achieving those reductions for implementing additional (beyond-the-floor) controls for heat exchange systems, we conclude that the MACT requirements for heat exchange systems provide an ample margin of safety to protect public health and prevent an adverse environmental effect.

The final requirements for heat exchange systems will also reduce VOC emissions by 4,100 ton/yr. Reducing VOC emissions may provide the added benefit of reducing ambient concentrations of ozone and may reduce fine particulate matter. The annualized nationwide cost impacts of these final standards for heat exchange systems are estimated to be $3.0 million. Our economic analysis indicates that this cost will have little impact on the price and output of petroleum products.

D. What other revisions and clarifications are we making?

As proposed, we are amending 40 CFR 63.650(a) of subpart CC to replace “gasoline loading racks” with “Group 1 gasoline loading racks” to clarify the applicability of the requirements. Furthermore, as we proposed on November 10, 2008, we are also finalizing proposed amendments to the cross-references to subparts R and Y of 40 CFR part 63 in the rule text and in Tables 4 and 5 of subpart CC because subparts R and Y were amended and the revised cross-references clarify the requirements of subpart CC.

We are finalizing amendments to Table 6 to 40 CFR part 63, subpart CC (General Provisions Applicability to Subpart CC) to bring the table up to date with requirements of the General Provisions that have been amended since this table was created, to correct cross references, and to incorporate additional sections of the General Provisions that are necessary to implement other subparts that are cross referenced by this rule. With respect to the exemption from emission standards during periods of SSM in the General Provisions (see, e.g., 40 CFR 63.6(f) and (h)), we note that on December 19, 2008, in a decision addressing a challenge to the 2002, 2004 and 2006 amendments to those provisions, the Court of Appeals for the District of Columbia Circuit vacated the SSM exemption. Sierra Club v. EPA (D.C. Cir. No. 02-1135).

The CAA section 112(d)(2) and (d)(3) MACT standard we are promulgating today for heat exchange systems is not implicated by that decision because it does not rely on or reference the provisions of the vacated rule and because the MACT standard applies at all times. We are amending Table 6 to clarify that the MACT standard for heat exchange systems applies at all times.

We are still evaluating the recent court decision, and the time for appeal of that decision has not yet run. At this time, we are not making any additional changes to table 6 with respect to the SSM provisions in 40 CFR 63.6(f)(1) and (h)(1). We have completed our assessment of the General Provisions and their application to Subpart CC to the best of our ability at this time. The recent court decision requires further analysis, and we are currently evaluating how to address SSM events for refinery MACT 1 sources in light of the court decision.

We are also finalizing amendments to Table 1 and Table 7 to delete methyl ethyl ketone (also known as 2-butanone) from the HAP listed in those tables because methyl ethyl ketone has been delisted as a HAP. We are finalizing amendments to clarify the applicability sections by changing general references to “the promulgation date” to specify the actual promulgation date of the original subpart CC. Finally, we are also finalizing amendments to clarify how owners and operators should comply with overlapping standards for equipment leaks and storage vessels.

E. What is the compliance schedule for the final amendments?

The final amendments to the Refinery MACT 1 rule will be effective on [INSERT DATE OF PUBLICATION]. Under section 112(i)(1) of the CAA, any new facility must comply upon startup or on the effective date of the rule, whichever is later. For purposes of determining compliance with these amendments, a new source is a source that commenced construction or reconstruction after September 4, 2007 (the initial date of proposal for these regulations). Consistent with the requirements of CAA section 112(1)(3), the owner or operator of an existing source (including an existing source for these amendments that is currently subject to 1995 MACT 1 standards for new sources) must comply with the heat exchange system requirements and the Group 1 storage vessel requirements in subpart WW of this part (as specified in this subpart) no later than [INSERT DATE 36 MONTHS FROM DATE OF PUBLICATION]. The basis for the 3-year compliance period is set forth below in our responses to comment. For storage vessels, the 3-year compliance period applies in lieu of the provision in subpart WW that allows up to 10 years to retrofit EFR storage vessels with the guide pole and other fitting controls.

IV. Summary of Revised Risk Analysis Results

A. Revision of the Emission Inventory

Comments received on the emission inventory used for the draft baseline risk assessment for Refinery MACT 1 sources were evaluated and incorporated into the final inventory if deemed appropriate and reasonable from an engineering standpoint. The comments covered 101 facilities and included data provided for three facilities not contained in the original dataset. After evaluating the comments, emissions data were corrected at 48 facilities, emission point identifiers were corrected at 3 facilities, stack parameters were revised at 4 facilities, and location data were corrected at 61 facilities. The final petroleum refinery emission inventory contains information for 156 facilities representing the entire source category.

Nationwide refinery HAP emissions estimates did not change dramatically as a result of the revisions made pursuant to the comments, dropping by only about 2 percent. The baseline HAP emissions from the MACT 1 source category are 7,200 tons per year. In addition, metal HAP emissions were removed from the inventory because they are not emitted by the emission points covered by Refinery MACT 1. Metal HAP are emitted by other source categories located at refineries, most notably by the emission points covered by Refinery MACT 2. These metal HAP emissions will be included in the RTR assessment for that category.

B. Baseline Risk Assessment

The final baseline risk assessment for Refinery MACT 1 sources is detailed in the document entitled, “Final Baseline Residual Risk Assessment for MACT I Petroleum Refining Sources,” which has been placed in the docket for this rulemaking. A summary of the results of that risk assessment is found in Table 1.

Table 1. Overall Summary of Source Category Level Risks for 156

Petroleum Refineries[a,b]

Result		HAP "Drivers"
Cancer Risks		
Maximum Individual Lifetime Cancer Risk (in 1 million) from any Facility in the Category	30	naphthalene, polycyclic organic matter (POM)
Number of Facilities with Maximum Individual Lifetime Cancer Risk:		
Greater than or equal to 100 in 1 million	0	n/a
Greater than or equal to 10 in 1 million	5	naphthalene, POM, benzene, ethylene dibromide, 1,3-butadiene, tetrachloroethylene, methyl tert-butyl ether, carbon tetrachloride
Greater than or equal to 1 in 1 million	77	naphthalene, POM, benzene, ethylene dibromide, 1,3-butadiene, tetrachloroethylene, methyl tert-butyl ether, carbon tetrachloride, ethylene dichloride, vinyl chloride
Chronic Noncancer Risks		
Maximum Respiratory Hazard Index	0.3	Diethanolamine
Number of Facilities with Maximum Respiratory Hazard Index:		
Greater than 1	0	n/a
Acute Noncancer Refined Results		
Maximum Acute Hazard Quotient	8, 0.06 5, 2, 0.06	Benzene (REL, AEGL-1) Hydrofluoric Acid (REL, AEGL-1, AEGL-2)
Number of Facilities With Potential for Acute Effects	8	benzene, hydrofluoric acid
Population Exposure		
Number of People Living Within 50 Kilometers of Facilities Modeled	90,000,000	n/a
Number of People Exposed to Cancer Risk:		
Greater than or equal to 100 in 1 million	0	n/a
Greater than or equal to 10 in 1 million	4,000	n/a
Greater than or equal to 1 in 1 million	460,000	n/a
Number of People Exposed to Noncancer Respiratory Hazard Index:		
Greater than 1	0	n/a
Estimated Cancer Incidence (excess cancer cases per year)	0.03 - 0.05	n/a
Contribution of HAP to Cancer Incidence		
Benzene	48%	n/a
naphthalene	21%	n/a
POM	15%	n/a
1,3-butadiene	5%	n/a
tetrachloroethylene	4%	n/a

[a] There were 162 petroleum refineries estimated to be subject to the MACT standard when initially proposed (60 FR 16090, March 29, 1995), and 156 petroleum refineries were identified in the National Emissions Inventory and modeled in the Screening Risk Assessment.
[b] Note that cancer and noncancer risks are presented to 1 significant figure. Thus, when tabulating the number of facilities above a certain risk threshold (1 in a million, 10 in a million…), rounding to 1 significant figure must be considered. (e.g., a facility with a cancer risk of 1.48 is NOT considered to be GREATER than 1 in a million).

The maximum individual cancer risk for the petroleum refining source category is 30-in-1 million. The maximum individual cancer risk for the source category as a whole is dominated by the risks associated with emissions of naphthalene and polycyclic organic matter (POM); however, the maximum individual cancer risk level associated with each facility and the specific pollutants which contribute the most to that level vary significantly from facility to facility. The total cancer incidence for the source category was estimated to be between 0.03 and 0.05 cancer cases per year, or about 1 case in every 20 to 30 years (this range of cancer incidence depends on the range of the Integrated Risk Information System (IRIS) cancer potency factors for benzene, each end of which is considered equally plausible). The cancer incidence for the source category is dominated by risks associated with benzene and naphthalene. The estimated maximum individual cancer risk exceeded 10-in-1 million at 5 facilities and exceeded 1-in-1 million at 77 facilities. Based on the conservative assumption that all

90,000,000 individuals living within 50 km of a petroleum refinery are exposed for 70 years, approximately 4,000 people were estimated to have cancer risks above 10-in-1 million and approximately 460,000 people were estimated to have cancer risks above 1-in-1 million.

Chronic noncancer inhalation risks were not identified as significant, with the maximum chronic target organ specific hazard index associated with the cumulative impacts of all noncarcinogenic HAP emitted by these sources being less than 1. While there were reported emissions of one persistent HAP (POM) from this source category, our multipathway screening indicated that neither significant ingestion health risks nor environmental risks would be anticipated to result from exposures to media concentrations associated with the deposition of these emissions. No other potential environmental risks, including those as a direct result of exposure of flora and fauna to ambient air concentrations, were identified. For additional details on the multipathway screening and the environmental assessment, see “Final Baseline Residual Risk Assessment for MACT I Petroleum Refining Sources,” which has been placed in the docket for this rulemaking.

Our analysis of potential acute impacts indicates a potential exceedance of acute thresholds at 8 out of the 156 facilities, with maximum potential offsite impacts at 8 and 5 times the acute reference exposure level (REL) for benzene and hydrofluoric acid (i.e., for benzene, maximum HQ_{REL}= 8, 5 facilities with potential HQ_{REL} greater than 1; and for hydrofluoric acid, maximum HQ_{REL}=5, 3 facilities with potential HQ_{REL} greater than 1), and a potential exceedance of the acute exposure guideline level (AEGL-1) and the emergency response planning guideline (ERPG-1) level for hydrofluoric acid (HQ_{AEGL-1} = HQ_{ERPG-1} = 2) at one facility. There were no potential exceedances of the AEGL-1 or ERPG-1 levels for benzene (maximum HQ_{AEGL-1} = HQ_{ERPG-1} = 0.06). There were also no potential exceedances of the AEGL-2 or ERPG-2 level for hydrofluoric acid (maximum HQ_{AEGL-2} = HQ_{ERPG-2} = 0.06). According to the California Environmental Protection Agency, acute exposure to hydrofluoric acid can be associated with eye and respiratory irritation and acute exposure to benzene can be associated with reproductive/developmental effects (see: http://www.oehha.ca.gov/air/pdf/acuterel.pdf). We note that the number of facilities with potential for exceedance of an acute exposure value (eight) is small relative to the total number of facilities in the source category (156). The number of people living within a mile of the five sites with potential acute benzene impacts is about 3,000; the number of people living within a mile of the three sites with potential acute hydrofluoric acid impacts is about 8,000. Concerning potential acute benzene exposures, while the maximum benzene HQ_{REL} value is 8, the corresponding HQ_{AEGL-1} value is 0.06, indicating that, while we cannot rule out the possibility of acute health impacts, we are not close to exposures at the AEGL-1 level, which is defined as an exposure level “above which the general population, including sensitive individuals, could experience notable discomfort, irritation, or certain asymptomatic, non-sensory effects.” Regarding potential acute hydrofluoric acid exposures, we note that the source of the emissions is fugitive emissions, indicating that the reported emissions are estimates based on long-term consideration of leaking pipes, equipment, etc. In general, such emissions do not vary dramatically in time, and our use of the emissions multiplier of 10 in estimating acute exposure from long-term average emissions estimates is likely conservative. We note that our screening indicates no potential to exceed the AEGL-2 level for hydrofluoric acid, defined as an exposure level “above which the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.” We conclude that short-term exceedances of the AEGL-1 level are possible for one facility and that HQ_{REL} values greater than 1 may still be possible for three facilities.

Since the estimated maximum individual cancer risk for the source category is less than 100-in-1 million, and since chronic noncancer risks, multipathway risks, and environmental risks were determined to be negligible, we conclude from this risk assessment that the risks associated with the Refinery MACT 1 source category are acceptable. We recognize that we cannot completely rule out the potential for acute exposures above the AEGL-1 for hydrofluoric acid and the REL for benzene; however, we conclude that risks associated with the Refinery MACT 1 source category are acceptable on the basis that our assessment of such potential impacts is based on a conservative exposure scenario (particularly regarding the simultaneous occurrence of worst-case meteorological conditions and peak emission conditions) and other conservative screening assumptions (particularly regarding the potential for fugitive hydrogen fluoride emissions to peak dramatically in the short-term) and since it identifies only a limited number of facilities and potentially impacted people. We recognize that a number of commenters have criticized our risk assessment as underestimating true risks, believing that emissions from petroleum refineries are greater than those used in our assessment. However, we conclude that our final risk assessment is based on reasonable estimates of emissions which have been subjected to public review twice (once, through an Advanced Notice of Proposed Rulemaking and again through our Notice of Proposed Rulemaking) as well as several reviews by our in-house emissions, exposure, and engineering experts. Besides the extensive process undertaken to develop the emissions inventory for this source category, we have several indications that our emissions are not unreasonable, including several modeling analyses and an evaluation of ambient monitoring data near two refineries. These are provided in the docket and discussed below.

C. Model Plant Analysis

In response to comments that the National Emissions Inventory (NEI) data set understates actual emissions, a detailed model plant analysis was used to provide an alternative baseline HAP emission estimate for all Refinery MACT 1 emissions sources. The model plant analysis used process-specific production capacities to estimate emissions of HAP by source type for all refineries. In addition to baseline emissions, the model plant analysis was also used to evaluate risk associated with different levels of control for heat exchange systems, storage vessels and wastewater treatment systems.

In terms of total HAP emissions, the model plant analysis projects approximately 60 percent higher total HAP emissions than the NEI data set. The total nationwide HAP emissions estimate at baseline projected by the model plant analysis is 11,300 ton/yr, while the total nationwide HAP emissions estimate in the NEI data set is 7,200 ton/yr. Looking only at benzene emissions, the model plant analysis estimates a nationwide total of 1,330 ton/yr, whereas the NEI data set includes a total of 708 ton/yr of benzene emissions. For naphthalene, another HAP that significantly contributes to risk, the model plant analysis estimates emissions of 63 ton/yr, while the NEI data set contains a total of 82 ton/yr. Thus, while the model plant analysis has higher emissions of benzene (by almost a factor of 2) than the NEI, the NEI contains higher emissions of some other important (with respect to risk drivers) HAP (e.g., naphthalene emissions in the NEI are higher by 30 percent). In terms of the overall emissions estimates, the model plant analysis indicates that there could be a low bias in reported emissions, although it is within a factor of 2, whereas previous studies identified in the proposal indicated that the bias might be significantly higher. The estimated maximum individual cancer risk (MIR) in the model plant analysis, was 60 in-1 million versus 30 in a million from our actual inventory; the baseline cancer incidence values from the model plant analysis were higher than those from our analysis based on the actual inventory by a factor of 2.5. Given the associated methodological uncertainties and limitation, however, there is considerable uncertainty associated with the MIR from the model plant analysis. For further details on the model plant analysis, refer to the memorandum entitled, “Model Plant Analysis of Residual Risk from Petroleum Refinery Emissions” which has been placed in the docket for this rulemaking.

D. Monitor-to-Model Comparison

Also in response to concerns about the understatement of emissions in the NEI data set, we conducted another analysis to asses the general magnitude of uncertainty, and the possibility of bias, in our facility-specific emissions estimates. This analysis compares ambient monitoring data for benzene from two monitoring sites near several refineries in the Texas City, Texas, to dispersion modeling results based on emissions data for those facilities. Results from the analysis indicate that the modeled benzene emissions at one refinery are consistent with the ambient levels being measured (and may even be an overestimate) and that the inventory may be low by a factor of 2 to 2.6 for the other refinery. These results are also consistent with the bias estimated using the model plant analysis described above. These results, however, are based on ambient concentrations and not risk, which may vary more or less than this factor of 2 to 2.6 due to the number of people exposed in a given area.

We also evaluated the conservatism of our acute screening method using this model-to-monitor comparison. Our results also indicated that our screening methodology for acute impacts is very conservative – the actual monitors measure an acute impact that is much lower than the peak HQ predicted using our screening method.[4] While it would be inappropriate to make conclusions about the total HAP emissions inventory for all 156 facilities based on this analysis of benzene data for two facilities, our analysis does provide anecdotal evidence which suggests that our annual emissions of that HAP are reasonably accurate. Furthermore, our analysis focuses on the compound which drives cancer incidence estimates for this source category, providing additional assurance that our cancer incidence estimates are likely within a factor of 2 or 3, and not low by a factor of 10 to 100, as suggested by some commenters. For further details on the model-to-monitor

[4] For one facility the acute screening HQ was a factor of 16 times the highest 1-hour concentration measured at the monitor. For the other facility, the acute screening HQ was a factor of 3.5 to 7 times the highest 1-hour concentration measured at the monitor.

comparison, refer to the memorandum entitled, “Statistical comparison of monitored and modeled ambient benzene concentrations near two petroleum refineries in Texas City, TX” which has been placed in the docket for this rulemaking.

E. Evaluation of Annual Versus Hourly Meteorological Data in TANKS Emission Estimation

In response to comments that emissions from storage tanks might be orders of magnitude higher than what would be predicted using standard emission estimation protocols, we evaluated the variability in short term emission rates for petroleum refinery storage vessels to determine if the use of annual meteorological data in the TANKS model biases the emission estimates as compared to using hourly meteorological data. In a study documented in “Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection” (Chambers and Strosher, 2006), VOC emission measurements determined using Differential Absorption LIDAR (DIAL) suggested that the emissions from storage vessels were approximately 30 times greater than projected by the facility using the TANKS emission model.

The American Petroleum Institute (API) submitted a letter (Watkins and Ritter, 2006) asserting that the short-term measurements reported in the DIAL study (Chambers and Strosher,

2006) are not indicative of the annual average emissions. API noted that there may have been maintenance issues with storage vessels, but they also outlined a number of reasons why short-term (on the order of 1 to 3 hours) emissions conducted in the summer (at higher than average temperatures) and during the day (when vessel loading activity and wind levels are higher), would be higher than the annual average emissions. API also cited a CONCAWE report (Smithers, et al, 1995) indicating that the TANKS model equations accurately estimated the emissions measured during a longer DIAL measurement study (90 hours). However, hourly input data were used in the TANKS model to estimate the storage vessel emissions during the CONCAWE study.

The differences between these two DIAL studies raised a question as to whether the use of hourly input data for a storage vessel would yield similar annual average emission estimates as the use of annual average meteorological data. Results of our evaluation indicate that a significant amount of variability in storage vessels emissions can occur over the short term, and that peak hourly emission rates as calculated using hourly input data can be a factor of 5 to 10 times higher than hourly emission rates calculated using annual input data. However, even with this variability, the use of annual average inputs appears to yield emission estimates that are consistent (within 20%) with annual estimates generated using hourly inputs over the long term. Based on this analysis, we do not believe that annual emissions estimated using the TANKS model (which is based on API storage vessel emission estimation procedures) are biased by a factor of 30, as has been suggested.

