ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2020–0371; FRL–8202–02–OAR]

RIN 2060–AU97

National Emission Standards for Hazardous Air Pollutants: Gasoline Distribution Technology Reviews and New Source Performance Standards Review for Bulk Gasoline Terminals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing the technology reviews (TR) conducted for the national emission standards for hazardous air pollutants (NESHAP) for gasoline distribution facilities and the review of the new source performance standards (NSPS) for bulk gasoline terminals pursuant to the requirements of the Clean Air Act (CAA). The final NESHAP amendments include revised requirements for storage vessels, loading operations, and equipment to reflect cost-effective developments in practices, processes, or controls. The final NSPS reflect the best system of emission reduction for loading operations and equipment leaks. In addition, the EPA is: finalizing revisions related to emissions during periods of startup, shutdown, and malfunction (SSM); adding requirements for electronic reporting; revising monitoring and operating requirements for control devices; and making other minor technical improvements. The EPA estimates that this final action will reduce hazardous air pollutant emissions from gasoline distribution facilities by over 2,200 tons per year (tpy) and volatile organic compound (VOC) emissions by 45,400 tpy.

DATES: The final rule is effective July 8, 2024.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2020–0371. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically through *https://www.regulations.gov/.*

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact U.S. EPA, Attn: Ms. Jennifer Caparoso, Mail Drop: E143–01, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711; telephone number: (919) 541–4063; and email address: *caparoso.jennifer@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AVO audio, visual, or olfactory
BACT best available control technology
BSER best system of emission reduction
CAA Clean Air Act
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS continuous emission monitoring system
CFR Code of Federal Regulations
CO carbon monoxide
CO_2 carbon dioxide
CPMS continuous parametric monitoring system
EAV equivalent annual value
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FR Federal Register
GACT generally available control technology
HAP hazardous air pollutant(s)
ICR information collection request
km kilometer
LAER lowest achievable emission rate
LDAR leak detection and repair
LEL lower explosive limit
MACT maximum achievable control technology
mg/L milligrams per liter
mph miles per hour
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NHV_{cz} combustion zone net heating value
NHV_{dil} net heating value dilution
NO_X nitrogen oxides
NSPS new source performance standards
O_3 ozone
OGI optical gas imaging
OMB Office of Management and Budget
ppmv parts per million volume
psig pounds per square inch gauge
PRA Paperwork Reduction Act
PV present value
RACT reasonably available control technology
RFA Regulatory Flexibility Act
RIA regulatory impact analysis
RTR risk and technology review
SO_2 sulfur dioxide
SSM startup, shutdown, and malfunction
TOC total organic carbon
tpy tons per year
TR technology review
U.S. United States
U.S.C. United States Code
VOC volatile organic compound(s)
VRU vapor recovery unit

Background information. On June 10, 2022, the EPA proposed revisions to both the major source and area source Gasoline Distribution NESHAP and the Bulk Gasoline Terminals NSPS based on the TR and NSPS review. In this action, the EPA is finalizing decisions and revisions for these rules. The EPA summarized some of the more significant comments we timely received regarding the proposed rules and provides responses in this preamble. A summary of all other public comments on the proposals and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutants for Gasoline Distribution Facilities and New Source Performance Standards for Bulk Gasoline Terminals, Background Information for Final Amendments, Summary of Public Comments and Responses,* Docket ID No. EPA–HQ–OAR–2020–0371. "Track changes" versions of the regulatory language that incorporates the changes in these rules are available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The source categories that are the subject of this final action are Gasoline Distribution regulated under 40 CFR part 63, subparts R and BBBBBB, and Bulk Gasoline Terminals [1] regulated under 40 CFR part 60, subparts XX and XXa. The EPA set maximum achievable control technology (MACT) standards for the gasoline distribution major source category in 1994 and conducted the residual risk and technology review (RTR) in 2006. The sources affected by the major source NESHAP for the gasoline distribution source category (40 CFR part 63, subpart R) are bulk gasoline terminals and pipeline breakout stations. The EPA set generally available control technology (GACT) standards for the gasoline distribution area source category in 2008. The sources affected by the area source NESHAP for the gasoline distribution source category (40 CFR part 63, subpart BBBBBB) are bulk gasoline terminals, bulk gasoline plants, and pipeline facilities. The EPA set the first NSPS for bulk gasoline terminals in 1983. Bulk gasoline terminals that commenced construction or modification after December 17, 1980, and on or before June 10, 2022, are regulated under the NSPS codified at 40 CFR part 60, subpart XX. Bulk gasoline terminals that commenced construction or modification after June 10, 2022, will be regulated under the NSPS codified at 40 CFR part 60, subpart XXa.

The statutory authority for these final rulemakings is sections 111 and 112 of the CAA. Section 111(b)(1)(B) of the CAA requires the EPA to ''at least every 8 years review and, if appropriate, revise'' the NSPS. Section 111(a)(1) of the CAA provides that performance standards are to ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' We refer to this level of control as the best system of emission reduction or ''BSER.'' Section 112(d)(6) of the CAA requires the EPA to review standards promulgated under CAA section 112(d) and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less often than every 8 years following promulgation of those standards. This is referred to as a ''technology review.''

The NSPS for Bulk Gasoline Terminals and the amendments to the NESHAP for Gasoline Distribution facilities finalized in this action fulfill the Agency's requirements, respectively, to review and, if appropriate, revise the NSPS and to review and revise as necessary the NESHAP at least every 8 years.

2. Summary of the Major Provisions of the Regulatory Action in Question

a. NESHAP Subpart R

The EPA is finalizing the requirement of a graduated vapor tightness certification from 0.5 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks. The EPA is also finalizing the requirement of fitting controls for external floating roof tanks consistent with the requirements in 40 CFR part 60, subpart Kb (NSPS subpart Kb). In addition, the EPA is finalizing the requirement of semiannual instrument monitoring for equipment leaks at major source gasoline distribution facilities.

b. NESHAP Subpart BBBBBB

The EPA is finalizing an area source emission limit of 35 milligrams of total organic carbon (TOC) per liter of gasoline loaded (mg/L) at large bulk gasoline terminals and vapor balancing [2] requirements for loading storage vessels and gasoline cargo tanks at bulk gasoline plants with actual throughput of 4,000 gallons per day or more. The EPA is also finalizing the requirement of a graduated vapor tightness certification from 0.5 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks. Additionally, the EPA is finalizing the requirement of fitting controls for external floating roof tanks consistent with the requirements in NSPS subpart Kb. Also, the EPA is finalizing the requirement of annual instrument monitoring for equipment leaks at area source gasoline distribution facilities.

c. NSPS Subpart XXa

The EPA is finalizing a new NSPS subpart XXa applicable to affected facilities that commence construction, modification, or reconstruction after June 10, 2022. For loading operations, the EPA is finalizing standards of performance for VOC that require new facilities to meet a 1.0 mg/L TOC emission limit and modified and reconstructed facilities to meet a 10 mg/L TOC emission limit. The EPA is also finalizing the requirement for gasoline cargo tanks of a graduated vapor tightness certification from 0.5 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size. In addition, the EPA is finalizing the requirement of quarterly instrument monitoring for equipment leaks.

3. Costs and Benefits

In accordance with Executive Order (E.O.) 12866 and 13563, the guidelines of the Office of Management and Budget (OMB) Circular A–4, and the EPA's *Guidelines for Preparing Economic Analyses,* the EPA prepared a Regulatory Impact Analysis (RIA) for the proposal of the rules included in this action. The RIA analyzed the benefits and costs associated with the projected emissions reductions under the proposed requirements, a less stringent set of requirements, and a more stringent set of requirements. Prior to the amendments made by E.O. 14094, the proposal of the area source NESHAP

[1] Petroleum Transportation and Marketing is the listed source category. Bulk Gasoline Terminals are the affected facilities regulated by the NSPS addressing the Petroleum Transportation and Marketing source category.

[2] When using a vapor balancing system, displaced vapors from a cargo tank are captured and routed through piping back to a storage vessel or vice-a-versa.

rule was significant under E.O. 12866, section 3(f)(1) due to its likely annual effect on the economy of $100 million or more in any one year on the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities. Specifically, monetized health benefits from projected VOC reductions associated with the proposed area source NESHAP rule amendments exceeded $100 million per year.

On April 6, 2023, President Biden issued E.O. 14094, Modernizing Regulatory Review, which increased the annual effect threshold for significance under E.O. 12866, section 3(f)(1) from $100 million to $200 million. This final action is significant under E.O. 12866, section 3(f)(1) as amended by E.O. 14094. Accordingly, the EPA has prepared a Regulatory Impact Analysis (RIA).

The EPA projected the emissions reductions, costs, and benefits that may result from the rules included in this final action, which are presented in detail in the RIA. We present these results for each of the three rules included in this final action, and also cumulatively. The RIA focuses on the elements of the final action that are likely to result in quantifiable cost or emissions changes compared to a baseline without the final NESHAP and NSPS amendments. We estimated the cost, emissions, and benefit impacts for the 2027 to 2041 period. We also show the present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this action in 2021 dollars. The year 2019 was used as the base year in the cost analyses at proposal. However, based on comments received, we updated our analyses to use 2021 as the base year.

The EPA also updated costs and emissions impacts in the RIA to incorporate changes to the economic environment since the proposal. Specifically, the interest rate used to annualize capital costs rose from 3.25 percent to 7.75 percent to reflect changes in the bank prime rate, the VOC recovery credit used to value gasoline product recovery was updated to reflect the 2021 wholesale price of gasoline, and the dollar-year was updated from 2019 to 2021 to reflect recent inflation.[3]

The initial analysis year in the RIA is 2027, as we assume the large majority of impacts associated with the final action will begin in that year. The most significant impacts of this final action are due to the regulation of existing sources under the major and area source NESHAP rules. These two rules, NESHAP subparts R and BBBBBB, require compliance with the existing source standards 3 years after the promulgation date of these final rules. As a result, compliance with the standards for existing sources will occur in 2027. The final analysis year is 2041, which allows us to present 15 years of projected impacts after all three of these rules are assumed to take effect.

The cost analysis presented in the RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components. The first component is a set of representative or model plants for each regulated facility, segment, and control option. The characteristics of a model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery of gasoline resulting from each control option. The second component is a set of projections of data for affected facilities, distinguished by vintage, year, and other necessary attributes (*e.g.,* precise content of material in storage vessels). Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, multiplying data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in recovered gasoline, which can then be sold where possible. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

The EPA expects health benefits as a result of the emissions reductions projected under this final action. We expect that hazardous air pollutants (HAP) emission reductions will improve health and welfare associated with those affected by these emissions. In addition, the EPA expects that VOC emission reductions that will occur concurrent with the reductions of HAP emissions will improve air quality and are likely to improve health and welfare associated with reduced exposure to ozone, particulate matter with a diameter less than 2.5 microns ($PM_{2.5}$), and HAP. The EPA expects disbenefits from secondary increases of carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and carbon monoxide (CO) emissions associated with the control options included in the cost analysis. The benefits of reduced premature mortality and morbidity associated with reduced exposure to VOC emissions and climate disbenefits associated with increased CO_2 emissions have been monetized for this final action. Our discussion of both the benefits and disbenefits, monetized and non-monetized, associated with this action are included in chapter 4 of the RIA.

Tables 1 through 3 of this document present the emission changes and the PV and EAV of the projected monetized benefits, compliance costs, and net benefits over the 2027 to 2041 period under the final action for each subpart. Table 4 of this document presents the same results for the cumulative impact of these rulemakings. Climate disbenefits are discounted using a 3 percent social discount rate. All other discounting of impacts presented uses social discount rates of 3 and 7 percent.

[3] The EPA used the wholesale price of gasoline in this analysis to provide a focus on the rulemaking's cost impacts to affected firms, including the impact of product recovery upon the cost to these firms. Use of the consumer price of gasoline would introduce market interactions that may make analysis of product recovery more difficult to estimate given passthrough of costs by firms to consumers. More explanation on the use of wholesale price of gasoline is found in Chapter 3 of the RIA.

Table 1—Monetized Benefits, Costs, Net Benefits, and Emissions Reductions of the Final NESHAP Subpart BBBBBB Amendments, 2027 Through 2041
[Dollar Estimates in Millions of 2021 Dollars] [a]

	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Benefits [b]	$200 and $1,600	$17 and $140	$120 and $980	$13 and $110
Climate Disbenefits (3%) [c]	$30	$2.5	$30	$2.5
Net Compliance Costs [d]	-$70	-$6.0	-$50	-$5.0
Compliance Costs	$230	$19	$160	$18
Value of Product Recovery	$300	$25	$210	$23
Net Benefits	$240 and $1,600	$21 and $140	$140 and $1,000	$16 and $110
Emissions Reductions (short tons)	2027–2041 Total			
VOC	605,000			
HAP	31,000			
Secondary Emissions Increases (short tons)	2027–2041 Total			
CO_2	490,000			
NO_x	280			
SO_2	0.67			
CO	1,300			
Non-monetized Benefits in this table	HAP benefits from reducing 31,000 short tons of HAP from 2027–2041			
	Climate and health disbenefits from increasing nitrogen oxides (NO_x) emissions by 280 short tons, sulfur dioxide (SO_2) by 0.67 short tons, and carbon monoxide (CO) by 1,300 short tons from 2027–2041			
	Visibility benefits			
	Reduced vegetation and ecosystem effects			

[a] Discounted to 2024. Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Short tons are standard English tons (2,000 pounds).
[b] Monetized benefits include ozone related health benefits associated with reductions in VOC emissions. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates. Disbenefits from additional CO_2 emissions resulting from application of control options are monetized and included in the table as climate disbenefits. Benefits from HAP reductions and VOC reductions outside of the ozone season remain unmonetized and are thus not reflected in the table. The unmonetized effects also include disbenefits resulting from the secondary impact of an increase in NO_x, SO_2, and CO emissions. Please see section 4.6 of the RIA for more discussion of the climate disbenefits.
[c] Climate disbenefits are based on changes (increases) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the disbenefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the disbenefits calculated using all four SC-CO_2 estimates; the additional disbenefit estimates range from PV (EAV) $6.1 million ($0.6 million) to $91 million ($7.6 million) from 2027–2041 for the final amendments. Please see table 4-10 of the RIA for the full range of SC-CO_2 estimates. As discussed in chapter 4 of the RIA, a consideration of climate disbenefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.
[d] Net compliance costs are the engineering control costs minus the value of recovered product. A negative net compliance cost occurs when the value of the recovered product exceeds the compliance costs.

Table 2—Monetized Benefits, Compliance Costs, Net Benefits, and Emissions Reductions of the Final NESHAP Subpart R Amendments, 2027 Through 2041
[Dollar Estimates in Millions of 2021 Dollars] [a]

	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Benefits [b]	$11 and $87	$0.89 and $7.3	$6.3 and $52	$0.70 and $5.8
Net Compliance Costs [c]	$22	$1.9	$16	$1.6
Compliance Costs	$38	$3.2	$27	$2.9
Value of Product Recovery	$16	$1.3	$11	$1.3
Net Benefits	-$11 and $65	-$1.0 and $5.4	-$9.7 and $36	-$0.9 and $4.2
Emissions Reductions (short tons)	2027–2041 Total			
VOC	32,000			
HAP	2,000			
Non-monetized Benefits in this table	HAP benefits from reducing 2,000 short tons of HAP from 2027–2041			
	Visibility benefits			
	Reduced vegetation and ecosystem effects			

[a] Discounted to 2024. Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Short tons are standard English tons (2,000 pounds).
[b] Monetized benefits include ozone related health benefits associated with reductions in VOC emissions. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates. Benefits from HAP reductions and VOC reductions outside of the ozone season remain unmonetized and are thus not reflected in the table.
[c] Net compliance costs are the engineering control costs minus the value of recovered product. A negative net compliance cost occurs when the value of the recovered product exceeds the compliance costs.

Table 3—Monetized Benefits, Costs, Net Benefits, and Emissions Reductions of the Final NSPS Subpart XXa, 2027 Through 2041
[Dollar Estimates in Millions of 2021 Dollars] [a]

	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Benefits [b]	$34 and $280	$2.8 and $24	$19 and $160	$2.1 and $17
Climate Disbenefits (3%) [c]	$4.9	$0.41	$4.9	$0.41
Net Compliance Costs [d]	$2.0	$0.20	$2.0	$0.10
Compliance Costs	$52	$4.4	$34	$3.8
Value of Product Recovery	$50	$4.2	$33	$3.7
Net Benefits	$27 and $270	$2.2 and $23	$13 and $150	$1.6 and $16
Emissions Reductions (short tons)	2027–2041 Total			
VOC	110,000			
HAP	4,400			
Secondary Emissions Increases (short tons)	2027–2041 Total			
CO_2	77,000			
NO_x	45			
SO_2	48			
CO	0			
Non-monetized Benefits in this table	HAP benefits from reducing 4,020 short tons of HAP from 2027–2041			
	Climate and health disbenefits from increasing nitrogen oxides (NO_x) emissions by 45 short tons and sulfur dioxide (SO_2) by 48 short tons from 2027–2041.			
	Visibility benefits			
	Reduced vegetation and ecosystem effects			

[a] Discounted to 2024. Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Short tons are standard English tons (2,000 pounds).

[b] Monetized benefits include ozone related health benefits associated with reductions in VOC emissions. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates. Disbenefits from additional CO_2 emissions resulting from application of control options are monetized and included in the table as climate disbenefits. Benefits from HAP reductions and VOC reductions outside of the ozone season remain unmonetized and are thus not reflected in the table. The unmonetized effects also include disbenefits resulting from the secondary impact of an increase in NO_x, SO_2, and CO emissions. Please see section 4.6 of the RIA for more discussion of the climate disbenefits.

[c] Climate disbenefits are based on changes (increases) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the disbenefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the disbenefits calculated using all four SC-CO_2 estimates; the additional disbenefit estimates range from PV (EAV) $0.93 million ($0.09 million) to $15 million ($1.2 million) from 2027–2041 for the final amendments. Please see table 4-10 of the RIA for the full range of SC-CO_2 estimates. As discussed in chapter 4 of the RIA, a consideration of climate disbenefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

[d] Net compliance costs are the engineering control costs minus the value of recovered product. A negative net compliance cost occurs when the value of the recovered product exceeds the compliance costs.

Table 4—Cumulative Monetized Benefits, Costs, Net Benefits, and Emissions Reductions of the Final Action, 2027 Through 2041
[Dollar Estimates in Millions of 2021 Dollars] [a]

	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Benefits [b]	$240 and $2,000	$20 and $170	$140 and $1,200	$16 and $130
Climate Disbenefits (3%) [c]	$35	$2.9	$35	$2.9
Net Compliance Costs [d]	-$46	-$3.9	-$35	-$2.9
Compliance Costs	$320	$27	$220	$25
Value of Product Recovery	$370	$31	$250	$28
Net Benefits	$250 and $2,000	$21 and $170	$140 and $1,200	$16 and $130
Emissions Reductions (short tons)	2027–2041 Total			
VOC	740,000			
HAP	38,000			
Secondary Emissions Increases (short tons)	2027–2041 Total			
CO_2	570,000			
NO_x	330			
SO_2	49			
CO	1,300			
Non-monetized Benefits in this table	HAP benefits from reducing 37,000 short tons of HAP from 2027–2041			
	Climate and health disbenefits from increasing nitrogen oxides (NO_x) emissions by 320 short tons, sulfur dioxide (SO_2) by 41 short tons, and carbon monoxide (CO) by 1,300 short tons from 2027–2041			
	Visibility benefits			
	Reduced vegetation and ecosystem effects			

[a] Discounted to 2024. Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Short tons are standard English tons (2,000 pounds).

[b] Monetized benefits include ozone related health benefits associated with reductions in VOC emissions. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates. Disbenefits from additional CO_2 emissions resulting from application of control options are monetized and included in the table as climate disbenefits. Benefits from HAP reductions and VOC reductions outside of the ozone season remain unmonetized and are thus not reflected in the table. The unmonetized effects also include disbenefits resulting from the secondary impact of an increase in NO_x, SO_2, and CO emissions. Please see section 4.6 of the RIA for more discussion of the climate disbenefits.

[c] Climate disbenefits are based on changes (increases) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the disbenefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the disbenefits calculated using all four SC-CO_2 estimates; the additional disbenefit estimates range from PV (EAV) $7.1 million ($0.7 million) to $110 million ($8.8 million) from 2027–2041 for the final amendments. Please see table 4-10 of the RIA for the full range of SC-CO_2 estimates. As discussed in chapter 4 of the RIA, a consideration of climate disbenefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

[d] Net compliance costs are the engineering control costs minus the value of recovered product. A negative net compliance cost occurs when the value of the recovered product exceeds the compliance costs.

B. Does this action apply to me?

The source categories that are the subject of this final action are Gasoline Distribution regulated under 40 CFR part 63, subparts R and BBBBBB, and Bulk Gasoline Terminals regulated under 40 CFR part 60, subparts XX and XXa. The 2022 North American Industry Classification System (NAICS) codes for the gasoline distribution industry are 324110, 493190, 486910, and 424710. The NAICS codes are not intended to be exhaustive but rather to serve as a guide for readers regarding entities likely to be affected by this final action. The NSPS codified in 40 CFR part 60, subpart XXa, are directly applicable to affected facilities that begin construction, reconstruction, or modification after June 10, 2022. If you have any questions regarding the applicability of these rules to a particular entity, you should carefully examine the applicability criteria found in the appropriate NESHAP and NSPS, and consult with the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your State air pollution control agency with delegated authority, or your EPA Regional Office.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/gasoline-distribution-mact-and-gact-national-emission-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same website.

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous.* This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by July 8, 2024. Under CAA section 307(b)(2), the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to reconsider the rules, ''[i]f the person raising an objection can demonstrate to the Administrator 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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both 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), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. NESHAP

The statutory authority for this action is provided by CAA sections 112 and 301, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a two-stage regulatory process to develop standards for HAP from stationary sources. Generally, the first stage involves establishing technology-based standards and the second stage involves evaluating those standards that are based on MACT to determine whether additional standards are needed to address any remaining risk associated with HAP emissions. This second stage is commonly referred to as the ''residual risk review.'' In addition to the residual risk review, the CAA also requires the EPA to review standards set under CAA section 112 every 8 years and revise the standards as necessary taking into account any ''developments in practices, processes, or control technologies.'' This review is commonly referred to as the ''technology review'' and is the subject of this final action. The discussion that follows identifies the most relevant statutory sections and briefly explains the contours of the methodology used to implement these statutory requirements.

In the first stage of the CAA section 112 standard setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. ''Major sources'' are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. All other sources are ''area sources.'' For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements, and nonair quality health and environmental impacts). These standards are commonly referred to as MACT standards. CAA section 112(d)(3) also establishes a minimum control level for MACT standards, known as the MACT ''floor.'' In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as beyond-the-floor standards. For categories of major sources and any area source categories subject to MACT standards, the second stage in standard-setting focuses on identifying and addressing any remaining (*i.e.,* ''residual'') risk pursuant to CAA section 112(f) and concurrently conducting a technology review pursuant to CAA section 112(d)(6). For categories of area sources subject to GACT standards, there is no requirement to address residual risk, but, similar to the major source categories, the technology review is required.

A technology review is required for all standards established under CAA section 112(d) including GACT standards that apply to area sources.[4] In conducting the technology review, the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008). *Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). The EPA is required to address regulatory gaps, such as missing MACT standards for listed air toxics known to be emitted from the major source category, and any new MACT standards must be established under CAA sections 112(d)(2) and (3), or, in specific circumstances, CAA sections 112(d)(4) or (h). *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020). For information on how EPA conducts a technology review, see 87 FR 35616 (June 10, 2022).

Several additional CAA sections are relevant as they specifically address regulation of hazardous air pollutant emissions from area sources. Collectively, CAA sections 112(c)(3), (d)(5), and (k)(3) are the basis of the Area Source Program under the Urban Air Toxics Strategy, which provides the framework for regulation of area sources under CAA section 112.

Section 112(k)(3)(B) of the CAA requires the EPA to identify at least 30 HAP that pose the greatest potential health threat in urban areas with a primary goal of achieving a 75 percent reduction in cancer incidence attributable to HAP emitted from stationary sources. As discussed in the Integrated Urban Air Toxics Strategy (64 FR 38706, 38715; July 19, 1999), the EPA identified 30 HAP emitted from area sources that pose the greatest potential health threat in urban areas, and these HAP are commonly referred to as the ''30 urban HAP.''

Section 112(c)(3), in turn, requires the EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation. The EPA implemented these requirements through the Integrated Urban Air Toxics Strategy by identifying and setting standards for categories of area sources including the Gasoline Distribution source category that is addressed in this action.

CAA section 112(d)(5) provides that for area source categories, in lieu of setting MACT standards (which are generally required for major source categories), the EPA may elect to promulgate standards or requirements for area sources ''which provide for the use of generally available control technology or management practices [GACT] by such sources to reduce emissions of hazardous air pollutants.'' In developing such standards, the EPA evaluates the control technologies and management practices that reduce HAP emissions that are generally available for each area source category. Consistent with the legislative history, we can consider costs and economic impacts in determining what constitutes GACT.

GACT standards were set for the Gasoline Distribution area source category in 2008. MACT standards were set for the Gasoline Distribution major source category in 1994 and the residual risk review and initial technology review for the major source category were completed in 2006. As noted above, this action finalizes the required CAA section 112(d)(6) technology reviews for the standards for major and area sources in that source category.

2. NSPS

The EPA's authority for the final NSPS rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into

[4] For categories of area sources subject to GACT standards, CAA sections 112(d)(5) and (f)(5) provide that the EPA is not required to conduct a residual risk review under CAA section 112(f)(2). However, the EPA is required to conduct periodic technology reviews under CAA section 112(d)(6).

account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA section 111(a)(1) makes clear that the EPA is to determine both the BSER for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, pursuant to CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible,'' such as when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of ''new source'' in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, ''reconstruction'' means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards.

The NSPS were promulgated for Bulk Gasoline Terminals in 1983. As noted earlier in this preamble, this action finalizes the required NSPS review for that source category. For information on how the EPA conducts a NSPS review, see 87 FR 35616 (June 10, 2022).

B. What are the source categories regulated in this final action?

1. NESHAP Subpart R

The EPA promulgated the major source Gasoline Distribution NESHAP on December 14, 1994 (59 FR 64303). The standards are codified at 40 CFR part 63, subpart R. The major source gasoline distribution industry consists of bulk gasoline terminals and pipeline breakout stations. The source category covered by this MACT standard currently includes 210 facilities.

The primary sources of HAP emissions at bulk gasoline terminals are gasoline loading racks, gasoline cargo tanks, gasoline storage vessels, and equipment in gasoline service. The primary sources of HAP emissions at pipeline breakout stations are gasoline storage vessels and equipment in gasoline service. Emissions from loading racks at major source gasoline terminals under NESHAP subpart R are required to be controlled by a vapor collection and processing system to meet a TOC emission limit of 10 mg/L. Gasoline cargo tanks must be certified to be vapor tight using a graduated vapor tightness requirement of 1.0 to 2.5 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks. Emissions from storage vessels with a design capacity greater than or equal to 75 cubic meters must be controlled by equipment designed to suppress emissions (*i.e.,* use an internal or external floating roof meeting certain requirements) or must capture and control emissions to a device achieving 95 percent reduction efficiency. Equipment leaks are subject to a leak detection and repair (LDAR) program using monthly inspections to identify leaks via audio, visual, or olfactory (AVO) methods and repair the leak identified.