In addition to these studies, we note that additional emission measurements using DIAL technology were undertaken in the summer of 2007 at a domestic oil refinery. However, at this time, a final report documenting the findings of the measurements and the process information at the time the measurements were taken has not been issued. While we have reviewed the draft report, we have not been able to draw any conclusions because site-specific process information on the sources of the emissions has not yet been made available to us. We plan to evaluate the final report once all relevant data become available. Furthermore, additional studies are being conducted using optical remote sensing technologies. Because these studies are not yet available, we are appropriately basing this rule on the best technical information available to us now. To the extent these studies are finalized and available, we would consider them as part of any future action addressing refinery emissions, such as the residual risk and technology review for Refinery MACT 2 sources.

We are appropriately basing this rule, however, on the information that is available to the Agency at this time. Based on the analyses summarized in Sections IV.C through E of this preamble, we believe the actual inventory data are reasonable and provide the best available data by which to assess the risks associated with Refinery MACT 1 emission sources. We note that, even if the emissions in the actual inventory were understated by a factor of 2 to 3, the maximum MIR would still be below 100-in-1 million (3 times the maximum MIR would yield an MIR of 90-in-1 million). Therefore, we conclude that the risks associated with Refinery MACT 1 sources are acceptable.

V. Summary of Comments and Responses

A. Heat Exchange Systems

On November 10, 2008, we issued a supplemental proposal with our revised MACT floor and beyond-the-floor analysis. In general, the comments received on the cooling tower requirements initially proposed on September 4, 2007, either have been addressed through the supplemental proposal or are not applicable to the final standards (e.g., clarifications to monitoring methods no longer required). The general comments regarding cooling tower requirements received on the initial proposal, which are still applicable, are summarized in “National Emission Standards for Hazardous Air Pollutants From

Petroleum Refineries: Background Information for Final Standards - Summary of Public Comments and Responses” located in the docket (Docket ID No. EPA-HQ-OAR-2003-0146). Comments received on the supplemental proposal are addressed in this section.

1. MACT Floor for Heat Exchange Systems

Comment: A few commenters noted that the leak definition proposed for new heat exchange systems of 3.1 ppmv has not been “demonstrated in practice.” One commenter stated that the leak definition of 3.1 ppmv was developed by the State of Texas from the AP-42 emission factor. The commenter stated that only one cooling tower is operating under a permit with that limit (the other cooling towers are under construction), and this cooling tower has only recently begun operating, so there is no significant experience operating with the identified new source limit or applying it to the range of operations and ages of exchangers in a typical refinery. The commenter asserted that some heat exchangers and heat exchange systems are difficult to control, and different leak definitions are appropriate for different situations within an individual refinery, so a set of requirements must be demonstrated to be workable on multiple heat exchange systems of varying services and ages before that set of requirements can be considered “demonstrated in practice." Another commenter stated that there is no demonstration that there is technology that can be applied to new sources that improves the emission performance of these systems when considered across the operating life of the facilities. Both commenters recommended setting the new source and existing source requirements equivalent at 6.2 ppmv. (One of the commenters noted that EPA's analysis shows that the next best controlled source has a limit of 5 ppmv, but the commenter noted that there is not much difference between the reductions achieved by a leak definition of 5 ppmv and a leak definition of 6.2, and 5 ppmv is not cost-effective. The commenter urged EPA to review cooling towers and heat exchange systems under CAA sections 112(d)(6) and 112(f)(2) and consider factors such as cost rather than developing a standard under CAA section 112(d)(2).

One commenter noted that in the State of Texas, if a particular cooling tower cannot meet its normal leak definition of 80 ppbw VOC in the water, the State allows that source to set a leak definition of up to 150 ppbw VOC in the water. For flexibility when dealing with continuous small seepage or situations where the particular HAP or VOC present are not completely stripped by the cooling tower, the commenter suggested that in any 1-year period, if monitoring shows three leaks above 6.2 ppmv but below 12 ppmv, EPA should allow that source to set a new leak definition of 12 ppmv.

Commenters stated that the leak definition of 6.2 ppmv VOC in the stripping gas is not stringent enough. One commenter noted that during cooling tower leak investigations conducted by the City of Houston and TCEQ, a potential leak measured at 2 ppm required sampling by summa canister to confirm the leak, and EPA's regulation should be at least that stringent. The commenter stated that a stringent leak threshold of 2 ppm will ensure that small leaks are found and repaired quickly, especially since the TCEQ leak threshold is 50 ppbv.

Several commenters supported using the modified El Paso Methods to detect leaks but suggested that cooling towers that have higher recirculation flow rates should have lower leak definitions than cooling towers with lower flows because the large cooling towers will have higher mass emissions at the same leak concentration.

Commenters stated that EPA failed to consider the TCEQ Highly Reactive VOC (HRVOC) rule in establishing the MACT floor. The commenters believe the HRVOC rule is applicable to several refinery cooling towers, requires continuous monitoring, and it has a more stringent leak definition and leak repair schedule. One commenter also cited a California refinery that is required to install and operate a continuous hydrocarbon analyzer and repair leaks above an agreed threshold.

Response: The TCEQ El Paso method has been demonstrated at numerous refineries and other similar sources as an effective means of identifying leaks in heat exchange systems. The method has been used extensively for over 20 years. As suggested by some commenters, the detection limit of the El Paso method is generally less than 2 ppmv, so leaks of 3.1 ppmv are quantifiable. Ongoing monitoring at refineries indicates that, when no leaks are present or after repairs are made, El Paso monitoring is able to detect leaks well below this leak threshold. As such, the monitoring method and the corrective action measures have been adequately demonstrated.

In criticizing our new source leak definition of 3.1 ppmv, the commenter recognizes that heat exchangers connected to one refinery cooling tower are subject to a monitoring program with a leak definition of 3.1 ppmv. Section 112(d)(3) of the CAA provides that new source MACT cannot be less stringent than “the emission control that is achieved in practice by the best controlled similar source.” The commenters’ concern that the facility has only recently begun operation and that there is not “significant” experience with the leak definition of 3.1 ppmv does not change the fact that this level is being achieved in practice and thus is the appropriate new source MACT floor. To the extent that the commenter suggests that the cooling towers meeting this limit are different and thus is presumably arguing that they must be subcategorized, the commenter failed to submit any data supporting such a claim. As one commenter suggested, we cannot set the new source limit at 6.2 ppmv because we are establishing these requirements under CAA section 112(d)(2), and we cannot consider cost in setting the MACT floor. The requirements for heat exchange systems are appropriately developed under CAA section 112(d)(2) because a MACT standard had not been previously developed for this emissions source.

One commenter noted that the TCEQ allows some discretion in setting the total strippable VOC concentration limit or altering the limit based on the performance history of the cooling tower. We do recognize that the cooling tower leak definitions for total strippable VOC required in Texas refinery permits varied from 40 parts per billion by weight (ppbw) (or 3.1 ppmv) to 280 ppbw (22 ppmv), including within this range leak definitions at 60 ppbw, 80 ppbw, 150 ppbw, and 180 ppbw, but the 6th percentile facility had a leak definition of 80 ppbw, or 6.2 ppmv total strippable organics as methane. While some permits issued by TCEQ contain language that allows an alteration request or a permit amendment application, as the commenter noted, the permit issued for the 6th percentile cooling tower did not include this type of permit condition. As we cannot establish a requirement less stringent than the MACT floor, we do not provide a 12 ppmv leak definition under any circumstances.

Most of the commenters requesting lower leak definitions appear to misunderstand the stringency of the requirements for heat exchange systems included in the supplemental proposal. Based on the liquid and air flow rates specified in the TCEQ El Paso method, and with the VOC measurements made as methane as required in the State permits and the supplemental proposal, a 3.1 ppmv VOC concentration in the gas stream from the El Paso stripping column is equivalent to 40 ppbw of strippable VOC (as methane) in the cooling water. The 6.2 ppmv leak threshold translates to a strippable VOC (as methane) in the cooling water of 80 ppbw.

The TCEQ HRVOC rule sets an action level that is 50 ppb by weight (ppbw) in the cooling water, not 50 ppb by volume (ppbv) in the stripping air as the commenter suggested. As such, the TCEQ HRVOC rule action level is actually slightly less stringent than the leak definition in the new source MACT requirements. Furthermore, the 50 ppbw threshold only triggers calculations of emissions, and not necessarily corrective action. Therefore, we disagree with commenters that suggest the HRVOC rule requirements are more stringent than the new or existing MACT floor requirements we established.

In our supplemental proposal, we specifically looked at lowering the leak definition for existing sources from 6.2 ppmv to 3.1 ppmv as part of our beyond-the-floor analysis, and determined that this was not cost-effective. Incrementally reducing the leak definition to 2 ppmv would be even less cost-effective than the option we evaluated. Furthermore, it would result in negligible additional emissions, and it is very near the limit of detection of the El Paso method. Therefore, we reject the option of setting the leak definition at 2 ppmv for new or existing sources because it is not a cost-effective.

The commenter requesting different leak definitions for different-sized cooling towers is essentially asking for less control for small cooling towers (i.e., an effective leak definition greater than 6.2 ppmv) and more control for larger cooling towers (i.e., an effective leak definition less than 6.2 ppmv, and in some cases less than 3.1 ppmv). In our review of permits, we found no basis for subcategorizing the cooling towers by different recirculation rates. In addition, the suggested approach is inconsistent with the MACT floor requirements we identified for heat exchange systems. As part of our residual risk impact analysis, we did account for the fact that cooling towers with higher recirculation rates would have larger allowable emissions under the rule. We used these estimates to assess the residual risk associated with heat exchange systems after implementation of the rule and determined that the MACT level of control provides an ample margin of safety.

We also disagree with the comments that claim we did not consider the HRVOC rule in our decision-making process. We found that most cooling towers that are subject to the HRVOC rule are associated with ethylene production units, and not refinery process units. As we specifically collected recent permit requirements for Texas refineries, to the extent there might be refinery cooling towers subject to the HRVOC rule, those requirements were considered in the development of the MACT floor. As explained above, we also disagree with the commenter’s characterization of the stringency of the HRVOC rule in comparison with the new and existing MACT floors.

Our analysis indicated that repair provisions were more important in reducing heat exchange system emissions than using continuous monitoring. Contrary to the commenter’s supposition, there are no repair schedules within the HRVOC cooling tower requirements. The commenter actually referenced the repair provisions for fugitive process equipment leaks (valves and pumps), which are not applicable to cooling towers. In the HRVOC rule, the action level is not a leak definition; rather, the leak definition is used to trigger more frequent monitoring for emission estimation and not specific repair requirements. In the HRVOC rules, facilities with cooling towers must meet an annual and an hourly site-wide HRVOC emissions cap. The hourly cap is quite high, and would not require any heat exchanger leaks to be repaired; the annual cap would tend to drive heat exchanger repairs. A medium-sized 30,000 gallon per minute cooling tower with a leak of 1,000 ppbw total VOC containing 20 percent HRVOC (as defined in the Texas rule) would have to repair within 45 days under the MACT floor requirements of this rule but would not necessarily have to repair in 45 days to comply with the HRVOC rule, which sets a site-wide cap of 10 ton/year (45 days of emissions would release 1.6 tons of HRVOC, under this scenario).

While different scenarios can be devised, the stringency of the Texas HRVOC rule is not as easy to categorize as the commenters suggest, and it could result in less emission reductions than the proposed new or existing source MACT floors.

Contrary to the commenter’s assertion, we also reviewed and evaluated the permit requirements for the cited California refinery, and the permit was included in the docket. The permit, dated April 17, 2008, included a provision for a continuous monitor to be installed at a future date, to be determined, and the planned monitor was not being used at the time of our review. Additionally, based on the cooling tower's recirculation rate and the permitted VOC daily emission rate, the apparent action level (also not yet determined) is likely to be much higher than the leak definition for existing source MACT floors. In the cooling tower memorandum, we only summarized the information from the top-ranked cooling towers; the cooling tower at this California refinery was not included in the memorandum because, based on actual permit conditions, this cooling tower is not among the top-performing 12 percent of cooling towers.

While continuous monitoring was not used by the top-performing cooling towers, and therefore is not part of the floor requirements, we did evaluate requiring continuous monitoring in our beyond-the-floor analysis. However, the cost-effectiveness of this option exceeded half a million dollars per ton of HAP reduced, and therefore, we did not require continuous monitoring as the standard. Rather, we adopted the floor as the MACT standard.

Comment: One commenter noted that the proposed recordkeeping and reporting requirements for heat exchange systems are unnecessarily burdensome, go far beyond the requirements for the MACT floor, and should be revised. For the notice of compliance status, the commenter noted that "heat exchange systems" are an artifact of the regulation, do not normally have specific names, and will change from time to time, so the requirement to identify the heat exchange systems that are subject to the requirements of this subpart should be changed to a list of cooling towers that serve any heat exchange system or systems in organic HAP service. For periodic reports, the commenter stated that: 1) the number of heat exchange systems in HAP service will change over time, so the requirement to report that number should be deleted; 2) the requirement to report the number of heat exchange systems in HAP service found to be leaking should be changed to a request to identify exchangers found to be leaking; 3) the requirement to report the number of leaks in §63.655(g)(9)(iii) duplicates the requirement in §63.655(g)(9)(iii); 4) §63.655(g)(9)(iii) should not require the reporting of measurements below the leak definition and should only ask for a summary of the leaks identified during the reporting period; 5) each 6-month period will include a lot of leaks, so there is no need to report the date of every leak (a record should be sufficient); 6) §63.655(g)(9)(v) should be revised to reflect all delays and to address situations when a leak is detected in one reporting period and repaired in the next; and 7) reporting the estimate of VOC emissions for delay of repair should only be required when the delay of repair option was invoked. For recordkeeping, the commenter stated that: 1) calculating the requested information for each heat exchanger in a refinery will take an estimated 40 hours per refinery and must be repeated every year; these burdens were not included in the ICR and do not add value for exchangers that will not be monitored due to low HAP content, that do not contact HAP, or would not leak into the cooling water; 2) although sources will need a record of which heat exchange systems include exchangers in organic HAP service to comply with the monitoring requirements, identification of all heat exchangers is not necessary; and 3) the information requested §63.655(i)(4)(iii)(E) is sometimes available for whole cooling towers but not readily available for heat exchange exit lines or cooling tower return lines. The commenter stated that temporary heat exchangers and sample coolers should be excluded from these recordkeeping and reporting requirements.

Response: We reviewed the recordkeeping and reporting requirements identified by the commenter. We do not see how the heat exchange system will be as variable as the commenter suggested. We have revised the definition of heat exchange system to clarify our intent. We also (1) amended §63.655(g)(9)(v) to more clearly indicate that all delayed repairs must be included and that delays may occur across reporting periods; (2) amended the reporting requirements in §63.655(g)(9)(vi) to clarify that leak emission estimates are only required for an actual delay of repair; and (3) clarified in §63.655(g)(9)(vi) that the flow rate is for the location where the monitoring occurs. It is anticipated that facilities will monitor at locations where the flow rate is known based on pump curves, heat balance calculations, or other engineering methods. A continuous flow monitor is not required, but a flow rate at the monitoring location is needed to assess the potential mass emissions associated with a leak. For the other comments, we find that the recordkeeping and reporting requirements are needed to document compliance with the rule. Specifically, identifying heat exchangers and heat exchange systems that are in organic HAP service, maintaining monitoring results, and reporting the date a leak is identified and repaired is essential for demonstrating compliance with the monitoring requirements.

2. Applicability Issues

Comment: One commenter supported changing the affected source from “cooling towers” to “heat exchange systems,” noting that it allows the facilities flexibility in monthly monitoring, leak tracking, and determining best sampling locations. Other commenters stated that Refinery MACT 1 should only apply to heat exchange systems that are part of cooling tower systems and should not apply to once-through cooling water systems. The commenters suggested that the supporting documentation indicates that only cooling tower heat exchange systems were evaluated, and if EPA wants to finalize requirements for once-through cooling water systems, the requirements must be properly evaluated and the analyses provided for comment. One commenter stated that the emissions from once-through cooling systems are fundamentally different than systems with cooling towers since once-through systems do not have the air contact and stripping properties of cooling towers, and as a result, a cost analysis of the two systems would show considerably different costs. The commenter also noted that the monitoring and repair techniques employed for the once-through systems are different than the monitoring for cooling tower systems, and these techniques and should be evaluated for Best Demonstrated Control Technology (BDT) if once-through cooling systems are included in the rule. One commenter noted that as proposed, the heat exchange system requirements apply to systems where the pressure gradient would not allow leakage into the cooling water. The commenter noted that these systems do not need monitoring, and a pressure gradient threshold of 35 kilopascals (kPa) should be included in the definition of “heat exchange system” to exempt these types of systems from Refinery MACT 1. Finally, the commenter stated that including the term “cooling tower” in the definition of “heat exchange system” could lead to confusion over the monitoring location requirements.

Response: EPA has developed MACT standards, such as the HON and Ethylene MACT, for heat exchange systems, and these standards include once-through cooling water systems. Generally the HON and Ethylene MACT standards allow alternative surrogate means of compliance that are equivalent to those standards. We considered and rejected these alternatives in the development of the requirements that we proposed for heat exchange systems and that we are now finalizing because the HON and Ethylene MACT standards are less stringent than our floor. We are not aware of any means of surrogate monitoring that would achieve identification of leaks equivalent to the floor level of monitoring required for refinery heat exchange systems.

We believe that control of once-through heat exchanger cooling systems is appropriate for several reasons, as outlined below. First, emissions of volatile HAP such as benzene occur readily from open water sources, which is why the Benzene Waste

Operations NESHAP and the Refinery MACT 1 wastewater provisions require wastewater streams with benzene (as a surrogate for volatile HAP) to be covered and controlled until an appropriate treatment process is used to recover or destroy the benzene. While the stripping process may not be as fast as in a cooling tower, the once-through cooling water will have a much longer exposure to the atmosphere than a system with a cooling tower. Thus, while the emissions may occur over a longer time period (over a larger area), all available scientific evidence and fate modeling studies of open water systems leads us to conclude that essentially all volatile HAP will be released into the atmosphere. As such, we see no reason why HAP leaks from heat exchange systems into once-through cooling water should be treated any differently than HAP leaks from heat exchange systems that have cooling towers.

Second, in conducting the MACT floor analysis for heat exchange systems presented in the supplemental proposal, we assumed that once-through cooling waters were included and that emissions from the once-through systems would be similar to those with recirculation of cooling waters. In reviewing the permits that formed the basis of the MACT floor analysis, we found that the majority did not indicate whether the system was once-through or recirculating. However, we note that some permits included text for monitoring of “cooling towers” and “cooling tower water” and some specified monitoring for “heat exchanger system cooling water.” The latter permits would appear to include once-through systems. Based on review of multiple references, the use of once-through cooling water in the petroleum refinery industry has been declining over the last 40 years, and is now a very small subset of the heat exchanger water systems. One reference indicated that a sample of facilities surveyed back in 1967 showed that only 5 percent of petroleum refineries were still using once-through cooling.[5] No more recent data could be found on how many refineries use once-through systems. A more recent study on once-through cooling systems for cogeneration facilities indicated that approximately 11 percent of non-utility plants that cogenerated power use once-through cooling; the 123 non-utility facilities included pulp and paper, chemical, iron and steel, aluminum, and petroleum refining industries.[6] Of the 123 facilities in the survey, 4 were confirmed petroleum refineries and 3 of these 4 sources provided a response to the survey. None of the 3 reported that once-through cooling systems were used.

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[5] Gibbons, D. C. The Economic Value of Water. Published by Resources for the Future. 1986.
[6] Veil, J., M. Pruder, D. Littleton, and D. Moses. “Cooling Water Use Patterns at U.S. Nonutility Electric Generating Facilities. Environmental Science and Policy. 2000.

Hypothetically, if we assumed that there were additional once-through cooling systems that were not included in our MACT floor analysis, we could assume that approximately 5 to 11 percent of the total cooling systems were once-through. The original number of cooling tower systems included in the MACT floor analysis was 520. If we assume that 5 to 11 percent of the cooling systems are once-through systems, then the total hypothetical number of cooling systems could range from 547 to 584 cooling systems. The MACT floor for these cooling systems would be based on the average emissions limitations achieved by the top 12 percent of cooling systems; the 6th percentile would be represented by the 33rd and the 35th cooling systems, respectively, for the hypothetical total number of cooling systems estimated to be 547 and 584. There would be no change in the MACT floor for existing sources for this hypothetical case. The MACT floor would be identical to the requirements in the supplemental proposal, i.e., the 33rd and 35th ranked cooling systems have requirements to implement corrective action and heat exchange leak repairs when the strippable total VOC concentration in stripped air exceeds 6.2 ppmv. The owner or operator must identify the leaking heat exchanger, and repair at the earliest opportunity and no later than the next scheduled shutdown.

To the extent the commenters are suggesting that once-through systems should be treated as a separate subcategory, they have provided no information to support that subcategorization is appropriate.

We agree with the commenter and have clarified in §63.654(b)(1) that the requirements do not apply to heat exchange systems where the minimum water-side pressure is 35 kPa greater than the maximum process-side pressure. We have also revised the definition of “heat exchange system” to identify the equipment that is included for closed-loop recirculation systems (systems with cooling towers), to identify the equipment that is included in the once-through systems, and to clarify that once-through systems are also regulated. Furthermore, definitions are provided for “cooling tower return line” and “heat exchanger exit line” to clarify the appropriate sampling locations. Sampling at either location is allowed; for once-through cooling systems, sampling is allowed at an aggregated location as long as it is before exposure to the atmosphere. To clarify this requirement, we have modified the definition of “heat exchange exit line” to be “the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere, whichever occurs first."

3. Compliance Schedule for Heat Exchange Systems

Comment: Several commenters supported the originally proposed compliance date of 3 years and 90 days. One commenter noted that the reference to 90 days in CAA section 112(f)(4) has been misread by some to limit compliance time, but since it is expected that installation of controls necessitates a longer time to comply, the waiver provisions should only be considered if EPA set a compliance deadline less than 3 years. Some commenters noted that 18 months should be sufficient for all new requirements, as industry is already familiar with many of the processes to be controlled and are already regulating these emissions.

Several commenters addressed the compliance dates relative to the supplemental proposal. For new sources, commenters noted that these requirements will be promulgated only 2 months after they were proposed in the supplemental proposal, which is inadequate time in which to have monitors purchased and operating. The commenters asserted that EPA should provide 1 year for new sources to comply with the standards.

Commenters specifically noted that although many Texas refiners are currently familiar with the monitoring methods required for heat exchange systems, it took years for them to gain that familiarity, and it will take time for other refiners to learn to perform the methods efficiently. One commenter noted that when monitoring begins, there will be an initial period in which multiple repairs are necessary, some of which may require shutdowns. The commenters recommended that EPA provide the full 3 years provided by the CAA for compliance with heat exchange system requirements; this additional time would allow refiners to become familiar with the monitoring method and to complete initial repairs during already scheduled shutdowns and turnarounds. Conversely, several commenters stated that the cooling tower standards should be implemented in 1 year rather than progressively over 3 years as proposed in the supplemental proposal. Another commenter stated that the 18-month compliance schedule for heat exchange systems in the supplemental proposal is preferable to the 3 year (and 90 days) compliance schedule in the original proposal.

Response: As an initial matter, we note that the originally proposed compliance schedule (i.e., three years and 90 days) should not have included the additional 90 days. Section 112(i)(3) of the CAA provides that existing sources must comply within “3 years after the effective date” of the standard. With respect to the 18-month compliance timeframe specified in our supplemental proposal, we agree that the comments have made valid points supporting adoption instead of a 3-year compliance period. The comments that many refineries do not have experience with the TCEQ El Paso method is supported by our review of cooling tower requirements for different States. We believe that some sources will need up to the full 3 years allowed under CAA section 112(i)(3) based on the estimated length of time required for refiners to survey the heat exchangers, identify those in organic HAP service, install the necessary sampling ports, purchase the Modified El Paso sampling system, familiarize themselves with the test method, and provide training to their employees. In addition, refiners will need to take steps to be prepared to repair leaking heat exchange systems. This includes performing initial sampling to identify heat exchangers that are prone to leakage or are in critical service, identify means to isolate or repair heat exchangers online, and to order and stock necessary equipment and spare parts.

With respect to new source requirements, the CAA specifies that such sources must comply upon start-up or the date of publication of the final rule, whichever is later. We note that, based on the definition of an affected source in the Refinery MACT 1 rule, a construction project significant enough to trigger the new source provisions is likely to take years to complete, and that any source undertaking such project has been on notice since our initial proposal that cooling tower monitoring (or heat exchange system monitoring) would be required.

4. Delay of Repair Provisions

Comment: Commenters noted that the new source delay of repair standards are based on cooling towers that are not yet operational, so those permit conditions are not "achieved in practice." The commenters argued that it takes time after startup of new facilities to determine if new, previously untested requirements are achievable or whether permit modifications are needed; it is also unknown if Texas will allow deviations from permit conditions and under what conditions for heat exchange system repairs. The commenters stated that the new source delay of repair standards must instead be based on "Repair and Delay 2" as described in Table 1 of EPA's supporting memorandum (which the commenter thought were the requirements for the existing source floor).

One commenter supported the 45-day repair allowance and delay of repair allowances. Another commenter stated that the maximum delay of repair should be 60 days because refineries already have 18 months to comply. Some commenters expressed concern that EPA proposed to disallow delay of repair for leaks above 62 ppmv after 3 years and noted that EPA has not demonstrated the rationale for removing that allowance. One commenter stated that EPA needs to address the situation in which multiple small leaks occur at multiple heat exchangers and the cumulative effect at the cooling tower return line is a leak above 62 ppmv. The commenters stated that unplanned shutdowns are expensive and disruptive but would be necessary when repair is infeasible without a shutdown. One commenter requested that EPA allow owners and operators to request delay of repair on a case-by-case basis when justified.

Response: The supplemental proposed MACT floor for both new and existing sources is repair within 45 days for leaks of 62 ppmv or greater. In establishing the floor, we found that the no delay of repairs requirement for large leaks has been implemented and required for 35 cooling towers at numerous facilities. Also, both the top-ranked and 6th percentile cooling tower had identical requirements excluding large leaks from delay of repair. As such, this requirement has been implemented and has been adequately demonstrated and it establishes the minimum floor requirement. In the supplemental proposal, we proposed to allow delay of repair for large leaks for the 18 month phase-in of the repair requirements, which correspond to the “Repair and Delay 2” provisions cited by the commenter. However, we have concluded that these temporary delay of repair provisions were not equivalent to the requirements for the MACT floor for existing heat exchange systems, which is why they were only temporary provisions in the supplemental proposal. Additionally, the 3-year compliance timeframe in the final rule will allow facilities sufficient time to resolve these initial problems. As discussed previously, we are now implementing all heat exchange system requirements for existing sources on the same 3-year schedule. Upon implementation of the required monitoring provisions, it is anticipated that leaks will be identified well before they become large. Thus, while delay of repairs are allowed for small leaks, it is the refinery owner or operator’s responsibility to order necessary parts and schedule a repair before the leak exceeds the 62 ppmv threshold. Negligence on the part of the owner or operator regarding this responsibility is not a reasonable justification for providing delay of repair provisions for large leaks. Consistent with the requirements that apply to the units which provided the basis for the MACT floor, any leak greater than 62 ppmv that is not repaired in the timelines provided in the rule is a deviation of the standard and subject to enforcement actions at the discretion of the Agency or permitting authority.

5. Monitoring Alternatives

Comment: Commenters noted that the concentration of heavy organic HAP and water soluble HAP can build up in recirculating cooling tower systems, and since the El Paso method involves more vigorous stripping than occurs in a cooling tower, monitoring might falsely indicate a leak. The commenters suggested that as an alternative, sources should be allowed to use methods they are presently using, including testing the inlet water to a heat exchange system and using the difference between the outlet and the inlet to determine if the leak definition is exceeded. One commenter noted that if once-through cooling systems continue to be considered affected facilities by EPA, it is important for the requirements to consider the baseline of HAP (or surrogate VOC) emissions in the inlet to the system so that facilities are only responsible for assessing any “increase” in the pollutant attributed to the operating facility, not pollutants in the water basin upstream of the facility. Another commenter requested that EPA allow owners or operators to demonstrate that another monitoring method such as CEMS or parameter monitoring is equivalent to the monitoring methods specified for heat exchange systems. One commenter requested that EPA continue to allow the method originally proposed as well as a relatively new analytical method for early detection developed by Baker Petrolite. Another commenter stated that the El Paso method measures VOC in the air, and EPA should allow any monitoring method that has adequate sensitivity to measure 80 ppbw of strippable VOC in the water or for a surrogate that can be correlated to strippable VOC and can be measured at a level that would indicate a leak of 80 ppbw of strippable VOC in the water for a particular heat exchange system. This monitoring flexibility would be helpful to confirm El Paso results as well as more efficient for sources that are required to conduct other types of monitoring by their State or local agency or for compliance with another Federal regulation (such as the HON).

Response: We acknowledge that some refineries have specific monitoring systems in-place and that the use of these monitoring systems would ease the burden on the refinery owner or operator. However, we are not aware of any practical alternatives that we can specify that provide an equivalent measure of strippable organics. Nor have any of the commenters provided evidence that a specific alternative method would result in an equivalent measure. For example, we have reviewed the “method for early detection developed by Baker Petrolite” and found that the detection level for most individual compounds is much higher than the total strippable VOC concentrations that define a leak for the MACT floor facility. That is, this method would not be able to identify small to medium-sized leaks that would be identified and would be required to be fixed by the MACT requirements for heat exchange systems.

Although we expect the El Paso column to mimic the stripping that occurs in the cooling tower, the amount of stripping that occurs in the cooling tower is dependent on the design and operation of the cooling tower. Moreover, the purpose for the use of the El Paso method is to detect leaks in heat exchange systems, not to estimate emissions. Consequently, we do not believe that analytical methods based on the measurement of single constituents or that employ inlet/outlet cooling tower water sampling are equivalent to the El Paso method for determining strippable VOC. That is, these alternative methods would not result in the same corrective action thresholds as the prescribed monitoring technique.

The commenters have provided no evidence that a build-up of heavy organics would cause a heat exchange system to exceed a leak definition of 6.2 ppmv total strippable VOC, nor have they provided compelling evidence that such a leak would not result in any air emissions. While we agree that the relative stripping efficiency of a given cooling tower will not necessarily match the stripping efficiency of the El Paso stripping column, it is unreasonable to conclude that the cooling tower will have no HAP emissions. Furthermore, the majority of HAP included in Table 1 are volatile. Thus, for a heat exchange system that is “in HAP service”, we believe it is appropriate to initiate corrective action if the leak threshold is exceeded because that corrective action will result in reduced HAP emissions.

As stated previously, the goal of the heat exchange system provisions is to identify and fix leaks at the heat exchanger to reduce subsequent emissions of HAP. For once-through cooling systems, we believe it is unlikely that the strippable organics concentration in the inlet water would exceed the leak threshold. Further, the commenters have provided no evidence that the fresh water feed for a once-through heat exchange system could contain enough strippable organics to cause a heat exchange system to exceed a leak definition of 6.2 ppmv total strippable VOC. Therefore, we have not provided any alternative leak detection procedure for once-through heat exchangers.

Comment: Commenters supported allowing the facility to demonstrate that a leak is not in a heat exchanger that is in HAP service. One commenter stated that if VOC testing indicates a leak in a heat exchange system, the facility should be allowed to speciate the compounds in the leak to determine if the leak is a HAP leak. Another commenter agreed, noting that proposed §63.654(e) requires monitoring of every individual exchanger in organic HAP service in a heat exchange system in order to prove that the leak is not from an exchanger in organic HAP service. The commenter stated that this requirement is very costly and recommended three alternatives: 1) the owner or operator should be allowed to determine the species in the process or processes served by the cooling tower to determine if the process is in HAP service; 2) the owner or operator should be allowed to speciate the sample from the cooling tower return line to determine the leaking heat exchanger; and 3) the owner or operator should be allowed to sample groups of heat exchangers rather than each individual heat exchanger.

One commenter noted that the supplemental proposal appears to only allow sampling at the outlet of each heat exchanger or at the inlet to a cooling tower, but it is often preferred to sample at branch points in cooling tower return piping for several reasons: 1) only a particular branch has exchangers in HAP service; 2) it is easier to identify the source of any leak that does occur; or 3) a particular cooling tower is shared among administrative units and compliance is more readily achieved if each unit is responsible for its own heat exchangers. The commenter also noted that the language is inconsistent with the definition of "heat exchange system," which can be any number of exchangers, not just one exchanger or all exchangers in a particular cooling water loop. The commenter suggested revisions to the definition of "cooling tower return line" to clarify the requirement.

Response: The purpose for the rule is to find and fix leaks for heat exchange systems in organic HAP service. If a leak is detected at a cooling tower return line or in a once-through system, the owner/operator can find and fix the leak by any means possible, including the means specified by the commenters. If, however, the owner/operator does not want to fix the leak because they believe that the leak is caused by heat exchangers that are not in organic HAP service, the only way to definitively prove that is to test the individual or groups of heat exchangers in organic HAP service that make up the system in which a leak has been detected.

The Texas permit data and TCEQ El Paso Method is based on strippable VOC. We found that this is an appropriate surrogate for HAP emissions for cooling towers that are in HAP service. A refinery may use speciation of the El Paso column stripping air or other methods at their discretion to determine the location of the leak. However, we cannot provide, based on the MACT floor requirements, an alternative action level that defines a

HAP leak as opposed to a VOC leak, as the commenter proposes.

We have made minor adjustments to the final standards to allow our intended outcome of alternative 3, as described by the commenter. Specifically, we have clarified the definition of heat exchanger exit line to include water lines from "one or more heat exchangers." This clarification is intended to allow monitoring using the Modified El Paso method from each heat exchanger <u>or group of heat exchangers</u> in organic HAP service upstream of the cooling tower return line. For example, if three process units are served by one heat exchange system and multiple heat exchangers are grouped by process unit and the three return lines combine before the main cooling tower return line, then the owner or operator may choose to measure each of the three return lines associated with a process unit in organic HAP service. If monitoring at those points results in concentrations less than the leak definition, then no repair is necessary.

6. Impact and Risk Estimates for Cooling Towers

<u>Comment</u>: Several commenters argued that EPA's estimates of baseline emissions were based on faulty and unsupported premises. One commenter stated that the model cooling tower sizes understate the emissions because the average flow rate is a factor of 2 less than in a study performed by the Galveston-

Houston Association for Smog Prevention (GHASP). One commenter said the emissions are understated because they do not include HAP emissions from SSM events. Two commenters questioned the use of TCEQ inventory data. One commenter stated that the TCEQ inventory appears to be biased low for HAP when compared to the Toxic Release Inventory (TRI) reported releases (on a plant-wide basis). The other commenter suggested that EPA mistakenly assumed the TCEQ data were based on controlled emission factors in projecting the baseline emissions ranging from 352 to 2,300 ton/yr because of the guidance provided in the 2006 TCEQ inventory guidelines for cooling towers. The commenter also cited a URS Report where two high rate leaks were identified as evidence that the baseline emission rates were too low.

Two commenters stated that the cooling tower impacts do not account for the maximum emissions allowed under the proposed MACT standard as required in its CAA 112(f)(2) risk determination. According to the commenters, the cooling tower impacts assume 50 percent of leaks are fixed as soon as possible rather than the 45 days allowed in the proposed rule, and they do not account for permitted delay of repair for up to 120 days. Also, the commenters stated that the EPA did not justify the 50 percent assumption for delay of repair and should assume all refineries will delay repair.

Two commenters also cited variability in the emissions from cooling towers as a concern. One commenter stated that the use of a single average HAP content for the cooling tower emissions estimates does not consider the range of potential HAP concentrations. Another commenter questioned the use of 2004 TCEQ inventory data by comparing the 2004 TCEQ inventory for selected refineries with TCEQ data for 2005 and 2006, which showed that the quantity and composition of emissions is variable from year to year. According to this commenter, EPA failed to account for this variability or provide rationale as to why the 2004 emissions data are representative, and therefore the analysis fails to capture all refinery emissions and is unlawful.

Response: We disagree with the commenters that state that the cooling tower emissions were understated or otherwise not properly characterized when developing the impacts and risk estimates. With respect to the cooling tower sizes, the GHASP study includes refineries and chemical plants, and the data are skewed by several large cooling towers, which we believe are associated with petrochemical (ethylene) plants and not refineries. Eliminating the three largest cooling towers of the 54 cooling towers in the GHASP dataset brings the data (which includes only the Houston area, which has larger than averagesized refineries) in reasonable agreement with the projected size-distribution of cooling towers (the mean cooling tower recirculation rate in the GHASP data is reduced from a factor of 200% to a factor of 50% above the mean flow rate in our impacts analysis). The TCEQ emissions data and the AP-42 emission factors are the best available data by which to estimate cooling tower emissions. The TRI does not provide emissions breakdown by source, so it is impossible to determine what emissions in the TRI are associated with cooling towers.

We specifically consider SSM emissions in the cooling tower impacts. Heat exchanger leaks that result in cooling tower emissions are a type of malfunction. If the units operate as designed, there would be no emissions from the cooling towers. No additional emissions are expected specific to cooling towers during start-up or shutdown events. The requirements for monitoring and repairing heat exchange systems directly address malfunction emissions.

We also note that selected short-term emissions from selected heat exchanger leaks are not indicative of the average long-term emissions that are appropriate for estimating chronic effects or life-time cancer incidence. Not all heat exchange systems leak every year, and the leaks that do occur do not last all year long. Note also that two of the “leaks” identified in the cited study were comparable to the controlled AP-42 emission factor. Our impact estimates directly account for the fact that some heat exchangers do not have leaks at all, some have small leaks, and some have large leaks. We compared emission estimates using a variety of methods and determined that the baseline and controlled emission estimates were as accurate and unbiased as we could develop.

The commenters also incorrectly characterized our emission estimates with respect to repair times. For cooling towers that were assumed to be repaired as soon as possible, we used the full 45-day repair allowance plus 15 days (one-half the monitoring frequency) for estimating the duration of the leak. Leaks may occur any time between monitoring events, but 15 days provides the best estimate of the average leak duration prior to identifying the leak. Once a refinery owner of operator measures a leak and identifies its source, they will also know what actions are needed to reduce the leak. In some instances, the refinery owner and operator will find that the cost of repairing the leak is easily offset by the recovery of the leaking product or process stream. In these cases, the refinery owner or operator will elect to repair the leak rather than delay repair. While data are limited, our best engineering estimate is that roughly 50 percent of leaks will be repaired within the first 45 days simply because it is economical to do so. For the 50 percent of leaks for which repair is delayed, 120 days was used as the duration of the leak when estimating the emissions from these units.

With respect to the TCEQ data, we are confident that the controlled AP-42 emission factors were generally used. Public comments were received on the original proposal requesting corrections be made to the emissions data for the highest emitting cooling towers in the TCEQ dataset because the uncontrolled AP-42 emission factor had been incorrectly used, and that the controlled AP-42 emission factor should be used. We also note that TCEQ’s 2006 guidance on use of AP-42 emission factors cited by the commenter came out well after the 2004 inventory was developed, so its use was not possible. Finally we note that, if the TCEQ inventory estimates were based on uncontrolled emission factors, then the 352 ton/yr projection from the TCEQ data would be the upper-end of the range, which would make the baseline emission estimate lower, not higher.