2. NESHAP Subpart BBBBBB

The EPA promulgated the area source Gasoline Distribution NESHAP on January 10, 2008 (73 FR 1916). The standards are codified at 40 CFR part 63, subpart BBBBBB. The area source gasoline distribution industry consists of bulk gasoline terminals, bulk gasoline plants, pipeline breakout stations, and pipeline pumping stations. The source category covered by this GACT standard currently includes approximately 9,000 facilities.

The primary sources of HAP emissions at bulk gasoline plants and bulk gasoline terminals are gasoline loading racks, gasoline cargo tanks, gasoline storage vessels, and equipment components in gasoline service. The primary sources of HAP emissions at pipeline breakout stations are gasoline storage vessels and equipment components in gasoline service; the HAP emissions at pipeline pumping stations are from equipment components in gasoline service. Emissions from loading racks at area source gasoline terminals with throughput of 250,000 gallons per day or greater are required under NESHAP subpart BBBBBB to reduce emissions of TOC to less than or equal to 80 mg/L of gasoline. Small bulk gasoline terminals (terminals with a combined throughput between 20,000 and 250,000 gallons per day) and bulk gasoline plants (facilities with gasoline throughput of 20,000 gallons per day or less) are required to use submerged filling with a submerged fill pipe that is no more than 6 inches from the bottom of the cargo tank. Gasoline cargo tanks must be certified to be vapor tight using a maximum allowable pressure loss of 3 inches of water pressure drop over a 5-minute period.

At bulk gasoline terminals and pipeline breakout stations, emissions from storage vessels with a design capacity greater than or equal to 75 cubic meters and a gasoline throughput greater than 480 gallons per day and all storage vessels with a design capacity greater than or equal to 151 cubic meters must be controlled by equipment designed to suppress emissions (*i.e.,* use an internal or external floating roof meeting certain requirements) or must capture and control emissions to a device achieving 95 percent reduction efficiency. Storage vessels below these thresholds must have fixed roofs and must maintain all openings in a closed position at all times when not in use.

Equipment leaks at all area source gasoline distribution facilities are subject to an LDAR program using monthly AVO methods.

3. NSPS

The EPA first promulgated new source performance standards for Bulk Gasoline Terminals on August 18, 1983 (48 FR 37578). These standards of performance are codified in 40 CFR part 60, subpart XX, and are applicable to sources that commence construction, modification, or reconstruction after December 17, 1980, and on or before June 10, 2022. These standards of performance regulate VOC emissions from bulk gasoline terminals.

The affected facility to which the provisions of NSPS subpart XX apply is the total of all the loading racks at a bulk gasoline terminal. The primary sources of VOC emissions subject to NSPS subpart XX are gasoline loading racks, gasoline cargo tanks, and equipment associated with the loading rack and associated vapor collection and processing system. Emissions from gasoline storage vessels are subject to separate NSPS (see 40 CFR part 60, subparts K, Ka, and Kb). VOC emissions from loading racks at gasoline terminals subject to NSPS subpart XX must meet a TOC emission limit of 35 mg/L, except for modified affected facilities with an existing vapor processing system (as of December 17, 1980), which must meet a TOC emission limit of 80 mg/L. Gasoline cargo tanks must be certified to be vapor tight using a maximum allowable pressure loss of 3 inches of water pressure drop over a 5-minute period. Leaks from equipment associated with the loading rack and associated vapor collection and processing system are subject to an LDAR program using monthly AVO methods.

C. What changes were proposed for the gasoline distribution NESHAP and for the bulk gasoline terminals NSPS in the June 10, 2022, proposal?

On June 10, 2022, the EPA published proposed rules in the **Federal Register** for the Gasoline Distribution NESHAP, 40 CFR part 63, subparts R and BBBBBB, and Bulk Gasoline Terminal NSPS, 40 CFR part 60, subpart XXa, that took into consideration the TR and NSPS review and respective analyses.

1. NESHAP Subpart R

In the proposed rule for the major source Gasoline Distribution NESHAP, 40 CFR part 63, subpart R, the EPA for new and existing sources proposed to:

- Retain the 10 mg/L TOC emission limit for gasoline loading racks controlled by thermal oxidation systems.
- Provide a 5,500 ppmv TOC emission limit for gasoline loading racks controlled by vapor recovery units (VRUs), which was determined to be equivalent to the 10 mg/L emission limit.
- Reduce the allowable pressure drop for certifying gasoline cargo tanks as vapor tight to a graduated vapor tightness requirement of 0.5 to 1.25 inches of water, depending on the cargo tank compartment size for gasoline cargo tanks.
- Include additional fitting requirements for storage vessels with external floating roofs.
- Add a requirement for storage vessels with internal floating roofs to maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the lower explosive limit (LEL).
- Require semiannual monitoring using either optical gas imaging (OGI) or EPA Method 21 and repair leaks identified from these monitoring events or leaks identified by AVO methods during normal duties.
- Revise certain requirements to clarify that the emission limits apply at all times.
- Add electronic reporting requirements.

2. NESHAP Subpart BBBBBB

In the proposed rule for the area source Gasoline Distribution NESHAP, 40 CFR part 63, subpart BBBBBB, the EPA proposed for new and existing sources to:

- Reduce the TOC emission limit for loading racks at large bulk gasoline terminals from 80 mg/L to 35 mg/L.
- Provide a 19,200 ppmv TOC emission limit for loading racks at large bulk gasoline terminals controlled by VRUs, which was determined to be equivalent to the 35 mg/L emission limit.
- Reduce the allowable pressure drop for certifying gasoline cargo tanks as vapor tight to a graduated vapor tightness requirement of 0.5 to 1.25 inches of water, depending on the cargo tank compartment size for gasoline cargo tanks.
- Include additional fitting requirements for storage vessels with external floating roofs.
- Add a requirement for storage vessels with internal floating roofs to maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the LEL.
- Add requirements for bulk gasoline plants with a capacity over 4,000 gallons per day to use vapor balancing between gasoline cargo tanks and gasoline storage vessels.
- Require pressure relief valves on fixed roof tanks to have opening pressures set to no less than 2.5 pounds per square inch gauge (psig).
- Require annual monitoring using either OGI or EPA Method 21 and repair leaks identified from these monitoring events or leaks identified by AVO methods during normal duties.
- Revise certain requirements to clarify that the emission limits apply at all times.
- Add electronic reporting requirements.

3. NSPS Subpart XXa

In the proposed rule for Bulk Gasoline Terminal NSPS, 40 CFR part 60, subpart XXa, the EPA proposed for new, modified, and reconstructed sources to:

- Define the affected facility to include all equipment in gasoline service at the bulk gasoline terminal.
- Limit VOC emissions as TOC from loading racks at new bulk gasoline terminals controlled with thermal oxidation systems to 1.0 mg/L and limit TOC emissions from loading racks controlled with thermal oxidation systems at modified or reconstructed bulk gasoline terminals to 10 mg/L.
- Provide 550 ppmv and 5,500 ppmv TOC emission limits for loading racks at bulk gasoline terminals controlled with VRUs, which were determined to be equivalent to the 1.0 mg/L and 10 mg/L proposed TOC emission limits, respectively.
- Require certification of gasoline cargo tanks as vapor tight using a graduated vapor tightness requirement 0.5 to 1.25 inches of water, depending on the cargo tank compartment size for gasoline cargo tanks.
- Require quarterly monitoring using either OGI or EPA Method 21 and repair leaks identified from these monitoring events or leaks identified by AVO methods during normal duties.
- Clarify that the emission limits apply at all times.
- Include electronic reporting requirements.

D. What outreach was conducted following the proposal?

As part of these rulemakings and pursuant to multiple EOs addressing environmental justice (EJ), the EPA engaged and consulted with pertinent stakeholders and the public, including communities with environmental justice concerns. The EPA provided interactions such as conducting a public hearing, offering information on the websites for these rules, and informing the public of the proposed action by sending notifications with summaries of the action and information on how to comment to pertinent stakeholders. These opportunities gave the EPA a chance to hear directly from pertinent stakeholders and the public, especially communities potentially impacted by this final action. Summaries of the public hearing and comments received can be found in the docket for this action.

III. What is included in these final rules and what is the rationale for the final decisions and amendments?

This action finalizes the EPA's determinations pursuant to the TR provisions of CAA section 112 for the Gasoline Distribution major and area source categories and amends both Gasoline Distribution NESHAPs based on those determinations. This action also finalizes the removal of SSM exemptions in the NESHAP. The EPA is further finalizing determinations of its review of the Bulk Gasoline Terminals NSPS pursuant to CAA section 111(b)(1)(B). In addition, this action finalizes electronic reporting, monitoring and operating requirements for control devices, and other minor technical improvements. This action also reflects several changes to the June 10, 2022, proposal in consideration of comments received during the public comment period. For each issue, this section provides a description of what the EPA proposed and what the EPA is finalizing for the issue, the EPA's rationale for the final decisions and amendments, and a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document available in the docket.

A. What are the final rule amendments based on the technology reviews for the gasoline distribution NESHAP and NSPS review for bulk gasoline terminals?

The EPA determined that there are developments in practices, processes, and control technologies for loading operations, storage vessels, and equipment leaks that warrant revisions to NESHAP subpart R and NESHAP subpart BBBBBB.

Therefore, to satisfy the requirements of CAA section 112(d)(6), the EPA is revising the NESHAP to include: a more stringent standard for gasoline loading racks at area sources, including requirements for vapor balancing for bulk gasoline plants with actual throughput of greater than 4,000 gallons per day; for both major and area sources, more stringent requirements for gasoline cargo tank vapor tightness; more stringent fitting control requirements for guidepoles on external floating roofs; the use of LEL monitoring to ensure the effectiveness of internal floating roofs; and instrument monitoring for equipment leaks. The final revisions are similar to those proposed. The most significant change from what was proposed is that we revised the throughput threshold requirement for which bulk gasoline plants must use vapor balancing to be determined by actual throughput rather than by maximum design capacity. Considering the analysis conducted to develop the 4,000 gallons per day threshold, provisions in NESHAP subpart BBBBBB, and comments received, the use of actual daily throughput and an annual averaging time is consistent with the analysis conducted and other provisions in NESHAP subpart BBBBBB. Upon consideration of public comments received, we also included an allowance to subtract methane from the TOC emission limit.

Pursuant to the requirements of CAA section 111(b)(1)(B), the EPA determined that updates to the BSER are warranted and is revising the standards of performance for loading operations and equipment leaks. The EPA is finalizing the revisions to the NSPS in a new subpart, 40 CFR part 60, subpart XXa, applicable to affected sources constructed, modified, or reconstructed after June 10, 2022. The NSPS subpart XXa includes: more stringent VOC standards (as TOC emission limits) for new, modified, or reconstructed gasoline loading racks; more stringent requirements for gasoline cargo tank vapor tightness; and instrument monitoring for equipment leaks. The final requirements in NSPS subpart XXa are similar to those proposed. The most significant change from what was proposed, after considering public comments received, is to define separate affected facilities: one specific to the loading rack and one specific to the equipment. Upon consideration of public comments received, we are also including an allowance to subtract methane from the TOC emission limit consistent with the most stringent emission limitations identified for new sources.

1. Standards for Loading Racks

Because most of the standards proposed for loading racks were primarily in NSPS subpart XXa, we discuss our review of the loading racks NSPS provisions first, and then cover additional technology review issues specific to NESHAP subparts R and BBBBBB.

a. NSPS Subpart XXa

i. What did the EPA propose pursuant to CAA section 111 for loading racks at new, modified, or reconstructed bulk gasoline terminals?

Based on the review of NSPS subpart XX requirements for loading racks at bulk gasoline terminals, we proposed to revise the TOC emission limit from loading racks at new bulk gasoline terminals controlled with thermal oxidation systems to 1.0 mg/L and to revise the TOC emission limit from loading racks at modified or reconstructed bulk gasoline terminals controlled with thermal oxidation systems to 10 mg/L. For thermal oxidation systems, we proposed continuous compliance with a temperature operating limit established as the lowest 3-hour average temperature from a compliant performance test. We also proposed enhanced provisions for flares to ensure good combustion efficiency.

For loading racks controlled with VRUs, we proposed corresponding emission limits of 550 ppmv and 5,500 ppmv TOC (as propane) for loading racks at new bulk gasoline terminals and for loading racks at modified or reconstructed bulk gasoline terminals, respectively. We determined that these concentration emission limits are, respectively, equivalent to the 1.0 mg/L and 10 mg/L proposed TOC emission limits for bulk gasoline terminals controlled with thermal oxidation systems. We proposed to express the concentration limit of 550 ppmv and 5,500 ppmv TOC (as propane) on a 3-hour rolling average because this provides an equivalent emission limit that is directly enforceable with the common monitoring systems used for VRUs. To prevent dilution, we proposed that only vacuum breaker valves can be used to introduce ambient air into the VRU control system.

We also proposed revisions to the affected facility defined in NSPS subpart XXa at 40 CFR 60.500a to include additional equipment at the gasoline distribution facility beyond just that at the loading racks or vapor processing system.

ii. How did the NSPS review change for gasoline loading racks at new, modified, or reconstructed bulk gasoline terminals?

We are finalizing the standards of performance for gasoline loading racks as proposed, except that we are including provisions to exclude the contribution of methane from the measured TOC emissions (as propane). As such, the final emission limits in NSPS subpart XXa are effectively 1.0 mg/L non-methane TOC for new sources and 10 mg/L non-methane TOC for modified and reconstructed sources, but facilities may choose to comply using direct TOC measurements without correcting for methane content.

We are also finalizing in the NSPS subpart XXa separate affected facility definitions for the loading racks and equipment. However, the loading rack affected facility definition in NSPS subpart XXa is similar to the provisions of NSPS subpart XX.

iii. What key comments did the EPA receive and what are the EPA's responses?

(A) Proposed Affected Facility

Comment: Several commenters recommended that the EPA retain the NSPS subpart XX affected facility definition and not expand the affected facility under NSPS subpart XXa to include pumps and lines from storage vessels or the vapor collection and processing systems. One commenter stated that NSPS subpart XXa should be revised to clarify that a modification is triggered only by changes to the facility that result in an emissions increase associated with the loading rack itself, and not by changes to other equipment at the bulk gasoline terminal.

Response: At proposal, we expanded the affected facility definition in NSPS subpart XXa to ensure that all gasoline service equipment at the bulk gasoline terminal is subject to the equipment leak monitoring requirements. However, we did not intend the result of adding a pump or valve in gasoline service to trigger additional loading rack control requirements. Therefore, in the final rule, we are instead defining two separate affected facilities: a ''gasoline loading rack affected facility'' and a ''collection of equipment at a bulk gasoline terminal affected facility.'' First, the gasoline loading rack affected facility is being defined as ''the total of all the loading racks at a bulk gasoline terminal that deliver liquid product into gasoline cargo tanks including the gasoline loading racks, the vapor collection systems, and the vapor processing system.'' This definition is similar to the affected facility definition in NSPS subpart XX. The loading rack emission limits apply specifically to the gasoline loading rack affected facility; therefore, new equipment in the tank farm area would not trigger NSPS applicability for the loading rack requirements. The collection of equipment at a bulk gasoline terminal affected facility is being defined as ''all equipment associated with the loading of gasoline at a bulk gasoline terminal including the lines and pumps transferring gasoline from storage vessels, the gasoline loading racks, the vapor collection systems, and the vapor processing system.'' This definition is consistent with our proposal and will ensure that all equipment associated with loading of gasoline at the bulk gasoline terminal is subject to the equipment leak provisions. The result of this finalized definition is that new equipment in the tank farm area would trigger NSPS subpart XXa applicability for the equipment leak requirements.

(B) Proposed Emission Limits

Comment: Several commenters suggested that the 1 mg/L TOC emission limit for new facilities in NSPS subpart XXa is not cost-effective and has not been adequately demonstrated in practice. The commenters stated that the limit has not been demonstrated in practice because the permits impose a 1 mg/L non-methane hydrocarbon standard and the EPA did not propose to exclude methane from the TOC measurement. The commenters recommended that the EPA adopt a 10 mg/L TOC emission limit (or some lower limit but higher than 1 mg/L) that has been adequately demonstrated. According to one commenter, the only permits that they identified with a 1 mg/L limit were for sources in nonattainment areas subject to ''lowest achievable emission rate'' (LAER) requirements, which do not consider cost. The BSER, on the other hand, allows costs to be considered and the commenter stated that the 1 mg/L emission limit is not cost-effective. A commenter provided an example cost estimate, calculated cost effectiveness for each model plant, then averaged those to indicate that the ''average'' cost effectiveness was approximately $35,000 per ton VOC. Because the EPA noted that a cost of $8,300 per ton VOC is not cost-effective, the commenter concluded that the 1 mg/L emission limit is not cost-effective. One commenter suggested that the assumption of 8,760 hours of operation for the RACT/BACT/LAER Clearinghouse facility used to establish the 1.0 mg/L emission limit for new sources is overly conservative and should be re-evaluated and a lower new source emission limit should be established.

Response: First, we recognize that NSPS subpart XX allows methane and ethane to be excluded from TOC as they are not VOC. However, based on the typical composition of gasoline, we did not expect that there would be appreciable quantities of methane or ethane in the gasoline vapors and thus concluded that the emission limit would be the same with or without the allowance to exclude methane and ethane. We also understand that the non-dispersive infrared (NDIR) monitor, which is a commonly used monitoring system for VRUs, can correct for methane concentration but not for ethane concentration. In reviewing the test and monitoring data for facilities meeting the 1.0 mg/L emission limit as well as the 10 mg/L emission limit, we concluded that it is possible, if not likely, that the reported TOC emissions already exclude methane, because the applicable limits allow the exclusion of methane from the TOC value and the instrument used to make the TOC measurements can simultaneously assess methane concentration and output non-methane TOC. These data are available in the docket. Because the source test summaries we have likely do not report the methane concentration measured, we cannot assess the impacts of including methane in the TOC. However, given the high removal efficiencies of VRUs achieving the 1.0 mg/L or 10 mg/L emission limit and the fact that methane is not well-controlled by carbon adsorption, it is possible that small quantities of methane in the gasoline vapors can significantly contribute to the TOC in the VRU exhaust. We also recognize that the 1.0 mg/L permit limit, upon which the new source emission limit in the proposed NSPS subpart XXa was established, is in terms of total non-methane hydrocarbon. While the contribution of ethane can be excluded from TOC based on provisions in NSPS subpart XX, the instruments commonly used to measure TOC cannot independently measure and correct for the contribution of ethane in TOC. Considering all of these factors, we are finalizing that the TOC emission limits may exclude methane content if measured according to EPA approved methods. We are not including provisions to exclude ethane content from measured TOC. We are also finalizing recordkeeping and reporting requirements that correspond to the revisions for excluding methane content from the TOC emission limits.

With the allowance to exclude methane, we disagree that the 1.0 mg/L TOC emission limit is not achievable. For example, the Buckeye Perth Amboy Terminal's U24 gasoline loading racks have had a 1 mg/L emission limit for nearly 10 years and we have two different source tests conducted several years apart that indicate that the system readily achieves a level of less than 1.0 mg/L non-methane TOC. In fact, while the facility is achieving the 1.0 mg/L emission limit, one of the tests indicated emissions of 0.6 mg/L non-methane TOC. However, considering process and ambient temperature variability, this source test suggests that a limit lower than 1.0 mg/L may not be achievable at all times. As such, we conclude that the 1.0 mg/L (non-methane) TOC limit is achievable and appropriate for new sources.

With respect to our cost analysis, we maintain, as detailed in the June 10, 2022, proposal (87 FR 35622), that the 1.0 mg/L TOC emission limit for new sources is cost-effective. The commenter indicated that a VRU used to meet 1 mg/L rather than 10 mg/L would be $300,000 more for all model plants. We disagree this is accurate for all model plants. The information we received from a control device manufacturer [5] indicates that the smallest unit they make is essentially for model plant 3. Nonetheless, we added $100,000 to the cost of these smaller units when projecting the costs to meet 1 mg/L. Additionally, we note that smaller facilities will likely use a thermal oxidation system or flare instead of a VRU. For the largest facility (model plant 5), we estimated increased costs of $150,000. If we accept that a VRU for the largest model plant would cost an extra $300,000, the cost effectiveness from 10 mg/L to 1 mg/L is under $3,000 per ton of VOC, which we find cost-effective. We also note that the method used by the commenter to calculate the average cost effectiveness is not the way we calculate average cost effectiveness. We assess the total costs across all affected facilities and divide by the cumulative emission reductions across all affected facilities. Due to recent trends in inflation, interest rates, and gasoline prices, we re-evaluated our costs from 2019 dollars to 2021 dollars (the most recent year for which wage and other cost factors are available). While costs increased, product recovery credits also increased so the reanalysis did not alter our conclusions (see memorandum *Updated New Source Performance Standards Review for Bulk Gasoline Terminals* included in Docket ID No. EPA–HQ–OAR–2020–0371). Therefore, we maintain that 1.0 mg/L (non-methane) TOC is the standard of performance that reflects the BSER for new sources.

Comment: One commenter noted that the EPA-proposed loading rack TOC emission limit of 10 mg/L for modified and reconstructed sources is less stringent than requirements for reconstructed sources that have been successfully implemented in some States, such as Massachusetts where loading rack emissions are limited to 2 mg/L in the permits for five reconstructed bulk gasoline terminals. According to the commenter, these standards should be viewed by the EPA as evidence of the cost effectiveness of those requirements. On the other hand, one commenter suggested that 35 mg/L is an appropriate standard for modified sources. The commenter noted that the EPA concluded that it was not cost-effective to require area source facilities to upgrade to 10 mg/L for the NESHAP and the EPA failed to demonstrate why it would be cost-effective for modified sources subject to the NSPS.

Response: Based on our cost analysis as provided in the proposal (June 10, 2022; 87 FR 35622), we determined that it was not cost-effective to require existing sources that are modified or reconstructed to meet a 1 mg/L TOC emission limit. While we did not specifically evaluate a 2 mg/L limit, we expect that the upgrades needed to meet a 2 mg/L limit would be essentially the same as those needed to meet a 1 mg/L limit and would likewise not be cost-effective. With respect to differences in conclusion for modified and reconstructed sources in NSPS subpart XXa as compared to the revised standards for NESHAP subpart BBBBBB, the assessment that a 35 mg/L limit was the appropriate level for NESHAP subpart BBBBBB was based on the cost effectiveness of the HAP emission reductions, which were estimated to be only 4 percent of the VOC emission reductions. However, for the NSPS subpart XXa analysis, we found, when considering the VOC emission reductions, that it was cost-effective for modified and reconstructed sources to require control system upgrades to meet a 10 mg/L TOC limit. We therefore maintain that, when considering VOC emission reductions, a 10 mg/L TOC limit is cost-effective and is the standard of performance that reflects the BSER for modified and reconstructed sources.

(C) Proposed Monitoring Requirements

Comment: Several commenters stated that the flare monitoring provisions to meet the requirements in the Refinery NESHAP at 40 CFR 63.670 and that were proposed as an alternative for NESHAP subpart BBBBBB are also appropriate for meeting the 10 mg/L TOC limit for modified and reconstructed sources and therefore should be allowed as a compliance alternative to continuous temperature monitoring for thermal oxidation systems in NSPS subpart XXa and NESHAP subpart R subject to the 10 mg/L emission limit. One commenter recommended that the following revisions be made for ''flare provisions'' if added for thermal oxidation systems meeting the 10 mg/L limit:

- Eliminate the flare tip velocity limit or allow its determination using an engineering assessment.
- Eliminate the net heating value dilution (NHV_{dil}) operating parameter requirement because of differences in refinery flares and gasoline distribution thermal oxidation systems.

On the other hand, one commenter stated that the proposed flare monitoring requirements were inadequate to demonstrate continuous compliance. According to the commenter, net heating values of the gas streams at gasoline distribution facilities exhibit significant variability and 2 weeks of sampling cannot capture this variability. Furthermore, the commenter noted, the proposed sampling allowance incentivizes gasoline distribution facilities to sample when net heating values are higher than normal to minimize (or eliminate) the need to add supplemental fuel. Similarly, the commenter noted, the proposed single sample collected when loading a single gasoline cargo tank was not sufficient to determine compliance with the NHV_{dil} parameter. According to the commenter, continuous composition or net heating value monitoring must be required for flares (or grab sampling every 8 hours).

Response: We agree with the commenters who suggest that the flare monitoring provisions are appropriate and can be allowed for thermal oxidation systems subject to the 10 mg/L TOC emission limit, because the thermal oxidation systems used in the gasoline distribution industry are largely enclosed combustors. The flare monitoring provisions are commensurate with meeting a 10 mg/L emission limit and that is why we proposed that flares could be used to meet the 10 mg/L emission limit for modified and reconstructed sources, but not for new sources subject to the 1 mg/L emission limit.

We also agree that, because gasoline loading must be conducted at low pressures (less than 18 inches of water pressure), it is very unlikely that the flare tip velocity limits would ever be exceeded and that a design evaluation could be conducted to assess the maximum loading rate (vapor displacement rate) to determine if, based on the flare tip diameter (and number of flare tips, if staged flare tip design is used), the flare tip velocity would always be below 60 feet per second. If so, net heating value measurements and continuous flow monitoring would not be needed to demonstrate compliance with the flare tip velocity limit. Therefore, we are including in the final NSPS subpart XXa at 40 CFR 60.502a(c)(3)(ix) provisions to comply with the flare tip velocity limit using the provisions as described earlier. We are also specifying that records of these one-time flare tip velocity assessment must be maintained for as long as the owner or operator is using this compliance provision.

[5] See Docket ID No. EPA–HQ–OAR–2020–0371–0041.

We disagree that these enclosed combustors cannot be over-assisted and maintain that the proposed NHV_{dil} operating limit is needed. The air-assist operating parameter was developed based on a flare manufacturer testing facility using propane or propylene as the fuel with flare tips ranging from 1.5 inches to 24 inches in diameter. As such, we consider these test data to be widely applicable to a variety of industrial flares. We understand that the burner tips in most thermal oxidation systems are staged with air-assist at each tip. This would be similar to the 1.5-inch flare tip included in the study data. The wind speeds during the test of this small flare were low, typically under 5 miles per hour (mph), and the performance of the flare was not a function of wind speed. The commenter provided no data or reasonable argument to support the idea that enclosed combustors cannot be over-assisted. Therefore, we are retaining the requirements to meet the NHV_{dil} operating limit.

While we agree that the flare monitoring requirements in the Refinery NESHAP at 40 CFR 63.670 are reasonable for sources subject to the 10 mg/L TOC emission limit, we also agree that the operating limits included in 40 CFR 63.670 must be met at all times when liquid product is loaded into gasoline cargo tanks. Based on the comments received, we considered the impacts of different relative loading rates of gasoline and diesel fuel (or other non-gasoline products) and agree that the net heating value of vapors directed to the flare or thermal oxidation system can vary significantly based on the types and the relative volumes of products loaded. We expect that the provisions in 40 CFR 63.670(j)(6) are reasonable for flare gas streams that ''. . . have consistent composition (or a fixed minimum net heating value) . . .'' and we expect that gasoline loading operations (loading only gasoline products) would meet this criterion regardless of the grade of gasoline loaded (regular, premium, or non-ethanol) as the net heating value of the vapors would always be well above 270 Btu/scf. However, if other liquid products are loaded into non-gasoline cargo tanks and the displaced vapors from these loading operations are also sent to the same flare, then the vapors discharged to the flare would not have a consistent composition or a fixed minimum net heating value. Therefore, we are clarifying in 40 CFR 60.502a(c)(3)(vii) that, for the purposes of NSPS subpart XXa, the application for an exemption from monitoring required under 40 CFR 63.670(j)(6) must include a minimum ratio of gasoline loaded to total liquid product loaded and, if perimeter air-assisted, a minimum gasoline loading rate. We consider this to be part of the explanation of conditions that ensure that the flare gas net heating value is consistent and of conditions expected to produce the flare gas with lowest net heating value as required in 40 CFR 63.670(j)(6)(i)(C). We are also clarifying that, as required in 40 CFR 63.670(j)(6)(i)(D), samples must be collected at the conditions expected to produce the flare gas with lowest net heating value as identified in 40 CFR 63.670(j)(6)(i)(C), which includes the applicable minimum gasoline loading rates identified in the application.