Finally, while leaks from heat exchangers that give rise to cooling tower emissions are inherently random and variable, our analysis was specifically designed to provide an estimate of the long-term (life-time) exposure from cooling tower emissions. Assuming that all leaks come from a specific unit with high HAP content, that all leaks are big, and that all repairs will be delayed provides a completely unrealistic picture of long-term emissions. When assessing short-term exposure, we multiplied our long-term emissions by a factor of 10, which effectively accounts for the variability in emissions cited by the commenters.

Comment: One commenter stated that the cancer incidence and cancer incidence reductions for the different control levels are very small, but empirical data [in GHASP Report 2006] shows substantial emissions reductions. The commenter stated that cooling tower emission reductions are estimated by EPA to be 4 to 10 percent, but the GHASP Report 2006 shows reductions on the order of 90 percent. As such, the emission and reduction estimates are unreasonable and conclusions drawn from the model estimates are unreliable.

Response: The model plant analysis includes all emission sources covered under the Refinery MACT 1 regulation. If, at baseline, cooling towers represent only 5 percent of a refineries HAP emissions, a 90 percent reduction in cooling tower emissions would only result in a 4.5 percent reduction in the nationwide baseline HAP emissions from refineries, and this would translate into a cancer incidence reduction that is also approximately 4.5 percent (0.001 to 0.002 cases/year). The cooling tower impact memo (Docket ID No. EPA-HQ-OAR-2003-0146-0143) indicates that the proposed MACT requirements for cooling towers will result in an 82 percent reduction in VOC and HAP emissions from cooling towers.

B. Storage Vessels

1. Compliance Schedule

Comment: Several commenters supported the 10-year compliance window allowed by 40 CFR part 63, subpart WW. Some commenters expressed concern that the proposed compliance date of 90 days after publication of the final amendments in 40 CFR 63.640(h)(4) could be interpreted as overriding the 10-year compliance schedule in subpart WW; these commenters requested clarification that the compliance deadline for installation of controls is the next time the storage vessel is taken out of service or within 10 years if installation cannot be made without taking the storage vessel out of service. For new sources, one commenter noted that these requirements will be promulgated only 2 months after they were proposed in the supplemental proposal, and 2 months is inadequate notice to install necessary controls. The commenter asserted that EPA should provide 1 year for new sources to comply with the standards.

On the other hand, several commenters opposed a long compliance window for storage vessels, stating that these new standards need to be implemented as soon as possible and not wait 10 years. Two commenters suggested that 6 months (180 days) be provided from the date of promulgation; another commenter recommended only 90 days be allowed as required in CAA section 112(f)(4)(A) because guide pole retrofit kits are readily available and are easy to install with no down time for the storage vessel. One commenter stated that refiners should schedule taking affected storage vessels out of service as soon as possible to install controls; the commenter suggested that EPA should require them to submit a schedule within 6 months. Several commenters stated that the CAA section 112(f)(4) timing is clearly applicable, which allows EPA to provide a maximum of 2 years to comply. The commenters noted that even if EPA follows CAA section 112(i)(3), which is more permissive than CAA section 112(f)(4), it allows a maximum of 3 to 4 years for compliance, so EPA’s proposed compliance schedule for storage vessels is illegal. One commenter stated that guide pole controls have been required through the NSPS since the 1980’s, so there is no need and it is unlawful to delay adding these controls.

Response: For existing Group 1 storage vessels, the supplemental proposal would have required that owners and operators comply with the requirements in subpart WW of this part within 90 days. The 90-day period is sufficient to transition the inspection and recordkeeping and reporting requirements of subpart WW; however, it is not sufficient for refinery owners and operators to install the controls. For safety reasons, the storage vessels must typically be emptied and degassed before the controls can be installed. We note that subpart WW provides up to 10 years for the installation of fitting controls. However, we agree with commenters that in this case the CAA does not provide for a 10-year compliance schedule. Therefore, we evaluated the feasibility of requiring the controls over a shorter time period.

Our original analysis of the cost-effectiveness of these controls was based on allowing owners and operators installing controls during a normal tank cleanout, which is typically every 10 years. It should be possible for refinery owners and operators to empty and degas tanks when individual process units are shut down for maintenance or during a plant turn-around. These generally occur every 2 to 5 years, depending on the process. In addition, refineries typically have multiple storage vessels in each service providing some level of flexibility in cleaning out and installing storage vessel controls while process units remain in operation. As such, we believe most refinery owners or operators will be able to retrofit those tanks that are not already compliant with the new standards within the first 3 years. If a refinery owner and operator have an adequate rationale why the controls could not be installed within the 3-year timeframe, they may petition their permitting authority for an additional year to install the necessary controls, as provided in CAA section 112(i)(3).

To determine the costs associated with a 3-year compliance timeframe (with the possible 1 year extension from the permitting authority), we revised our impact analysis to evaluate the magnitude of the additional emissions that occur during emptying and degassing a storage vessel as well as the loss of product that will occur during an additional tank degassing episode. We found that these additional emissions were small compared to the emission reductions achieved by complying earlier than the time proposed. Therefore, based on our analysis we concluded that the additional storage vessels controls result in a cost savings if sources are required to install controls within 3 years, recognizing that sources may, if necessary to install controls, request an additional year to comply from their permitting authority

2. Control Requirements

Comment: A wide range of comments were received regarding the Group 1 storage vessel requirements. Some commenters supported Option 1, no further controls, noting that the risk reductions achieved by the storage vessels control options were small. Some commenters supported Option 2 but requested that EPA use clear terminology consistent with the most recent rules and technologies for storage vessels: 40 CFR part 63, subpart WW (Generic MACT) and the Storage Tank Emission Reduction Partnership Program (STERPP) (described at 65 FR 19891).

Several commenters supported Option 3 but requested specific revisions. One commenter noted that the STERPP includes the flexible enclosure system as a control system for EFR storage vessels with slotted guide poles, but 40 CFR part 63, subpart WW, does not. The commenter requested that EPA revise Refinery MACT 1 to allow a flexible enclosure system as a control option. Another commenter similarly requested a sleeve-without-a-float option for EFR slotted guide poles. Several commenters noted that by removing the references to the HON storage vessel requirements, EPA removed requirements for storage vessels that are controlled using closed vent systems and control devices. The commenters recommended that rather than continuing to reference the HON, Refinery MACT 1 should reference the NESHAP for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

(40 CFR part 63, subpart SS). The commenters noted that this subpart was developed as a “companion” set of requirements to subpart WW and is equivalent to the HON in stringency.

Commenters supported requirements for slotted guide poles but objected to the proposed requirements to equip other deck fittings with gaskets. The commenters noted that EPA should have evaluated full guide pole controls separately from other fitting controls; instead, EPA evaluated only pole sleeves for slotted guide poles as Option 2 and included the pole wiper in Option 3. If the analysis had been done that way, the commenters stated that EPA would have concluded that other deck fittings achieve little emission reductions and are not cost-effective.

Commenters also noted that proposed Option 3 would require deck fitting gaskets on IFR storage vessels, and they requested that EPA remove those requirements due to the small emission reductions achieved and unreasonable cost-effectiveness. Commenters noted that in the preamble to the supplemental proposal, EPA stated the intent to regulate EFR storage vessels, not IFR, and there is no supporting documentation to show the impacts of controls on IFR vessels. One commenter suggested language for ensuring that IFR vessels are not required to comply with the guide pole and deck fittings requirements of subpart WW.

Response: In response to the commenters who opposed any additional requirements because the current standards provide an ample margin of safety, we note that while we have determined that the risk reduction gained by requiring additional storage vessel controls is limited, HAP emission reductions can be achieved at a cost savings. This is because the annual value of recovered product exceeds the annualized cost of the controls. For these reasons, we are requiring these controls only under CAA section 112(d)(6). The commenters supporting proposed Option 1 did not dispute the overall cost-effectiveness of the storage vessel control requirements, nor did they contend that Options 2 or 3 provide no emission or risk reduction. That is, the commenters provided no data or comments to suggest that the controls will not reduce emissions and risk in a cost-effective manner. Therefore, we maintain that the additional control requirements included in the final amendments are justified under CAA section 112(d)(6).

We agree with the commenters that flexible enclosure systems are not included in subpart WW and that the Agency has found these controls to be equivalent to other identified controls. We therefore have added these systems as an option for EFR storage vessels. The sleeve-without-a-float option identified by the commenter is also equivalent and is already allowed in the subpart WW standards, as long as the pole sleeve is accompanied by a pole wiper (see 40 CFR 63.1063(a)(2)(viii)(B)).

We agree that requirements for closed vent systems were accidentally removed from the rule when we removed the cross reference to the HON and should continue to be provided in subpart CC. Therefore, we have added references to 40 CFR part 63, subpart SS where needed.

As explained in the supplemental proposal and accompanying documentation, control of deck fittings with gaskets is included in subpart WW and is a low-cost way to further reduce HAP emissions from storage vessels. Adding the deck fitting controls on EFR that already have guide pole controls reduces HAP emissions by 100 ton/yr at a cost savings of $1,800 per ton of HAP reduced.

The commenters are correct that the text of the proposed rule would have required guidepole controls and deck fittings on IFR storage vessels, a result we did not intend. We have revised the rule so that the requirements do not apply to IFR storage vessels. The emission reductions achieved by these fitting controls for IFR storage vessels are not large (only 13 tons of organic HAP emissions) and the cost-effectiveness is $48,000 per ton of HAP reduced. These costs are disproportionate with the emission reduction and the risk reduction that would be achieved. As such, we rejected these additional controls for IFR storage tanks as not required to provide an ample margin of safety under CAA section 112 (f) and not necessary as a cost-effective technological or other improvement under CAA section 112(d)(6).

Comment: Some commenters argued that options for Group 1 storage vessels do not go far enough to reduce emissions and risk. Specifically, commenters requested that EPA consider: (1) requiring slotted guide pole sleeves and gasketed covers for IFR storage vessels (not just EFR); (2) requiring emissions controls during roof landings associated with deliveries and transfers; (3) restricting roof landings for convenience; (4) requiring add-on controls for degassing and interior storage vessel cleaning; and (5) requiring domes or covers for EFR storage vessels. Commenters also asked EPA to consider: (1) requiring annual inspections of all IFR and EFR storage vessels and seals, regardless of seal type; (2) requiring infrared camera inspections during each annual secondary seal inspection of all IFR and EFR storage vessel openings, including seals, hatches, gaskets, fittings and slotted membranes instead of visual inspections through a manhole or roof hatch; (3)

requiring detailed inspections of seals and fittings every 10 years; (4) establishing a more rigorous leak detection program; and (5) eliminating 30-day extensions to the time allowed for a leak repair. Commenters stated that incorporation of more effective technology such as the infrared cameras is consistent with the obligation imposed by the CAA to review technological developments every 8 years. One commenter noted that retrofitting EFR storage vessels with geodesic domes and controlling storage vessel roof landings and degassing is required in certain California bulk terminals and were recently proposed by the State of New Jersey. According to the commenter, EPA's failure to consider these developments renders the supplemental proposal incomplete, arbitrary, and unlawful.

Response: In response to these comments, we evaluated a number of additional control options. First, we evaluated an option for requiring gasketed fitting controls on IFR storage vessels. As described in the response to the previous comment, we determined that these control options were not required to provide an ample margin of safety. Next, we evaluated requiring EFR storage vessels to be retrofitted with geodesic domes (essentially converting them to IFR storage vessels). Installation of geodesic domes on EFR storage vessels yields significant additional HAP emission reductions. However, the cost-effectiveness of requiring geodesic domes for gasoline storage vessels is approximately $28,000 per ton of HAP reduced and the cost-effectiveness of requiring geodesic domes for other Group 1 storage vessels is approximately $140,000 per ton of HAP reduced. Based on our evaluation of the risk reduced in light of the cost, we have concluded that these controls are not required to provide an ample margin of safety and are not necessary under CAA section 112(d)(6).

With respect to storage vessel roof landings at petroleum refineries, the commenters provided no data to support their conclusion that roof landings occur for convenience or that suggests that storage vessel roof landings occur frequently or result in emissions that would cause significant risk. Commenters provided information on roof landings at storage and transfer facilities where roof landings occur routinely. This information is not relevant to refineries. For refineries, there is no need to routinely land the vessel roof, and the emissions that occur during landings would represent significant product losses, so the refineries have an incentive to avoid these roof landings. We note that the final rule for storage vessels requires refiners to keep records of all floating roof landings. These records will provide a means of obtaining data by which roof landing emissions can be better characterized.

When a storage vessel is landed on its legs or emptied there are organic vapors that may include HAP or VOC under the roof. To control the emissions of these vapors or to remove them to allow for cleaning or inspection of the inside of the tank, the tank must be degassed. Certain State and local air pollution control agencies have developed requirements to control these vapors during the degassing process. Based on information supplied by one of the commenters regarding the New Jersey regulation, degassing emissions are less than 1 percent of the baseline emissions from storage vessels. Reducing this small fraction of storage vessel emissions will have an imperceptible impact on the projected risks from all Refinery MACT 1 sources. Additionally, given the reported cost-effectiveness of degassing control as $2,300 to $4,300 per ton of VOC reduced, the cost-effectiveness of these controls in terms of HAP emissions reductions would range from $21,000 to $40,000 per ton of HAP reduced. Based on the limited emissions and risk reductions achieved by these controls and considering the cost of these controls, we conclude that these controls are not necessary to provide an ample margin of safety to protect public health and are not necessary under CAA section 112(d)(6).

Subpart WW does require thorough inspection of seals and fittings at least every 10 years (or when the tank is emptied and degassed). It also requires inspection of EFR primary seals every 5 years, EFR secondary seals annually, IFR visual inspections of deck, deck fittings, and rim seals annually (or thorough inspection every 5 years). These inspection frequencies have been developed over many years of experience and are based on the likelihood of a seal failure and an evaluation of the costs of performing the inspections and the emissions avoided by finding leaks more quickly with more frequent monitoring. Additionally, there are significant hazards associated with monitoring and repairing seals and fittings on storage vessels. Providing a 30-day extension to repair leaks is far preferable to requiring unsafe repairs and potentially catastrophic releases associated with an explosion of a tank. Based on our review of these provisions and inspection requirements in other storage vessel standards, we believe the monitoring requirements provided in subpart WW to be adequate to ensure compliance with the standards.

We encourage the use of infrared (IR) cameras to identify VOC and HAP emission leaks on a voluntary basis. We have recently published an alternative work practice protocol where owner/operators can elect to use the IR camera to help comply with equipment leak regulations. Substantial research has been done over several years to develop an IR camera-based approach for that application and even after that effort we do not believe that we are yet in a position to require the use of the IR camera for finding equipment leaks. For storage vessels, we are not aware of any information that correlates emissions that would occur under the current storage tank seal gap requirements with what the IR camera would see to know that the camera would in fact be better than visual seal gap measurements.

3. Impact Estimates for Storage Vessels

Commenters cited a number of inconsistencies in the overall storage vessels analysis to support their assertion that EPA overstated the emission reduction impacts of Option 3 as included in the supplemental proposal: 1) the supporting documentation states that the evaluation was based on pontoon-type EFR storage vessels, but the TANKS model gasoline storage vessels were based on double-deck type EFR storage vessels; 2) the quantity of deck fittings is not the same in each TANKS run for gasoline storage vessels; 3) the analysis states that the number of calculated turnovers is 182-190 per year, but the given throughput and storage vessels dimensions would result in 59-60 turnovers per year; 4) the analysis states that the model gasoline storage vessels were based on a Reid vapor pressure of 11 psi, but the TANKS runs show 8.3 psi; 5) the vapor-phase HAP content for these storage vessels is overestimated (the gasoline

HAP content of 10.8 weight percent is four times higher than the TANKS default of 2.7 percent, which is about three times higher than is presently allowed in gasoline due to EPA regulations); and 6) the TANKS runs in the supporting documentation show gaskets on roof legs, which are not required by 40 CFR part 63, subpart WW (the gaskets are applied to deck covers, and roof legs do not have deck covers) or by any other Federal regulation. One commenter noted that EPA did not consider how many sources had already installed the required controls; the commenter believed that a large number of sources installed controls voluntarily as part of STERPP.

One commenter questioned EPA's assumption that shells are in "good condition" for the storage vessel emission estimates, and noted that EPA may not get the reduction anticipated if storage vessel seals are leaking or poor work practices are used. Another commenter questioned the fixed assumptions of API gravity of the crude oil, stating that the analysis did not account for the variability in volatility of crude oil.

Response: We appreciate the commenters' thorough review of the "Storage Vessel Impacts Memo." We acknowledge that there were minor differences between the actual TANKS model runs (included as attachments to the Storage Vessel Impact Memo) and the descriptions of the inputs to the TANKS model as described in the Storage Vessel Impact Memo. Specific replies to the commenters' specific issues follow: 1) a pontoon roof was used for crude and jet naphtha storage vessels; a double-deck floating roof was used for the gasoline storage vessel; 2) it appears that for one of the model storage vessels, the typical fittings setting was selected and altered, which altered the fittings used for selected runs. These changes made small changes in the emission estimates, which have been corrected; these changes are so small that they do not affect the conclusions drawn from the analysis; 3) the reported throughput and the storage vessel volume match the turnover rates; perhaps the commenter did not multiply by pi; 4) the default properties for gasoline RVP 8.3 were used for all gasoline model runs to estimate VOC emissions; 5) the HAP content of gasoline was based on the compositional data external to the TANKS model [We note that recent data obtained regarding the HAP vapor composition of gasoline (see Docket Item No. EPA-HQ-OAR-2006-0406-0045) suggests that the HAP content for gasoline vapor has decreased slightly (by 30 percent), but not by a factor of 3 or 4 suggested by the commenter.]; and 6) a few selected runs did evaluate the effect of gaskets on roof legs; however, we never intended to require gaskets on roof legs. The emissions for EFR storage vessels have been recalculated using ungasketed roof legs for all scenarios; these revisions made very small impacts on the overall costs of the control options we considered, and did not impact the conclusions drawn as a result of the analysis.

The storage vessel design properties and the storage vessel content properties were selected to be representative of the range of Group 1 storage vessels and to provide a relative impact estimate for requiring additional controls on there storage vessels. While individual storage vessel sizes, roof-types, number of fittings, and storage vessel contents vary from vessel to vessel, the analysis performed here provides a reasonable basis for evaluating the different control options that were considered for Group 1 storage vessels.

To the extent that more storage vessels are presently controlled than we estimated, it would proportionally reduce both the costs and the projected emission reductions associated with these control requirements. However, these revisions to the analysis would not change the cost-effectiveness of those requirements or the conclusions drawn as a result of the analysis. We note that the commenter provided no direct data to support their assertion that more storage vessels have already installed the required controls than we had projected. We appropriately developed our emission estimates based on the best data we had available, and we reiterate that, even if the number of tanks needing controls is overstated, the cost-effectiveness and therefore our decision regarding the final requirements for Group 1 storage vessels is unaffected.

Comment: Commenters noted that many refinery storage vessels are already subject to new source performance standards (NSPS) in 40 CFR part 60, subpart Kb, and stated that vessels in compliance with the NSPS should be considered also in compliance with Refinery MACT 1. Commenters recommended that a Group 1 storage vessel that is part of an existing source would comply with 40 CFR part 60, subpart Kb; a Group 1 storage vessel that is part of a new source may choose to comply only with subpart Kb; and a Group 2 storage vessel would comply only with subpart Kb. One commenter requested that EPA clearly state that uncontrolled slotted guide poles are a violation of the no visible gap provisions in the NSPS subparts Ka and Kb.

Commenters also requested that EPA address the overlap between Refinery MACT 1 and the NESHAP for Benzene Emissions from Benzene Storage Vessels (40 CFR part 61, subpart Y). Commenters noted that sources with storage vessels that are already meeting 40 CFR part 61, subpart Y may not feel that the benefits of 40 CFR part 63, subpart WW outweigh the burdens of re-permitting and revising compliance systems, and these sources should be allowed to chose whether to comply with 40 CFR part 63, subpart WW or continue complying with 40 CFR part 61, subpart Y. One commenter recommended that a Group 1 storage vessel part of an existing source would comply with 40 CFR part 61, subpart Y, a Group 1 storage vessel part of a new source may choose to comply only with subpart Y, and a Group 2 storage vessel would comply only with subpart Y. The commenter also recommended adding a new paragraph (n)(10) with exceptions similar to those included in paragraph (n)(8).

Response: We have reviewed the rules identified and have determined that they are equivalent if an EFR storage vessel has guide pole controls such as specified by STERPP (described at 65 FR 19891). If a guide pole on an EFR storage vessel is not controlled, then that storage vessel is not in compliance with the no visible opening requirements in 40 CFR part 60, subpart Kb. We have amended 40 CFR 63.640(n) to specify that a Group 1 storage vessel at a new or existing source that is subject to Refinery MACT 1 as well as 40 CFR part 60, subpart Kb and/or 40 CFR part 61, subpart Y may choose to comply with any of those applicable subparts.

C. Wastewater Treatment

Comment: Several commenters supported EBU Option 1 for no further action, noting that BWON EBU are more efficient than EPA assumed and the ample margin of safety expected in the BWON rulemaking is being achieved. Commenters stated that: (1) Option 2 is not justified under CAA section 112(d)(6) or (f); (2) the current Refinery MACT 1 already provides an ample margin of safety and the low risk results do not warrant further control; (3) Option 2 is not likely to realize significant benzene or risk reductions; (4) the replacement of actual wastewater emissions data with hypothetical benzene emissions is not justified; and (5) Option 2 is not cost-effective.

On the other hand, several commenters supported the Option 2 requirements for a performance demonstration on EBU and encouraged EPA to add this standard to the final rule because it will help reduce HAP emissions and cancer risk. Other commenters supported requirements more stringent than Option 2, including: (1) eliminating the 10 megagrams per year (Mg/yr) benzene cutoff or reducing the cutoff to 5 Mg/yr; (2) eliminating the exemption from controls for up to 2 Mg/yr benzene loading; (3) requiring benzene loading rate monitoring for facilities below the thresholds; (4) lowering the benzene concentration from 10 parts per million (ppm) to 5 ppm for flow rates greater than 0.02 liter per minute; (5) requiring all facilities to cover and control oil-water separators and/or diffused air floatation (DAF) units; (6) requiring monthly calculations using WATER9 for wastewater treatment systems; and (7) requiring quarterly performance demonstrations identical to the initial performance demonstration to verify ongoing compliance.

Several commenters stated that, if Option 2 were promulgated, the Appendix C test procedures and performance test requirements in the HON should be used rather than requiring multiple test zones for all EBU. These commenters also recommended the operating parameters specified in subpart G (mixed liquor volatile suspended solids, flow, and hydraulic retention time) be used rather than those proposed for amended Refinery MACT 1. Several commenters noted that the food-to-microorganism (F/M) ratio is not a useful operating parameter to monitor because it is nearly impossible to operate the EBU in such a way to determine the maximum F/M ratio.

Response: In performing the RTR of Refinery MACT 1 emission sources at petroleum refineries, we noted that few refineries were reporting emissions from their EBU and thus the NEI was deficient with regard to EBU emissions. Commenters suggesting that we are replacing “actual wastewater emissions data” in the ANPR data set with “hypothetical data” misunderstand the NEI data and wastewater estimates. To the extent refineries include emission estimates in the NEI, the estimates are not based on actual measured emissions from EBU; these are not like stacks that are easily tested. Rather, EBU emissions data in the NEI are estimated through emission modeling. It was evident in the 22 refinery study (summarized in the memorandum “Collection of Detailed Benzene Emissions Data from 22 Petroleum Refineries,” Docket ID No. EPA-HQ-OAR-2003-0146-0015), as well as in the overall NEI dataset, that refineries either assume zero emissions from the EBU or they estimate emissions from the EBU using models in which they assume a very high biodegradation rate. Only 79 out of 153 refineries reported any benzene emissions from any wastewater source in the proposal NEI dataset, and we received no additional information from industry during the public comment period. An assumption of no emissions is not equivalent to “actual wastewater emissions data” and the omission of emission estimates should not be construed as “real” data. While some refineries may have adequately characterized emissions from their wastewater treatment systems, our experience and our review of the ANPR data set indicate that this is not true for many refineries.

Although we believe that the NEI data set does not fully characterize benzene emissions from wastewater treatment systems, we did develop baseline risk estimates for all the

Refinery MACT 1 sources from this NEI data set. However, in order to assess the difference in control options for various emission sources, including storage vessels and wastewater, we also developed model plant baseline and control options. During this effort, we recognized that the approach used at proposal to extrapolate baseline risks and risk reductions from wastewater treatment options had deficiencies. As described in the supplemental proposal and in a detailed technical memorandum (see Docket No. EPA-HQ-OAR-2003-0146), we revised our analysis approach for estimating the model plant baseline emissions and projecting the emissions and risk reductions achieved by the various regulatory options. At proposal, we had estimated the baseline HAP emissions from EBU to be 5,000 ton/yr and the HAP emission reductions for the enhanced EBU monitoring (Option 2) to be 1,800 ton/yr. Based on our revised analysis, the baseline HAP emissions from all wastewater treatment sources are now estimated to be approximately 1,800 ton/yr, and the HAP emission reductions projected are estimated to be 210 ton/yr. The benzene emission reductions are now projected to be just over 63 ton/yr (compared to 138 ton/yr estimated at proposal). This refined analysis also indicated that reduction in EBU emissions was associated with no reduction in maximum individual risk (as at proposal) and that reduction in cancer incidence was only

0.001 to 0.002 cases per year (approximately 4 percent) rather than 0.01 to 0.02 cases per year (15 percent) as projected at proposal.

We also reviewed our cost analysis. Commenters expressed concern that we understated the costs for the demonstration procedures in the proposed rule. Moreover, they recommend that the procedures in appendix C are sufficient and that we not take final action on the proposed requirements. We reviewed their concerns and agree with commenters that procedures in appendix C to 40 CFR part 63 and associated guidance for evaluation of mixing characteristics are reasonable and should be available for use by refinery owners and operators. We believe our cost estimates more accurately reflect the costs for the EBU demonstration in Appendix C and, therefore, we did not revise them.

Based solely on the initial demonstration costs and on-going monitoring costs, the projected costs of the EBU control option is $1.1-million, with emission reductions of 210 ton/yr of HAP for an overall cost-effectiveness of $5,400 per ton of HAP reduced. If a facility has to install a steam stripper or make significant modifications to the EBU in order to comply with the proposed requirements, the costs could be significantly higher. Capital costs for a steam stripper for a typical refinery with a total annual benzene (TAB) of approximately 50 Megagrams per year (Mg/yr) is projected to be approximately $6 million with the annualized costs of $2.8 million. Assuming the HAP reductions that are achieved when an 80-percent effective EBU is replaced by a steam stripper, the cost of steam stripping is estimated to exceed $35,000 per ton of HAP reduced. Thus, while we evaluated improved monitoring of EBU as a development in practices associated with the wastewater treatment provisions in Refinery MACT 1, we conclude that this development in practice is not cost-effective in light of the emissions and risk reduction achieved and is not, therefore, required under CAA section 112(d)(6). During our technology review, we identified no other developments in practices, processes, or technologies applicable to reduce emissions from petroleum refinery wastewater treatment systems. For that same reason, we also concluded under CAA section 112(f)(2) that improved monitoring was not necessary to provide an ample margin of safety.

We also evaluated a control option requiring facilities with a TAB less than 10 Mg/yr to comply with the wastewater collection and treatment control requirements required for facilities with a TAB of 10 Mg/yr or more. The emission reductions achieved by requiring controls and performance tests for all refinery facilities is 690 ton/yr of HAP and is projected to cost $15.5-million per year, for a cost-effectiveness of just over $22,000 per ton of HAP reduced. Cancer incidence reduction associated with this option was approximately 0.003 to 0.005 cases/year.

Table 2 of this preamble provides information relevant to our proposed ample margin of safety determination under CAA section 112(f)(2) for wastewater. Specifically, the table presents the baseline risk, the risk associated with the proposed Option 2 for EBU, and the risk for the control option requiring facilities with a TAB less than 10 Mg/yr to comply with the wastewater collection and treatment control requirements.

Table 2. Inhalation Risk Impacts for Wastewater Options

Parameter		MACT 1 Baseline	EBU Option 2[c]	Control of <10 Mg TAB Facilities[c]
Maximum Individual Risk	Cancer (in 1 million)	30	30	30
	Noncancer (HI)	0.3	0.3	0.3
Size of Population at Cancer Risk	> 100-in-1 million	0	0	0
	> 10-in-1 million	4,000	3,900	3,600
	> 1-in-1 million	460,000	440,000	410,000
Number of Plants at	> 100-in-1 million	0	0	0

Cancer Risk Level	> 10-in-1 million	5	5	3
	> 1-in-1 million	77	76	70
Population with HI > 1[a]		0	0	0
No of Plants with HI > 1		0	0	0
Annual Cancer Incidence[b]		0.032 - 0.049	0.031 - 0.047	0.029 - 0.044
Cancer Incidence Reduction (Percent)		NA	4	10
HAP Emission Reduction (Percent)		NA	4	6

[a] If the Hazard Index (HI) is calculated to be less than or equal to 1, then no adverse non-cancer chronic health effects are expected as a result of the exposure. However, an HI exceeding 1 does not translate to a probability that adverse effects occur. Rather, it suggests the possibility that adverse health effects may occur. Acute non-cancer effects not estimated in this analysis.
[b] The range of cancer incidence reflects the cancer potency range of benzene, either end of which is considered equally plausible.
[c] The data in these two columns are calculated from the baseline risk assessment using the relative reductions from the model plant analysis. Note that we cannot be sure that the MIR and HI will remain the same as the baseline because we used a Monte Carlo analysis and we do not actually know which facilities already have these controls in place.

Based on our analysis, these control options are not cost-effective in light of the small risk reduction achieved, and we therefore conclude that the controls are not required to provide an ample margin of safety. As stated previously, for the same reasons, we conclude that these controls are not necessary under CAA section 112(d)(6).

D. Benzene Fenceline Monitoring

Comment: Many commenters supported requiring fenceline monitoring of ambient benzene concentrations because they stated

EPA knows current emissions estimates are too low. Commenters asserted that fenceline monitoring would: (1) ensure that refinery emissions are not causing unacceptable adverse health effects; (2) help fill gaps in the emissions inventory for refinery risk assessment and address EPA's concerns about uncertainty in identifying and characterizing emissions sources; (3) help in calculating residual risk; (4) assist in confirming the source and direction of emissions, particularly when industrial plants are located close to each other as in the Houston Ship Channel; and (5) help to identify whether modeling to Census Block Centroids adequately predicts the risk posed in the many neighborhoods that are immediately adjacent to these facilities. Commenters also supported monitoring of HAP other than benzene at the fenceline and suggested that each refinery should monitor the HAP with the highest emissions or the HAP causing the most health concerns in a specific area. Some commenters supported the development of ambient benzene concentration standards through a regulatory framework similar to the NAAQS. Commenters stated that the cost of the fenceline monitors should be incurred by the refiners because it is unfair to expect citizens to pay for ambient air monitoring with tax dollars. Commenters also urged EPA to investigate monitoring methods beyond those mentioned in the preamble; one commenter expressed concern that the diffusive tube sampling system would not be able to determine which site is responsible for elevated levels of benzene. Commenters suggested investigating or requiring technologies such as Automated Gas Chromotography (AutoGC), Ultra Violet Differential Optical Absorption Spectroscopy (UV DOAS), Fourier Transform InfraRed (FTIR), and Differential Absorption Light Detection and Ranging (DIAL). Commenters supporting FTIR noted that FTIR operates continuously and can cover a greater area and number of air pollutants at one time; other commenters noted that FTIR at Texas Petrochemicals only detects emissions along a single path and misses emissions above or below the beam. One commenter recommended that EPA require both short-term advanced remote sensing monitoring and long-term diffusive tube monitoring to address underreporting of actual emissions.

On the other hand, many commenters opposed fenceline monitoring because it is not determinative of the source of emissions, and, therefore, it is an ineffective tool for the purpose of emission estimation, quantification, and source apportionment (i.e., monitors will detect emissions from all nearby sources including refinery competitors, chemical manufacturers, pharmaceutical companies, equipment manufacturers and other processes, as well as mobile sources such as vehicles). Some commenters noted that EPA does not have authority to impose fenceline monitoring under CAA section 112, because fenceline monitoring would cover sources at facilities outside of this Refinery MACT 1 rulemaking. Commenters stated that the monitors are difficult and costly to install and operate, the results are difficult to interpret correctly due to local wind directions/meteorology, and monitors will not accurately assess benzene or other HAP risks from a specific facility because the fenceline concentrations are not directly related to population exposures or maximum exposures. Commenters noted that the fenceline monitoring required at a few refineries has provided little useful data for assessing chronic exposure; the data are generally more helpful in detecting hazardous sudden release situations. Sophisticated dispersion modeling may provide a better picture of the differentiation of source contributions of benzene throughout a refinery, according to the commenters. One commenter noted that finalizing the proposed alternative to Method 21 (Smart LDAR) would promote more useful and readily available techniques such as infrared cameras. For all these reasons, the commenters stated that fenceline monitoring should be a case-by-case or research activity and not imposed on all sources through regulation. If EPA decides to include fenceline monitoring in the amendments to the Refinery MACT 1, the commenters stated that only the highest risk sources should be addressed, facilities should have flexibility in designing a monitoring program, and facilities should be allowed to use existing monitoring measurements that meet EPA data requirements.

<u>Response</u>: We believe that fenceline monitoring holds promise as a cost-effective method for assessing fenceline HAP concentrations. However, as the commenters suggest, there are numerous issues that must be addressed before this type of monitoring can be deployed on a large scale or for regulatory purposes, including temporal and spatial variability of emissions, consideration of background ambient concentrations, differentiation of sources, and the use of meteorological information. To that end, we are currently conducting a long term fenceline demonstration study to help address these issues. For more information regarding details of the study, we have placed the Quality Assurance Project Plan (QAPP) for the study in the docket.

E. General Provisions Applicability

<u>Comment</u>: One commenter supported the revisions to Table 6 of Refinery MACT 1 in the supplemental proposal but had a few suggested revisions. First, the commenter noted that EPA proposed that §§63.5(d)(1)(iii), (d)(2), and (d)(3)(ii) apply to

Refinery MACT 1. The commenter stated that this change would require owners and operators to include considerable emission and control information in requests to construct or reconstruct, and this information has not previously been required. In particular, the commenter noted, the proposal to require measured emission data in the Notice of Compliance Status required by §63.5(d)(1)(iii) would be very costly, and the permitting authority is the best party to identify where testing is required to confirm mass emission limitations are being met. The commenter recommended that EPA not finalize this proposed requirement; if finalized, the requirements should only apply to construction or reconstruction that commenced after September 7, 2007.

Second, the commenter stated that §63.8(b)(2), which EPA proposed should apply to Refinery MACT 1, specifies monitoring location requirements that may conflict with existing monitoring locations. If owners or operators do not already have monitors in locations that comply with §63.8(b)(2), they could be out of compliance on the date these requirements are finalized. The commenter noted that EPA has not evaluated the impacts of these efforts, and no additional compliance time has been provided, so EPA should not finalize this proposal.

Finally, the commenter noted that EPA proposed to require

Refinery MACT 1 sources to comply with §§63.1(b)(3) and 63.10(b)(3), which require owners and operators to keep "negative" records. The commenter stated that these records serve no purpose and have not been kept in the past.

Response: We have reviewed the General Provisions (40 CFR part 63 subpart A) and Table 6 of Refinery MACT 1 as included in the supplemental proposal, and we have determined that the emission estimates in §63.5(d)(1)(ii)(H) and the emission measurements in (d)(1)(iii) are not necessary. Given the types of emission sources affected by Refinery MACT 1, estimating the emissions "...in units and averaging times specified by the relevant standard" is not relevant for most of the sources. The permitting authority has a right to require HAP emission estimates for Refinery MACT 1 process units, but the permitting authority has discretion on what emission estimates are needed. Paragraph 63.5(d)(1)(iii) is unworkable for most Refinery MACT 1 emission sources as these sources do not lend themselves to direct emission measurements. However, the information required under §63.5(d)(2) and (3) is reasonable and necessary information needed by permitting agencies and we are including these requirements from the General Provisions in Table 6 of Refinery MACT 1 in the final amendments.

Paragraph 63.8(b)(2) provides specific guidelines and options for monitoring when emissions from two or more affected sources are combined before being released into the air. While Refinery MACT 1 does specify locations to conduct monitoring, it does not address instances where multiple emission sources are combined. We find that §63.8(b)(2) provides useful guidance that does not contradict or otherwise alter the monitoring locations specified in Refinery MACT 1. As such, we are specifying in Table 6 of Refinery MACT 1 that §63.8(b)(2) applies.

We agree with the commenter that §§63.1(b)(3) and 63.10(b)(3) should not apply because the records required in these sections apply to applicability determinations that have long been completed and the records required under these sections would no longer need to be retained because they would be over 5 years old. Furthermore, the amendments specify the records needed for the new heat exchange system requirements and any additional requirements specified under these sections are not necessary.

VI. Summary of Impacts

The total capital investment cost of the final amendments is estimated at $27 million. The controls required by the final amendments are expected to yield a net savings of $3.4 million in the total annualized cost, which includes $10.5 million credit for recovery of lost product and the annualized cost of capital. The final amendments will achieve a nationwide HAP emission reduction of about 2,300 ton/yr with a concurrent reduction in VOC emissions of about 19,000 ton/yr. Table 3 of this preamble summarizes the cost and emission reduction impacts of the final standards and amendments.

Table 3. Nationwide Impacts of Storage Vessel Amendments and Heat Exchange System Standards

Affected source	Total capital investment ($ million)	Total annualized cost without recovery ($ million)	Product recovery credit ($ million)	Total annualized costs ($ million/ yr)	HAP emission reductions (ton/yr)	Cost-effectiveness ($/ton HAP)
Storage vessels	10	2.0	(8.3)	(6.3)	1,650	-3,800
Heat exchange systems	16	5.2	(2.2)	3.0	630	4,700
Total	27	7.2	(10.5)	(3.4)	2,300	-1,500

Table 4 of this preamble summarizes the risks associated with the final amendments.

Table 4. Inhalation Risk Impacts for Final Amendments to 40 CFR Part 63 Subpart CC

Parameter		Refinery MACT 1 Baseline Risk	Refinery MACT 1 with Heat Exchange System MACT Baseline Risk[d]	Risk for Final Amendments[a,d]
Maximum Individual Risk	Cancer (in 1 million)	30	30	30
	Noncancer (HI)	0.3	0.3	0.3
	> 100-in-1 million	0	0	0

at Cancer Risk	> 10-in-1 million	4,000	3,800	3,500
	> 1-in-1 million	460,000	440,000	400,000
Number of Plants at Cancer Risk Level	> 100-in-1 million	0	0	0
	> 10-in-1 million	5	5	5
	> 1-in-1 million	77	77	74
Population with HI > 1[b]		0	0	0
No of Plants with HI > 1		0	0	0
Annual Cancer Incidence[c]		0.032 - 0.049	0.031 - 0.047	0.028 - 0.043
Cancer Incidence Reduction (Percent)		NA	4	12
HAP Emission Reduction (Percent)		NA	6	20

[a] Final amendments include additional requirements for Group 1 storage vessels.
[b] When the Hazard Index (HI) is calculated to be less than or equal to 1, then no adverse non-cancer chronic health effects are expected as a result of the exposure. Acute non-cancer effects not estimated in this analysis.
[c] The range of cancer incidence reflects the range of cancer potency for benzene, either end of which is considered equally plausible.
[d] The data in these two columns are calculated from the baseline risk assessment using the relative reductions from model plant analysis. Note that we cannot be sure that the MIR and HI will remain the same as the baseline because we used a Monte Carlo analysis and we do not actually know which facilities already have these controls in place.