Furthermore, we are specifying that the affected source must operate at or above the minimum values specified in its application at all times when liquid product is loaded into cargo tanks for which vapors collected are sent to the flare or, if applicable, to a thermal oxidation system. We consider that the provisions of 40 CFR 63.670(j)(6) are reasonable and can be used to demonstrate that the net heating value of the vapors collected and sent to the flare (or thermal oxidation system) are sufficient to comply with the flare net heating value operating limits. However, given the variability in net heating values expected with the loading of different liquid products, we determined that clarifying how the provisions of 40 CFR 63.670(j)(6) should be applied for the gasoline distribution industry was appropriate. We also concluded that it was critical to set these minimum gasoline loading rates as operating limits to ensure continuous compliance with the conditions tested as part of the application. For flares (or thermal oxidation systems) that are unassisted or perimeter air-assisted, the vent gas net heating value is the same as the combustion zone net heating value (NHV_{cz}). If the testing conducted under 40 CFR 63.670(j)(6) as specified in 40 CFR 60.502a(c)(3)(vii) shows that the vent gas net heating value meets or exceeds the NHV_{cz} operating limit, compliance with the minimum ratio of the volume of gasoline loaded to total liquid products loaded can be used directly to demonstrate compliance with the NHV_{cz} operating limit. Similarly, for perimeter air-assisted flares (or thermal oxidation systems), if the testing conducted under 40 CFR 63.670(j)(6) as specified in 40 CFR 60.502a(c)(3)(vii) shows that the device meets or exceeds the NHV_{dil} operating limit at the highest fixed or highest air-assist rate used, then compliance with the minimum gasoline loading rate can be used directly to demonstrate compliance with the NHV_{dil} operating limit.

We considered using the 15-minute block periods as specified in the cross-referenced requirements in 40 CFR 63.670(e) and (f) for these loading ratio or loading rate operating limits. However, we expected there may be issues at the end of a loading event if gasoline loading ended 1-minute into the next 15-minute block if the owner or operator was required to meet a minimum gasoline loading rate for that 15-minute block. Considering comments received on the 3-hour rolling average, which suggested using 36 5-minute periods, we are finalizing provisions at 40 CFR 60.502a(c)(3)(vii)(E) that the loading rate operating limit will be monitored on 5-minute block periods and calculated on a rolling 15-minute period across three contiguous 5-minute block periods. We used the term ''contiguous'' here to highlight that these periods are connected without a break, unlike the ''consecutive'' periods used in the definition of 3-hour rolling average. We also note that the operating limits in 40 CFR 63.670(e) and (f), as modified in 40 CFR 60.502a(c)(3)(i), apply when ''vapors displaced from gasoline cargo tanks during product loading is routed to the flare for at least 15-minutes.'' For the liquid product loading operating limits used as an alternative to meet 40 CFR 63.670(e) and (f), we are requiring these limits be calculated on a rolling 15-minute period basis considering only those periods when liquid product is loaded into gasoline cargo tanks for any portion of three contiguous 5-minute block periods. The phrase ''any portion of three contiguous 5-minute block periods'' reflects, in practice, how one would determine when ''vapors displaced from gasoline cargo tanks during product loading is routed to the flare for at least 15-minutes.'' If there is a 5-minute block when no liquid product was loaded into gasoline cargo tanks, then the previous rolling 15-minute period would end and the next rolling 15-minute period would not be calculated until there are three contiguous 5-minute block periods in which liquid product was loaded into gasoline cargo tanks for at least some portion of each of the three contiguous 5-minute block periods. With these clarifications and added operating limits, we conclude that the provisions allowing a one-time net heating value determination according to the provisions of 40 CFR 63.670(j)(6) are sufficient for demonstrating continuous compliance with the net heating value operating limits.

With respect to the comment received opposing the proposed use of a single sample while loading only gasoline to assess the NHV_{dil} operating limit, we note that this operating parameter is an issue primarily when the waste gas flow rate is low. Therefore, we sought to assess whether auxiliary fuel was needed to ensure combustion at these low flow rates, which would occur when loading a single gasoline cargo tank. However, upon further review, we expect the NHV_{dil} operating limit to be most difficult to meet when the gasoline loading rate is at its minimum and the net heating value is low (as when the ratio of the volume of gasoline loaded to total liquid product loaded is at its minimum). Therefore, we stipulated that facility owners or operators would have to establish these minimums in their application and test the net heating value of the vent gas under those circumstances. With these conditions clearly delineated in the final provisions at 40 CFR 60.502a(c)(3)(vii), no additional sampling requirements are needed in the proposed requirements at 40 CFR 60.502a(c)(3)(ix), which are now included within 40 CFR 60.502a(c)(3)(viii) of the final rule. Consistent with the flare provisions at 40 CFR 63.670(j)(6)(i)(F), a single value for the vent gas net heating value (either the lowest single value or the 95th percent confidence value) must be used for all vent gas flow rates. Therefore, consistent with the provisions at 40 CFR 63.670(j)(6)(i)(F), flare (or thermal oxidation system) owners or operators must use the net heating value as determined based on the sampling conducted consistent with their application under 40 CFR 63.670(j)(6). With the elimination of the separate sampling protocol, we are combining the revisions proposed at 40 CFR 60.502a(c)(3)(ix) with those proposed at 40 CFR 60.502a(c)(3)(viii). Thus, 40 CFR 60.502a(c)(3)(viii) now contains a single assessment of the quantity of natural gas needed in order to demonstrate continuous compliance with the NHV_{cz} operating limit and, if applicable, with the NHV_{dil} operating limit. Because the net heating value parameter used under 40 CFR 60.502a(c)(3)(viii) is now the one determined under 40 CFR 60.502a(c)(3)(vii), facilities electing this option would also have to monitor and comply with the minimum ratio of gasoline to total liquid products loaded and, if applicable, the minimum gasoline loading rate. We also note that we expect far fewer facilities will use the minimum supplemental gas addition rate option in 40 CFR 60.502a(c)(3)(viii) because this option would only be needed if the owner or operator cannot demonstrate compliance with the flare operating limits based solely on the vent gas net heating value and the minimum ratio of gasoline to total liquid products loaded and, if applicable, the minimum gasoline loading rate as determined under 40 CFR 60.502a(c)(3)(vii).

Because the provisions in the final rule more clearly account for the variability of the net heating value of the vapors sent to the flare based on the different liquid products loaded, we consider the final provisions to be more robust than those initially proposed and we consider them reasonable and appropriate for demonstrating continuous compliance with the flare provisions or for a thermal oxidation system subject to a 10 mg/L TOC emission limit. Therefore, we are finalizing the flare monitoring alternative for thermal oxidation systems for modified or reconstructed gasoline loading rack affected facilities under NSPS subpart XXa. Because NESHAP subpart R also has a 10 mg/L emission limit, we determined that the flare monitoring alternative in NSPS subpart XXa can be used for thermal oxidation systems used to control emissions from loading racks at bulk gasoline terminals subject to NESHAP subpart R. We are also retaining the proposed provisions that thermal oxidation systems used to control emissions from loading racks at bulk gasoline terminals subject to NESHAP subpart BBBBBB can use these flare monitoring alternatives in NSPS subpart XXa.

Comment: Several commenters objected to the proposed definition of a ''3-hour rolling average.'' According to the commenters, regulated parties cannot comply with the proposed definition because they cannot determine the point in time when ''all emissions from the loading event have cleared the control device'' particularly for VRUs. According to the commenter, vapors from loading may be processed and recovered in a VRU well after active loading is completed. The commenters recommended that this phrase be deleted from the proposed definition of ''3-hour rolling average.'' One commenter noted that the proposed definition of ''3-hour rolling average'' differs significantly from industry practice and, thus, would require a reprogramming of the programmable logic controllers for virtually all existing units, as well as likely revision of thousands of permits. One commenter noted that the clause, ''periods when gasoline loading is not being conducted are not considered valid data,'' is inconsistent with the definition of gasoline cargo tank, where diesel fuel loading into a cargo tank that previously had gasoline should be counted, and so the entire sentence should be deleted. The commenter also suggested that the 3-hour average should be clarified to consist of thirty-six 5-minute periods of valid data. One commenter noted that data from periods when gasoline loading is not being conducted may be necessary to demonstrate compliance with permit or other requirements. Commenters also recommended that, because the performance test is a 6-hour test, the EPA should use a 6-hour rolling average for the proposed concentration limits for VRUs (rather than a 3-hour rolling average). According to commenters, the 3-hour averaging time makes the standard more stringent, and the longer 6-hour averaging period for the emission limit (or operating parameter) would be more representative of the conditions seen throughout the day. According to some commenters, the 3-hour average combined with the numerical limit established for VRUs will either require upgrades of control systems or result in either slowdowns or shutdowns of gasoline loading during the heat of the day, creating artificial fuel availability constraints.

Response: First, we agree with commenters that it is difficult to know when all vapors have cleared the control device system, particularly when a vapor recovery system is used. When a vapor recovery system is used, there may be emissions during carbon bed regeneration even when there is no liquid product being loaded into gasoline cargo tanks. For thermal oxidation systems, on the other hand, the vapors clear the control device in a matter of a minute or two. Therefore, rather than using this general phrase within the definition of ''3-hour rolling average,'' we are specifying within the control device-specific requirements in 40 CFR 60.502a what constitutes valid data that must be included in the 3-hour rolling average. For vapor recovery systems, the 3-hour rolling average concentration emission limit applies during all periods when the vapor recovery system is operating, which may include times when no liquid product is being loaded but the system is still online and capable of processing gasoline vapors. We also note that the vapor recovery system must be operating, at a minimum, whenever liquid product is loaded into gasoline cargo tanks. For thermal oxidation systems, where the gasoline vapors quickly pass through the control system, the 3-hour rolling average applies specifically when liquid product is loaded into gasoline cargo tanks.

We agree with the commenter who noted that the definition of gasoline cargo tank includes tank trucks or railcars into which gasoline is being loaded or that contained gasoline on the immediately previous load. There are several places in the proposed rules where we used ''loading gasoline'' when the correct term is ''loading liquid product into a gasoline cargo tank.'' We are revising this terminology throughout each of the gasoline distribution rules. We also are clarifying (in the description of the monitored parameter, *i.e.,* combustion zone temperature) how the ''previous load'' impacts the valid data for the operating limit. If an owner or operator has information on previous cargo tank contents, then they may exclude from the 3-hour rolling average those periods when there is liquid product being loaded but there are no gasoline cargo tanks being loaded. If an owner or operator does not have information on previous cargo tank contents, then they must assume that liquid product loading is loaded into a gasoline cargo tank and must meet the operating limit during periods of liquid product loading, because the cargo tank could have contained gasoline on the immediately previous load. All owners or operators of thermal oxidizer systems must exclude from the 3-hour rolling average those periods when there is no liquid product being loaded. Because we acknowledge that liquid product loading can be very intermittent, we agree that the operating limit should be evaluated on 5-minute periods. If any liquid product is loaded into a gasoline cargo tank during a 5-minute period, that 5-minute period must be included in the 3-hour rolling average.

With respect to the stringency of the 3-hour rolling average combined with the concentration limit established for VRUs, we first note that we used direct calculation of vapors displaced during loading to determine the concentration limit equivalent to the 1.0 and 10 mg/L TOC emission limits. We also note that the current rules do not specify an averaging time for the operating parameters. As discussed in the preamble of the June 10, 2022, proposal (87 FR 35618), part of our motivation in setting numerical concentration standards and establishing specific timeframes for operating limits is to make requirements for all gasoline distribution facilities consistent. While we recognize that the performance test is 6 hours in duration for thermal oxidation systems, there is no longer a performance test for VRUs. Owners or operators of VRUs must conduct performance evaluations of their TOC continuous emission monitoring system (CEMS). The performance evaluation consists of a minimum of nine test runs, with each test run being a sampling traverse of a minimum of 21 minutes in duration. Thus, the performance evaluation is a minimum of 189 minutes in duration, which is approximately 3 hours. We selected a 3-hour average to be consistent with the duration of the performance evaluation. We also proposed that the temperature operating limit for thermal oxidation systems will be determined on a 3-hour rolling average basis and provided specific requirements on how that 3-hour rolling average temperature operating limit must be developed.

Upon consideration of the comments received, we are maintaining the use of a 3-hour rolling average for CEMS and operating parameters used to demonstrate continuous compliance. However, we are revising and clarifying the definition of ''3-hour rolling average'' to more clearly delineate data that must be included in the 3-hour rolling average based on the type of control system used and more appropriately to use the phrase ''gasoline cargo tank'' and account for periods when a non-gasoline product is loaded into a cargo tank that contained gasoline during its previous load.

(D) Proposed VRU Operation To Minimize Air Intrusion

Comment: Several commenters expressed concern over the EPA's proposed requirement that only vacuum breaker valves can be used to introduce ambient air into the VRU control system in order to prevent dilution of the emissions measurement. According to the commenters, the proposed rule could, if misinterpreted, impact the design and operation of carbon-based vapor recovery units. The use of pressure swing adsorption is the underlying basis for most, if not all, VRUs in operation in the U.S. According to the commenters, the use of purge air at the completion of a regeneration cycle (while the system is under vacuum) is a critical step in the operation of a VRU and is integral to its effectiveness.

Response: We understand the concern commenters have with the proposed requirements that only vacuum breaker valves can be used to introduce ambient air into the VRU. Both operators and control device manufacturers have indicated that the introduction of some purge air (or nitrogen) while the unit is under vacuum is critical for effective VRU performance. Upon review of the information provided by commenters, we are revising 40 CFR 60.502a(b)(2)(iii) and (c)(2)(iii) to require the facility to ''[o]perate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.''

iv. What is the rationale for the EPA's final approach for the NSPS review?

As described in the preamble to the June 2022 proposal (87 FR 35622; June 10, 2022), we determined that the BSER was VRU with submerged loading for new bulk gasoline terminals and the TOC emission limitation that reflects the application of the BSER is 1.0 mg/L. For systems with a VRU, this is a concentration of 550 ppmv TOC (as propane), which we determined was equivalent to an emission limit of 1.0 mg/L. We also determined in the June 2022 proposal that the BSER for modified or reconstructed bulk gasoline terminals was VRU with submerged loading and the TOC emission limitation that reflects the application of the BSER is 10 mg/L. For systems using a VRU, this is a concentration of 5,500 ppmv TOC (as propane), which we determined was equivalent to an emission limit of 10 mg/L. Consistent with our proposed BSER analysis, we are finalizing our determination that the BSER is VRU and the loading rack TOC emission limits are 1.0 mg/L, or 550 ppmv TOC (as propane) for facilities controlled with vapor recovery systems, for new bulk gasoline terminals and 10 mg/L, or 5,500 ppmv TOC (as propane) for facilities controlled with vapor recovery systems, for modified or reconstructed bulk gasoline terminals, as proposed except that we are allowing the exclusion of methane from the measured TOC for reasons discussed in section III.A.1.a.iii of this preamble. With the exclusion of methane, we are finalizing additional test methods applicable for non-methane organic carbon and additional reporting requirements to indicate whether the measurement method used in the performance test or CEMS corrects for methane concentration. We are also finalizing recordkeeping and reporting requirements that correspond to the revisions for excluding methane content from the TOC emission limits.

For reasons discussed in section III.A.1.a.iii of this preamble, we are finalizing two separate affected facilities definitions for NSPS subpart XXa: ''gasoline loading rack affected facility'' and ''collection of equipment at a bulk gasoline terminal affected facility.'' The ''gasoline loading rack affected facility'' definition being finalized is similar to the affected facility definition in NSPS subpart XX. We are providing separate affected facilities definitions to expand the equipment leak provisions to all equipment in gasoline service at the bulk gasoline terminal, so that the equipment changes that are remote from the loading racks and associated vapor processing system do not trigger a modification to the loading rack affected facility.

Because flares can be used to comply with the 10 mg/L TOC emission limit and because many thermal oxidation systems used in the gasoline distribution industry are enclosed combustors, we find that the flare monitoring alternatives are appropriate for thermal oxidation systems required to meet the 10 mg/L emission limit. We are clarifying in the final rule at 40 CFR 60.502a(c)(3)(vii) the requirements for using one-time assessment of net heating value for vapors with consistent composition or a minimum net heating value as provided in 40 CFR 63.670(j)(6) when vapors from loading of different liquid products are processed by the flare or thermal oxidation system. We are requiring facilities using this one-time assessment to monitor gasoline and total liquid product loading rates and maintain the ratio of gasoline to total liquid product loaded above the levels in their application under 40 CFR 63.670(j)(6). For perimeter air-assisted flares or thermal oxidation systems, gasoline loading rates must also be maintained as levels at or above the minimum gasoline loading rates specified in their application under 40 CFR 63.670(j)(6). We are also finalizing recordkeeping and reporting requirements that correspond to the requirements to maintain a minimum ratio of gasoline to total liquid product loaded and, if applicable, a minimum gasoline loading rate.

For reasons described in section III.A.1.a.iii.C of this preamble, we are finalizing a provision at 40 CFR 60.502a(c)(3)(ix) for conducting a one-time engineering assessment as a means to demonstrate compliance with the flare tip velocity operating limits. We are also finalizing recordkeeping requirements related to this one-time assessment when this compliance method is used.

We are finalizing revised provisions at 40 CFR 60.502a(b)(2)(iii) and (c)(2)(iii) to allow some purge air or nitrogen to be introduced while the system is under vacuum and being regenerated as needed to effectively remove VOC from the adsorption media, based on evaluation of comments received. We based the final NSPS limits largely on the emission limits achieved by VRUs in practice. We found the description of the process, especially from the carbon adsorption system vendors, compelling, and we did not intend for our proposal to alter the regeneration methods used for the control systems upon which the BSER was established. Our final provision regarding the vacuum purge retains the limitation that, consistent with 40 CFR 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

After a review of all the comments, we are adding details of the time periods that must be included or excluded from the 3-hour rolling average as part of the requirements of the monitoring operating parameters. This allows us to specify the time periods applicable to different control devices rather than using the general phrase ''all emissions from the loading event have cleared the control device.'' For thermal oxidation systems, we are clarifying that the operating limits apply at all times when liquid product is loaded into gasoline cargo tanks. We are also finalizing requirements that, if the immediately previous load of a cargo tank is not known, then the cargo tank must be assumed to be a gasoline cargo tank. We are also finalizing requirements that periods when there is no liquid product loading must be excluded from the 3-hour rolling average. For vapor recovery systems, we are clarifying that the operating limits apply at all times that the vapor system is operating, because emissions can come from the regeneration of a carbon bed even though there is no liquid product loading. We are also adding recordkeeping and reporting requirements related to periods when gasoline cargo tanks are being loaded as well as an indication as to whether cargo tanks are assumed to be gasoline cargo tanks because the previous load of the cargo tank being loaded is unknown.

With these specific time frames moved to the description of the monitoring requirements for the monitored parameters, we are finalizing the definition at 40 CFR 60.501a of ''3-hour rolling average'' as follows:

3-hour rolling average means the arithmetic mean of the previous thirty-six 5-minute periods of valid operating data collected, as specified, for the monitored parameter. Valid data excludes data collected during periods when the monitoring system is out of control, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. The thirty-six 5-minute periods should be consecutive, but not necessarily continuous if operations or the collection of valid data were intermittent.

b. NESHAP Subpart R

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the major source gasoline distribution source category?

Based on our technology review for loading racks at major sources, we proposed to retain the 10 mg/L TOC emission limit currently required in NESHAP subpart R. However, we proposed that the 10 mg/L TOC emission limit would apply to loading racks controlled by thermal oxidation systems or flares. For thermal oxidation systems, we proposed continuous compliance with a temperature operating limit established as the lowest 3-hour average temperature from a compliant performance test. For flares, we proposed enhanced provisions to ensure good combustion efficiency. For loading racks controlled by VRUs, we proposed to express this emission limit in terms of a concentration limit of 5,500 ppmv TOC (as propane) on a 3-hour rolling average because this provides an equivalent emission limit that is directly enforceable with the common monitoring systems used for VRUs. To prevent dilution, we proposed that only vacuum breaker valves can be used to introduce ambient air into the VRU control system.

ii. How did the technology review change for gasoline loading racks at major source gasoline distribution facilities?

The are no significant changes in the technology review conclusions for loading racks at major source gasoline distribution facilities.

iii. What key comments did the EPA receive and what are the EPA's responses?

Several commenters supported the conclusion to maintain the 10 mg/L

TOC emission limit for major source gasoline distribution facilities.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the loading rack emission limits as proposed. Because many of the specific monitoring requirements cross-reference provisions in NSPS subpart XXa, revisions related to allowing the exclusion of methane from measured TOC, allowance for thermal oxidation systems to use the flare monitoring provisions, use of vacuum purge gas for VRUs, and revisions to the definition of 3-hour rolling average also impact the final requirements and associated recordkeeping and reporting requirements for gasoline loading operations at major source facilities. Our rationale for these revisions is summarized in section III.A.1.a.iv of this preamble.

At proposal, we specifically excluded reference to 40 CFR 60.504a(d) at proposed 40 CFR 63.428(d) because we did not intend to require facilities subject to NESHAP subpart R to install pressure CPMS on existing loading racks. However, we note that the cross-referenced standards at 40 CFR 60.502(h) indicate that pressure must be monitored continuously as specified in 40 CFR 60.504a(d). In reviewing the final requirements, we determined that it was reasonable to allow facilities that have a pressure CPMS to use it for this compliance, but that additional language was needed to expressly provide pressure monitoring during performance tests or performance evaluations that we intended to allow. Therefore, we are adding an alternative monitoring provision at 40 CFR 63.427(f) that allows pressure monitoring during performances tests or performance evaluations following the provisions in 40 CFR 60.503(d) to determine that the system is appropriately designed and operated at or below a pressure of 18 inches of water during product loading as an alternative to using a pressure CPMS.

c. NESHAP Subpart BBBBBB

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the area source gasoline distribution source category?

Based on our technology review for loading racks at area sources, we proposed to lower the allowable TOC emission limit from 80 mg/L to 35 mg/L for large bulk gasoline terminals in NESHAP subpart BBBBBB. We proposed that the 35 mg/L TOC emission limit would apply to loading racks controlled by thermal oxidation systems or flares. For thermal oxidation systems, we proposed continuous compliance with a temperature operating limit established as the lowest 3-hour average temperature from a compliant performance test and proposed enhanced provisions for flares to ensure good combustion efficiency. We proposed to allow the use of a ''flare monitoring alternative'' as an alternative to the temperature operating limit for thermal oxidation systems. For loading racks controlled by VRUs, we proposed to express this emission limit in terms of a concentration limit of 19,200 ppmv TOC as propane on a 3-hour rolling average because this provides an equivalent emission limit that is directly enforceable with the common monitoring systems used for VRUs. To prevent dilution, we proposed that only vacuum breaker valves can be used to introduce ambient air into the VRU control system. For loading racks at small bulk terminals, we proposed to retain submerged filling currently required in NESHAP subpart BBBBBB.

For bulk gasoline plants, we proposed to add requirements to use vapor balancing between gasoline cargo tanks and gasoline storage vessels for bulk gasoline plants with a gasoline throughput over 4,000 gallons per day. We proposed to require pressure relief valves on fixed roof tanks used in vapor balancing to have opening pressures set no less than 2.5 psig.

ii. How did the technology review change for gasoline loading racks at area source gasoline distribution facilities?

We did not revise our proposed technology review for bulk gasoline terminals. We revised the proposed vapor balancing provisions to apply to bulk gasoline plants that have an actual throughput of 4,000 gallons per day or more on an annual average basis rather than using maximum calculated design throughput. We also revised the vapor balancing storage tank provisions regarding the minimum pressure relief device opening pressure, reducing it from 2.5 psig to 18 inches of water (0.65 psig).

iii. What key comments did the EPA receive and what are the EPA's responses?

Comment: Several commenters supported the EPA's proposal to reduce the emission limit for gasoline loading racks at large bulk gasoline terminals from 80 mg/L TOC to 35 mg/L TOC, noting that control systems to meet 35 mg/L TOC are ''generally available'' and cost-effective. One commenter further noted that area source facilities are not large HAP emitters (by definition) and should not be subject to the 10 mg/L TOC emission limit that the EPA considered. Another commenter agreed that it is not cost-effective to require vapor collection and control for ''small bulk gasoline terminals'' and provided cost estimates for four example small terminals. A couple commenters also suggested that the EPA underestimated the costs for ''large bulk gasoline terminals'' to meet a 10 mg/L emission limit, so the EPA should retain the proposed 35 mg/L limit and not reduce it to 10 mg/L.

Response: The EPA appreciates the support for reducing the TOC emission limit for gasoline loading racks at large bulk gasoline terminals from 80 mg/L to 35 mg/L. As discussed in our June 2022 proposal, we agree that further reducing the emission limits for area source bulk gasoline terminals is not cost-effective (87 FR 35620; June 10, 2022). We are finalizing the 35 mg/L TOC emission limit for large bulk gasoline terminals at area source gasoline distribution facilities.

Comment: One commenter stated that the EPA significantly underestimated the economic impact of the proposed rule on small business energy marketers. Based on survey results presented in the comment, the commenter stated that dropping the current compliance threshold from a 20,000 gallon maximum daily design threshold to 4,000 gallons would pull virtually every small bulk gasoline plant into vapor balancing requirements, forcing small energy marketers out of the wholesale gasoline market. The commenter stated that using a maximum daily design throughput as a threshold for compliance is not an accurate or meaningful method to control emissions from bulk gasoline plants, which may be assessed based on the size of the storage tank at the facility, and suggested the actual daily throughput averaged over a longer time period, like a month, is a better method to establish a compliance threshold without placing a heavier burden on small bulk gasoline plants than necessary.

Response: We identified several states with these requirements and expected that many existing cargo tanks would be fitted with appropriate piping to accommodate vapor balancing, which would minimize the impacts of the proposed requirements. We note that the State requirements we reviewed each applied the vapor balancing requirement to bulk gasoline plants with daily throughputs of 4,000 gallons per day or more. In reviewing these requirements more closely, we found that these daily averages were to be calculated on a monthly or annual average basis. When we evaluated the costs and cost effectiveness of requiring smaller bulk gasoline plants to use submerged loading and concluded that it was not cost-effective for them to do so, we based our analysis on the actual average throughput values, not design capacity values.

We used the maximum calculated design throughput to use consistent terminology with how a facility determines their gasoline distribution facility type (*e.g.,* bulk gasoline plant or bulk gasoline terminal). Based on previous analyses, we estimated that there were 5,913 bulk gasoline plants, 1,715 of which already had vapor balancing for both deliveries and loading. We estimated that 270 bulk gasoline plants would need to add vapor balancing to either deliveries or loading, and 2,095 bulk gasoline plants would need to add vapor balancing to both deliveries and loading. The remaining 1,833 bulk gasoline plants were projected to be exempt from the vapor balancing requirement since their throughput is less than 4,000 gallons per day. Thus, we projected that at least 30 percent of bulk gasoline plants could use the throughput exemption. Consistent with our analysis and the State rule requirements used to support our proposal (87 FR 35621; June 10, 2022), we are revising the 4,000 gallon per day threshold to be based on an actual throughput basis. We note that table 1, item 1(ii), of NESHAP subpart BBBBBB contains a provision to calculate the average daily throughput of gasoline storage tanks using an annual averaging time. In addition, table 2 of NESHAP subpart BBBBBB uses annual averaging time to determine control requirements for bulk gasoline terminals. Therefore, because the State requirements we reviewed used an annual averaging time, and because NESHAP subpart BBBBBB already contains provisions using an annual averaging time, we are finalizing the requirement to use an annual averaging time. Additionally, we selected the annual averaging time because we expected an annual average to be more consistent, with less chance of facilities fluctuating from below to above the threshold than when a monthly or daily averaging time is used.

We also added requirements to maintain records of gasoline throughput and the time frame in which to add vapor balancing controls if a bulk gasoline plant newly triggers the requirement. With the revision to use actual throughput rather than capacity, we determined that the economic impacts we estimated at proposal for bulk gasoline plants are reasonable and accurate. That is, we expected that a significant number of bulk gasoline plants will be below the applicability threshold we proposed, but our evaluations were based largely on applicability to State rules and other assessments that were based on actual throughputs. Therefore, we agree that we likely understated the impact of the proposed provisions for vapor balancing at bulk gasoline plants based on a maximum calculated design throughput. However, with the revision of the thresholds to an actual throughput basis, our previous projections of the number of facilities impacted by the vapor balancing requirements are now accurate and commensurate with the final rule requirements. Therefore, we are finalizing the proposed vapor balancing requirements, but only for bulk gasoline plants that have an actual throughput of 4,000 gallons per day assessed on an annual average basis.

Comment: Some commenters stated that the pressure relief device setting of no less than 2.5 psig for fixed roof storage tanks would exceed safe pressure for some storage tanks and should be removed from both the vapor balancing and fixed roof storage tank requirements in proposed NESHAP subpart BBBBBB.

Response: We understood most conservation (pressure relief) vents on atmospheric tanks use a release pressure of 2.5 psig or less. Considering the storage of gasoline, which has a partial pressure of over 3 psia, it would seem that fixed roof tanks would vent frequently if the conservation vents open at a pressure under 2.5 psig. In the proposal, we therefore expected 2.5 psig to be a reasonable requirement for pressure relief devices used for vapor balancing and on fixed roof storage tanks. However, based on our research concerning this comment, we now understand that ''atmospheric tanks'' are generally designed to operate between atmospheric pressure up to 2.5 psig and that ''low pressure tanks'' are designed to operate between 2.5 and 15 psig. Thus, the proposed requirement would be readily achievable for low-pressure tanks, but pressure relief devices on atmospheric tanks would generally begin to relieve pressure below 2.5 psig (typically between 0.8 and 1.5 psig). Essentially, the proposed requirement would require storage tanks at bulk gasoline plants subject to the proposed vapor balancing requirement and small, low throughput tanks at area source gasoline distribution facilities to replace some atmospheric storage tanks with low-pressure tanks. It is unclear what fraction of existing gasoline storage tanks are of low-pressure design that may be able to meet this pressure requirement, but it is expected that a significant number of existing gasoline storage tanks are atmospheric tanks and would thus need to be replaced to meet this requirement. We had not considered these additional costs at proposal. Equipment costs are estimated to be about $50,000 per tank, so installed costs (including removal of the old tank) are about $100,000 per tank not considering business interruptions during tank replacement. We project that, for a 10,000 gallon per day throughput bulk gasoline plant, the vapor balancing requirement with a tank replacement to meet the 2.5 psig minimum pressure relief limit would have cost $70,000 per ton of HAP reduced. This would not be cost-effective for the HAP emitted by these sources. The existing requirements in the gasoline distribution rules require that no pressure relief device open at pressures less than 18 inches of water, which is 0.65 psia. Based on this existing requirement, we expect that atmospheric storage vessels used at gasoline distribution facilities would not have devices opening at less than 0.65 psia. Therefore, we agree with commenters that the 2.5 psig requirement for pressure relief devices associated with fixed roof tanks and vapor balancing is not technically feasible without replacing numerous atmospheric storage tanks. We determined that replacing these atmospheric storage tanks is not cost-effective for the HAP emitted by these sources. Because our proposed standards required the vapor balancing system to be operated at pressures less than 18 inches of water column with no pressure relief device opening at pressures less than 18 inches of water column, and because fixed roof storage tanks are part of the vapor balancing system, we are finalizing that the appropriate minimum pressure relief device opening pressure for fixed roof storage tanks should be 18 inches of water column (0.65 psia).

Comment: Several commenters recommended that area sources using thermal oxidation systems should be able to utilize alternative monitoring protocols to temperature continuous parametric monitoring systems (CPMS) currently in NESHAP subpart BBBBBB. While temperature CPMS are required for major sources complying with the 10 mg/L TOC emission limit, according to the commenters, a temperature CPMS is not needed to demonstrate compliance with a 35 mg/L limit. The commenters suggested that there would be no, or very small, emission reductions gained by a temperature CPMS, the emission reductions would not be worth the costs, and there would be additional secondary emissions resulting from increased fuel use to maintain temperatures during periods of low loading rates. The commenters stated that stack temperature monitoring is inappropriate and unnecessary to meet a 35 mg/L TOC limit. Temperatures often decrease during periods of low loading, but these low temperatures do not signal poor combustion efficiency, rather, low heat release rates due to lower flows. One commenter further indicated that temperature is not indicative of thermal oxidation system performance, providing a 2006 performance test, which, according to the commenter, demonstrated that high combustion efficiency and low emissions were achieved at low (as well as high) temperatures. The commenters suggested that the EPA should allow for the use of the existing thermal oxidation system monitoring alternative in NESHAP subpart BBBBBB.

According to the commenters, the EPA is on record indicating that pilot flame monitoring is sufficient for area sources [to meet 80 mg/L] and has not provided justification why it is not sufficient now. One commenter also stated that the EPA provided no justification as to why the flare requirements are applicable to these thermal oxidation systems or why they provide better assurance than the current alternative provisions. The commenter also stated that the cost impacts for this proposed ''flare'' alternative were understated. The commenter suggested that, if the EPA believes more continuous monitoring of proper operation of the air-assist blower and vapor line valve is needed, the EPA could revise existing language at 40 CFR 63.11092(b)(1)(iii)(B)(*2*)(*ii*) to require only automated alarms and shutdown (rather than to perform daily visual observations).

One trade organization requested source test data from member facilities that are subject to emission limits above 10 mg/L and that do not use auxiliary fuel. Over 60 source tests were submitted and each one showed emissions meeting the 35 mg/L limit. The commenter concluded that this demonstrates that gasoline vapors are highly combustible and auxiliary fuel is not needed.

Response: While several commenters appeared to oppose the temperature operating limit, we note that the existing NESHAP subpart BBBBBB also has a temperature operating limit as a compliance option. We disagree with the commenters suggesting that temperature is not a good indicator of performance. Based on the data provided by the commenter, while there are periods of high combustion efficiency and low emissions when the temperature is low, the temperature versus emission rate and temperature versus efficiency graphs showed that all exceedances of 35 mg/L (or control efficiencies less than 98 percent) were at temperatures under 900 °F. Thus, one can conclude from the data presented that operating at a minimum combustion temperature of 900 °F would ensure that the source would meet the 35 mg/L emission limit at all times. We therefore conclude that setting a minimum operating temperature is a reasonable continuous compliance method.

Second, we note that we proposed an alternative compliance option to the temperature operating limit. The key difference between the existing and our proposed alternative to temperature monitoring in NESHAP subpart BBBBBB is that the proposed alternative is designed to ensure that the combustion unit is not over assisted. We proposed this more rigorous compliance alternative because the applicable emission limit was lowered from 80 mg/L to 35 mg/L and due to our improved understanding of air-assisted combustion devices gained over the past 10 years. The proposed monitoring alternative is similar to the previous NESHAP subpart BBBBBB requirements with respect to continuous pilot flame monitoring. However, we found that the previous NESHAP subpart BBBBBB requirements, which included daily visual inspection to verify the proper operation of the air-assist blower and the vapor line valve, would not ensure good combustion during periods of low flow if the air blower is set at a high, fixed level to prevent smoking during periods of high gasoline vapor flow. That is, many of the vapor combustors used at gasoline distribution facilities are essentially enclosed air-assisted flares and the existing requirements in NESHAP subpart BBBBBB did not prevent over-assisting the combustor during low flow events. Therefore, we proposed a more substantive alternative to direct temperature monitoring to ensure that these combustors are meeting the applicable emission limit at all times, including periods of low gasoline vapor flow.

While the proposed requirements are more substantive, there are parallels with the existing requirements. For example, proper functioning of the air-assist blower could be simply an assessment of whether the blower is on or not. This requirement would not prevent over-assisting the combustor. However, if a multispeed air blower is used, proper functioning of the air-assist blower could consider that the air-assist rates are low during low gasoline vapor flow rates and higher at higher vapor flow rates, which could help to prevent over-assisting. Proper functioning of the vapor line valve should prevent very low flows to the combustion unit, since the vapor line valve would remain closed until a set pressure is exceeded. Without the vapor line valve, the vapor flow rate could approach zero, such that the allowable air-assist rate would also approach zero. However, with the vapor line valve, the minimum vapor line flow is a step function above zero. This means the air-assist blower can remain on at some low flow setting because gasoline vapor flow will always be some step above zero based on the pressure setting for the vapor line valve. One can consider the proposed requirements to be a more detailed requirement of the provisions in 40 CFR 63.11092(b)(1)(iii)(B)(*2*)(*ii*) ''. . . the proper operation of the assist-air blower and the vapor line valve.'' For low gasoline vapor flows, low air-assist rates are needed to prevent over-assisting the combustor. For higher gasoline vapor flows, higher air-assist rates may be needed to prevent smoking from the combustor. Thus, in context of the proposed rule, proper operation of the air-assist blower would translate to using an appropriate air-assist rate relative to the gasoline vapor flow rate, and the proper operation of the vapor line valve should prevent very low flows to the combustion unit, allowing a lower air-assist flow rate to be determined.

We proposed to allow an initial assessment of net heating values of gasoline vapors to see if auxiliary fuel is needed to meet the combustion zone net heating value. For unassisted or air-assisted flares, we expect gasoline vapors will routinely exceed the minimum required combustion zone net heating value. The combustion zone net heating value operating limit becomes more important if steam assist is used. For gasoline distribution facilities that use air-assisted thermal oxidation systems or flares, it is possible that the air-assist rate may be too high during periods of low gasoline vapor flow and overdilute the gasoline vapors prior to effective combustion. We proposed that facilities could use an assessment of the flow rate when only loading one cargo tank to project the low flow rate by which to assess whether the air-assist flow rate is low enough not to over-assist the flare during low flow events. As noted in response to comments regarding the monitoring provisions for thermal oxidation systems and flares in section III.A.1.a.iii.C of this preamble, we have revised and clarified the requirements for the initial assessment of net heating values at 40 CFR 60.502a(c)(3)(vii) and allow owners or operators to establish a minimum gasoline loading rate operating limit, in addition to a minimum ratio of gasoline to total product loading rate, that can be used to ensure vapor flow rates are high enough for a set air-assist rate to demonstrate compliance with the NHV_{dil} operating parameter. If the air-assist rate is too high, facilities can lower the air-assist rate or add auxiliary fuel according to the provisions in 40 CFR 60.502a(c)(3)(viii) to ensure that enough heat release is provided to ensure high combustion efficiencies at low flow rates.

We appreciate the data collected and provided by the commenter that showed many facilities could meet the 35 mg/L TOC emission limit without the use of auxiliary fuel. We expect some facilities will conduct sampling of their heat content and assess their air addition rates and determine that no additional fuel is needed. Thus, we expect many facilities will be able to meet the 35 mg/L TOC emission limit without auxiliary fuel. However, the performance tests are typically done with high loading rates, and may not adequately reflect the performance for air-assisted combustion units when operated at low loading rates. Therefore, we are finalizing requirements to either continuously monitor the net heating value of the vapors discharged to the flare or thermal oxidation system or to perform an initial assessment to determine a minimum gasoline loading rate operating limit that ensures high combustion efficiencies. As proposed, facilities that cannot meet the NHV_{dil} operating limit based on the minimum gasoline loading rate operating limit can determine a minimum auxiliary fuel addition rate (perhaps with a dual speed or variable speed blower) needed to ensure good combustion efficiencies at these lower flow rates that might not be well-represented during the performance test. Without this assessment, we remain unconvinced that the mere presence of a pilot flame, along with daily inspections of the vapor line valve and air blower, are adequate to ensure a 35 mg/L TOC emission limit is met at all times.

Comment: One commenter recommended that sources using VRU should be able to implement alternative monitoring protocols as set forth under 40 CFR 63.11092(b)(1)(i)(B)(*1*)(*i*)–(*iii*). According to the commenter, the EPA has not referenced any data suggesting that the alternative monitoring options would not be sufficient to ensure compliance with a 35 mg/L (or 19,200 parts per million by volume (ppmv) as propane) TOC emission limit. Alternatively, if the EPA believes that CEMS must be required at all bulk gasoline terminal facilities subject to NESHAP subpart BBBBBB, then the EPA should allow the alternative monitoring protocols for periods of shutdown or repairs to CEMS rather than requiring the loading racks to be taken out of service. A few additional commenters did not object to the requirement to use a CEMS, but similarly stated that the current alternative monitoring protocols should be allowed for periods of shutdown or repairs to CEMS. According to the commenter, there would be cost impacts that were not considered by the EPA if no alternative is provided when the CEMS is inoperable or out-of-control.

Response: We proposed the concentration limit specifically so that a CEMS could be used to demonstrate continuous compliance with the TOC emission limit for VRU. We proposed to require CEMS for all rules, including NESHAP subpart BBBBBB, because a CEMS can directly assess compliance with the emission limit and the design and operating parameters cannot provide this direct assessment. However, we did not estimate costs for back-up CEMS nor facility disruptions for periods of CEMS outages. Therefore, we sought to provide an alternative to using a CEMS that could be used for limited periods of CEMS outages, but not one that could be used indefinitely as an ongoing alternative to a CEMS.

In the cited alternative monitoring protocols in NESHAP subpart BBBBBB, the regeneration cycles were based largely on design considerations, with monthly measurements of the carbon bed outlet to ensure breakthrough had not occurred near the end of an adsorption cycle. With facilities using CEMS, they will have recent data on regeneration cycle times (that can be normalized by product loading quantities) by which to base the regeneration cycle times to use during CEMS outages. This method follows many of the requirements in the existing NESHAP subpart BBBBBB alternative, but the operating parameters are based on those used to meet the emission limit when the CEMS was operating, which provides better assurance that the VRU is meeting the emission limit than cycle times and other operating parameters that are based solely on design considerations. We are providing specific provisions on how cycle times and other operating limits will be established based on operations just prior to the CEMS outages. We are setting a maximum number of hours for which the alternative monitoring method can be used at 240 hours in a calendar year. We consider this time period to be adequate to conduct maintenance on or to replace the CEMS, as needed. Because the operating parameters are specific to recent carbon adsorption system operating conditions, we determined that this alternative would provide compliance assurance during a 2-week period. We also selected this time period to emphasize that this is a limited use alternative and that CEMS should be used as the compliance method for all VRU. While most commenters requesting an alternative to CEMS cited the NESHAP subpart BBBBBB provisions, we find this limited alternative to the use of a CEMS would also provide adequate short-term compliance assurance for VRUs meeting more stringent emission limits in NESHAP subpart R and NSPS subpart XXa. Therefore, we are finalizing this alternative in all of the gasoline distribution rules as a temporary means to demonstrate compliance during periods of CEMS outages.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the loading rack emission limits for area source bulk gasoline terminals as proposed. Because many of the specific monitoring requirements cross-reference provisions or contain similar provisions as in NSPS subpart XXa, revisions related to allowing the exclusion of methane from measured TOC, use of vacuum purge gas for VRUs, revisions to the definition of 3-hour rolling average, and associated revisions to the recordkeeping and reporting requirements also impact the final requirements for gasoline loading operations at area source facilities. Our rationale for these revisions is summarized in section III.A.1.a.iv of this preamble.

We are revising the proposed requirements for vapor balancing at bulk gasoline plants. First, for reasons discussed in section III.A.1.c.iii of this preamble, we are revising the threshold for bulk gasoline plants required to use vapor balancing from a maximum calculated design throughput of 4,000 gallons per day or more to an annual average actual throughput of 4,000 gallons per day or more, to better align with the analysis conducted regarding the cost effectiveness of this threshold and other provisions in NESHAP subpart BBBBBB. We are also revising the minimum pressure setting for fixed roof storage vessels used in vapor balancing from 2.5 psig to 18 inches of water column.

For reasons as explained in section III.A.1.b.iv, we specifically referenced vapor tight provisions at 40 CFR 63.422(c) and (e) in proposed item 1(g) of table 2 to subpart BBBBBB because we did not intend to require facilities subject to NESHAP subpart BBBBBB to install pressure CPMS on existing loading racks. However, as discussed in section III.A.2.b.iii of this preamble, we received comment that the cross-referenced sections to the NESHAP subpart R requirements were incomplete and incorrect. As such, we are finalizing the vapor-tightness requirements by cross-referencing the provisions in NSPS subpart XXa. Therefore, similar to the final requirements we added in NESHAP subpart R, we are adding a monitoring alternative at 40 CFR 63.11092(h) to allow pressure measurements made during performances tests or performance evaluations following the provisions in 40 CFR 60.503(d) as an alternative to using a pressure CPMS to determine that the system is appropriately designed and operated at or below a pressure of 18 inches of water during product loading. We are also adding a cross-reference to 40 CFR 63.11092(h) in item 1(f) of table 2 (corresponding to proposed item 1(g) of table 2) to clarify that existing sources under NESHAP subpart BBBBBB have the option to either install a pressure CPMS or to periodically verify the appropriate design and operation of the system by measuring pressure of the system during performance tests or evaluations following the requirements in 40 CFR 60.503(d).

We are maintaining the compliance methods, as proposed, including provision for thermal oxidation systems to either monitor combustion zone temperature or use the flare monitoring alternative and for VRU to use a CEMS. However, in response to comments, as discussed in section III.A.1.c.iii of this preamble, we are providing a limited, short-term alternative to using a CEMS for bulk gasoline terminals using a VRU that can be used for periods of CEMS outages.

2. Standards for Cargo Tank Vapor Tightness

a. NESHAP Subpart R

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the major source gasoline distribution source category?

The EPA proposed a graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks. The existing requirement in NESHAP subpart R is a graduated vapor tightness certification requirement ranging from 1.0 to 2.5 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks. We proposed that cargo tanks certified prior to 3 years from the promulgation date would have to certify to the existing levels and that cargo tanks certified on or after 3 years from the promulgation date would have to certify to the proposed lower levels.

ii. How did the technology review change for gasoline cargo tanks at major source gasoline distribution facilities?

We did not revise our proposed technology review for cargo tank vapor tightness requirement. However, we revised the timing of the new requirements so that all cargo tanks undergoing annual certification would be certified at the lower allowable pressure drop level within 3 years of promulgation of the final rule.

iii. What key comments did the EPA receive and what are the EPA's responses?

We received general support for the proposed cargo tank vapor tightness requirements, particularly the harmonizing of requirements across the three rules (NESHAP subparts R and BBBBBB and NSPS subpart XXa).

Comment: One commenter stated that compliance with a CAA section 112(d) rule must be "as expeditiously as practicable" and "in no event later than 3 years after the effective date of such standard." With respect to cargo tanks, the commenter stated that the Agency did not demonstrate why 3 years was needed to comply with the revised vapor tightness requirements. Specifically, the commenter noted that, if 3 years are provided before the new vapor tightness certification limits become effective and an additional year is then required for the entire fleet of gasoline cargo tanks to be certified at that lower level, then the proposal is effectively providing a 4-year compliance schedule, which is not provided under CAA section 112(d). The commenter recommended that no more than 2 years be provided to implement the new limits and no more than 3 years provided to implement and certify the cargo tanks at that lower level.

Response: For cargo tanks, we agree that compliance with the revised vapor tightness requirements and annual certification can be implemented in 3 years. Therefore, within 3 years from the promulgation date of the rule, we are requiring that all cargo tanks loaded must be certified at the lower vapor tightness values. That way, the entire fleet of gasoline cargo tanks would have certifications at the lower level within 3 years of the promulgation date of this final rule rather than requiring that certifications at the lower level begin at 3 years after the promulgation date. Therefore, we have eliminated provisions that would allow an additional year to test and fully implement the new cargo tank vapor tightness requirements.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks, as proposed. We are finalizing a compliance schedule that ensures that all gasoline cargo tanks are certified at the lower levels within 3 years of the promulgation date of the final rule because the CAA requires compliance as expeditiously as practicable and no later than 3 years after the promulgation date.

b. NESHAP Subpart BBBBBB

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the area source gasoline distribution source category?

The EPA proposed a graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks to harmonize gasoline cargo tank requirements with those in NESHAP subpart R.

ii. How did the technology review change for gasoline cargo tanks at area source gasoline distribution facilities?

We did not revise our proposed technology review for cargo tank vapor tightness requirement. However, since we cross-reference the vapor-tight certification requirements in NESHAP subpart R, the timing of the final requirements was revised such that gasoline cargo tanks must be certified at the lower levels in order to be loaded no later 3 years from the promulgation date of the final rule.

iii. What key comments did the EPA receive and what are the EPA's responses?

Comment: One commenter noted that the revisions to table 2 result in NESHAP subpart BBBBBB no longer expressly requiring the annual certification testing, in that table 2 item 1(g) now references paragraphs 40 CFR 63.422(c) and (e), neither of which specify conducting the annual certification test. The commenter recommended that the text of table 2 item 1(g) be edited to read, ''. . . into vapor-tight gasoline cargo tanks using the procedures specified in § 63.11094(b).''

Response: We agree that the references to 40 CFR 63.422(c) and (e) are incorrect. However, 40 CFR 63.11094(b) addresses only recordkeeping requirements and not the requirements to not load non-vapor tight cargo tanks. Upon further review, the provisions in table 2, item 1(g) were intended to be similar to the current requirements in item 1(e). Therefore, we are revising the entry in table 2, proposed item 1(g) (which is now 1(f) in the final rule) to reference the NSPS subpart XXa requirements at 40 CFR 60.502a(e) through (i) and are also adding a cross-reference to 40 CFR 63.11092(g) and (h), which specifies the test methods for the annual certification and alternative monitoring requirements for pressure of the loading rack system, respectively. In addition, we are revising the provisions in table 2, item 2(c) to limit loading to vapor-tight gasoline cargo tanks using the procedures specified in 40 CFR 60.502a(e) and adding a cross reference to 40 CFR 63.11092(g).

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks, as proposed. We are revising the entry in table 2, items 1(f) and 2(c), to reference the correct NSPS subpart XXa requirements and also adding a cross-reference to 40 CFR 63.11092(g), which specifies the test methods for the annual certification. Through these cross-references, we are finalizing requirements that certification of a gasoline cargo tank at the lower levels be conducted within 3 years from the promulgation date of the final rule to ensure that all gasoline cargo tanks are certified at the lower levels within 3 years of the promulgation date of the final rule because the CAA requires compliance as expeditiously as practicable and no later than 3 years after the promulgation date.

c. NSPS Subpart XXa

i. What did the EPA propose pursuant to CAA section 111 for new, modified, or reconstructed bulk gasoline terminals?

The EPA proposed a graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks to harmonize gasoline cargo tank requirements with those in NESHAP subparts R and BBBBBB.

ii. How did the NSPS review change for gasoline cargo tanks at new, modified, or reconstructed bulk gasoline terminals?

We did not revise our proposed NSPS review for cargo tank vapor tightness requirement.

iii. What key comments did the EPA receive and what are the EPA's responses?

We received general support for the proposed cargo tank vapor tightness requirements, particularly the harmonizing of requirements across the three rules (NESHAP subparts R and BBBBBB and NSPS subpart XXa).

iv. What is the rationale for the EPA's final approach for the NSPS review?

For reasons detailed in our June 2022 proposal (87 FR 35622; June 10, 2022), we are finalizing the graduated vapor tightness certification requirement ranging from 0.50 to 1.25 inches of water pressure drop over a 5-minute period, depending on the cargo tank compartment size for gasoline cargo tanks, as proposed. We are finalizing requirements, as proposed, that all gasoline cargo tanks loaded at gasoline loading rack affected facilities subject to NSPS subpart XXa must be certified at the lower levels upon startup of the affected facility, as required under section 111 of the CAA. We are clarifying in 40 CFR 60.502a(e) that these provisions apply to the ''gasoline loading rack affected facility'' and that the applicable vapor-tight gasoline cargo certification methods are in 40 CFR 60.503a(f), consistent with the definition of ''vapor-tight gasoline cargo tanks'' in 40 CFR 60.501a. We are also clarifying that if the previous contents of a cargo tank are not known, you must assume that cargo tank is a gasoline cargo tank. These revisions are being made to be consistent with the nomenclature revisions for the loading racks as described in section III.A.1.iv of this preamble. These revisions also help clarify the requirements that ensure loading occurs only in vapor-tight gasoline cargo tanks as defined in NSPS subpart XXa.

3. Standards for Gasoline Storage Vessels

a. NESHAP Subpart R

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the major source gasoline distribution source category?

The EPA proposed additional fitting requirements for storage vessels with external floating roofs as specified in 40 CFR 60.112b(a)(2)(ii). We also proposed requirements for storage vessels with internal floating roofs to maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the LEL. We proposed test method procedures for determining the LEL inside a storage vessel above the internal floating roof and corresponding recordkeeping and reporting requirements.

ii. How did the technology review change for gasoline storage vessels at major source gasoline distribution facilities?

We did not revise our proposed technology review for storage vessels. However, we have made minor revisions to the test method procedures associated with the 25 percent of the LEL level.

iii. What key comments did the EPA receive and what are the EPA's responses?

Comment: Several commenters opposed the 25 percent of the LEL level for various reasons. Two commenters stated that the EPA did not adequately demonstrate that LEL monitoring is an effective defect detection practice, and it should not be required. Two commenters stated that the EPA evaluated LEL as a monitoring enhancement, but proposed it as a standard and did not adequately identify controls, costs, or emission reductions for this standard. To assess if the LEL monitoring is warranted, the commenters recommended that the EPA fully account for costs of replacing the internal floating roof, not just the cost of monitoring. One commenter cited the NSPS subpart Kb final rule preamble (52 FR 11420; April 8, 1987) that stated that ''[t]he Agency is not aware of any method by which an annual concentration measurement could be used to establish the condition of the control equipment.'' According to the commenters, the EPA has not provided sufficient data to alter that conclusion and should withdraw the proposed LEL monitoring requirement.