VII. Conclusions of Risk and Technology Review

Based on our risk analysis, the maximum MIR for Refinery MACT 1 sources is 30-in-1 million, and there are approximately 460,000 people exposed to risks exceeding 1-in-1 million due to Refinery MACT 1 emission sources. As the maximum MIR is less than 100-in-1 million, baseline cancer incidence is low (0.03-0.05 cases per year), and chronic and acute noncancer health effects are unlikely, we conclude that the risks are acceptable.

As described in our original proposal on September 4, 2007 (72 FR 50716) and in “National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Background Information for Final Standards - Summary of Public Comments and Responses" (see Docket No. EPA-HQ-OAR-2003-0146), we did not identify any developments in practices, processes, and control technologies for miscellaneous process vents, equipment leaks, gasoline loading racks, and marine vessel loading operations that were cost effective in light of the HAP emission and risk reductions that would be achieved (see technical memoranda for these sources in Docket No. EPA-HQ-OAR-2003-0146). Based on these findings, we are concluding that additional controls are not necessary for these sources under CAA section 112(f)(2) to provide an ample margin of safety to protect public health and are not necessary under CAA section 112(d)(6). Accordingly, for purposes of section 112(f)(2), we are re-adopting the MACT standards for miscellaneous process vents, equipment leaks, gasoline loading racks, and marine vessel loading operations.

We are establishing MACT standards for heat exchange systems under CAA section 112(d)(2) that are based on our floor determination. Additional beyond-the-floor requirements were not cost-effective in light of the additional HAP emission reductions that would be achieved, so the floor level of control was selected for MACT. For this same reason, we concluded that the MACT requirements provide an ample margin of safety to protect public health and that additional requirements are not needed under CAA section 112(f)(2).

We are finalizing amendments to the storage vessel requirements under CAA section 112(d)(6) technology review, as described previously in this preamble. Under our CAA section 112(f)(2) analysis we determined that the residual risk from the existing MACT standard is acceptable with an ample margin of safety. The risk reduction that will result from the new storage vessel controls is limited, but additional HAP emission reductions are achieved at a savings. For this reason, we are promulgating these controls only under CAA section 112(d)(6) alone.

For wastewater treatment systems, we identified an improvement in practices related to monitoring EBU. We evaluated this new monitoring requirement as part of our risk and technology review; however, we determined that it would not cost-effectively reduce HAP emissions and risk from petroleum refinery wastewater streams and, therefore, concluded that this improved monitoring was not necessary under CAA section 112(d)(6). For the same reasons, we rejected this control option as necessary to provide an ample margin of safety under CAA section 112(f)(2). Accordingly, for purposes of section 112(f)(2), we are re-adopting the MACT standards for wastewater treatment systems.

In conclusion, we are determining under CAA section 112(f)(2) that the Refinery MACT standards, including the new standard for heat exchange systems, provide an ample margin of safety. We are adopting new requirements for Group 1 storage vessels as necessary under CAA section 112(d)(6).

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it may raise novel legal or policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in this rule will be submitted for approval to OMB under the Paperwork Reduction

Act, 44 U.S.C. 3501, et seq. The information collection requirements are not enforceable until OMB approves them. The information requirements in the final amendments include monitoring, recordkeeping and reporting provisions for storage vessels and cooling towers. Owners or operators of storage vessels must comply with the inspection, recordkeeping, and reporting requirements in 40 CFR part 63, subpart WW. Owners or operators of cooling towers must conduct monthly monitoring of each heat exchanger to identify and repair leaks. Records of monitoring and repair data also must be kept. All respondents must submit one-time notifications and semiannual compliance reports.

The information collection requirements in this final rule are needed by EPA and delegated authorities to determine that compliance has been achieved. The recordkeeping and reporting requirements in this final rule are based on the information collection requirements in the part 63 General Provisions (40 CFR part 63, subpart A). The recordkeeping and reporting requirements in the General Provisions are mandatory pursuant to section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the information collection requirements for which a claim of confidentiality is safeguarded according to CAA section 114(c) and the Agency’s implementing regulations at 40 CFR part 2, subpart B.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 13,714 labor hours per year at a cost of $1,056,081 for one new refinery and 153 existing refineries. The average annual reporting burden is 3184.32 labor hours for 726.3 total annual responses; the average annual burden per response is 4.38 hours. Responses include notifications of compliance status for cooling towers and storage vessels at new and existing refineries, notification of initial startup for storage vessels at one new refinery, and semiannual compliance reports containing information on cooling towers and storage vessels at new and existing refineries. Capital/startup costs are estimated at $16,306,000. The operation and maintenance costs associated with the final rule amendments are estimated at $61,711. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers issued by OMB for various regulations to list the information requirements contained in this final rule. This amendment updates the table to list the information requirements being promulgated today as amendments to the NESHAP for petroleum refineries.

EPA will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the Paperwork Reduction Act (44 U.S.C. 3501, et seq.) and OMB's implementing regulations at 5 CFR part 1320.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

For the purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) a small business that meets the Small Business Administration size standards for small businesses at 13 CFR 121.201 (a firm having no more than 1,500 employees); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based on our economic impact analysis, the amendments will result in a nationwide net annualized cost savings of about $3.4 million due to a return of about $10.5 million per year from reductions in product losses. Only one heavy oil refinery entity would incur net annualized costs as a result of the final amendments, and this refinery entity is a small entity. All other refineries would have net savings. Net annualized costs for this affected small refinery entity are well below 0.01 percent of its revenue; therefore, no adverse economic impacts are expected for any small entity. Thus, the costs associated with the final amendments will not result in any “significant” adverse economic impact for any small or large entity.

D. Unfunded Mandates Reform Act

This final rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or to the private sector in any one year. As discussed earlier in this preamble, these amendments result in nationwide net savings to the private sector and do not impose costs on state, local, or tribal governments. Thus, the final rule is not subject to the requirements of sections 202 and 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The final amendments contain no requirements that apply to such governments, and impose no obligations upon them.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure “meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.” “Policies that have federalism implications” is defined in the Executive Order to include regulations that have “substantial direct effects on the States, on the relationship between the national government and the

States, or on the distribution of power and responsibilities among the various levels of government."

The final amendments do not have federalism implications. They would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final amendments add control and performance demonstration requirements. They do not modify existing responsibilities or create new responsibilities among EPA Regional offices, States, or local enforcement agencies. Thus, Executive Order 13132 does not apply to the final amendments.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The final amendments will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. The final amendments impose no requirements on tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in Executive Order 12866, and because the Agency does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in the "Final Baseline Residual Risk Assessment for MACT I Petroleum Refining Sources," which is available in the docket.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that the final amendments are not likely to have any adverse energy effects because they result in overall savings due to product recovery.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104-113, 15

U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

This final rule involves technical standards. The EPA has decided to use "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources", Revision Number One, dated January 2003, and will incorporate the method by reference (see 40 CFR 63.14). This method is available at http://www.tceq.state.tx.us/assets/public/implementation/air/sip/sipdocs/2002-12-HGB/02046sipapp_ado.pdf, or from the Texas Commission on Environmental Quality (TCEQ) Library, P.O. Box 13087, Austin, Texas, 78711-3087, telephone number (512) 239-0028. This method was chosen because it is an effective means to determine leaks from heat exchangers and it is the method used in the best performing facilities. This TCEQ method utilizes a dynamic or flow-through system for air stripping a sample of the water and analyzing the resultant off-gases for

VOC using a common flame ionization detector (FID) analyzer. While direct water analyses, such as purge and trap analyses of water samples utilizing gas chromatography and/or mass spectrometry techniques, have been shown to be effective for cooling tower measurements of heavier molecular weight organic compounds with relatively high boiling points, it has been determined that this approach may be ineffective for capture and measurement of VOC with lower boiling points, such as ethylene, propylene, 1,3-butadiene, and butenes. The VOC with a low molecular weight and boiling point are generally lost in the sample collection step of purge/trap type analyses. Consequently, this TCEQ air stripping method is used for cooling tower and other applicable water matrix emission measurements of VOC with boiling points below 140 ^{o}F.

Under §§63.7(f) and 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures in the final rule and amendments.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629 (Feb. 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

This rulemaking will achieve significant reductions of HAP emissions from storage vessels and cooling towers located at petroleum refineries. Exposure to HAP emissions raises concerns regarding environmental health for the U.S. population in general including the minority populations and low-income populations that are the focus of the Environmental Justice Executive Order.

EPA has evaluated several regulatory strategies for reductions in emissions from petroleum refineries, and we believe that we have selected controls that provide an ample margin of safety to the public, including sensitive sub-populations.

The emission reductions from the new standards finalized in the petroleum refinery rule will have beneficial effects on communities in proximity to petroleum refineries, including low-income and minority communities. For example, the new standards for cooling towers and storage vessels will reduce air toxics emissions from petroleum refineries by 2,300 tons and VOC emissions by 19,000 tons annually.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This final rule will be effective on [INSERT DATE OF PUBLICATION].

List of Subjects in 40 CFR Parts 9 and 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

____

Dated:

____

Stephen L. Johnson,
Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is 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, 1318, 1321, 1326, 1330, 1342, 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. The table in Section 9.1 is amended by:

a. Removing the entry for 63.654 under the heading "National Emission Standards for Hazardous Air Pollutants for Source Categories"; and

b. Adding an entry for 63.655 in numerical order under the indicated heading 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[3]	
* * * * *	
63.655	2060–0340
* * * * *	

* * * * *

[3] The ICRs referenced in this section of the table encompass the applicable general provisions contained in 40 CFR part 63, subpart A, which are not independent information collection requirements.

Part 63--[AMENDED]

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

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

Subpart A--[AMENDED]

4. Section 63.14 is amended by adding paragraph (n) to read as follows:

§63.14 Incorporations by reference.

* * * * *

(n) The following material is available from the Texas Commission on Environmental Quality (TCEQ) Library, Post Office Box 13087, Austin, Texas 78711-3087, telephone number (512) 239-0028 or at http://www.tceq.state.tx.us/assets/public/implementation/air/sip/sipdocs/2002-12-HGB/02046sipapp_ado.pdf:

(1) “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water

Sources", Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003, IBR approved for §63.654(c)(1) and (g)(4)(i) of Subpart CC of this part.

(2) [Reserved]

Subpart CC--[AMENDED]

5. Section 63.640 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (b)(2);

c. Revising paragraph (c) introductory text;

d. Revising paragraphs (c)(6) and (7);

e. Adding paragraph (c)(8);

f. Revising paragraphs (e) introductory text, and (e)(2)(iii);

g. Revising paragraphs (f) introductory text, and (f)(5);

h. Revising paragraph (h) introductory text;

i. Revising paragraphs (h)(1) and (2);

j. Revising paragraph (h)(4);

k. Adding paragraph (h)(6);

l. Revising paragraphs (k)(1), (k)(2)(i), (k)(2)(ii), (k)(2)(iii), and the first sentence in paragraph (k)(2)(vi);

m. Revising paragraphs (l) introductory text, and (l)(2)(i), the first sentence in paragraph (l)(2)(ii), the first sentence in paragraph (l)(3) introductory text, paragraphs (l)(3)(i) and (l)(3)(ii), the first sentence in paragraph (l)(3)(vi), and the first sentence in paragraph (l)(3)(vii);

n. Revising paragraphs (n) introductory text, (n)(1) and (n)(2), (n)(8) introductory text, (n)(8)(ii), and (n)(9)(i);

o. Adding paragraphs (n)(8)(vii) and (n)(10); and

p. Revising paragraph (p).

§63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(5) through (8) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section:

* * * * *

(b) * * *

(2) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units shall be reported as specified in §63.655(h)(6)(i).

(c) For the purposes of this subpart, the affected source shall comprise all emissions points, in combination, listed in paragraphs (c)(1) through (8) of this section that are located at a single refinery plant site.

*   *   *   *   *

(6) All marine vessel loading operations located at a petroleum refinery meeting the criteria in paragraph (a) of this section and the applicability criteria of subpart Y, §63.560;

(7) All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in paragraph (a) of this section; and

(8) All heat exchange systems associated with petroleum refining process units meeting the criteria in paragraph (a) of this section and which are in organic hazardous air pollutants (HAP) service as defined in this subpart.

*   *   *   *   *

(e) The owner or operator of a storage vessel constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (e)(1) and (e)(2) of this section to determine whether a storage vessel is part of a source to which this subpart applies. The owner or operator of a storage vessel constructed after August 18, 1994, shall follow the procedures specified in paragraphs (e)(1), (e)(2)(i), and (e)(2)(ii) of this section to determine whether a storage vessel is part of a source to which this subpart applies.

* * * * *

(2) * * *

(iii) If the predominant use of a storage vessel varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that storage vessel during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(ii).

(f) The owner or operator of a distillation unit constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(4) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies. The owner or operator of a distillation unit constructed after August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(5) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies.

* * * * *

(5) If the predominant use of a distillation unit varies from year to year, then the applicability of this subpart shall

be determined based on the utilization of that distillation unit during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(iii).

* * * * *

(h) Except as provided in paragraphs (k), (l), or (m) of this section, sources subject to this subpart are required to achieve compliance on or before the dates specified in paragraphs (h)(1) through (6) of this section.

(1) Except as provided in paragraphs (h)(1)(i) and (iv) of this section, new sources that commence construction or reconstruction after July 14, 1994, shall be in compliance with this subpart upon initial startup or August 18, 1995, whichever is later.

(i) Storage vessels at new sources that commence construction or reconstruction after August 18, 1995, but before September 4, 2007, shall comply with the new source requirements for storage vessels specified in §63.646(a) through (l) upon startup and the new source requirements for storage vessels specified in §63.646(m) no later than [INSERT DATE 36 MONTHS AFTER DATE OF PUBLICATION].

(ii) Heat exchange systems at new sources that commence construction or reconstruction after August 18, 1995, but before September 4, 2007, shall comply with the existing source requirements for heat exchange systems specified in §63.654 no later than [INSERT DATE 36 MONTHS AFTER DATE OF PUBLICATION]

(iii) Storage vessels at new sources that commence construction or reconstruction after September 4, 2007, shall be in compliance with the new source requirements in §63.646(m) upon initial startup or [INSERT DATE OF PUBLICATION], whichever is later.

(iv) Heat exchange systems at new sources that commence construction or reconstruction after September 4, 2007, shall be in compliance with the new source requirements in §63.654 upon initial startup or [INSERT DATE OF PUBLICATION], whichever is later. (2) Except as provided in paragraphs (h)(3) through (h)(6) of this section, existing sources shall be in compliance with this subpart no later than August 18, 1998, except as provided in §63.6(c)(5) of subpart A of this part, or unless an extension has been granted by the Administrator as provided in §63.6(i) of subpart A of this part.

* * * * *

(4) A Group 1 storage vessel that is part of an existing source shall be in compliance with §63.646 as specified in paragraphs (h)(4)(i) through (h)(4)(iii).

(i) Except for existing floating roof storage vessels, a Group 1 storage vessel that is part of an existing source shall be in compliance with §63.646(a) through (l) of this subpart no later than August 18, 1998. An owner or operator may elect to comply with §63.646(m) of this subpart instead of §63.646(a) through (l) of this subpart.

(ii) Existing Group 1 floating roof storage vessels shall be in compliance with §63.646(a) through (l) of this subpart at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, whichever is first. An owner or operator may elect to comply with §63.646(m) of this subpart instead of §63.646(a) through (l) of this subpart.

(iii) All Group 1 storage vessels that are part of an existing source shall be in compliance with §63.646(m) of this subpart no later than [INSERT DATE 36 MONTHS FROM DATE OF PUBLICATION].

* * * * *

(6) Heat exchange systems at an existing source shall be in compliance with the existing source standards in §63.654 no later than [INSERT DATE 36 MONTHS FROM DATE OF PUBLICATION].

* * * * *

(k) * * *

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements upon initial startup of the reconstructed source or by August 18, 1995,

whichever is later; and

(2) * * *

(i) The application for approval of construction or reconstruction shall be submitted as soon as practical before the construction or reconstruction is planned to commence (but it need not be sooner than November 16, 1995);

(ii) The Notification of Compliance Status report as required by §63.655(f) for a new source, addition, or change;

(iii) Periodic Reports and other reports as required by §63.655(g) and (h);

* * * * *

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R.* * *

* * * * *

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, marine tank vessel loading operation, or heat exchange system that meets the criteria in paragraphs (c)(1) through (8) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emissions point(s) (as defined in §63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraphs (i) or (j) of this section, the requirements in paragraphs (l)(1) through (3) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by §63.655(f).

* * * * *

(2) * * *

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by August 18, 1998, whichever is later.

(ii) If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), the owner or operator shall be in compliance upon initial startup or by August 18, 1998, whichever is later, unless the owner or operator demonstrates to the Administrator that achieving compliance will take longer than making the change.* * *

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, marine tank vessel loading operation, or heat exchange system meeting the criteria in paragraphs (c)(1) through (8) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section.* * *

(i) The Notification of Compliance Status report as required by §63.655(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.655(g) and (h);

* * * * *

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R.* * *

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y.* * *

* * * * *

(n) Overlap of subpart CC with other regulations for storage vessels. As applicable, paragraphs (n)(1), (n)(3), (n)(4), (n)(6), and (n)(7) of this section apply for Group 2 storage vessels and paragraphs (n)(2) and (n)(5) of this section apply for Group 1 storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section.

(2) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb and/or 40 CFR part 61, subpart Y is required to comply only with 40 CFR part 60, subpart Kb except as provided in paragraph (n)(8) of this section; 40 CFR part 61, subpart Y except as provided in paragraph (n)(10) of this section; or this subpart.

* * * * *

(8) Storage vessels described by paragraphs (n)(1) and (n)(3) of this section are to comply with 40 CFR part 60, subpart Kb except as provided in paragraphs (n)(8)(i) through (n)(8)(vii) of this section. Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 60, subpart Kb shall comply with subpart Kb except as provided in paragraphs (n)(8)(i) through (n)(8)(vii) of this section.

* * * * *

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in 40 CFR 60.113b(b) or to inspect the vessel to determine compliance with 40 CFR 60.113b(a) because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or §63.120(b)(7)(ii) of subpart G (only up to the compliance date specified in paragraph (h)(1)(i), (h)(1)(iii), or (h)(4)(iii) of this section, as applicable) or either §63.1063(c)(2)(iv)(A) or §63.1063(c)(2)(iv)(B) of subpart WW.

* * * * *

(vii) To be in compliance with 40 CFR 60.112b(a)(2)(ii), external floating roof storage vessels must be equipped with guidepole controls as described in Appendix I: Acceptable Controls for Slotted Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (65 FR 19891).

(9) * * *

(i) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in 40 CFR 60.113a(a)(1) because the floating roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or §63.120(b)(7)(ii) of subpart G (only up to the compliance date specified in paragraph (h)(1)(i), (h)(1)(iii), or (h)(4)(iii) of this section, as applicable) or either §63.1063(c)(2)(iv)(A) or §63.1063(c)(2)(iv)(B) of subpart WW.

* * * * *

(10) Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 61, subpart Y shall comply with subpart Y except as provided for in paragraphs (n)(10)(i) through (n)(10)(vii) of this section.

(i) Storage vessels that are to comply with 40 CFR 61.271(b) are exempt from the secondary seal requirements of 40 CFR 61.271(b)(2)(ii) during the gap measurements for the primary seal required by 40 CFR 61.272(b).

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in 40 CFR 61.272(b) or to inspect the vessel to determine compliance with 40 CFR 61.272(a) because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or §63.120(b)(7)(ii) of subpart G (only up to the compliance date specified in paragraph (h)(1)(i), (h)(1)(iii), or (h)(4)(iii) of this section, as applicable) or either §63.1063(c)(2)(iv)(A) or §63.1063(c)(2)(iv)(B) of subpart WW.