Response: As part of the notice of data availability (87 FR 49795; August 12, 2022) the EPA provided the background information used in the LEL analysis. It is clear that internal floating roofs that had visible inspection issues (*e.g.,* liquid on top of the floating roof) had high LEL concentrations in the headspace (well over 25 percent of the LEL) and those that did not have visible inspection issues had lower LEL concentrations (generally well below 25 percent of the LEL). Our emission estimates from various storage vessel requirements assume proper seals and other equipment are in-place and operating as required. If these controls are not operating as intended, the emissions from these storage vessels can be much higher. We found that the visual inspections are subjective and may, at times, not be performed well. For example, although a hired contractor for BP's Carson Refinery had reported no problems with the facility's 26 floating roof storage vessels from 1994 to 2002, a South Coast Air Quality Management District inspection ''revealed that more than 80 percent of the tanks had numerous leaks, gaps, torn seals, and other defects that caused excess emissions.'' [6] Therefore, at proposal, we sought a less subjective means to verify performance of the floating roofs. We concluded that, given the preponderance of internal floating roof storage vessels in this source category, periodic LEL monitoring could be used to ensure the floating roofs are performing as intended.

We acknowledge that it is difficult to estimate the emission impacts of these LEL requirements because we do not have data on the number of poorly functioning floating roofs. We note that the storage vessel standards for NESHAP subpart R (as well as NESHAP subpart BBBBBB) rely heavily on the NSPS subpart Kb requirements. NSPS subpart Kb already requires repair of floating roofs that fail inspection and failure of the LEL monitoring triggers the same repairs. As such, we consider that these repairs are already required and the LEL requirement predominately makes the required inspections less subjective. In the worst-case scenario, a poorly operated internal floating roof can have emissions similar to those of a fixed roof storage vessel. In establishing the floating roof requirements, we already determined that installing a floating roof was cost-effective and that the costs of replacing a poorly functioning floating roof is not significantly different from the costs of retrofitting a fixed roof storage vessel. In our analysis, we used a 15-year life for the internal floating roof storage vessel. Thus, replacement of the internal floating roof every 15 years to ensure the emission reductions are achieved are inherent in the original costing assessment. Therefore, if an internal floating roof has failed to the point that 25 percent of the LEL is exceeded, and the LEL level cannot be reduced without making repairs to the internal floating roof, we see no reason that these storage vessels should remain in service. Thus, we have already considered that replacement of the internal floating roof, if it has reached its end of life and is no longer reducing emissions as intended, is reasonable. While most poorly performing floating roofs can be repaired, rather than replaced, we maintain that replacing a failing internal floating roof is a reasonable requirement when repairs are ineffective.

Since our statement in 1987 and as noted in our memorandum *Review of LEL Testing Requirements for Internal Floating Roof Tanks,* two States have developed rules that use LEL monitoring as a means to ensure that floating roofs are controlling emissions as intended. We note that these rules effectively set a maximum LEL limit that must be met—essentially an ''emission limitation,'' not just a monitoring requirement—and we modeled our proposed provision following these State rules. Furthermore, the National Fire Protection Association (NFPA) standard sets a maximum LEL limit of 25 percent for explosion prevention for internal floating roof storage vessels. Based on these developments, we concluded that establishing a maximum LEL level for internal floating roofs was reasonable and necessary when taking into account developments in practices, processes, and control technologies.

Comment: Several commenters suggested that, if the EPA finalizes the LEL monitoring requirement, the following revisions be made to the LEL monitoring requirements as proposed:

(1) Adopt higher LEL action levels: 50 percent for storage vessels installed prior to the effective date of the NSPS in part 60, subpart Kb, and 30 percent for storage vessels constructed, reconstructed or modified after the effective date of NSPS subpart Kb. According to the commenter, these limits would be more consistent with State requirements.

(2) Allow calibration according to the manufacturer's recommendations, which may specify a different calibration gas (other than methane) or different calibration methods. Some instruments use docking stations for calibration, so cannot attach tubing.

(3) Shorten LEL measurement period to a total of 10 minutes with 5 minutes of recorded measurement data (concentrations do not change significantly and minimize time needed to be on the roof). In addition, facilities should have the option to record the highest measured value in lieu of recording a 5-minute rolling average or allow operators flexibility in their recordkeeping based on their internal systems and operations.

(4) LEL should be a monitoring requirement, not a standard, so corrective action should be specified. Recommended that a failed LEL inspection should trigger the obligation to conduct a second confirmatory test within 30 days. If the second test shows that the initial inspection was an anomaly, no further action should be required. If the second inspection confirms an exceedance of the percentage LEL limit, then a third confirmatory test must be conducted within 30 days. If all inspections confirm the presence of gasoline vapors above the percentage LEL limit, then the tank must undergo repairs during the next regularly scheduled degassing event or inspected as specified in 40 CFR 63.1063(d)(1).

(5) Remove the requirement that LEL measurements not be taken when wind speeds exceed 10 mph, as this is unworkable for some locations according to the commenters. One commenter recommended that the EPA only require regulated entities to use best efforts to block wind from the inspection area, document wind speed and direction, and use best engineering judgment regarding whether wind speed would affect the validity of the measurements. Another commenter suggested revising the provision to be the greater of 10 mph or the average monthly wind speed at the site.

(6) State that the LEL monitoring is to be conducted while the internal floating roof is floating and with no product movement.

Response: Regarding the action level of the LEL requirement (item 1), we considered the State rule requirements

[6] Mokhiber, Russell. Multinational Monitor; Washington Vol. 24, Iss. 4, (April 2003): 30.

in establishing the threshold. However, we expect these rules were established prior to the NFPA standard establishing a 25 percent of the LEL limit. From the data we collected, there were very few measurements that exceeded 25 percent of the LEL that did not also exceed 50 percent of the LEL. Thus, when failures occurred, the LEL was often very high. In the LEL measurements that we have, there were cases where LEL levels of 30 percent were observed, but the facilities conducted corrective actions and reduced the emissions from these tanks. Based on these observations and considering the NFPA standard, we maintain that the appropriate limit for LEL levels for internal floating roof storage vessels is 25 percent.

Regarding the calibration requirements (item 2), we agree that the use of other calibration gases is acceptable, provided appropriate correction factors are applied specifically to the calibration gas used. We have modified the monitoring method to incorporate this flexibility and added a corresponding recordkeeping and reporting requirement to indicate the gas used for calibration. However, we maintain that the calibration should be made with tubing attached. This will help to ensure no leaks in the tubing or other issues that may impact the LEL measurements when the tubing is attached. Therefore, we are not revising the proposed requirement to perform calibration with the tubing attached.

Regarding reducing the duration of the LEL monitoring (item 3), we find that a 10-minute testing period (5-minute stabilization + 5 minutes of reading) only provides one 5-minute average and is not as representative as the proposed 20-minute test period. However, if the LEL level is clearly exceeded in the first 5-minute average, we agree that continued monitoring is not necessary. Therefore, we have added a provision to the duration of the test provisions in 40 CFR 63.425(j)(3)(ii) that allows discontinuing testing when one 5-minute average exceeds the 25 percent of the LEL level.

Regarding an exceedance of the LEL requirement triggering corrective action (item 4), we note that the LEL monitoring does trigger corrective action as specified in 40 CFR 63.423(b)(2), ''A deviation of the LEL level is considered an inspection failure under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2) and must be remedied as such.'' These sections require the storage vessels be repaired or taken out of service. We agree that re-monitoring should be done to confirm the repair has been successful, but some corrective action is needed on the floating roof prior to the second monitoring event. We do not agree with the commenter that the only corrective action needed is to re-monitor the LEL in the storage vessel. As such, we are revising 40 CFR 63.423(b)(2) to clearly require re-monitoring of the LEL to confirm repair. Specifically, we are adding the following sentence at the end of 40 CFR 63.423(b)(2): ''Any repairs made must be confirmed effective through re-monitoring of the LEL and meeting the level in this paragraph (b)(2) within the timeframes specified in § 60.113b(a)(2) or § 63.1063(e), as applicable.''

Regarding the maximum wind speed for the LEL monitoring test (item 5), we reviewed average wind speed data for various locations and agree that the 10 mph limit may be too restrictive at some locations. However, the inspections should be performed when the wind speeds are typically low, as in the morning hours. After review of the annual average wind speeds, as well as daily fluctuations in wind speed,[7] we considered whether the inspections could be performed at wind speeds under 15 mph, even when the annual average wind speed exceeds this level. After considering the comment and wind speed data, we agree to amend the wind speed requirement as follows: ''LEL measurements shall be taken when the wind speed at the top of the tank is 5 mph or less to the extent practicable, but in no case shall LEL measurements be taken when the sustained wind speed at top of tank is greater than the annual average wind speed at the site or 15 mph, whichever is less.''

Regarding specifications for the floating roof when the LEL monitoring test is performed (item 6), the test should be conducted under normal operations and the roof should not be resting on the support legs. Thus, we agree with the commenter that the roof should be floating and that testing should not be conducted when either the storage vessel is empty or the roof landed on the support legs. We recognize potential safety issues may occur if the storage vessel is being filled and significant vapors are being expelled, but we do not want to forbid any movement of liquid during the test, as that may disrupt plant operations. Therefore, we have included language in the final rule that outline that the test ''. . . should be conducted when the internal floating roof is floating with limited product movement . . .''

In considering the regulatory language proposed along with various needs to potentially re-monitor (due to high winds or to confirm repair) or to time inspections during periods of limited product movement, we found that the proposed requirement to monitor during each visual inspection required under 40 CFR 60.113b(a)(2) or 63.1063(d)(2) to be unnecessary. We intended that LEL monitoring would be conducted annually. While we anticipate that LEL monitoring would generally be conducted as part of the visual inspection requirements, mandating that they be conducted together will likely increase the number of LEL re-monitoring events required. Therefore, we are also revising 40 CFR 63.425(j)(1), as part of the revisions in response to these comments, to replace the proposed phrase ''during each visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2)'' with ''at least once every 12 months'' to clarify that the LEL monitoring is to be conducted annually, and that it may, but is not required to, be conducted during the visual inspection.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing additional fitting requirements for storage vessels with external floating roofs as proposed because we determined these fitting requirements were cost-effective. We are also finalizing requirements for storage vessels with internal floating roofs to maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the LEL, as proposed, because we determined that LEL monitoring is a development in practices that helps ensure the internal floating roof is operating effectively to reduce emissions. For reasons discussed in section III.A.3.a.iii of this preamble, we are making minor revisions to the proposed test method procedures for determining the LEL for storage vessels with internal floating roofs to clarify the test procedures and make them more flexible in response to public comments received. We are also adding and revising corresponding recordkeeping and reporting requirements.

b. NESHAP Subpart BBBBBB

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the area source gasoline distribution source category?

We proposed requirements for storage vessels with internal floating roofs to

[7] *https://windexchange.energy.gov/maps-data/325* for annual averages; *https://www.visualcrossing.com/weather-data* for hourly and daily averages.

maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the LEL. We cross-referenced the proposed test method procedures for determining the LEL in NESHAP subpart R. We also proposed that fixed roof storage vessels must have pressure relief valves with opening pressures set no less than 2.5 psig.

ii. How did the technology review change for gasoline storage vessels at area source gasoline distribution facilities?

We did not revise our proposed technology review regarding the maximum 25 percent of the LEL for internal floating roof storage vessels. However, because we cross-reference the LEL testing requirements in NESHAP subpart R, there are minor revisions in the proposed LEL test method. We also revised the proposed fixed roof storage vessel provisions regarding the minimum pressure relief device opening pressure, reducing it from 2.5 psig to 18 inches of water (0.65 psig).

iii. What key comments did the EPA receive and what are the EPA's responses?

The key comments received regarding the LEL requirement are summarized in section III.A.3.a.iii of this preamble. The key comments received regarding the proposed 2.5 psig minimum pressure relief device opening pressure requirement for fixed roof storage vessels are summarized in section III.A.1.c.iii of this preamble.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing requirements for storage vessels with internal floating roofs to maintain the concentrations of vapors inside a storage vessel above the floating roof to less than 25 percent of the LEL, as proposed, because we determined that LEL monitoring is a development in practices that helps ensure the internal floating roof is operating effectively to reduce emissions. For reasons discussed in section III.A.3.a.iii of this preamble, we are making minor revisions to the proposed test method procedures for determining the LEL for storage vessels with internal floating roofs to clarify the test procedures and make them more flexible in response to public comments received. We are also adding and revising corresponding recordkeeping and reporting requirements. For reasons discussed in section III.A.1.c.iii of this preamble, we are revising the minimum pressure setting for fixed roof storage vessels from 2.5 psig to 18 inches of water column.

4. Standards for Equipment Leaks

a. NESHAP Subpart R

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the major source gasoline distribution source category?

We proposed to require semiannual instrument monitoring of all equipment in gasoline service using either OGI according to proposed appendix K to 40 CFR part 60 (appendix K) or EPA Method 21. We also proposed to require repair of any leaks identified from a monitoring event or any leaks identified by AVO methods during normal duties.

ii. How did the technology review change for equipment leaks at major source gasoline distribution facilities?

There are no significant changes in our proposed technology review conclusions for equipment leaks at major source gasoline distribution facilities.

iii. What key comments did the EPA receive and what are the EPA's responses?

Comment: Several commenters stated that the EPA's cost estimates for the proposed instrument monitoring provisions are understated for the reasons outlined below. If the EPA used the cost assumptions outlined below, the instrument cost effectiveness compared to AVO monitoring, using the EPA's emission estimates, would be $40,000 to $50,000 per ton HAP reduced, so instrument monitoring is not a cost-effective alternative to AVO.

- AVO inspections are part of normal walk around inspections, which would occur in the absence of the rule, so no cost savings should be applied for discontinuing monthly AVO inspections.
- Method 21 monitoring costs are low.
  - Startup cost for a Method 21 instrument monitoring program is about $15,000 to $30,000. According to the commenter, the EPA did not include connectors in the number of components in the startup cost estimate.
  - Quarterly leak detection and repair (LDAR) monitoring costs are typically $10,000 to $20,000 per year (2 to 4 times the EPA estimate). This may be due, in part, to the EPA using an idealized component monitoring rate of 75 components an hour (commenter suggested 80 percent of this rate, or 60 components per hour, is more realistic).
  - Costs do not include license fees for enterprise software, which costs about $5,000 per year nor additional costs for monitoring difficult-to-monitor components (lifts, etc.).
- Optical gas imaging (OGI) monitoring costs are low:
  - Startup costs are likely $5,000 to $10,000, (not $1,000 to $1,500).
  - Monitoring rate of 750 components an hour is idealized and at the minimum time per component specified in proposed appendix K. Considering viewing from 2 angles and required breaks specified in appendix K, a more realistic average monitoring rate is 192 components per hour.

One commenter also stated that it may be technically infeasible with so many facilities having to do monitoring in 3 years. Also, the high demand for this service will likely increase costs.

Response: Regarding the commenter's note that AVO inspections are a part of normal walk around inspections, the EPA recognizes that this type of equipment leak monitoring is part of standard operations at gasoline distribution facilities. However, through discussions with industry, it was understood that the routine walk throughs are not performed with the same level of thoroughness as the monthly inspections. Additionally, the monthly inspections require time to document the inspection. To account for these more thorough AVO inspections, the EPA determined that it is appropriate to apply a cost savings for discontinuing the monthly AVO inspection requirement.

With respect to EPA Method 21 startup costs, we used the equipment counts for the model plant to estimate the startup costs. We assumed that only pumps and valves would need to be tagged, so connectors were excluded from the component count used in the startup costs. Facilities must know all equipment that need to be inspected via the current monthly AVO requirements, so the startup cost for Method 21 at gasoline distribution facilities is expected to be less than for facilities that have not had any LDAR requirements. As such, we consider the Method 21 startup costs we estimated to be reasonable for these facilities.

The EPA appreciates the commenter's feedback on lowering the monitoring rate used for Method 21 to 80 percent of the proposed value of 75 components per hour. The EPA notes that the comment does not include a rationale for why 80 percent of the proposed value is appropriate. The monitoring rate used in our analysis is based on discussions with LDAR contractors and is considered reasonable for these facilities.

If an owner or operator decided to perform instrument monitoring in-house, then we recognize that a software license would need to be purchased to manage the LDAR program. In our analysis, however, we assumed that all instrument monitoring is performed by an external contractor based on the size of typical gasoline distribution facilities (*i.e.,* considering equipment costs and number of equipment components to be monitored). We assumed that these contractors already have a software license for an LDAR management program and the LDAR contractor can output data for the facility in Excel or as a comma-separated values (CSV) file. As such, we assumed the cost of using the license is already built into the contractor's LDAR monitoring cost.

With respect to OGI startup costs, as noted previously, facilities must know all equipment that needs to be inspected via the current monthly AVO requirements, so the startup cost for OGI at gasoline distribution facilities is expected to be less than for facilities that have not had any LDAR requirements. We consider the OGI startup costs we estimated at proposal to be reasonable for these facilities.

The commenter's feedback on the OGI monitoring rate was based on the proposed appendix K; however, in light of public comments, the EPA subsequently issued a supplemental proposal with revised requirements in appendix K. Therefore, the EPA reviewed the OGI monitoring rate used in the equipment leak model compared to the requirements in appendix K, as reflected in the supplemental proposal. The OGI monitoring rate in the equipment leaks model was kept at 750 components per hour, which accounts for the amount of time needed to view each component (assumed 4 seconds per component based on the appendix K requirements in the supplemental proposal to view each component at 2 angles for 2 seconds per component per angle, and the breaks required for technicians, which require a 5-minute break after 30 minutes of viewing).

Based on our updated cost analysis in 2021 dollars, we determined that savings from not conducting monthly AVO monitoring and the value of the product not lost offsets the cost of semiannual instrument monitoring. We also found that the incremental cost of semiannual instrument monitoring compared to annual instrument monitoring was $6,700 per ton of HAP reduced, which we consider to be reasonable. Therefore, we maintain that semiannual instrument monitoring is cost-effective for major source gasoline distribution facilities. For more information regarding our revised costs analysis for instrument monitoring, see memorandum *Updated Control Options for Equipment Leaks at Gasoline Distribution Facilities* in Docket ID No. EPA–HQ–OAR–2020–0371.

With respect to the comment suggesting it may be technically infeasible to conduct monitoring in 3 years due to demand, we see no basis for this claim. The leak inspection service industry is mature and while there may be many gasoline distribution facilities, a semiannual monitoring requirement for these facilities will not overly stretch the capacity of the service providers. We provide up to 3 years to comply with the instrument monitoring requirements. Facilities may begin instrument monitoring prior to the end of the 3-year period to avoid any potential contractor supply issues if that is a concern.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the equipment leak requirements for major source gasoline distribution facilities as proposed because we determined that semiannual instrument monitoring is cost-effective for major source gasoline distribution facilities. Facilities will have 3 years from the promulgation date of the rule to comply with the semi-annual equipment leaks instrument monitoring requirement.

b. NESHAP Subpart BBBBBB

i. What did the EPA propose pursuant to CAA section 112(d)(6) for the area source gasoline distribution source category?

We proposed to require annual instrument monitoring of all equipment in gasoline service using either OGI according to proposed appendix K or EPA Method 21. We also proposed to require repair of any leaks identified from a monitoring event or any leaks identified by AVO methods during normal duties.

ii. How did the technology review change for equipment leaks at area source gasoline distribution facilities?

There are no significant changes in the proposed technology review conclusions for equipment leaks at area source gasoline distribution facilities.

iii. What key comments did the EPA receive and what are the EPA's responses?

In addition to the general key comments received regarding the equipment leaks monitoring as summarized in section III.A.4.a.iii of this preamble, the following comment was received specific to area source gasoline distribution facilities:

Comment: One commenter stated that the proposed LDAR requirement is particularly burdensome for bulk gasoline plants and pipeline pumping stations. These facilities have limited staff and are often remote. Also, many of the EPA's costs are assumed to be linear by number of components and some may be less linear, so the costs are further understated for these small facilities.

Response: With respect to higher burden for bulk gasoline plants and pipeline pumping stations, our cost estimates for instrument monitoring have two elements. One element is fixed costs per monitoring event; the second element is variable costs associated with the number of equipment components monitored. When considering both of these cost elements, we agree that the overall cost of monitoring (on a per component basis) is higher for bulk gasoline plants and pipeline pumping stations than it is for bulk gasoline terminals and pipeline breakout stations. However, our cost estimates take this into account because they consider the fixed costs associated with having a contractor perform instrument monitoring.

Based on our updated cost analysis in 2021 dollars, we determined that savings from not conducting monthly AVO monitoring and the value of the product not lost offsets the cost of annual instrument monitoring and results in a net cost savings compared to monthly AVO monitoring. We also found that the incremental cost of semiannual instrument monitoring compared to annual instrument monitoring was $12,500 per ton of HAP reduced, which we determined was unreasonable. Therefore, we maintain that annual instrument monitoring is cost-effective for area source gasoline distribution facilities. For more information regarding our revised costs analysis for instrument monitoring, see memorandum *Updated Control Options for Equipment Leaks at Gasoline Distribution Facilities* in Docket ID No. EPA–HQ–OAR–2020–0371.

iv. What is the rationale for the EPA's final approach for the technology review?

We are finalizing the equipment leak requirements for area source gasoline distribution facilities as proposed because we determined that annual instrument monitoring is cost-effective for area source gasoline distribution facilities. Facilities will have 3 years from the promulgation date of the final rule to comply with the annual equipment leak instrument monitoring requirement.

c. NSPS Subpart XXa

i. What did the EPA propose pursuant to CAA section 111 at new, modified, or reconstructed bulk gasoline terminals?

We proposed to require quarterly instrument monitoring of all equipment in gasoline service using OGI according to proposed appendix K or quarterly instrument monitoring of pumps, valves, and pressure relief devices and annual monitoring of connectors using EPA Method 21. We also proposed to require repair of any leaks identified from a monitoring event or any leaks identified by AVO methods during normal duties.

ii. How did the NSPS review change for equipment leaks at new, modified, or reconstructed bulk gasoline terminals?

There are no significant changes in the proposed BSER conclusions for equipment leaks at facilities subject to NSPS subpart XXa.

iii. What key comments did the EPA receive and what are the EPA's responses?

Key comments received regarding the NSPS affected facility definition for the equipment leak monitoring requirements are summarized in section III.A.1.a.iii of this preamble. General comments received on the cost assumptions used in the equipment leaks analysis are summarized in section III.A.4.a.iii of this preamble.

Comment: Several commenters stated that OGI monitoring cannot rely on appendix K because that has not been finalized and the gasoline distribution rules must have a public comment period after the finalization of appendix K on which to evaluate its inclusion in the rules.

Response: Appendix K was proposed prior to the proposal of the gasoline distribution technology and NSPS reviews, so it was available for comment. Commenters had both the opportunity to comment on appendix K by submitting comments to the Oil and Natural Gas Sector Climate review docket, Docket ID No. EPA–HQ–OAR–2021–0317, which it appears that the commenters did, and on our proposed use of appendix K in the gasoline distribution sector. Since commenters had the opportunity to comment on appendix K and on our proposed use of appendix K, we see no reason not to finalize the use of appendix K as proposed.

iv. What is the rationale for the EPA's final approach for the NSPS review?

We are finalizing the equipment leak monitoring frequency for NSPS subpart XXa as quarterly monitoring because, as described in the June 2022 proposal (87 FR 35627; June 10, 2022), we found this monitoring frequency cost-effective for VOC emission reductions at new, modified, and reconstructed affected facilities. We have also revised the affected facility definition, as described in section III.A.1.a.iv of this preamble, to separate the NSPS subpart XXa affected facility into a ''gasoline loading rack affected facility'' and a ''collection of equipment at a bulk gasoline terminal affected facility.''

B. Other Actions the EPA is Finalizing and the Rationale

1. SSM

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit (the court) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standards apply continuously. The EPA has determined the reasoning in the court's decision in *Sierra Club* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2 and 63.2) (definition of malfunction). As explained in the June 10, 2022, proposal preamble (87 FR 35628), the EPA interprets CAA sections 111 and 112 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA sections 111 and 112 standards.

a. Elimination of the SSM Exemption in NESHAP Subpart R

The EPA proposed amendments to NESHAP subpart R to remove provisions related to SSM that are not consistent with the requirement that the standards apply at all times. More information concerning the elimination of SSM provisions is in the preamble to the proposed rule (87 FR 35628; June 10, 2022). The EPA is finalizing removal of the SSM provisions in NESHAP subpart R as proposed with the exception that we are including language that follows the language in 40 CFR 63.8(d)(3) in two paragraphs instead of just one as proposed and revising the language to align with the language more closely in 40 CFR 63.8(d)(3). The EPA had proposed to add language at 40 CFR 63.428(d)(4), as renumbered in the proposal, that followed the language in 40 CFR 63.8(d)(3) with the last sentence replaced to eliminate reference to SSM plan. As described in section III.B.3.g.i of this preamble, the EPA is finalizing existing and new recordkeeping provisions for the loading rack provisions in 40 CFR 63.428(c) and (d), so the EPA is including this added language in both 40 CFR 63.428(c)(4) and (d)(4) in the final rule so that it applies to bulk gasoline terminals regardless of whether they are complying with the current or new loading rack provisions.

b. Revisions To Address SSM Provisions in NESHAP Subpart BBBBBB

The EPA proposed amendments to NESHAP subpart BBBBBB to remove references to malfunction and revise certain entries to Table 4 to Subpart BBBBBB of Part 63—Applicability of General Provisions (table 4 to subpart BBBBBB) that are not consistent with the requirement that the standards apply at all times. More information concerning the proposed amendments is available in the preamble to the proposed rule (87 FR 35630; June 10, 2022). The EPA is finalizing the amendments in NESHAP subpart BBBBBB as proposed with the exception that we are revising the language in 40 CFR 63.11094(m), which was proposed at 40 CFR 63.11094(k), to align with the language more closely in 40 CFR 63.8(d)(3).

c. Finalize NSPS Subpart XXa Without SSM Exemptions

The EPA proposed standards in NSPS subpart XXa that apply at all times. The EPA is finalizing in 40 CFR part 60, subpart XXa, specific requirements at 40 CFR 60.500a(c) that override the 40 CFR part 60 general provisions for SSM requirements. In finalizing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in the preamble to the proposed rule (87 FR 35630; June 10, 2022), has not finalized alternate standards for those periods.

2. Electronic Reporting

To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators of bulk gasoline terminals subject to the new NSPS at 40 CFR part 60, subpart XXa, and gasoline distribution facilities subject to NESHAP at 40 CFR part 63, subparts R and BBBBBB, submit electronic copies of required performance test reports, performance evaluation reports, semiannual reports, and Notification of Compliance Status reports through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum, *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. The final rules require that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [8] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, performance evaluation results of CEMS measuring relative accuracy test audit pollutants that are supported by the ERT at the time of the test must be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance evaluation results must be submitted in PDF using the attachment module of the ERT. For semiannual reports under NSPS subpart XXa and semiannual compliance reports under NESHAP subparts R and BBBBBB, the final rules require that owners and operators use the appropriate spreadsheet template to submit information to CEDRI. The final version of the template for these reports will be located on the CEDRI website.[9] The final rules require that Notification of Compliance Status reports be submitted as a PDF upload in CEDRI.

Furthermore, the EPA is finalizing, as proposed, provisions in NSPS subpart XXa that allow owners and operators the ability to seek extensions for submitting electronic reports for circumstances beyond the control of the facility, *i.e.,* for a possible outage in CDX or CEDRI or for a force majeure event, in the time just prior to a report's due date, as well as the process to assert such a claim. These extensions were not added specifically to NESHAP subparts R and BBBBBB because they are codified in 40 CFR part 63, subpart A, General Provisions, at 40 CFR 63.9(k).

3. Technical and Editorial Changes

a. Applicability Equations in NESHAP Subpart R

The EPA proposed amendments to NESHAP subpart R to remove applicability equations in 40 CFR 63.420 and have applicability determined solely based on major source determination. The EPA proposed a 3-year period for the removal of the use of the applicability equations. The Agency also proposed to remove two related definitions for ''controlled loading rack'' and ''uncontrolled loading rack.'' The EPA received comment that the definitions of ''controlled loading rack'' and ''uncontrolled loading rack,'' should not be deleted until the applicability equations can no longer be used. The EPA reviewed the use of these terms in NESHAP subpart R and confirmed those terms are only used in the applicability equations. The EPA agrees with commenters that the definitions of ''controlled loading rack'' and ''uncontrolled loading rack'' should remain in NESHAP subpart R to define the terms used in the applicability equations while they are still available for use. Therefore, the EPA is not finalizing the proposed deletion of the terms ''controlled loading rack'' and ''uncontrolled loading rack'' from 40 CFR 63.421. Otherwise, we are finalizing the transition away from using the applicability equations as proposed.

b. Definitions of Bulk Gasoline Terminal, Pipeline Breakout Station, and Pipeline Pumping Station

In NESHAP subparts R and BBBBBB, the EPA proposed to transition to new definitions of ''bulk gasoline terminal'' and ''pipeline breakout station'' over a 3-year period. We also proposed to revise the definition of ''pipeline pumping station'' in NESHAP subpart BBBBBB, effective on the effective date. The proposed revision to the definition of ''bulk gasoline terminal'' was minor, clarifying that the facility ''. . . subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities . . .'' We did not receive any comments on the proposed definition of ''bulk gasoline terminal,'' and we are finalizing the definition as proposed with the exception of the definition in NESHAP subpart BBBBBB. We are finalizing the definition of ''bulk gasoline terminal'' in NESHAP subpart BBBBBB to be consistent with the gasoline throughput requirements currently in the rule. The definition of ''bulk gasoline terminal'' in NESHAP subpart BBBBB is ''any gasoline facility which . . . has a gasoline throughput of 20,000 gallons per day (75,700 liter per day) or greater.'' The revisions to the definition of ''pipeline pumping station'' were proposed to clarify that pipeline pumping stations do not have gasoline loading racks. We did not receive any comments on the proposed definition of ''pipeline pumping station,'' and we are finalizing the definition as proposed.

The proposed revisions to the ''pipeline breakout station'' definition added two sentences to clarify that facilities that have gasoline loading racks are to be considered bulk gasoline terminals rather than pipeline breakout stations. These two added sentences were: ''Pipeline breakout stations do not have loading racks. If any gasoline is loaded into cargo tanks, the facility is a bulk gasoline terminal for the purposes of this subpart provided the facility-wide gasoline throughput (including pipeline throughput) exceeds the limits specified for bulk gasoline terminals.''

Comment: A commenter stated that pipeline facilities may have loading racks, but these may not be used for gasoline loading (*i.e.,* for diesel fuel loading or other materials) or rarely used for gasoline loading (*e.g.,* used only when conducting maintenance on storage tanks). According to the commenter, these limited loading operations should not trigger the loading rack control requirements for bulk gasoline terminals. The commenter also indicated that the parenthetical phrase ''including pipeline throughput'' is confusing and suggested that the throughput threshold consider only the ''gasoline loading design throughput.''

Response: We agree that the first sentence added to the definition of ''pipeline breakout station'' was overly broad and should be revised to specify that the loading racks are for loading gasoline into cargo tanks. If only diesel fuel loading is conducted at the facility,

[8] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[9] *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

the facility should be considered a pipeline station. With respect to the parenthetical phrase ''. . . (including pipeline throughput) . . .,'' we intentionally included this phrase to require all pipeline breakout stations to use their total facility gasoline throughput so that facilities that have both pipeline breakout operations and co-located gasoline loading operations would be considered bulk gasoline terminals. We note that the definition of bulk gasoline terminal also refers to the facility and does not limit the referenced throughput to just that of the loading operations. We consider the parenthetical helps to clarify the definition and is consistent with our interpretation that the 20,000 gallon per day throughput threshold within the definition of ''bulk gasoline terminal'' is a facility-level throughput and not limited to the throughput of only the gasoline loading racks. If all of the gasoline managed by the facility is not loaded into cargo tanks, as in the case of co-located pipeline breakout operations and gasoline loading operations, then the 20,000-gallon throughput threshold is to be evaluated based on the facility's total gasoline throughput and not just the throughput of the loading operations. For major sources of HAP emissions, this would require the loading operations to meet the 10 mg/L TOC limit in NESHAP subpart R. For area sources, the provisions for bulk gasoline terminals in NESHAP subpart BBBBBB have separate requirements based on the actual gasoline throughput of all loading racks at the facility. As such, area source facilities with co-located pipeline breakout operations and gasoline loading operations would be either subject to the proposed 35 mg/L TOC emission limit or the submerged fill requirements in NESHAP subpart BBBBBB based on the gasoline throughput of all loading racks.

We note that if only the loading rack throughput was used as suggested by the commenter, some co-located loading operations could be considered bulk gasoline plants. For major sources subject to NESHAP subpart R, these loading operations would have no control requirements, not even a submerged fill requirement. For area sources, the loading operations would be considered subject to the vapor balancing requirements proposed for bulk gasoline plants in NESHAP subpart BBBBBB if the gasoline throughput is 4,000 gallons per day or more. Because storage tanks at pipeline breakout stations are large and predominately controlled using floating roofs, the proposed vapor balancing requirement would not be appropriate. We find that the 20,000-gallon per day threshold for bulk gasoline terminals is most appropriately determined based on the total gasoline throughput of the facility and that treating facilities that may have been previously considered a pipeline breakout station with gasoline loading operations as a bulk gasoline terminal in all cases provides a reasonable method to ensure all loading operations have an applicable requirement.

After considering the comments received, we are finalizing the definitions of ''bulk gasoline terminal,'' ''pipeline breakout station,'' and ''pipeline pumping station'' as proposed with an additional clarification in the definition of ''pipeline breakout station'' through the addition of the underlined phrase: ''Pipeline breakout stations do not have loading racks *where gasoline is loaded into cargo tanks*.''

c. Definition of Gasoline

We proposed a minor revision to the definition of ''gasoline'' in NESHAP subpart BBBBBB to include the Reid vapor pressure in units of pounds per square inch (in addition to kilopascals) because those are the units of measure commonly used in the U.S. gasoline distribution industry. We proposed to directly include this same definition of ''gasoline'' in NESHAP subpart R, rather than rely on the definition of ''gasoline'' in NSPS subpart XX or XXa. We received no comment on these proposed revisions related to the definition of ''gasoline'' and are finalizing the revised or added definition as proposed.

d. Definition of Submerged Filling

Because we proposed to add submerged fill requirements in NESHAP subpart R, we also proposed to add a definition of ''submerged filling'' to NESHAP subpart R. The proposed definition of ''submerged filling'' was similar to the definition already included in NESHAP subpart BBBBBB. We received no comment on the proposed definition of ''submerged filling'' and are finalizing the added definition as proposed with the exception that we are removing the phrase ''for the purposes of this subpart'' from NSPS subpart XXa and NESHAP subpart R.

e. Definition of Flare and Thermal Oxidation System

We proposed a revision to the definitions of ''flare'' and ''thermal oxidation system'' in NESHAP subpart R. We proposed to include these same definitions of ''flare'' and ''thermal oxidation system'' to NESHAP subpart BBBBBB. These proposed revisions were to clarify the distinction between control systems subject to performance testing as thermal oxidation systems because they emit pollutants through a conveyance suitable for performance testing and flares are exempt from performance testing because they do not emit pollutants through a conveyance suitable for performance testing.

Comment: Several commenters requested that the EPA change the definition and phrasing in the rule from ''thermal oxidation system'' to ''vapor combustion unit'' because this is the term commonly used by the industry. One commenter noted that the use of ''thermal oxidation system'' is broadly inconsistent with the way gasoline vapor combustion units, flares, and thermal oxidation systems have been treated previously in these and other rules and how they are treated by States and in facility permits. One commenter recommended that in the definition of ''thermal oxidation system'' the EPA replace ''Auxiliary fuel may be used to heat air pollutants to combustion temperatures'' with ''Auxiliary fuel may be used to sustain combustion.'' One commenter recommended revising ''. . . device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize air pollutants . . .'' to more simply state ''device designed to mix air and vapors in direct contact with a flame to oxidize air pollutants'' because vapor combustion units commonly do not use auxiliary fuel and because effective combustion does not require heating.

Response: These gasoline distribution rules have long used the term ''thermal oxidation system.'' As such, facilities complying with these regulations must already be familiar with this term. We reviewed the revisions that would be needed to change this term to ''vapor combustion unit'' and were concerned by the possibility of missing all references to this term. However, during our review, we identified that we had not revised the phrase ''thermal oxidation system other than a flare'' in 40 CFR 63.427(a)(3) and 63.11092(b)(1)(iii) and (e)(1) and (2), and in item 1 of table 3 to NESHAP subpart BBBBBB. We are revising these references by deleting ''other than a flare'' from this phrase. With respect to comments suggesting further revisions to the definition of ''thermal oxidation system,'' we did not propose to revise the phrasing within the definition of ''thermal oxidation system'' that describes the device largely because we did not want to change the long-used description of the system in order to minimize potential inconsistencies with permits and other ancillary requirements for these control systems. Our proposed revisions were focused on including the phrase that ''[t]hermal oxidation systems emit pollutants through a conveyance suitable to conduct a performance test.'' Because we had not proposed additional revisions and did not intend to alter the historically used terms, we decided to not make additional revisions to the definition of ''thermal oxidation system.''

Upon considering the comments received, we are finalizing the revisions to the definitions of ''flare'' and ''thermal oxidation system'' as proposed. We are also revising the instances where ''thermal oxidation system other than a flare'' was used to simply say ''thermal oxidation system'' because flares are not a subset of thermal oxidation systems based on the final definitions.

f. Additional Part 63 General Provision Revisions

We proposed to revise a number of entries in Table 1 to Subpart R of Part 63—General Provisions Applicability to This Subpart (table 1 to subpart R) and to table 4 to subpart BBBBBB in the proposed rule to correct paragraph references, correct a typographical error, and update certain entries to reflect proposed revisions to the rules. Upon further review of table 1 to subpart R, we are revising the entry for 40 CFR 63.9(f) to ''no.'' This provision is a notification for conducting visible emission observations. There is not a requirement in NESHAP subpart R to conduct routine visible emission observations. Upon further review of table 4 to subpart BBBBBB, we are revising the entry for 40 CFR 63.7(e)(3) to also include an exception for 40 CFR 63.11092(e). The performance test requirements in NSPS subpart XXa, which are referenced in NESHAP subpart BBBBBB, specify the test run duration. We are also revising the entry for 40 CFR 63.10(b)(2)(ii) to correct the cross-reference.

Comment: One commenter stated the addition of 40 CFR 63.11(c) through (e) to table 4 to subpart BBBBBB should be changed to ''yes'' because some bulk gasoline terminals may be using these equipment leak alternative monitoring provisions and they should not be required to change until appendix K provisions are finalized. The commenter noted that the NESHAP subpart R table includes ''yes'' for these paragraphs.

Response: We reviewed the alternative work practice equipment leak provisions in 40 CFR 63.11(c) through (e) and see no reason why these provisions would apply after the full implementation of the revisions requiring OGI monitoring using the procedures in appendix K. We also note that the current Method 21 monitoring in NESHAP subparts R and BBBBBB is primarily limited to monitoring of the vapor collection system prior to a performance test to ensure the vapor collection system is operated with no detectable emissions. OGI is not approved as an alternative to Method 21 for no detectable emissions monitoring events. With that said, we agree that there is a discrepancy between the entries in table 1 to subpart R and table 4 to subpart BBBBBB and there should not be. There may be facilities, particularly for gasoline terminals co-located with other facilities, that may have Method 21 monitoring provisions for which this OGI alternative is applicable. As such, it is possible that some facilities could use the alternative work practice standards in 40 CFR 63.11(c) through (e) in lieu of the monthly AVO monitoring requirements. Considering these conditions, we are revising the entry for 40 CFR 63.11(c) through (e) in table 4 to subpart BBBBBB to ''yes, except . . .'' and indicating that the equipment leak alternative work practice is not applicable to Method 21 monitoring associated with performance testing and is not applicable upon compliance with the instrument monitoring equipment leak provisions in 40 CFR 63.11089(c). We are also adding a similar comment to the entry for 40 CFR 63.11(c), (d), and (e) in table 1 to subpart R to indicate that the equipment leak alternative work practice is not applicable to Method 21 monitoring associated with performance testing and is not applicable upon compliance with the instrument monitoring equipment leak provisions in 40 CFR 63.424(c).

Comment: One commenter stated that the proposed revision to the note for the entry at 40 CFR 63.11(b) in table 4 to subpart BBBBBB and for the entry 40 CFR 63.11(a) through (b) in table 1 to subpart R should not be finalized. According to the commenter, the provision is unnecessary for flares controlling loading, because the rule specifies the flare requirements for those flares, but the facility may have other flares not used to control gasoline loading, and those flares can still comply with the provisions at 40 CFR 63.11(b). A commenter also noted a cross-reference error for the entry 40 CFR 63.11(a) through (b) in table 1 to subpart R.

Response: The note helps to clarify the flare provisions applicable to the sources covered under NESHAP subparts R and BBBBBB. We are revising the entry for 40 CFR 63.11(b) in table 4 to subpart BBBBBB by replacing ''until compliance'' with ''except these provisions no longer apply for flares used to comply'' and ''Item 2.b'' with ''Item 2'' to indicate that the exception applies for flares complying with the flare provisions in NSPS subpart XXa, which are referenced in NESHAP subpart BBBBBB. For table 4 to subpart BBBBBB, we are finalizing the table as proposed except for the revisions to the entries for 40 CFR 63.7(e)(3), 63.10(b)(2)(ii), 63.11(b), and 63.11(c) through (e).

In NESHAP subpart R, upon transition to the flare provisions in NSPS subpart XXa, which are referenced in NESHAP subpart R, flares at major source gasoline distribution facilities will no longer comply with the flare provisions in 40 CFR 63.11(b). We are retaining the note except, based on the comment about a cross-reference error in table 1 to subpart R, we are revising the reference to ''. . . § 63.425(b)(2) . . .'' in the note for the entry for 40 CFR 63.11(a) and (b) to ''. . . §§ 63.422(b)(2) and 63.425(d)(2) . . .''

Comment: One commenter noted a typographical error in table 1 to subpart R, ''. . . specifices . . .'' in the row included for the entry for 40 CFR 63.8(d)(3).

Response: Based on the comments received, we are correcting the typographical error in the comment included for the entry for 40 CFR 63.8(d)(3) to ''. . . specifies . . .'' Except for the revisions to the entries for 40 CFR 63.8(d)(3), 63.9(f), 63.11(c), (d), and (e), and 63.11(a) and (b), we are finalizing table 1 to subpart R as proposed.

g. Editorial Corrections

We proposed a number of editorial and typographical corrections. We are finalizing these revisions as proposed. We are also making clarifying revisions to spell out acronyms at first use or to replace words with acronyms. In addition, we are making clarifying revisions to consistently refer to ''liquid product'' loaded into ''gasoline cargo tanks.'' We are also making conforming revisions between the three rules to ensure similar requirements. Additionally, we are clarifying current requirements and those requirements that take effect by the compliance date. We received comment regarding several cross-reference errors or other editorial corrections. After reviewing these comments, we are revising cross-references and also making the following corrections in the final rules:

i. NESHAP Subpart R

- At 40 CFR 63.422(a)(2), we are revising the term ''affected facility'' to ''gasoline loading rack affected facility'' commensurate with the final terms used in NSPS subpart XXa. We are also adding a sentence at the end of the paragraph based on a clarification requested by comments that, for the purposes of NESHAP subpart R, the definition of ''vapor-tight gasoline cargo tanks'' in 40 CFR 63.421 applies to the cross-referenced provisions in NSPS subpart XXa. Specifically, the added sentence reads: ''For purposes of this subpart, the term ''vapor-tight gasoline cargo tanks'' used in § 60.502a(e) of this chapter shall have the meaning given in § 63.421.''
- At 40 CFR 63.422(c)(1), we are adding ''or'' after the semicolon as requested by a commenter to better clarify that the provisions in this paragraph are alternatives to those in 40 CFR 63.422(c)(2) and (3).
- At 40 CFR 63.425(d), we are adding the phrase ''. . . and, if applicable, the provisions in paragraph (j) of this section'' to the end of the first sentence to clarify that annual LEL monitoring must also be conducted for internal floating roof storage vessels in addition to the requirements in 40 CFR 60.113b.
- At 40 CFR 63.425(e)(1), we are redesignating the table as table 1 to paragraph (e)(1) because it is the first table in the section and immediately follows paragraph (e)(1).
- At 40 CFR 63.425(f), we are deleting the phrase, ''except omit section 4.3.2 of Method 21'' because Method 21 does not contain section 4.3.2.
- At 40 CFR 63.425(g)(3), we are revising the definition of the term ''N'' to refer to the fourth column of table 1 to paragraph (e)(1) because we added a column to table 1 to paragraph (e)(1) and did not update this cross-reference.
- We received comment that the proposed paragraph at 40 CFR 63.427(d) is confusing and appears to make operating both above and below the operating limits a deviation. We are revising 40 CFR 63.427(d) to indicate that the vapor processing system should be operated in a manner consistent with the minimum and/or maximum operating parameter value or required procedures. Operation in a manner that constitutes a period of excess emission or failure to perform required procedures are considered a deviation of the emissions standard.
- One commenter noted that 40 CFR 63.428(c) was renumbered as 40 CFR 63.428(d), but no new paragraph (c) was added. The commenter noted that a new paragraph (c) should be added and marked as ''Reserved.'' Upon review, we noted that the paragraph we intended to add as paragraph (d) was not included in the redline/strikeout version of the regulatory text. Therefore, we are not revising the paragraph numbering at 40 CFR 63.428(c) as proposed. We are revising the introductory text in 40 CFR 63.428(c) to clarify that the recordkeeping requirements in that paragraph (c) are for bulk gasoline terminals subject to the provisions of 40 CFR 63.422(b)(1), which contains the current requirements that expire in 3 years. We are adding a new paragraph (d) that provides the recordkeeping requirements specific to 40 CFR 63.422(b)(2), which contains the updated monitoring requirements for thermal oxidation systems, vapor recovery systems, and flares used to control emissions from loading operations analogous to the recordkeeping requirements in NSPS subpart XXa.
- We are revising 40 CFR 63.428(h) by replacing ''delegated air agency'' with ''delegated authority.''
- We are revising 40 CFR 63.428(l)(2)(ii) to clarify that the periodic reports referenced are those required as specified in 40 CFR 60.115b based on a comment received suggesting there was a cross-referencing error.

ii. NESHAP Subpart BBBBBB

- At 40 CFR 63.11083(c), we are adding ''. . . § 63.11086(a) or in . . .'' after ''as specified in'' to note that the 3-year compliance schedule also applies to bulk gasoline plants with an increase in daily throughput that exceeds the 4,000 gallons per day threshold for vapor balancing.
- We are revising 40 CFR 63.11092(i) to align the conduct of performance tests with the requirements in NESHAP subpart R and clarify how performance tests should be conducted.
- We are clarifying in 40 CFR 63.11094 that records must be maintained for at least 5 years unless otherwise specified.
- One commenter noted that inconsistencies in the phrasing of vapor tightness recordkeeping requirements between NESHAP subparts R and BBBBBB and NSPS XXa. The commenter suggested consistently adding the phrasing used at proposed 40 CFR 63.11094(b) with respect to provision that vapor tightness documentation may be made available ''. . . during the course of a site visit, or within a mutually agreeable time frame'' to all rules. Upon review, we find that this phrasing is a hold-over from when hardcopy documentation was required, and an electronic record provided as an alternative. We have proposed the use of electronic records and have found that access to electronic records is sufficient. If an inspector wants to view the electronic records, these should be available for review at the time of the inspection and provided to the inspector. We are not requiring facilities to provide hardcopies of the records. The owner or operator may elect to use hardcopy records, but we not requiring these. For consistency, we are not finalizing the proposed additions to 40 CFR 63.11094(b) in NESHAP subpart BBBBBB which includes the phrase cited by the commenter.
- One commenter noted that 40 CFR 63.11094(c) was deleted and no new paragraph (c) was added. The commenter recommended that a new paragraph (c) should be added and marked as ''Reserved.'' Upon review, we decided to renumber proposed 40 CFR 63.11094(d) to 40 CFR 63.11094(c) and similarly renumber the other paragraphs in this section in a sequential manner.
- One commenter noted that proposed 40 CFR 63.11094(e)(1) and (e)(2)(i) contain citations to 40 CFR 63.11092(f), which pertains to storage while 40 CFR 63.11094(e) pertains to control devices for the loading racks. Upon review, we are rewording proposed 40 CFR 63.11094(e), now paragraph (f), to include the storage vessel provisions in 40 CFR 63.11092(f).
- One commenter noted that 40 CFR 63.11094(f) cites paragraphs (f)(1) through (7) but the text only contains paragraphs (f)(1) through (4). With respect to the missing paragraphs in 40 CFR 63.11094(f)(5) through (7), these were intended to be the recordkeeping requirements for facilities complying with the new emission limits when using different control technologies. Through a clerical error, these requirements were not included in the proposed redline of the rule. We are adding these requirements to the final rule to specify the recordkeeping requirements for these control scenarios. These recordkeeping requirements are similar to those in NSPS subpart XXa and are commensurate with the reporting requirements that were included in the NESHAP subpart BBBBBB proposal.

iii. NSPS Subpart XXa

- At 40 CFR 60.501a, we are deleting the duplicative definition of ''flare'' that was inadvertently included at the end of the definition of ''equipment.''
- At 40 CFR 60.502a(b) and (c), we are adding ''. . . no later than the date on which § 60.8(a) requires a performance test to be completed'' at the

end of the first sentence to clarify that, for sources for which a performance test or evaluation is required, full compliance cannot be assessed until the performance test or performance evaluation is conducted.

- One commenter noted that 40 CFR part 63, subpart BBBBBB, cross-references the provisions at 40 CFR 60.502a(c)(3) as an alternative for use for thermal oxidation systems, but the cross-referenced provisions appear to only apply to flares. The commenter recommended adding language at 40 CFR 60.502a(c)(3) to indicate that the paragraph also applies to thermal oxidation systems for which these provisions are specified. We agree with the commenter and note that this language is also needed based on the expanded use of these flare monitoring provisions as detailed in sections III.A.1.a.iii and iv of this preamble. We are adding ''. . . or if a thermal oxidation system for which these provisions are specified as a monitoring alternative is used . . .'' to 40 CFR 60.502a(c)(3) to clearly indicate that these provisions apply to certain thermal oxidation systems.
- At 40 CFR 60.502a(c)(3)(vi), we are deleting the word ''gasoline'' in reference to cargo tanks because the flow rate of vapors to the vapor collection systems is based on the total liquid loading rates of all cargo tanks for which vapors are displaced to the vapor collection systems and not just those that meet the definition of ''gasoline cargo tank.'' We are also rephrasing the introduction to more clearly indicate that ''you may elect'' to use this alternative to determine flare waste gas flow rates.
- At 40 CFR 60.502a(h), we are revising ''450 millimeters'' to ''460 millimeters'' to correct unit conversion from 18 inches.
- At 40 CFR 60.503a(a)(1), we are adding the sentence, ''The three-run requirement of § 60.8(f) does not apply to this subpart.'' to clarify that only one 6-hour test as described in 40 CFR 60.503a(c) must be conducted.
- At 40 CFR 60.503a(a)(2), we are replacing ''. . . potential sources in the terminal's vapor collection system equipment . . .'' with ''. . . equipment, including loading arms, in the gasoline loading rack affected facility . . .'' to require that the pre-performance test leak monitoring include all equipment in the gasoline loading rack affected facility, which includes equipment at the loading racks and the vapor processing system.
- At 40 CFR 60.505a(a)(6), we are adding a requirement to maintain records for leaks identified under 40 CFR 60.503a(a)(2) similar to the requirement to maintain records for leaks identified under 40 CFR 60.502a(j).
- At 40 CFR 60.505a(c)(6)(ii)(A) and (B), we are removing a redundant reference to 40 CFR 60.502a(j)(2); 40 CFR 60.505a(c)(6)(ii) already indicated that the applicability of these paragraphs is limited to leaks identified under 40 CFR 60.502a(j)(2), which are leaks identified using AVO methods during normal activities.

iv. NSPS Subpart XX

- We are revising NSPS subpart XX at 40 CFR 60.500(b) to finalize the proposed amendments so that NSPS subpart XX applies to affected facilities that commence construction or modification after December 17, 1980, and on or before June 10, 2022.

C. What are the effective and compliance dates of the standards?

1. NESHAP Subpart R

The revisions to the MACT standards being promulgated in this action are effective on July 8, 2024.

The compliance date for existing gasoline distribution facilities subject to NESHAP subpart R is May 10, 2027, with the exception of the changes to table 1 of subpart R, the removal of the SSM exemptions, the finalized external floating roof storage vessel fitting controls, and performance test and performance evaluation reporting requirements. As explained in the preamble of the proposed action (87 FR 35634; June 10, 2022) and in section III.A.2.a.iv of this preamble, the EPA considers 3 years after the promulgation date of the final rule to be as expedient as practicable to implement the final requirements. The EPA does not expect any of the final revisions to table 1 of subpart R to increase burden to any facility and can be implemented without delay. For the removal of the SSM exemptions, we are finalizing that facilities must comply by the effective date of the final rule. The compliance times we are finalizing will ensure that the regulations are consistent with the decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008) in which the court vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of hazardous air pollutants during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and (h)(1). The EPA removed these SSM exemptions from the CFR in March 2021 to reflect the court's decision (86 FR 13819). The EPA does not expect any of the final revisions pertaining to SSM in table 1 of subpart R to increase burden to any facility and can be implemented without delay. In addition, we do not expect additional time is necessary generally for facilities to comply with changes to SSM provisions because we have concluded that the sources can meet the standards at all times, as described in section III.B.1.a. We are therefore finalizing that facilities must comply no later than the effective date of this final rule.

As explained in the preamble of the proposed action (87 FR 35635; June 10, 2022), the EPA is finalizing the requirements to install fitting controls for external floating roof storage vessels the next time the storage vessel is completely emptied and degassed or 10 years after the promulgation date of the final rule, whichever occurs first, to align the installation of controls with a planned degassing event, to the extent practicable to minimize the offsetting emissions that occur due to a degassing event. The reporting requirements for performance tests and performance evaluations are required to be submitted following the procedures in 40 CFR 63.9(k) 180 days after the promulgation date. New sources must comply with all of the standards immediately upon the effective date of the standard, July 8, 2024, or upon startup, whichever is later.

2. NESHAP Subpart BBBBBB

The revisions to the GACT standards being promulgated in this action are effective on July 8, 2024.

The compliance date for existing gasoline distribution facilities subject to NESHAP subpart BBBBBB is May 10, 2027, with the exception of the changes to table 4 of subpart BBBBBB, revisions to SSM provisions, the finalized external floating roof storage vessel fitting controls, and performance test and performance evaluation reporting requirements. As explained in the preamble of the proposed action (87 FR 35635; June 10, 2022) and in section III.A.2.b.iv of this preamble, the EPA considers 3 years after the promulgation date of the final rule to be as expedient as practicable to implement the final requirements.