(iii) If a failure is detected during the inspections required by 40 CFR 61.272(a)(2) or during the seal gap measurements required by 40 CFR 61.272(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(10)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in 40 CFR 61.272(a)(2) or 40 CFR

61.272(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with subpart Y of part 61 may submit the inspection reports required by 40 CFR 61.275(a), (b)(1), and (d) as part of the periodic reports required by this subpart, rather than within the 60-day period specified in 40 CFR 61.275(a) and (b)(1).

(vi) The reports of rim seal inspections specified in 40 CFR 61.275(d) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in 40 CFR 61.272(b)(4). Documentation of the inspections shall be recorded as specified in 40 CFR 61.276(a).

(vii) To be in compliance with 40 CFR 61.271(b)(3), external floating roof storage vessels must be equipped with guidepole controls as described in Appendix I: Acceptable Controls for Slotted Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (65 FR 19891).

* * * * *

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (h) of this section, equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated

before September 4, 2007, are required to comply only with the provisions specified in this subpart.

(2) Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

* * * * *

6. Section 63.641 is amended by:

a. Adding, in alphabetical order, definitions for “Cooling tower,” “Cooling tower return line,” “Heat exchange system,” and “Heat exchanger exit line”; and

b. Revising the definitions of “Continuous record” and “Reference control technology for storage vessels” to read as follows:

§63.641 Definitions.

* * * * *

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every hour and recorded at the frequency specified in §63.655(i).

* * * * *

Cooling tower means a heat removal device used to remove the heat absorbed in circulating cooling water systems by transferring the heat to the atmosphere using natural or mechanical draft.

Cooling tower return line means the main water trunk lines at the inlet to the cooling tower before exposure to the atmosphere.

* * * * *

Heat exchange system means a device or series of devices used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (i.e., non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (e.g., river or pond water). For closed-loop recirculation systems, the heat exchange system consists of a cooling tower, all heat exchangers that are serviced by that cooling tower, and all water lines to and from the heat exchanger(s). For once-through systems, the heat exchange system consists of one or more heat exchangers servicing an individual process unit and all water lines to and from the heat exchanger(s). Intentional direct contact with process fluids results in the formation of a wastewater.

Heat exchanger exit line means the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere, in, as an example, a once-through cooling system, whichever occurs first.

* * * * *

Reference control technology for storage vessels means either:

(a) For Group 1 storage vessels complying with §63.646(m):

(1) An internal floating roof meeting the specifications of §§63.1063(a)(1)(i) and (b) of subpart WW;

(2) An external floating roof meeting the specifications of §63.1063(a)(1)(ii), (a)(2), and (b) of subpart WW;

(3) An external floating roof converted to an internal floating roof meeting the specifications of §63.1063(a)(1)(ii) and (b); or

(4) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume (ppmv).

(5) For purposes of emissions averaging, these four technologies are considered equivalent.

(b) For all other storage vessels:

(1) An internal floating roof meeting the specifications of §63.119(b) of subpart G except for §63.119 (b)(5) and (b)(6);

(2) An external floating roof meeting the specifications

of §63.119(c) of subpart G except for §63.119(c)(2);

(3) An external floating roof converted to an internal floating roof meeting the specifications of §63.119(d) of subpart G except for §63.119(d)(2); or

(4) A closed-vent system to a control device that reduces organic HAP emissions by 95-percent, or to an outlet concentration of 20 ppmv.

(5) For purposes of emissions averaging, these four technologies are considered equivalent.

* * * * *

7. Section 63.642 is amended by revising paragraphs (k)(1) and (l)(2) to read as follows:

§63.642 General standards.

* * * * *

(k) * * *

(1) The owner or operator using this compliance approach shall also comply with the requirements of §63.655 as applicable.

* * * * *

(l) * * *

(2) Comply with the requirements of §§63.652, 63.653, and 63.655, as applicable.

* * * * *

8. Section 63.644 is amended by:

a. Revising paragraph (b) introductory text;

b. Revising paragraph (c)(1);

c. Revising paragraph (d); and

d. Revising paragraph (e) to read as follows:

§63.644 Monitoring provisions for miscellaneous process vents.

* * * * *

(b) An owner or operator of a Group 1 miscellaneous process vent may request approval to monitor parameters other than those listed in paragraph (a) of this section. The request shall be submitted according to the procedures specified in §63.655(h). Approval shall be requested if the owner or operator:

* * * * *

(c) * * *

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether a vent stream flow is present at least once every hour. Records shall be generated as specified in §63.655(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

* * * * *

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.655(f)(3) shall be submitted in the Notification of Compliance Status report.

(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.655(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

9. Section 63.645 is amended by revising paragraph (h)(2) to read as follows:

§63.645 Test methods and procedures for miscellaneous process vents.

* * * * *

(h) * * *

(2) Where the recalculated TOC emission rate is greater

than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.655(f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640.

* * * * *

10. Section 63.646 is amended by:

a. Revising paragraph (a);

b. Revising paragraphs (b)(1); and

c. Adding paragraph (m) to read as follows:

§63.646 Storage vessel provisions.

(a) Except for Group 1 storage vessels complying with paragraph (m) of this section, each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of this section.

(b) * * *

(1) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

* * * * *

(m) On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in §63.640(h)(1)(i), (h)(1)(iii) and (h)(4)(iii) of this subpart, the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW or subpart SS according to the requirements in paragraphs (m)(1) through (m)(10) of this section.

(1) As used in paragraph (m) of this section, all terms not defined in §63.641 shall have the meaning given them in 40 CFR part 63, subpart A, subpart WW, or subpart SS. The definitions of “Group 1 storage vessel” and “storage vessel” in §63.641 shall apply in lieu of the definition of “storage vessel” in §63.1061 of subpart WW.

(i) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(ii) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, Method 18 of 40 CFR part 60, appendix A-6 shall be used.

(2) For purposes of this subpart, §63.1063(a)(2) does not apply to internal floating roof storage vessels at existing sources subject to this subpart. For purposes of this subpart, §§63.1063(a)(2)(vii) and (viii) do not apply to internal floating roof storage vessels at new sources subject to this subpart.

(3) For purposes of this subpart, §§63.1063(a)(1)(i)(D), (a)(1)(ii)(C), (a)(2)(ix) do not apply to storage vessels at existing sources subject to this subpart.

(4) In addition to the options presented in §§63.1063(a)(2)(vii)(A), 63.1063(a)(2)(vii)(B), and 63.1064, an external floating roof storage vessel may comply with §63.1063(a)(2)(vii) using a flexible enclosure system as described in item 6 of Appendix I: Acceptable Controls for Slotted Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (65 FR 19893).

(5) For the purposes of this subpart, references shall apply as specified in paragraphs (5)(i) through (v) of this section.

(i) All references to “the proposal date for a referencing subpart” and “the proposal date of the referencing subpart” in subpart WW mean September 4, 2007.

(ii) All references to “promulgation date of standards for an affected source or affected facility under a referencing subpart” in subpart SS mean [INSERT DATE OF PUBLICATION].

(iii) All references to “the proposal date of the relevant standard established pursuant to CAA section 112(f)” in subpart SS mean September 4, 2007.

(iv) All references to “the proposal date of a relevant standard established pursuant to CAA section 112(d)” in subpart SS mean July 14, 1994.

(v) All references to the “required control efficiency” in subpart SS means reduction of organic HAP emissions by 95 percent or to an outlet concentration of 20 ppmv.

(6) When complying with the inspection requirements of §63.1063(d) of subpart WW of this part, owners and operators of internal floating roof storage vessels at existing sources subject to this subpart are not required to comply with the provisions for deck fittings specified in §63.1063(d).

(7) Failure to perform inspections and monitoring required by paragraph (m) of this section shall constitute a violation of the applicable standard of this subpart.

(8) References in §63.1066(a) to initial startup notification requirements do not apply.

(9) References to the Notification of Compliance Status in §63.999(b) mean the Notification of Compliance Status required by §63.655(f).

(10) References to the Periodic Reports in §§63.1066(b) and 63.999(c) mean the Periodic Report required by §63.655(g).

11. Section 63.650 is amended by revising paragraph (a) to read as follows.

§63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (c) of this section, each owner or operator of a Group 1 gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R, §§63.421, 63.422(a) through (c) and (e), 63.425(a) through (c) and (i), 63.425(e) through (h), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k).

* * * * *

12. Section 63.651 is amended by revising paragraphs (a) and (c) to read as follows:

§63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.568.

* * * * *

(c) The notification reports under §63.567(b) are not required.

* * * * *

13. Section 63.652 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (d)(2);

c. Revising paragraph (e)(5);

d. Revising the first sentence of paragraph (f)(3) introductory text;

e. Revising the first sentence in paragraph (g)(5)(ii)(B)(1);

f. Revising paragraph (h)(3); and

g. Revising paragraph (l)(1) to read as follows:

§63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek to comply with the emission standard in §63.642(g) by using emissions averaging according to §63.642(l) rather than following the provisions of §§63.643 through 63.647, and §§63.650 and 63.651. Existing marine tank vessel loading operations located at the Valdez Marine Terminal source may not comply with the standard by using emissions averaging.

*   *   *   *   *

(d) * * *

(2) Group 1 emission points that are controlled by a reference control technology unless the reference control technology has been approved for use in a different manner and a higher nominal efficiency has been assigned according to the procedures in paragraph (i) of this section. For example, it is not allowable to claim that an internal floating roof meeting only the specifications stated in the reference control technology definition in §63.641(a) (i.e., that meets the specifications of §63.1063(a)(1)(i) and (b) but does not have controlled fittings per §63.1063(a)(2)) applied to a storage vessel is achieving greater than 95 percent control;

*   *   *   *   *

(e) * * *

(5) Record and report quarterly and annual credits and debits in the Periodic Reports as specified in §63.655(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by §63.655(g)(8)(iii).

(f) * * *

(3) For emission points for which continuous monitors are

used, periods of excess emissions as defined in §63.655(g)(6)(i).* * *

* * * * *

(g) * * *

(5) * * *

(ii) * * *

(B) * * *

(1) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.565(d) of subpart Y.* * *

* * * * *

(h) * * *

(3) Emissions from storage vessels shall be determined as specified in §63.150(h)(3) of subpart G, except as follows:

(i) For storage vessels complying with §63.646(a) through (l):

(A) Section 63.119(b) or §63.119(b) except for §63.119(b)(5) and (b)(6) shall apply instead of §63.119(b) in §63.150(h)(3) of subpart G.

(B) Section §63.119(c) or §63.119(c) except for §63.119(c)(2) shall apply instead of §63.119(c) in §63.150(h)(3) of subpart G.

(C) Section 63.119(d) or §63.119(d) except for

§63.119(d)(2) shall apply instead of §63.119(d) in §63.150(h)(3) of subpart G.

(ii) For storage vessels complying with §63.646(m):

(A) Sections 63.1063(a)(1)(i), (a)(2), and (b) of subpart WW or §§63.1063(a)(1)(i) and (b) of subpart WW shall apply instead of §63.119(b) in §63.150(h)(3) of subpart G.

(B) Sections 63.1063(a)(1)(ii), (a)(2), and (b) of subpart WW shall apply instead of §63.119(c) in §63.150(h)(3) of subpart G.

(C) Sections 63.1063(a)(1)(i), (a)(2), and (b) of subpart WW or §§63.1063(a)(1)(i) and (b) of subpart WW shall apply instead of §63.119(d) in §63.150(h)(3) of subpart G.

* * * * *

(l) * * *

(1) The owner or operator shall notify the Administrator of excess emissions in the Periodic Reports as required in §63.655(g)(6).

* * * * *

14. Section 63.653 is amended by:

a. Revising paragraphs (a)(3)(i), (a)(3)(ii), and (a)(7);

b. Revising paragraph (b);

c. Revising paragraph (c); and

d. Revising paragraphs (d) introductory text, (d)(2)(vii) introductory text, and (d)(2)(viii)(G) to read as follows:

§63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

* * * * *

(a) * * *

(3) * * *

(i) Perform the monitoring or inspection procedures in §63.646 and either §63.120 of subpart G or §63.1063 of subpart WW, as applicable; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in §63.646 of this subpart and either §63.120(d) of subpart G or §63.985(b) of subpart SS, as applicable.

* * * * *

(7) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in §§63.643 through 63.647 and §§63.650 and 63.651, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in §63.655(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by §63.655

shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by §63.655.

(d) Each owner or operator of an existing source who elects to comply with §63.655(g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

* * * * *

(2) * * *

(vii) The information specified in §63.655(h)(4) for:

* * * * *

(viii) * * *

(G) For each pollution prevention measure, treatment process, or control device used to reduce air emissions of organic HAP from wastewater and for which no monitoring parameters or inspection procedures are specified in §63.647, the information specified in §63.655(h)(4) shall be included in the Implementation Plan.

* * * * *

15. Sections 63.654 and 63.655 are redesignated as §§63.655 and 63.656.

16. Section 63.654 is added to read as follows:

§63.654 Heat exchange systems.

(a) Except as specified in paragraph (b) of this section, the owner or operator of a heat exchange system that meets the criteria in §63.640(c)(8) must comply with the requirements of paragraphs (c) through (g) of this section.

(b) A heat exchange system is exempt from the requirements in paragraphs (c) through (g) of this section if it meets any one of the criteria in paragraphs (b)(1) through (2) of this section.

(1) All heat exchangers that are in organic HAP service within the heat exchange system that either:

(A) Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or.

(B) Employ an intervening cooling fluid, containing less than 5 percent by weight of total HAP listed in Table 1 to this subpart, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

(2) The heat exchange system cools process fluids that contain less than 5 percent by weight of total HAP listed in

Table 1 to this subpart (i.e., the heat exchange system does not contain any heat exchangers that are in organic HAP service as defined in this subpart).

(c) The owner or operator must perform monthly monitoring to identify leaks of total strippable volatile organic compound (VOC) from each heat exchange system subject to the requirements of this subpart according to the procedures in paragraphs (c)(1) and (2) of this section.

(1) Collect and analyze a sample from each cooling tower return line prior to exposure to air for each heat exchange system in organic HAP service or from each heat exchanger exit line for each heat exchanger or group of heat exchangers in organic HAP service within that heat exchange system to determine the total strippable VOC concentration (as methane) from the air stripping testing system using “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14). The owner or operator of a once-through heat exchange system may elect to also monitor monthly (in addition to monitoring each heat exchanger exit line) the fresh

water feed line prior to any heat exchanger to determine the total strippable VOC concentration (as methane) prior to the heat exchange system using the Modified El Paso Method.

(2) For a heat exchange system at an existing source, a leak is a total strippable VOC concentration (as methane) in the stripping gas of 6.2 ppmv or greater. For a heat exchange system at a new source, a leak is a total strippable VOC concentration (as methane) in the stripping gas of 3.1 ppmv or greater.

(d) If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs (e) and (f) of this section. Actions that can be taken to achieve repair include but are not limited to:

(1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(2) Blocking the leaking tube within the heat exchanger;

(3) Changing the pressure so that water flows into the process fluid;

(4) Replacing the heat exchanger or heat exchanger bundle; or

(5) Isolating, bypassing, or otherwise removing the

leaking heat exchanger from service until it is otherwise repaired.

(e) If the owner or operator detects a leak when monitoring a cooling tower return line under paragraph (c)(1) of this section, the owner or operator may conduct additional monitoring to identify leaks of total strippable VOC emissions using Modified El Paso method from each heat exchanger or group of heat exchangers in organic HAP service associated with the heat exchange system for which the leak was detected. If the additional monitoring shows that the total strippable VOC concentration in the stripped air at the heat exchanger exit line for each heat exchanger in organic HAP service is less than 6.2 ppmv for existing sources or less than 3.1 ppmv for new sources, the heat exchange system is excluded from repair requirements in paragraph (d) of this section.

(f) The owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in paragraphs (f)(1) through (3) of this section is met. The owner or operator must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.

(1) If the repair is technically infeasible without a shutdown and the total strippable VOC concentration (as methane)

is initially and remains less than 62 ppmv for all monthly monitoring periods during the delay of repair, the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monthly monitoring, the total strippable VOC concentration (as methane) is 62 ppmv or greater, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded 62 ppmv total strippable VOC (as methane), except as provided in paragraph (f)(3) of this section.

(2) If the necessary equipment, parts, or personnel are not available and the total strippable VOC concentration (as methane) is initially and remains less than 62 ppmv for all monthly monitoring periods during the delay of repair, the owner or operator may delay the repair for a maximum of 120 calendar days. The owner or operator must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monthly monitoring, the total strippable VOC concentration (as methane) is 62 ppmv or greater, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded 62 ppmv total strippable VOC (as methane).

(g) To delay the repair under paragraph (f) of this section, the owner or operator must record the information in paragraphs (g)(1) through (g)(4) of this section.

(1) The reason(s) for delaying repair.

(2) A schedule for completing the repair as soon as practical.

(3) The date and concentration of the leak as first identified and the results of all subsequent monthly monitoring events during the delay of repair.

(4) An estimate of the potential emissions from the leaking heat exchange system or heat exchanger following the procedures in paragraphs (g)(4)(i) and (g)(4)(ii) of this section.

(i) Determine the total strippable VOC concentration in the cooling water, in parts per million by weight (ppmw), using equation 7-1 from Modified El Paso method (incorporated by reference in §63.14), based on the total strippable concentration in the stripped air, ppmv, from monitoring.

(ii) Calculate the VOC emissions for the leaking heat exchange system or heat exchanger by multiplying the VOC concentration in the cooling water, ppmw, by the flow rate of the cooling water from the leaking tower or heat exchanger and by the expected duration of the delay.

17. Newly redesignated §63.655 is amended by:

a. Revising the first sentence of paragraph (b);

b. Revising the first sentence of paragraph (c);

c. Revising paragraphs (f)(1) introductory text, (f)(1)(i)(B)(2), and (D)(2);

d. Adding paragraph (f)(1)(vi);

e. Revising paragraph (f)(3) introductory text;

f. Revising paragraphs (g) introductory text, (g)(1), (g)(2), (g)(3), (g)(4), (g)(5), and (g)(8)(ii)(C);

g. Adding paragraph (g)(9);

h. Revising the first sentence in paragraph (h)(2)(i)(B) and revising paragraph (h)(2)(ii);

i. Revising paragraph (i)(1) introductory text;

j. Adding paragraphs (i)(1)(v) and (i)(1)(vi);

k. Redesignating existing paragraph (i)(4) as (i)(5); and

l. Adding paragraph (i)(4) to read as follows.

§63.655 Reporting and recordkeeping requirements.

* * * * *

(b) Each owner or operator subject to the gasoline loading rack provisions in §63.650 shall comply with the recordkeeping and reporting provisions in §63.428 (b) and (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R.* * *

(c) Each owner or operator subject to the marine tank vessel loading operation standards in §63.651 shall comply with the recordkeeping and reporting provisions in §63.567(a) and §63.567(c) through (k) of subpart Y.* * *

* * * * *

(f) * * *

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (f)(1)(vi) of this section.

(i) * * *

(B) * * *

(2) The design evaluation documentation specified in §63.120(d)(1)(i) of subpart G or §63.985(b)(1)(i) of subpart SS (as applicable), if the owner or operator elects to prepare a design evaluation; or

* * * * *

(D) * * *

(2) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.120(e) of subpart G or §63.987(b) of subpart SS, as applicable; and

* * * * *

(vi) For each heat exchange system, identification of the heat exchange systems that are subject to the requirements of this subpart.