The EPA does not expect any of the final revisions to table 4 of subpart BBBBBB to increase burden to any facility and can be implemented without delay. For the revisions to table 4 of subpart BBBBBB that remove references to vacated provisions and the removal of references to malfunction, we are finalizing that facilities must comply by the effective date of the final rule. We do not expect additional time is necessary generally for facilities to comply with changes to SSM provisions because we have concluded that the sources can meet the standards at all times, as described in section III.B.1.c.

As explained in the preamble of the proposed action (87 FR 35635; June 10, 2022), the EPA is finalizing the requirements to install fitting controls for external floating roof storage vessels the next time the storage vessel is completely emptied and degassed or 10 years after the promulgation date of the final rule, whichever occurs first, to align the installation of controls with a planned degassing event, to the extent practicable to minimize the offsetting emissions that occur due to a degassing event. The reporting requirements for performance tests and performance evaluations are required to be submitted following the procedures in 40 CFR 63.9(k) 180 days after the promulgation date. New sources must comply with all of the standards immediately upon the effective date of the standard, July 8, 2024, or upon startup, whichever is later.

3. NSPS Subpart XXa

The effective date of the final rule requirements in 40 CFR part 60, subpart XXa, will be July 8, 2024. Affected sources that commence construction, reconstruction, or modification after June 10, 2022, must comply with all requirements of 40 CFR part 60, subpart XXa, no later than the effective date of the final rule or upon startup, whichever is later. This proposed compliance schedule is consistent with CAA section 111(e).

IV. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

A. What are the affected facilities?

There are approximately 9,500 facilities subject to the Gasoline Distribution NESHAPs and the Bulk Gasoline Terminals NSPS. An estimated 210 facilities are classified as major sources, and 9,260 are area sources. The EPA estimated that there will be 5 new facilities and 15 modified/reconstructed facilities subject to NSPS subpart XXa in the next 5 years.

B. What are the air quality impacts?

This final action will reduce HAP and VOC emissions from Gasoline Distribution NESHAP and Bulk Gasoline Terminals NSPS sources. In comparison to baseline emissions of 6,110 tpy HAP and 121,000 tpy VOC, the EPA estimates HAP and VOC emission reductions of approximately 2,220 and 45,400 tpy, respectively, based on our analysis of the final rules in this action as described in sections III.A and B in this preamble. Emission reductions and secondary impacts (*e.g.,* emission increases associated with supplemental fuel or additional electricity) by rule are listed below.

1. NESHAP Subpart R

For the major source rule, the EPA estimates HAP and VOC emission reductions of approximately 134 and 2,160 tpy, respectively, compared to baseline HAP and VOC emissions of 845 and 18,200 tpy. The EPA estimates that the final rule will not have any secondary pollutant impacts. More information about the estimated emission reductions and secondary impacts of this final action for the major source rule can be found in the document, *Updated Major Source Technology Review for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) NESHAP.*

2. NESHAP Subpart BBBBBB

For the area source rule, the EPA estimates HAP and VOC emission reductions of approximately 2,090 and 40,300 tpy, respectively, compared to baseline HAP and VOC emissions of 5,260 and 99,400 tpy. The EPA estimates that the final rule will result in additional emissions of 32,400 tpy of carbon dioxide, 19 tpy of nitrogen oxides, and 86 tpy of carbon monoxide. More information about the estimated emission reductions and secondary impacts of this final action for the area source rule can be found in the document, *Updated Area Source Technology Review for Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities NESHAP.*

3. NSPS Subpart XXa

For the NSPS, the EPA estimates VOC emission reductions of approximately 2,950 tpy compared to baseline emissions of 3,890 tpy. The EPA estimates that the final rule will result in additional emissions of 2,140 tpy of carbon dioxide, 1.3 tpy of nitrogen oxides, and 1.3 tpy of sulfur dioxide. More information about the estimated emission reductions and secondary impacts of this final action for the NSPS can be found in the document, *Updated New Source Performance Standards Review for Bulk Gasoline Terminals.*

C. What are the cost impacts?

This final action will cost (in 2021 dollars) approximately $75.8 million in total capital costs and result in total annualized cost savings of $3.77 million per year (including product recovery) based on our analysis of the final action described in sections III.A and B of this preamble. Costs by rule are listed below.

1. NESHAP Subpart R

For the major source rule, the EPA estimates this final rule will cost approximately $2.38 million in total capital costs and $1.91 million per year in total annualized costs (including product recovery). More information about the estimated cost of this final action for the major source rule can be found in the document, *Updated Major Source Technology Review for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) NESHAP.*

2. NESHAP Subpart BBBBBB

For the area source rule, the EPA estimates this final rule will cost approximately $66.2 million in total capital costs and have cost savings of $5.74 million per year in total annualized costs (including product recovery). More information about the estimated cost of this final action for the area source rule can be found in the document, *Updated Area Source Technology Review for Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities NESHAP.*

3. NSPS Subpart XXa

For the NSPS, the EPA estimates this final rule will cost approximately $7.20 million in total capital costs and $66,000 per year in total annualized costs (including product recovery). More information about the estimated cost of this final action for the NSPS can be found in the document, *Updated New Source Performance Standards Review for Bulk Gasoline Terminals.*

D. What are the economic impacts?

The EPA conducted economic impact analyses, contained in the RIA, for this final action. The RIA is available in the docket for this action. The economic impact analyses contain two parts. The economic impacts of the final action on small entities are calculated as the percentage of total annualized costs incurred by affected ultimate parent owners to their revenues. This ratio provides a measure of the direct economic impact to ultimate parent owners of gasoline distribution facilities while presuming no impact on consumers. We estimate that the average small entity impacted by the final action will incur total annualized costs of 0.40 percent of their revenue, with none exceeding 6.56 percent. We estimate that fewer than 9 percent of impacted small entities will incur total annualized costs greater than 1 percent of their revenue and that fewer than 3 percent will incur total annualized costs greater than 3 percent of their revenue. This is based on a conservative estimate of costs imposed on ultimate parent companies, where total annualized costs imposed on a facility are at the upper bound of what is possible under the rule and do not include product recovery as a credit. More explanation of these economic impacts can be found in section V.C, the Regulatory Flexibility Act (RFA), and in the RIA for this final action. The RIA also contains a supplementary analysis of small business impacts using data from the U.S. Census Bureau.

The EPA also prepared a partial equilibrium model of the U.S. gasoline market in order to project changes caused by this final action to the price and quantity of gasoline sold from 2027 to 2041. Using this model, the price of gasoline is projected to rise by less than 0.006 percent (less than two hundredths of a cent) in all years from 2027 to 2041, whereas the quantity of gasoline consumed is projected to fall by less than 0.002 percent in all years from 2027 to 2041. These projections consider the costs imposed by amendments to NESHAP subpart BBBBBB, NESHAP subpart R, and amendments to the NSPS promulgated in subpart XXa.

Thus, economic impacts are expected to be low for affected companies and industries impacted by this final action, and there are not likely to be substantial impacts on the markets for affected products. The costs of the final action are not expected to result in a significant market impact, regardless of whether they are passed on to the purchaser or absorbed by the firms. We note that these economic impacts do not include the expected product recovery of gasoline under each of these final rules. The RIA for this final action includes more details and discussion of these projected impacts.

E. What are the benefits?

The emission controls installed to comply with the final action are expected to reduce VOC emissions which, in conjunction with nitrogen oxides and in the presence of sunlight, form ground-level ozone (O_3). This section reports the estimated ozone-related benefits of reducing VOC emissions in terms of the number and value of avoided ozone-attributable deaths and illnesses.

As a first step in quantifying O_3-related human health impacts, the EPA consults the *Integrated Science Assessment for Ozone* (Ozone ISA) [10] as summarized in the *Technical Support Document for the Final Revised Cross State Air Pollution Rule Update.*[11] This document synthesizes the toxicological, clinical, and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (*i.e.,* hours or days-long) or chronic (*i.e.,* years-long) exposure. For each outcome, the Ozone ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship, or not likely to be a causal relationship.

In brief, the Ozone ISA found short-term (less than one month) exposures to ozone to be causally related to respiratory effects, a ''likely to be causal'' relationship with metabolic effects and a ''suggestive of, but not sufficient to infer, a causal relationship'' for central nervous system effects, cardiovascular effects, and total mortality. The Ozone ISA reported that long-term exposures (one month or longer) to ozone are ''likely to be causal'' for respiratory effects including respiratory mortality, and a ''suggestive of, but not sufficient to infer, a causal relationship'' for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality.

For all estimates, we summarized the monetized ozone-related health benefits using discount rates of 3 percent and 7 percent for both short-term and long-term effects for the 15-year analysis period of these rules discounted back to 2024 rounded to 2 significant figures. All estimates are presented in 2021 dollars. For the full set of underlying calculations see the Gasoline Distribution Benefits workbook, available in the docket for this action as an attachment to the RIA. In addition, we include the monetized disbenefits from additional CO_2 emissions using a 3 percent rate, which occur with NESHAP subpart BBBBBB and NSPS subpart XXa but not NESHAP subpart R since there are no additional CO_2 emissions as a result of the NESHAP subpart R final rule. The EPA has prepared a benefits analysis, contained in the RIA and summarized here, to provide the public the same extent of analysis, including monetized benefits and disbenefits, for the rules in this final action as was provided for the proposal RIA.

Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). A qualitative discussion of the health effects associated with HAP emitted from sources subject to control under the final action is included in the RIA.

1. NESHAP Subpart R

The PV of the benefits for the final amendments to NESHAP subpart R range from $11 million at a 3 percent discount rate to $6.3 million at a 7 percent discount rate for short-term effects and $87 million at a 3 percent discount rate to $52 million at a 7 percent discount rate for long-term effects. The EAV of the benefits for the final amendments to NESHAP subpart R range from $0.89 million at a 3 percent discount rate to $0.70 million at a 7 percent discount rate for short-term effects and $7.3 million at the 3 percent discount rate to $5.8 million at a 7 percent discount rate for long-term effects.

2. NESHAP Subpart BBBBBB

The PV of the net benefits (monetized health benefits minus monetized climate disbenefits) for the final amendments to NESHAP subpart BBBBBB range from $170 million at a 3 percent discount rate to $90 million at a 7 percent discount rate for short-term effects and $1,600 million at a 3 percent discount rate to $950 million at a 7 percent discount rate for long-term effects. The EAV of the net benefits for the final amendments to NESHAP subpart BBBBBB range from $15 million at a 3 percent discount rate to $11 million at a 7 percent discount rate for short-term effects and $140 million at the 3 percent discount rate to $110 million at a 7 percent discount rate for long-term effects.

3. NSPS Subpart XXa

The PV of the net benefits (monetized health benefits minus monetized

[10] U.S. EPA (2020). Integrated Science Assessment for Ozone and Related Photochemical Oxidants. U.S. Environmental Protection Agency. Washington, DC. Office of Research and Development. EPA/600/R–20/012. Available at: *https://www.epa.gov/isa/integrated-science-assessment-isa-ozone-and-related-photochemical-oxidants.*

[11] U.S. EPA. 2021. Technical Support Document (TSD) for the Final Revised Cross-State Air Pollution Rule Update for the 2008 Ozone Season NAAQS Estimating PM2.5- and Ozone-Attributable Health Benefits. *https://www.epa.gov/sites/default/files/2021-03/documents/estimating_pm2.5-_and_ozone-attributable_health_benefits_tsd.pdf.*

climate disbenefits) for the final NSPS subpart XXa range from $29 million at a 3 percent discount rate to $14 million at a 7 percent discount rate for short-term effects and $280 million at a 3 percent discount rate to $160 million at a 7 percent discount rate for long-term effects. The EAV of the net benefits for the final NSPS subpart XXa range from $2.4 million at a 3 percent discount rate to $1.7 million at a 7 percent discount rate for short-term effects and $24 million at the 3 percent discount rate to $17 million at a 7 percent discount rate for long-term effects.

4. Cumulative Benefits Across Rules

The PV of the net benefits (monetized health benefits minus monetized climate disbenefits) for all three rules cumulatively range from $210 million at a 3 percent discount rate to $110 million at a 7 percent discount rate for short-term effects and $2,000 million at a 3 percent discount rate to $1,200 million at a 7 percent discount rate for long-term effects. The EAV of the net benefits for all three rules cumulatively range from $17 million at a 3 percent discount rate to $13 million at a 7 percent discount rate for short-term effects and $170 million at the 3 percent discount rate to $130 million at a 7 percent discount rate for long-term effects.

F. What analysis of environmental justice did the EPA conduct?

The EPA defines EJ as ''the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people: (i) Are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and (ii) have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.'' [12] In recognizing that communities with EJ concerns often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,*[13] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance.

1. NESHAP Subpart R

To examine the potential for any EJ issues that might be associated with gasoline distribution major source facilities subject to NESHAP subpart R, we performed a proximity demographic analysis at proposal, which is an assessment of individual demographic groups of the populations living within 5 kilometers (km, ~3.1 miles) and 50 km (~31 miles) of the facilities. The EPA then compared the data from this analysis to the national average for each of the demographic groups. We have determined that the affected facilities did not change as a result of public comments. Therefore, the analysis from the proposed rule is still applicable for this final action.

In summary, the results of the demographic proximity analysis indicate that, for populations within 5 km (~3.1 miles) of the 117 major source gasoline distribution facilities,[14] the percent of the population that is Hispanic or Latino is significantly higher than the national average (33 percent versus 19 percent). Specifically, populations around 12 facilities are more than three times the national average for the percent that is Hispanic/Latino (greater than 56 percent). The percent of the population that is African American (15 percent) and Other and Multiracial (10 percent) are slightly above the national averages (12 percent and 8 percent, respectively). The percent of people living below the poverty level (17 percent) and those over 25 without a high school diploma (18 percent) are higher than the national averages (13 percent and 12 percent, respectively). The percent of people living in linguistic isolation is higher than the national average (9 percent versus 5 percent).

More detailed results of the demographic proximity analysis can be found in section IV.F. of the proposed rule's preamble (see 87 FR 35638; June 10, 2022) and in the technical report, *Analysis of Demographic Factors for Populations Living Near Gasoline Distribution Facilities,* available in Docket ID No. EPA–HQ–OAR–2020–0371.

As noted earlier in this preamble, the EPA determined that the standards should be revised to reflect cost-effective developments in practices, process, or controls. Because we based the analysis of the impacts and emission reductions on model plants, we are not able to ascertain specifically how the potential benefits will be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule. However, we anticipate that the changes to NESHAP subpart R will generally improve human health exposures for populations in surrounding communities. The EPA estimates that NESHAP subpart R will reduce HAP emissions from gasoline distribution facilities by 130 tpy and VOC emissions by 2,200 tpy. The changes will have beneficial effects on air quality and public health for populations exposed to emissions from gasoline distribution facilities that are major sources and will provide additional health protection for most populations, including communities already overburdened by pollution, which are often people of color, low-income, and indigenous communities.

2. NESHAP Subpart BBBBBB

To examine the potential for any EJ issues that might be associated with gasoline distribution area source facilities subject to NESHAP subpart BBBBBB, we performed a proximity demographic analysis at proposal, which is an assessment of individual demographic groups of the populations living within 5 km and 50 km of the facilities. The EPA then compared the data from this analysis to the national average for each of the demographic groups. We have determined that the affected facilities did not change as a result of public comments. Therefore, the analysis from the proposed rule is still applicable for this final action.

In summary, the results of the demographic analysis indicate that, for populations within 5 km of 1,229 area source gasoline distribution facilities,[15] the Hispanic or Latino (26 percent) and African American (18 percent) populations are significantly larger than the national averages (19 percent and 12 percent, respectively). Specifically,

[12] 88 FR 25251 (April 26, 2023); *https://www.federalregister.gov/documents/2023/04/26/2023-08955/revitalizing-our-nations-commitment-to-environmental-justice-for-all.*

[13] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[14] The EPA estimates there are approximately 210 major source gasoline distribution facilities; however, we had location information for only 117 of the facilities.

[15] The EPA estimates there are approximately 9,260 area source gasoline distribution facilities; however, we had location information for only 1,229 of the facilities.

populations around 102 facilities are more than three times the national average for the percent that is Hispanic/Latino (greater than 56 percent) and the populations around 218 facilities are more than three times the national average for the percent that is African American (greater than 36 percent).

The percent of the population that is Other and Multiracial (10 percent) is slightly above the national average (8 percent). The percent of people living below the poverty level (18 percent) and those over 25 without a high school diploma (16 percent) are higher than the national averages (13 percent and 12 percent, respectively). The percent of people living in linguistic isolation was higher than the national average (9 percent versus 5 percent).

More detailed results of the demographic proximity analysis can be found in section IV.F. of the proposed rule's preamble (see 87 FR 35639; June 10, 2022) and in the technical report, *Analysis of Demographic Factors for Populations Living Near Gasoline Distribution Facilities,* available in Docket ID No. EPA–HQ–OAR–2020–0371.

As noted earlier, the EPA determined that the standards should be revised to reflect cost-effective developments in practices, process, or controls. Because we based the analysis of the impacts and emission reductions on model plants, we are not able to ascertain specifically how the potential benefits will be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule. However, we anticipate that the changes to NESHAP subpart BBBBBB will generally improve human health exposures for populations in surrounding communities. The EPA estimates that NESHAP subpart BBBBBB will reduce HAP emissions from gasoline distribution facilities by 2,100 tpy and VOC emissions by 40,300 tpy. The changes will have beneficial effects on air quality and public health for populations exposed to emissions from gasoline distribution facilities that are area sources and will provide additional health protection for most populations, including communities already overburdened by pollution, which are often people of color, low-income, and indigenous communities.

3. NSPS Subpart XXa

As indicated in the proposal, the locations of any new Bulk Gasoline Terminals that will be subject to NSPS subpart XXa are not known. In addition, it is not known which existing Bulk Gasoline Terminals may be modified or reconstructed and subject to NSPS subpart XXa. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule. However, we anticipate that the changes to NSPS subpart XXa will generally minimize future emissions to levels of BSER and human health exposures for populations in surrounding communities of new, modified, or reconstructed facilities, including those communities with higher percentages of people of color, low income, and indigenous communities. Specifically, the EPA determined that the standards should be revised to reflect BSER. The EPA estimates that NSPS subpart XXa will reduce VOC emissions by 3,000 tpy. The changes will have beneficial effects on air quality and public health for populations exposed to emissions from gasoline distribution facilities with new, modified or reconstructed sources and will provide additional health protection for most populations, including communities already overburdened by pollution, which are often people of color, low-income, and indigenous communities.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Gasoline Distribution Technology Review and Standards of Performance for Bulk Gasoline Terminals Review* (Ref. EPA–452/R–24–022), is also available in the docket.[16]

[16] A discussion of the market failure that this rulemaking action addresses can be found in Chapter 1 of the Regulatory Impact Analysis.

B. Paperwork Reduction Act (PRA)

1. NESHAP Subpart R

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 1659.12. You can find a copy of the ICR in the docket, and it is briefly summarized here. The information collections requirements are not enforceable until OMB approves them.

The EPA is finalizing amendments that revise provisions pertaining to emissions during periods of SSM, add requirements for electronic reporting of periodic reports and performance test results, and make other minor clarifications and corrections. This information will be collected to assure compliance with NESHAP subpart R.

Respondents/affected entities: Owners or operators of gasoline distribution facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart R).

Estimated number of respondents: 210 (assumes no new respondents over next 3 years).

Frequency of response: Initially, semiannually, and annually.

Total estimated burden: 16,300 hours (per year) to comply with the promulgated amendments in the NESHAP. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $ 972,013 (per year), including no annualized capital or operation and maintenance costs, to comply with the promulgated amendments in the NESHAP.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

2. NESHAP Subpart BBBBBB

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2237.07. You can find a copy of the ICR in the docket, and it is briefly summarized here. The information collections requirements are not enforceable until OMB approves them.

The EPA is finalizing amendments that revise provisions to add requirements for electronic reporting of periodic reports and performance test results, and make other minor clarifications and corrections. This information will be collected to assure compliance with NESHAP subpart BBBBBB.

Respondents/affected entities: Owners or operators of gasoline distribution facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart BBBBBB).

Estimated number of respondents: 9,263 (assumes no new respondents over the next 3 years).

Frequency of response: Initially, semiannually, and annually.

Total estimated burden: 83,882 hours (per year) to comply with the promulgated amendments in the NESHAP. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $ 5,001,981 (per year), including no annualized capital or operation and maintenance costs, to comply with the promulgated amendments in the NESHAP.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

3. NSPS Subpart XXa

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2720.01. You can find a copy of the ICR in the docket, and it is briefly summarized here. The information collections requirements are not enforceable until OMB approves them.

The EPA is finalizing provisions to require electronic reporting of periodic reports and performance test results. This information will be collected to assure compliance with NSPS subpart XXa.

Respondents/affected entities: Owners or operators of bulk gasoline terminals.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart XXa).

Estimated number of respondents: 12 (assumes four new respondents each year over the next 3 years).

Frequency of response: Initially, semiannually, and annually.

Total estimated burden: 1,132 hours (per year) to comply with all of the requirements in the NSPS. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $ 66,930 (per year), including no annualized capital or operation and maintenance costs, to comply with all of the requirements in the NSPS.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have significant economic impacts on a substantial number of small entities under the RFA. The small entities subject to the requirements of these rules are small businesses that own gasoline distribution facilities. For NESHAP subpart R, the EPA determined that two small entities are affected by the amendments, which is 5 percent of all affected ultimate parent companies. Neither of these small entities is projected to incur costs from this rule greater than 1 percent of their sales. For NESHAP subpart BBBBBB, the EPA determined that 116 small entities are affected by these amendments, which is 42 percent of all affected ultimate parent companies. Less than 9 percent of these small entities (10 total) are projected to incur costs from this rule greater than 1 percent of their annual sales, and less than 3 percent (3 total) are project to incur costs greater than 3 percent of their annual sales (with a maximum economic impact of 6.56 percent) without including expected gasoline product recovery. Finally, for NSPS subpart XXa, the EPA did not identify any small entities that are affected by NSPS subpart XXa and does not project that any entities affected by the NSPS will incur costs greater than 1 percent of their annual sales. Inclusion of expected gasoline product recovery will reduce these small entity impact estimates. Details of the analyses for each rule are presented in the RIA available in the docket.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. While this action creates an enforceable duty on the private sector, the cost does not exceed $100 million or more.

E. Executive Order 13132: Federalism

This action does not have federalism implications. This action will 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.

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

This action does not have Tribal implications, as specified in Executive Order 13175. The EPA estimates there are approximately 210 major source and 9,260 area source gasoline distribution facilities; however, we had location information for only 117 of the major source facilities and 1,229 of the area source facilities. None of the facilities that have been identified as being affected by this action are owned or operated by Tribal governments or located within Tribal lands. Thus, Executive Order 13175 does not apply to this action. However, consistent with the *EPA Policy on Consultation with Indian Tribes,* the EPA offered government-to-government consultation with Tribes by sending a letter dated June 24, 2022, inviting all federally recognized Tribes to request a consultation. No Tribes requested a consultation.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. The final rules lower gasoline vapors and are projected to improve overall health including children.

H. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The EPA expects these rules will not reduce crude oil supply, fuel production, coal production, natural gas production, or electricity production. The EPA estimates these rules will have minimal impact on the amount of imports or exports of crude oils, condensates, or other organic liquids used in the energy supply industries. Given the minimal impacts on energy supply, distribution, and use as a whole nationally, no significant adverse energy effects are expected to occur. For more information on these estimates of energy effects, please refer to Chapter 5 of the RIA available in the docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards. The EPA has decided to use EPA Method 18. While the EPA identified ASTM 6420–18 as being potentially applicable, the Agency decided not to use it. The use of this voluntary consensus standard would be impractical because it has a limited list of analytes and is not suitable for analyzing many compounds that are expected to occur in gasoline vapor.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

For NESHAP subparts R and BBBBBB, the EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. The percent Hispanic or Latino population, African American, and Other and Multiracial are above the national averages for these demographic groups. The percent of people living below the poverty level and those over 25 without a high school diploma, and people living in linguistic isolation are also higher than the national averages. The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with environmental justice concerns. The EPA estimates that these NESHAP final rules will reduce HAP emissions from gasoline distribution facilities by over 2,200 tpy and VOC emissions by 42,500 tpy.

For NSPS subpart XXa, the EPA believes that it is not practicable to assess whether this action is likely to result in new disproportionate and adverse effects on communities with environmental justice concerns, because the location and number of new, modified, or reconstructed sources is unknown. Because NSPS subpart XXa applies to future new facilities, the locations of such Bulk Gasoline Terminals that will be subject to NSPS subpart XXa are not known. In addition, it is not known which existing Bulk Gasoline Terminals may be modified or reconstructed and subject to NSPS subpart XXa. Thus, we are limited in our ability to estimate the potential EJ impacts of this subpart, but we note that future emission increases associated with construction of any new, modified, or reconstructed sources will be minimized to levels of BSER.

The information supporting this Executive order review is contained in section IV.F. of this action, with additional details in section IV.F. of the proposed rules' preamble (87 FR 35637; June 10, 2022), and in the technical report, *Analysis of Demographic Factors for Populations Living Near Gasoline Distribution Facilities,* available in Docket ID No. EPA–HQ–OAR–2020–0371.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Parts 60 and 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60 and 63 of the Code of Federal Regulations are amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart XX—Standards of Performance for Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After December 17, 1980, and On or Before June 10, 2022

■ 2. The heading for subpart XX is revised to read as set forth above.

■ 3. Section 60.500 is amended by revising paragraph (b) to read as follows:

§ 60.500 Applicability and designation of affected facility.

* * * * *

(b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, and on or before June 10, 2022, is subject to the provisions of this subpart.

* * * * *

■ 4. Subpart XXa is added to read as follows:

Subpart XXa—Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction After June 10, 2022

Subpart XXa—Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction After June 10, 2022

§ 60.500a Applicability and designation of affected facility.

(a) You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the affected facilities listed in paragraphs (a)(1) and (2) of this section.

(1) Each gasoline loading rack affected facility, which is the total of all the loading racks at a bulk gasoline terminal that deliver liquid product into gasoline cargo tanks including the gasoline loading racks, the vapor collection systems, and the vapor processing system.

(2) Each collection of equipment at a bulk gasoline terminal affected facility, which is the total of all equipment associated with the loading of gasoline at a bulk gasoline terminal including the lines and pumps transferring gasoline from storage vessels, the gasoline loading racks, the vapor collection

systems, and the vapor processing system.

(b) Each affected facility under paragraph (a) of this section for which construction, modification (as defined in § 60.2 and detailed in § 60.14), or reconstruction (as detailed in § 60.15 and paragraph (e) of this section) is commenced after June 10, 2022, is subject to the provisions of this subpart.

(c) All standards including emission limitations shall apply at all times, including periods of startup, shutdown, and malfunction. As provided in § 60.11(f), this paragraph (c) supersedes the exemptions for periods of startup, shutdown, and malfunction in subpart A of this part.

(d) A newly constructed gasoline loading rack affected facility that was subject to the standards in § 60.502a(b) will continue to be subject to the standards in § 60.502a(b) for newly constructed gasoline loading rack affected facilities if they are subsequently modified or reconstructed.

(e) For purposes of this subpart:

(1) The cost of the following frequently replaced components of the gasoline loading rack affected facility shall not be considered in calculating either the ''fixed capital cost of the new components'' or the ''fixed capital cost that would be required to construct a comparable entirely new facility'' under § 60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(2) Under § 60.15, the ''fixed capital cost of the new components'' includes the fixed capital cost of all depreciable components, except components specified in paragraph (e)(1) of this section which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following June 10, 2022. For purposes of this paragraph (e)(2), ''commenced'' means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.501a Definitions.