* * * * *

(3) For each monitored parameter for which a range is required to be established under §63.120(d) of subpart G or §63.985(b) of subpart SS for storage vessels or §63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

* * * * *

(g) The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the compliance exceptions specified in paragraphs (g)(1) through (6) of this section or paragraph (g)(9) of this section occur. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions identified in paragraph (g)(1) through (6) of this section or paragraph (g)(9) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (9) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraph (g)(2) through (g)(5) of this section. Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with §63.646(a) through (l).

(2) Internal floating roofs. (i) An owner or operator who elects to comply with §63.646(a) through (l) by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with §63.120(a) of subpart G in which a failure is detected in the control equipment.

(A) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G, the specifications and requirements listed in paragraphs (g)(2)(i)(A)(1) through (g)(2)(i)(A)(3) of this section apply.

(1) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside

the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(2) Except as provided in paragraph (g)(2)(i)(C) of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(3) If an extension is utilized in accordance with §63.120(a)(4) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(a)(4) of subpart G; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(B) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G (i.e., internal inspections), the specifications and requirements listed in paragraphs (g)(2)(ii) (B)(1) and (g)(2)(i)(B)(2) of this section apply.

(1) A failure is defined as any time in which the internal

floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with §63.646(m) by using a fixed roof and an internal floating roof shall submit the results of each inspection conducted in accordance with §63.1063(c)(1), (d)(1), and (d)(2) of subpart WW in which a failure is detected in the control equipment. For vessels for which inspections are required under §63.1063(c) and (d), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) through (g)(2)(ii)(C) of this section apply.

(A) A failure is defined in §63.1063(d)(1) of subpart WW.

(B) Each Periodic Report shall include a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs.

(C) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) of subpart WW shall, in the next Periodic Report, submit the documentation required by §63.1063(e)(2).

(3) External floating roofs. (i) An owner or operator who elects to comply with §63.646(a) through (l) by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i)(A) and (g)(3)(i)(B) of this section.

(A) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with §63.120(b) of subpart G in which the seal and seal gap requirements of §63.120(b)(3), (b)(4), (b)(5), or (b)(6) of subpart G are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A)(1) through (g)(3)(i)(A)(4) of this section.

(1) The date of the seal gap measurement.

(2) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (b)(4) of subpart G.

(3) A description of any seal condition specified in §63.120(b)(5) or (b)(6) of subpart G that is not met.

(4) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(B) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(b)(7)(ii) or (b)(8) of subpart G, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(C) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by §63.120(b)(10) of subpart G. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(i)(C)(1) and (g)(3)(i)(C)(2) of this section.

(1) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new

source, the slotted membrane has more than 10 percent open area.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with §63.646(m) by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(ii)(A) and (g)(3)(ii)(B) of this section.

(A) For vessels for which inspections are required under §63.1063(c)(2), (d)(1), and (d)(3) of subpart WW, the owner or operator shall submit, as part of the Periodic Report, a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs. A failure is defined in §63.1063(d)(1).

(B) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) of subpart WW shall, in the next Periodic Report, submit the documentation required by those paragraphs.

(4) An owner or operator who elects to comply with §63.646(a) through (l) by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (g)(2)(i) of this

section.

(5) An owner or operator who elects to comply with §63.646(a) through (l) or §63.646(m) by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(4)(i) through (g)(4)(iii) of this section, as applicable.

(i) The Periodic Report shall include the information specified in paragraphs (g)(4)(i)(A) and (g)(4)(i)(B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of either §63.119(e)(1) or (e)(2) of subpart G or either §63.985(a) and (b) or §63.987(a) of subpart SS, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the requirements of either §63.119 (e)(1) or (e)(2) of subpart G or either §63.985(a) and

(b) or §63.987(a) of subpart SS, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include identification of the control device for which the measured parameters were outside of the established ranges and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in §63.11(b) of subpart A of this part and shall include identification of the flare that does not meet the general requirements specified in §63.11(b) of subpart A and reasons the flare did not meet the general requirements specified in §63.11(b) of subpart A.

(iv) An owner or operator who elects to comply with §63.646(m) by installing an alternate control device as described in §63.1064 of subpart WW shall submit, as part of the next Periodic Report, a written application as described in §63.1066(b)(3) of subpart WW.

* * * * *

(8) * * *

(ii) * * *

(C) The information required to be reported by §§63.567(e)(4) and 63.567(j)(3) of subpart Y for each marine tank vessel loading operation included in an emissions average, unless the information has already been submitted in a separate report;

* * * * *

(9) For heat exchange systems, Periodic Reports must include the following information:

(i) The number of heat exchange systems in HAP service.

(ii) The number of heat exchange systems in HAP service found to be leaking.

(iii) A summary of the monitoring data that indicate a leak, including the number of leaks determined to be equal to or greater than the leak definitions specified in §63.654(c)(2);

(iv) If applicable, the date a leak was identified, the date the source of the leak was identified, and the date of repair;

(v) If applicable, a summary of each delayed repair, including the original date and reason for the delay and the date of repair, if repaired during the reporting period; and

(vi) If applicable, an estimate of VOC emissions for each delayed repair over the reporting period.

(h) * * *

(2) * * *

(i) * * *

(B) Except as provided in paragraph (h)(2)(i)(C) of this section, if the internal inspection required by §§63.120(a)(2), 63.120(a)(3), or 63.120(b)(10) of subpart G or §63.1063(d)(1) of subpart WW is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel.* * *

* * * * *

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by §63.120 (b)(1) or (b)(2) of subpart G or §63.1062(d)(3) of subpart WW. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

*   *   *   *   *

(i) *   *   *

(1) Each owner or operator subject to the storage vessel provisions in §63.646(a) through (l) shall keep the records specified in §63.123 of subpart G of this part except as specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section. Each owner or operator subject to the storage vessel provisions in §63.646(m) shall keep records as specified in paragraphs (i)(1)(v) and (i)(1)(vi) of this section.

*   *   *   *   *

(v) Each owner or operator of a Group 1 storage vessel subject to the provisions in §63.646 (m) shall keep the records specified in §63.1065 of subpart WW.

(vi) Each owner or operator of a Group 2 storage vessel shall keep the records specified in §63.1065(a) of subpart WW. If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

*   *   *   *   *

(4) The owner or operator of a heat exchange system subject to the monitoring requirements in §63.654 shall comply

with the recordkeeping requirements in paragraphs (i)(4)(i) through (vi) of this section.

(i) Identification of all heat exchangers at the facility and the average annual HAP concentration of process fluid or intervening cooling fluid estimated when developing the Notification of Compliance Status report.

(ii) Identification of all heat exchange systems that are in organic HAP service. For each heat exchange system that is subject to this subpart, this must include identification of all heat exchangers within each heat exchange system, identification of the individual heat exchangers in organic HAP service within each heat exchange system, and, for closed-loop recirculation systems, the cooling tower included in each heat exchange system.

(iii) Results of the following monitoring data for each monthly monitoring event:

(A) Date/time of event.

(B) Barometric pressure.

(C) El Paso air stripping apparatus water flow (ml/min) and air flow, ml/min, and air temperature, °C.

(D) FID reading (ppmv).

(E) Heat exchange exit line flow or cooling tower return line flow at the El Paso monitoring location, gal/min.

(F) Calibration information identified in Section 5.4.2 of the Modified El Paso Method, incorporated by reference in §63.14(n).

(iv) The date when a leak was identified and the date when the heat exchanger was repaired or taken out of service.

(vi) If a repair is delayed, the reason for the delay, the schedule for completing the repair, and the estimate of potential emissions for the delay of repair.

* * * * *

18. Newly redesignated §63.656 is amended by revising the first sentence of paragraph (c)(1) to read as follows:

§63.656 Implementation and enforcement.

* * * * *

(c) * * *

(1) Approval of alternatives to the requirements in §§63.640, 63.642(g) through (l), 63.643, 63.646 through 63.652, and 63.654. * * *

* * * * *

Appendix to Subpart CC of Part 63—Tables--[AMENDED]

19. Table 1 of the appendix to subpart CC is revised to read as follows:

TABLE 1——HAZARDOUS AIR POLLUTANTS

Chemical name	CAS No.[a]
Benzene	71432

Biphenyl	92524
Butadiene (1,3)	106990
Carbon disulfide	75150
Carbonyl sulfide	463581
Cresol (mixed isomers[b])	1319773
Cresol (m-)	108394
Cresol (o-)	95487
Cresol (p-)	106445
Cumene	98828
Dibromoethane (1,2) (ethylene dibromide)	106934
Dichloroethane (1,2)	107062
Diethanolamine	111422
Ethylbenzene	100414
Ethylene glycol	107211
Hexane	110543
Methanol	67561
Methyl isobutyl ketone (hexone)	108101
Methyl tert butyl ether	1634044
Naphthalene	91203
Phenol	108952
Toluene	108883
Trimethylpentane (2,2,4)	540841
Xylene (mixed isomers[b])	1330207
xylene (m-)	108383
xylene (o-)	95476
xylene (p-)	106423

[a] CAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.
[b] Isomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

20. Table 4 of the appendix to subpart CC is revised to read as follows:

TABLE 4——GASOLINE DISTRIBUTION EMISSION POINT RECORDKEEPING AND REPORTING REQUIREMENTS[a]

Reference (section of subpart Y)	Description	Comment

63.428(b) or (k)	Records of test results for each gasoline cargo tank loaded at the facility.	
63.428(c)	Continuous monitoring data recordkeeping requirements.	
63.428(g)(1)	Semiannual report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.428(h)(1) through (h)(3)	Excess emissions report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.

[a] This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

21. Table 5 of the appendix to subpart CC is revised to read as follows:

TABLE 5--MARINE VESSEL LOADING OPERATIONS RECORDKEEPING AND REPORTING REQUIREMENTS[a]

Reference (section of subpart Y)	Description	Comment
63.562(e)(2)	Operation and maintenance plan for control equipment and monitoring equipment	
63.565(a)	Performance test/site test plan	The information required under this paragraph is to be submitted with the Notification of Compliance Status report required under 40 CFR part 63, subpart CC.

63.565(b)	Performance test data requirements	
63.567(a)	General Provisions (subpart A) applicability	
63.567(c)	Request for extension of compliance	
63.567(d)	Flare recordkeeping requirements	
63.567(e)	Summary report and excess emissions and monitoring system performance report requirements	The information required under this paragraph is to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.567(f)	Vapor collection system engineering report	
63.567(g)	Vent system valve bypass recordkeeping requirements	
63.567(h)	Marine vessel vapor-tightness documentation	
63.567(i)	Documentation file maintenance	
63.567(j)	Emission estimation reporting and recordkeeping procedures	

[a] This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

22. Table 6 of the appendix to subpart CC is revised to read as follows:

TABLE 6-—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC[a]

Reference	Applies to subpart CC	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	Reserved.
63.1(a)(6)	Yes	Except the correct mail drop (MD) number is C404-04
63.1(a)(7)-63.1(a)(9)	No	Reserved.
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12)	Yes	
63.1(b)(1)	Yes	
63.1(b)(2)	No	Reserved.
63.1(b)(3)	No	
63.1(c)(1)	Yes	
63.1(c)(2)	No	Area sources are not subject to subpart CC.
63.1(c)(3)-63.1(c)(4)	No	Reserved.
63.1(c)(5)	Yes	Except that sources are not required to submit notifications overridden by this table.
63.1(d)	No	Reserved.
63.1(e)	No	No CAA section 112(j) standard applies to the affected sources under subpart CC.
63.2	Yes	§63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC.
63.3	Yes	
63.4(a)(1)–63.4(a)(2)	Yes	
63.4(a)(3)-63.4(a)(5)	No	Reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	Except the cross-reference to §63.9(b) is changed to §63.9(b)(4) and (5). Subpart CC overrides §63.9(b)(2).
63.5(b)(5)	No	Reserved.

63.5(b)(6)	Yes	
63.5(c)	No	Reserved.
63.5(d)(1)(i)	Yes	Except that the application shall be submitted as soon as practicable before startup, but no later than 90 days after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC.
63.5(d)(1)(ii)	Yes	Except that for affected sources subject to subpart CC, emission estimates specified in §63.5(d)(1)(ii)(H) are not required.
63.5(d)(1)(iii)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)	Yes	
63.6(a)	Yes	
63.6(b)(1)-63.6(b)(5)	No	Subpart CC specifies compliance dates and notifications for sources subject to subpart CC.
63.6(b)(6)	No	Reserved.
63.6(b)(7)	Yes	
63.6(c)(1)-63.6(c)(2)	No	§63.640 of subpart CC specifies the compliance date.
63.6(c)(3)–63.6(c)(4)	No	Reserved.
63.6(c)(5)	Yes	
63.6(d)	No	Reserved.
63.6(e)(1)	Yes	Except the startup, shutdown, or malfunction plan does not apply to Group 2 emission points that are not part of an emissions averaging group.[b]
63.6(e)(2)	No	Reserved.
63.6(e)(3)(i)	Yes	Except the startup, shutdown, or malfunction plan does not apply to Group 2 emission points that are not part of an emissions averaging group.[b]

63.6(e)(3)(ii)	No	Reserved.
63.6(e)(3)(iii)-63.6(e)(3)(ix)	Yes	Except the reports specified in §63.6(e)(3)(iv) do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report.
63.6 (f)(1)	Yes	Except for the heat exchange system standards, which apply at all times
63.6(f)(2) and (3)	Yes	Except the phrase “as specified in §63.7(c)” in §63.6(f)(2)(iii)(D) does not apply because subpart CC does not require a site-specific test plan.
63.6(g)	Yes	
63.6(h)(1) and 63.6(h)(2)	Yes	Except §63.6(h)(2)(ii), which is reserved.
63.6(h)(3)	No	Reserved.
63.6(h)(4)	No	Notification of visible emission test not required in subpart CC.
63.6(h)(5)	No	Visible emission requirements and timing is specified in §63.645(i) of subpart CC.
63.6(h)(6)	Yes	
63.6(h)(7)	No	Subpart CC does not require opacity standards.
63.6(h)(8)	Yes	
63.6(h)(9)	No	Subpart CC does not require opacity standards.
63.6(i)	Yes	Except for §63.6(i)(15), which is reserved.
63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after compliance date, as specified in §63.655(f) of subpart CC.
63.7(a)(3)	Yes	
63.7(a)(4)	Yes	
63.7(b)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.
63.7(c)	No	Subpart CC does not require a site-specific test plan.

63.7(d)	Yes	
63.7(e)(1)	Yes	Except the performance test must be conducted at the maximum representative capacity as specified in §63.642(d)(3) of subpart CC.
63.7(e)(2)-63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives without additional notification or approval.
63.7(g)	No	Performance test reporting specified in §63.655(f).
63.7(h)(1)	Yes	
63.7(h)(2)	Yes	
63.7(h)(3)	Yes	Yes, except site-specific test plans shall not be required, and where §63.7(g)(3) specifies submittal by the date the site-specific test plan is due, the date shall be 90 days prior to the Notification of Compliance Status report in §63.655(f).
63.7(h)(4)(i)	Yes	
63.7(h)(4)(ii)	No	Site-specific test plans are not required in subpart CC.
63.7(h)(4)(iii) and (iv)	Yes	
63.7(h)(5)	Yes	
63.8(a)	Yes	Except §63.8(a)(3), which is reserved.
63.8(b)	Yes	
63.8(c)(1)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	Except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately.

63.8(c)(4)	Yes	Except Subpart CC specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is “once every hour rather” than “for each successive 15-minute period.”
63.8(c)(5)–63.8(c)(8)	No	
63.8(d)	No	
63.8(e)	No	Subpart CC does not require performance evaluations; however, this shall not abrogate the Administrator’s authority to require performance evaluation under section 114 of the Clean Air Act.
63.8(f)(1)	Yes	
63.8(f)(2)	Yes	
63.8(f)(3)	Yes	
63.8(f)(4)(i)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(5)	Yes	
63.8(f)(6)	No	Subpart CC does not require continuous emission monitors.
63.8(g)	No	Subpart CC specifies data reduction procedures in §63.655(i)(3).
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in §63.9(a)(4)(ii).
63.9(b)(1)	Yes	Except the notification of compliance status report specified in §63.655(f) of subpart CC may also serve as the initial compliance notification required in §63.9(b)(1)(iii).
63.9(b)(2)	No	A separate Initial Notification report is not required under subpart CC.
63.9(b)(3)	No	Reserved.

63.9(b)(4)	Yes	Except for subparagraphs §63.9(b)(4)(ii) through (iv), which are reserved.
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test and does not require a site-specific test plan.
63.9(f)	No	Subpart CC does not require advanced notification of visible emissions test.
63.9(g)	No	
63.9(h)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§63.644(d) of subpart CC specifies record retention requirements.
63.10(b)(2)(i)	Yes	
63.10(b)(2)(ii)	Yes	
63.10(b)(2)(iii)	No	
63.10(b)(2)(iv)	Yes	
63.10(b)(2)(v)	Yes	
63.10(b)(2)(vi)	Yes	
63.10(b)(2)(vii)	No	
63.10(b)(2)(viii)	Yes	
63.10(b)(2)(ix)	Yes	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xi)	No	
63.10(b)(2)(xii)	Yes	
63.10(b)(2)(xiii)	No	
63.10(b)(2)(xiv)	Yes	
63.10(b)(3)	No	
63.10(c)(1)-63.10(c)(6)	No	
63.10(c)(7) and 63.10(c)(8)	Yes	

63.10(c)(9)-63.10(c)(15)	No	
63.10(d)(1)	Yes	
63.10(d)(2)	No	§63.655(f) of subpart CC specifies performance test reporting.
63.10(d)(3)	No	Results of visible emissions test are included in Compliance Status Report as specified in §63.655(f).
63.10(d)(4)	Yes	
63.10(d)(5)(i)	Yes[b]	Except that reports required by §63.10(d)(5)(i) may be submitted at the same time as periodic reports specified in §63.655(g) of subpart CC.
63.10(d)(5)(ii)	Yes	Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the startup, shutdown, and malfunction plan and that cause the source to exceed any applicable emission limitation do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report.
63.10(e)	No	
63.10(f)	Yes	
63.11–63.16	Yes	

[a] Wherever subpart A specifies “postmark” dates, submittals may be sent by methods other than the U.S. Mail (e.g., by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

[b] The plan, and any records or reports of startup, shutdown, and malfunction do not apply to Group 2 emission points that are not part of an emissions averaging group.

23. Table 7 of the appendix to subpart CC is revised to read as follows:

TABLE 7——FRACTION MEASURED (F_M), FRACTION EMITTED (F_E), AND FRACTION REMOVED (FR) FOR HAP COMPOUNDS IN WASTEWATER STREAMS

Chemical name	CAS No.[a]	F_m	F_e	Fr
Benzene	71432	1.00	0.80	0.99

Biphenyl	92524	0.86	0.45	0.99
Butadiene (1,3)	106990	1.00	0.98	0.99
Carbon disulfide	75150	1.00	0.92	0.99
Cumene	98828	1.00	0.88	0.99
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00	0.64	0.99
Ethylbenzene	100414	1.00	0.83	0.99
Hexane	110543	1.00	1.00	0.99
Methanol	67561	0.85	0.17	0.31
Methyl isobutyl ketone (hexone)	108101	0.98	0.53	0.99
Methyl tert butyl ether	1634044	1.00	0.57	0.99
Naphthalene	91203	0.99	0.51	0.99
Trimethylpentane (2,2,4)	540841	1.00	1.00	0.99
xylene (m-)	108383	1.00	0.82	0.99
xylene (o-)	95476	1.00	0.79	0.99
xylene (p-)	106423	1.00	0.82	0.99

[a] CAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

24. Table 10 of the appendix to subpart CC is amended by revising footnotes d, f, and g to read as follows:

TABLE 10——MISCELLANEOUS PROCESS VENTS——MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

* * * * *

[d] NCS = Notification of Compliance Status Report described in §63.655.

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[f] When a period of excess emission is caused by insufficient monitoring data, as described in §63.655(g)(6)(i)(C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

[g] PR = Periodic Reports described in §63.655(g).

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