The terms used in this subpart are defined in the Clean Air Act, in § 60.2, or in this section as follows:

3-hour rolling average means the arithmetic mean of the previous thirty-six 5-minute periods of valid operating data collected, as specified, for the monitored parameter. Valid data excludes data collected during periods when the monitoring system is out of control, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. The thirty-six 5-minute periods should be consecutive, but not necessarily continuous if operations or the collection of valid data were intermittent.

Bulk gasoline terminal means any gasoline facility which receives gasoline by pipeline, ship, barge, or cargo tank and subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities and has a gasoline throughput greater than 20,000 gallons per day (75,700 liters per day). Gasoline throughput shall be the maximum calculated design throughput for the facility as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

Continuous monitoring system is a comprehensive term that may include, but is not limited to, continuous emission monitoring systems, continuous parameter monitoring systems, or other manual or automatic monitoring that is used for demonstrating compliance on a continuous basis.

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

Flare means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 4.0 pounds per square inch (27.6 kilopascals) or greater which is used as a fuel for internal combustion engines.

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

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

Loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Submerged filling means the filling of a gasoline cargo tank through a submerged fill pipe whose discharge is no more than the 6 inches from the bottom of the tank. Bottom filling of gasoline cargo tanks is included in this definition.

Thermal oxidation system means an enclosed combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures. *Thermal oxidation systems* emit pollutants through a conveyance suitable to conduct a performance test.

Total organic compounds (TOC) means those compounds measured according to the procedures in Method 25, 25A, or 25B of appendix A–7 to this part. The methane content may be excluded from the TOC concentration as described in § 60.503a.

Vapor collection system means any equipment used for containing total organic compounds vapors displaced during the loading of gasoline cargo tanks.

Vapor processing system means all equipment used for recovering or oxidizing total organic compounds vapors displaced from the affected facility.

Vapor recovery system means processing equipment used to absorb and/or condense collected vapors and return the total organic compounds for blending with gasoline or other petroleum products or return to a petroleum refinery or transmix facility for further processing. Vapor recovery systems include but are not limited to carbon adsorption systems or refrigerated condensers.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 60.503a(f).

§ 60.502a Standard for volatile organic compound (VOC) emissions from bulk gasoline terminals.

(a) Each gasoline loading rack affected facility shall be equipped with a vapor collection system designed and operated to collect the total organic compounds vapors displaced from gasoline cargo tanks during product loading.

(b) For each newly constructed gasoline loading rack affected facility, the facility owner or operator must meet the applicable emission limitations in paragraph (b)(1) or (2) of this section no later than the date on which § 60.8(a) requires a performance test to be completed. A flare cannot be used to comply with the emission limitations in this paragraph (b).

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 1.0 milligram of total organic compounds per liter of gasoline loaded (mg/L). Continual compliance with this requirement must be demonstrated as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) and meet the emission limitation in this paragraph (b)(1).

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks. Valid operating data must exclude periods when there is no liquid product being loaded. If previous contents of the cargo tanks are known, you may also exclude periods when liquid product is loaded but no gasoline cargo tanks are being loaded provided that you excluded these periods in the determination of the combustion zone temperature operating limit according to the provisions in § 60.503a(c)(8)(ii).

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 550 parts per million by volume (ppmv) of TOC as propane determined on a 3-hour rolling average when the vapor recovery system is operating;

(ii) Operate the vapor recovery system during all periods when the vapor recovery system is capable of processing gasoline vapors, including periods when liquid product is being loaded, during carbon bed regeneration, and when preparing the beds for reuse; and

(iii) Operate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(c) For each modified or reconstructed gasoline loading rack affected facility, the facility owner or operator must meet the applicable emission limitations in paragraphs (c)(1) through (3) of this section no later than the date on which § 60.8(a) requires a performance test to be completed.

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 10 mg/L. Continual compliance with this requirement must be demonstrated as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) and meet the emission limitation in this paragraph (c)(1).

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks. Valid operating data must exclude periods when there is no liquid product being loaded. If previous contents of the cargo tanks are known, you may also exclude periods when liquid product is loaded but no gasoline cargo tanks are being loaded provided that you excluded these periods in the determination of the combustion zone temperature operating limit according to the provisions in § 60.503a(c)(8)(ii).

(iii) As an alternative to the combustion zone temperature operating limit, you may elect to use the monitoring provisions as specified in paragraph (c)(3) of this section.

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 5,500 ppmv of TOC as propane determined on a 3-hour rolling average when the vapor recovery system is operating;

(ii) Operate the vapor recovery system during all periods when the vapor recovery system is capable of processing gasoline vapors, including periods when liquid product is being loaded, during carbon bed regeneration, and when preparing the beds for reuse; and

(iii) Operate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(3) If a flare is used or if a thermal oxidation system for which these provisions are specified as a monitoring alternative is used, meet all applicable requirements specified in § 63.670(b) through (g) and (i) through (n) of this chapter except as provided in paragraphs (c)(3)(i) through (ix) of this section.

(i) For the purpose of this subpart, ''regulated materials'' refers to ''vapors displaced from gasoline cargo tanks during product loading''. If you do not know the previous contents of the cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(ii) In § 63.670(c) of this chapter for visible emissions:

(A) The phrase ''specify the smokeless design capacity of each flare and'' does not apply.

(B) The phrase ''and the flare vent gas flow rate is less than the smokeless design capacity of the flare'' does not apply.

(C) Substitute ''The owner or operator shall monitor for visible emissions from the flare as specified in § 60.504a(c)(4).'' for the sentence ''The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.''

(iii) The phrase ''and the flare vent gas flow rate is less than the smokeless design capacity of the flare'' in § 63.670(d) of this chapter for flare tip velocity requirements does not apply.

(iv) Substitute ''pilot flame or flare flame'' for each occurrence of ''pilot flame.''

(v) Substitute ''gasoline distribution facility'' for each occurrence of ''petroleum refinery'' or ''refinery.''

(vi) As an alternative to the flow rate monitoring alternatives provided in § 63.670(i) of this chapter, you may elect to determine flare waste gas flow rate by monitoring the cumulative loading rates of all liquid products loaded into cargo tanks for which the displaced vapors are managed by the affected facility's vapor collection system and vapor processing system.

(vii) If using provision in § 63.670(j)(6) of this chapter for flare vent gas composition monitoring, you must comply with those provisions as specified in paragraphs (c)(3)(vii)(A) through (G) of this section.

(A) You must submit a separate written application to the Administrator for an exemption from monitoring, as described in § 63.670(j)(6)(i) of this chapter.

(B) You must determine the minimum ratio of gasoline loaded to total liquid product loaded for which the affected source must operate at or above at all times when liquid product is loaded into cargo tanks for which vapors collected are sent to the flare or, if applicable, thermal oxidation system and include that in the explanation of conditions expected to produce the flare gas with lowest net heating value as required in § 63.670(j)(6)(i)(C) of this chapter. For air assisted flares or thermal oxidation systems, you must also establish a minimum gasoline loading rate (*i.e.,* volume of gasoline loaded in a 15-minute period) for which the affected source must operate at or above at all times and include that in the explanation of conditions that ensure the flare gas net heating value is consistent and representative of the lowest net heating value as required in § 63.670(j)(6)(i)(C).

(C) As required in § 63.670(j)(6)(i)(D) of this chapter, samples must be collected at the conditions identified in § 63.670(j)(6)(i)(C) of this chapter, which includes the applicable conditions specified in paragraph (c)(3)(vii)(B) of this section.

(D) The first change from winter gasoline to summer gasoline or from summer gasoline to winter gasoline, whichever comes first, is considered a change in operating conditions under § 63.670(j)(6)(iii) of this chapter and must be evaluated according to the provisions in § 63.670(j)(6)(iii). If separate net heating values are determined for summer gasoline loading versus winter gasoline loading, you may use the summer net heating value for all subsequent summer gasoline loading operations and the winter net heating value for all subsequent winter gasoline loading operations provided there are no other changes in operations.

(E) You must monitor the volume of gasoline loaded and the total volume of liquid product loaded on a 5-minute block basis and maintain the ratio of gasoline loaded to total liquid product loaded at or above the value determined in paragraph (c)(3)(vii)(B) of this section and, for air assisted flares or thermal oxidation systems, maintain the gasoline loading rate at or above the value determined in paragraph (c)(3)(vii)(B) on a rolling 15-minute period basis, calculated based on liquid product loaded during 3 contiguous 5-minute blocks, considering only those periods when liquid product is loaded into gasoline cargo tanks for any portion of three contiguous 5-minute block periods.

(F) For unassisted or perimeter air assisted flares or thermal oxidation systems, if the net heating value determined in § 63.670(j)(6)(i)(F) of this chapter meets or exceeds 270 British thermal units per standard cubic feet (Btu/scf), compliance with the ratio of gasoline loaded to total liquid product loaded as specified in paragraph (c)(3)(vii)(E) of this section demonstrates compliance with the flare combustion zone net heating value (NHV_{cz}) operating limit in § 63.670(e) of this chapter.

(G) For perimeter air assisted flares or thermal oxidation systems, if the net heating value determined in § 63.670(j)(6)(i)(F) of this chapter meets or exceeds the net heating value dilution parameter (NHV_{dil}) operating limit of 22 British thermal units per square foot (Btu/ft^2) at the flow rate associated with the minimum gasoline loading rate determined in paragraph (c)(3)(vii)(B) of this section at any air assist rate used, compliance with the minimum gasoline loading rate as specified in paragraph (c)(3)(vii)(E) of this section demonstrates compliance with the NHV_{dil} operating limit in § 63.670(f) of this chapter.

(viii) You may elect to establish a minimum supplemental gas addition rate and monitor the supplemental gas addition rate, in addition to the operating limits in paragraph (c)(3)(vii)(E) of this section, to demonstrate compliance with the flare combustion zone operating limit in § 63.670(e) of this chapter and, if applicable, flare dilution operating limit in § 63.670(f) of this chapter, as follows.

(A) Use the minimum flare vent gas net heating value prior to addition of supplemental gas as established in paragraph (c)(3)(vii) of this section.

(B) Determine the maximum flow rate based on the maximum cumulative loading rate for a 15-minute block period considering all loading racks at the affected facility and considering restrictions on maximum loading rates necessary for compliance with the maximum pressure limits for the vapor collection and liquid loading equipment specified in paragraph (h) of this section.

(C) Determine the supplemental gas addition rate needed to yield NHV_{cz} of 270 Btu/scf using equation in § 63.670(m)(1) of this chapter.

(D) For flares (or thermal oxidation systems) with perimeter assist air, determine the supplemental gas addition rate needed to yield NHV_{dil} of 22 Btu/ft^2 using equation in § 63.670(n)(1) of this chapter at the flare vent gas net heating value determined in paragraph (c)(3)(vii) of this section, the flare gas flow rate associated with the minimum gasoline loading rate as determined in paragraph (c)(3)(vii)(B) of this section, and the fixed air assist rate. If the air assist rate is varied based on total liquid product loading rates, you must use the air assist rate used at low flow rates and repeat the calculation using the minimum flow rate associated with each air assist rate setting and select the maximum supplemental gas addition rate across any of the air assist rate settings.

(E) Maintain the supplemental gas addition rate above the greater of the values determined in paragraphs (c)(3)(viii)(C) and, if applicable, (c)(3)(viii)(D) of this section on a 15-minute block period basis when liquid product is loaded into gasoline cargo tanks for at least 15-minutes.

(ix) As an alternative to determining the flare tip velocity rate for each 15-minute block to determine compliance with the flare tip velocity operating limit as specified in § 63.670(k)(2) of this chapter, you may elect to conduct a one-time flare tip velocity operating limit compliance assessment as provided in paragraphs (c)(3)(ix)(A) through (D) of this section. If the flare or loading rack configurations change (*e.g.,* flare tip modified or additional loading racks are added for which vapors are directed to the flare), you must repeat this one-time assessment based on the new configuration.

(A) Determine the unobstructed cross-sectional area of the flare tip, in units of square feet, as specified in § 63.670(k)(1) of this chapter.

(B) Determine the maximum flow rate, in units of cubic feet per second, based on the maximum cumulative loading rate for a 15-minute block period considering all loading racks at the gasoline loading racks affected facility and considering restrictions on maximum loading rates necessary for compliance with the maximum pressure limits for the vapor collection and liquid loading equipment specified in paragraph (h) of this section.

(C) Calculate the maximum flare tip velocity as the maximum flow rate from paragraph (c)(3)(ix)(B) of this section divided by the unobstructed cross-sectional area of the flare tip from paragraph (c)(3)(ix)(A) of this section.

(D) Demonstrate that the maximum flare tip velocity as calculated in paragraph (c)(3)(ix)(C) of this section is less than 60 feet per second.

(d) Each vapor collection system for the gasoline loading rack affected facility shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall be limited to vapor-tight gasoline cargo tanks according to the methods in § 60.503a(f) using the following procedures:

(1) The owner or operator shall obtain the vapor tightness annual certification test documentation described in § 60.505a(a)(3) for each gasoline cargo

tank which is to be loaded at the affected facility. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(2) The owner or operator shall obtain and record the cargo tank identification number of each gasoline cargo tank which is to be loaded at the affected facility.

(3) The owner or operator shall cross-check each cargo tank identification number obtained in paragraph (e)(2) of this section with the file of gasoline cargo tank vapor tightness documentation specified in paragraph (e)(1) of this section prior to loading any liquid product into the gasoline cargo tank.

(f) Loading of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall be conducted using submerged filling, as defined in § 60.501a, and only into gasoline cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(g) Loading of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall only be conducted when the terminal's and the cargo tank's vapor collection systems are connected. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(h) The vapor collection and liquid loading equipment for a gasoline loading rack affected facility shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 18 inches of water (460 millimeters (mm) of water) during product loading. This level is not to be exceeded and must be continuously monitored according to the procedures specified in § 60.504a(d).

(i) No pressure-vacuum vent in the gasoline loading rack affected facility's vapor collection system shall begin to open at a system pressure less than 18 inches of water (460 mm of water) or at a vacuum of less than 6.0 inches of water (150 mm of water).

(j) Each owner or operator of a collection of equipment at a bulk gasoline terminal affected facility shall perform leak inspection and repair of all equipment in gasoline service, which includes all equipment in the vapor collection system, the vapor processing system, and each loading rack and loading arm handling gasoline, according to the requirements in paragraphs (j)(1) through (8) of this section. The owner or operator must keep a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(1) Conduct leak detection monitoring of all pumps, valves, and connectors in gasoline service using either of the methods specified in paragraph (j)(1)(i) or (ii) of this section.

(i) Use optical gas imaging (OGI) to quarterly monitor all pumps, valves, and connectors in gasoline service as specified in § 60.503a(e)(2).

(ii) Use Method 21 of appendix A–7 to this part as specified in § 60.503a(e)(1) and paragraphs (j)(1)(ii)(A) through (C) of this section.

(A) All pumps must be monitored quarterly, unless the pump meets one of the requirements in § 60.482–1a(d) or § 60.482–2a(d) through (g). An instrument reading of 10,000 ppm or greater is a leak.

(B) All valves must be monitored quarterly, unless the valve meets one of the requirements in § 60.482–1a(d) or § 60.482–7a(f) through (h). An instrument reading of 10,000 ppm or greater is a leak.

(C) All connectors must be monitored annually, unless the connector meets one of the requirements in § 60.482–1a(d) or § 60.482–11a(e) or (f). An instrument reading of 10,000 ppm or greater is a leak.

(2) During normal duties, record leaks identified by audio, visual, or olfactory methods.

(3) If evidence of a potential leak is found at any time by audio, visual, olfactory, or any other detection method for any equipment (as defined in § 60.501a), a leak is detected.

(4) For pressure relief devices, comply with the requirements in paragraphs (j)(4)(i) through (ii) of this section.

(i) Conduct instrument monitoring of each pressure relief device quarterly and within 5 calendar days after each pressure release to detect leaks by the methods specified in paragraph (j)(1) of this section, except as provided in § 60.482–4a(c).

(ii) If emissions are observed when using OGI, a leak is detected. If Method 21 is used, an instrument reading of 10,000 ppm or greater indicates a leak is detected.

(5) For sampling connection systems, comply with the requirements in § 60.482–5a.

(6) For open-ended valves or lines, comply with the requirements in § 60.482–6a.

(7) When a leak is detected for any equipment, comply with the requirements of paragraphs (j)(7)(i) through (iii) of this section.

(i) A weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on equipment may be removed after it has been repaired.

(ii) An initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. An initial attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

(iii) Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (j)(8) of this section.

(A) For leaks identified pursuant to instrument monitoring required under paragraph (j)(1) of this section, the leak is repaired when instrument re-monitoring of the equipment does not detect a leak.

(B) For leaks identified pursuant to paragraph (j)(2) of this section, the leak is repaired when the leak can no longer be identified using audio, visual, or olfactory methods.

(8) Delay of repair of leaking equipment will be allowed according to the provisions in paragraphs (j)(8)(i) though (iv) of this section. The owner or operator shall provide in the semiannual report specified in § 60.505a(c), the reason(s) why the repair was delayed and the date each repair was completed.

(i) Delay of repair of equipment will be allowed for equipment that is isolated from the affected facility and that does not remain in gasoline service.

(ii) Delay of repair for valves and connectors will be allowed if:

(A) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482–10a or the requirements in paragraph (b) or (c) of this section, as applicable.

(iii) Delay of repair will be allowed for a valve, but not later than 3 months after the leak was detected, if valve assembly replacement is necessary, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.

(iv) Delay of repair for pumps will be allowed if:

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(k) You must not allow gasoline to be handled at a bulk gasoline terminal that contains an affected facility listed under § 60.500a(a) in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; and

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

§ 60.503a Test methods and procedures.

(a) *General performance test and performance evaluation requirements.* (1) In conducting the performance tests or evaluations required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods and procedures as specified in this section, except as provided in § 60.8(b). The three-run requirement of § 60.8(f) does not apply to this subpart.

(2) Immediately before the performance test, conduct leak detection monitoring following the methods in paragraph (e)(1) of this section to identify leakage of vapor from all equipment, including loading arms, in the gasoline loading rack affected facility while gasoline is being loaded into a gasoline cargo tank to ensure the terminal's vapor collection system equipment is operated with no detectable emissions. The owner or operator shall repair all leaks identified with readings of 500 ppmv (as methane) or greater above background before conducting the performance test and within the timeframe specified in § 60.502a(j)(7).

(b) *Performance test or performance evaluation timing.* (1) For each gasoline loading rack affected facility subject to the mass emission limits in § 60.502a(b)(1) or (c)(1), conduct the initial performance test of the vapor collection and processing systems according to the timing specified in § 60.8(a). For each gasoline loading rack affected facility subject to the emission limits in § 60.502a(b)(2) or (c)(2), conduct the initial performance evaluation of the continuous emissions monitoring system (CEMS) according to the timing specified for performance tests in § 60.8(a).

(2) For each gasoline loading rack affected facility complying with the mass emission limits in § 60.502a(b)(1) or (c)(1), conduct subsequent performance test of the vapor collection and processing system no later than 60 calendar months after the previous performance test.

(3) For each gasoline loading rack affected facility complying with the concentration emission limits in § 60.502a(b)(2) or (c)(2), conduct subsequent performance evaluations of CEMS for the vapor collection and processing system no later than 12 calendar months after the previous performance evaluation.

(c) *Performance test requirements for mass loading emission limit.* The owner or operator of a gasoline loading rack affected facility shall conduct performance tests of the vapor collection and processing system subject to the emission limits in § 60.502a(b)(1) or (c)(1), as specified in paragraphs (c)(1) through (8) of this section.

(1) The performance test shall be 6 hours long during which at least 80,000 gallons (300,000 liters) of gasoline is loaded. If this is not possible, the test may be continued the same day until 80,000 gallons (300,000 liters) of gasoline is loaded. If 80,000 gallons (300,000 liters) cannot be loaded during the first day of testing, the test may be resumed the next day with another 6-hour period. During the second day of testing, the 80,000-gallon (300,000-liter) criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput of gasoline normally occurs.

(2) If the vapor processing system is intermittent in operation and employs an intermediate vapor holder to accumulate total organic compounds vapors collected from gasoline cargo tanks, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.

(3) The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K \sum_{i=1}^{n} \left(V_{esi} C_{ei} \right) / \left(L 10^{6} \right)$$

Equation 1 to paragraph (c)(3)

Where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{esi} = volume of air-vapor mixture exhausted at each interval "i", scm.

C_{ei} = concentration of total organic compounds at each interval "i", ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10^{6} for propane, mg/scm.

(4) The performance test shall be conducted in intervals of 5 minutes. For each interval "i", readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be accounted for when determining the average total organic compounds concentration corresponding to the volume exhausted.

(5) Method 2B of appendix A–1 to this part shall be used to determine the volume (V_{esi}) of air-vapor mixture exhausted at each interval.

(6) Method 25, 25A, or 25B of appendix A–7 to this part shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. Method 25 must not be used if the outlet TOC concentration is less than 50 ppmv. The calibration gas shall be propane. If the owner or operator conducts the performance test using either Method 25A or Method 25B, the methane content in the exhaust vent may be excluded following the procedures in paragraphs (c)(6)(i) through (v) of this section. Alternatively, an instrument that uses gas chromatography with a flame ionization detector may be used according to the procedures in paragraph (c)(6)(vi) of this section.

(i) Measure the methane concentration by Method 18 of appendix A–6 to this part or Method 320 of appendix A to part 63 of this chapter.

(ii) Calibrate the Method 25A or Method 25B analyzer using both propane and methane to develop response factors to both compounds.

(iii) Determine the TOC concentration with the Method 25A or Method 25B analyzer on an as methane basis.

(iv) Subtract the methane measured according to paragraph (c)(6)(i) of this section from the concentration determined in paragraph (c)(6)(iii) of this section.

(v) Convert the concentration difference determined in paragraph (c)(6)(iv) of this section to TOC (minus methane), as propane, by using the response factors determined in paragraph (c)(6)(ii) of this section. Multiply the concentration difference in paragraph (c)(6)(iv) of this section by the ratio of the response factor for propane to the response factor for methane.

(vi) Methane must be separated by the gas chromatograph and measured by the flame ionization detector, followed by a back-flush of the chromatographic column to directly measure TOC concentration minus methane. Use a direct interface and heated sampling line from the sampling point to the gas chromatographic injection valve. All sampling components leading to the analyzer must be heated to greater than 110 °C. Calibrate the instrument with propane. Calibration error and calibration drift must be demonstrated according to Method 25A, and the appropriate procedures in Method 25A must be followed to ensure the calibration error and calibration drift are within Method 25A limits. The TOC concentration minus methane must be recorded at least once every 15 minutes. The performance test report must include the calibration results and the results demonstrating proper separation of methane from the TOC concentration.

(7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

(8) Monitor the temperature in the combustion zone using the continuous parameter monitoring system (CPMS) required in § 60.504a(a) and determine the operating limit for the combustion device using the following procedures:

(i) Record the temperature or average temperature for each 5-minute period during the performance test.

(ii) Using only the 5-minute periods in which liquid product is loaded into gasoline cargo tanks, determine the 1-hour average temperature for each hour of the performance test. If you do not know the previous contents of the cargo tank, you must assume liquid product loading is performed in gasoline cargo tanks such that you use all 5-minute periods in which liquid product is loaded into gasoline cargo tanks when determining the 1-hour average temperature for each hour of the performance test.

(iii) Starting at the end of the third hour of the performance test and at the end of each successive hour, calculate the 3-hour rolling average temperature using the 1-hour average values in paragraph (c)(8)(ii) of this section. For a 6-hour test, this would result in four 3-hour averages (averages for hours 1 through 3, 2 through 4, 3 through 5, and 4 through 6).

(iv) Set the operating limit at the lowest 3-hour average temperature determined in paragraph (c)(8)(iii) of this section. New operating limits become effective on the date that the performance test report is submitted to the U.S. Environmental Protection Agency (EPA) Compliance and Emissions Data Reporting Interface (CEDRI), per the requirements of § 60.505a(b).

(d) *Performance evaluation requirements for concentration emission limit.* The owner or operator shall conduct performance evaluations of the CEMS for vapor collection and processing systems subject to the emission limits in § 60.502a(b)(2) or (c)(2) as specified in paragraph (d)(1) or (2) of this section, as applicable.

(1) If the CEMS uses a nondispersive infrared analyzer, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8 of appendix B to this part. Method 25B in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. The owner or operator may request an alternative test method under § 60.8(b) to use a CEMS that excludes the methane content in the exhaust vent.

(2) If the CEMS uses a flame ionization detector, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8A of appendix B to this part. As part of the performance evaluation, conduct a relative accuracy test audit (RATA) following the procedures in Performance Specification 2, section 8.4, of appendix B to this part; the relative accuracy must meet the criteria of Performance Specification 8, section 13.2, of appendix B to this part. Method 25A in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. The owner or operator may exclude the methane content in the exhaust following the procedures in paragraphs (d)(2)(i) through (iv) of this section.

(i) Methane must be separated using a chromatographic column and measured by the flame ionization detector, followed by a back-flush of the chromatographic column to directly measure TOC concentration minus methane.

(ii) The CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8A of appendix B to this part, except the target compound is TOC minus methane. As part of the performance evaluation, conduct a RATA following the procedures in Performance Specification 2, section 8.4, of appendix B to this part; the relative accuracy must meet the criteria of Performance Specification 8, section 13.2, of appendix B to this part.

(iii) If the concentration of TOC minus methane in the exhaust stream is greater than 50 ppmv, Method 25 in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. If the concentration of TOC minus methane in the exhaust stream is 50 ppmv or less, Method 25A in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. If Method 25A is the reference method, the procedures in paragraph (c)(6) of this section may be used to subtract methane from the TOC concentration.

(iv) The TOC concentration minus methane must be recorded at least once every 15 minutes.

(e) *Leak detection monitoring.* Conduct the leak detection monitoring specified in § 60.502a(j)(1) for the collection of equipment at a bulk gasoline terminal affected facility using one of the procedures specified in paragraph (e)(1) or (2) of this section. Conduct the leak detection monitoring specified in paragraph (a)(2) of this section using the procedures specified in paragraph (e)(1) of this section, except that the instrument reading that defines a leak is specified in paragraph (a)(2) for all equipment, including loading arms, in the gasoline loading rack affected facility and the calibration gas in paragraph (e)(1)(ii) must be at a concentration of 500 ppm methane.

(1) Method 21 in appendix A–7 to this part. The instrument reading that defines a leak is 10,000 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7. The calibration

gases in paragraphs (e)(1)(i) and (ii) of this section must be used. The drift assessment specified in paragraph (e)(1)(iii) of this section must be performed at the end of each monitoring day.

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) Methane and air at a concentration of 10,000 ppm methane.

(iii) At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 to this part, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(2) OGI according to all the requirements in appendix K to this part. A leak is defined as any emissions plume imaged by the camera from equipment regulated by this subpart.

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

(1) Method 27 of appendix A–8 to this part. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm water (H_2O) (18 in. H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in table 1 to this paragraph (f)(1).

TABLE 1 TO PARAGRAPH (f)(1)—ALLOWABLE GASOLINE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Gasoline cargo tank or compartment capacity, gallons (liters)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)
2,500 or more (9,464 or more)	12.7 (0.50)
1,500 to 2,499 (5,678 to 9,463)	19.1 (0.75)
1,000 to 1,499 (3,785 to 5,677)	25.4 (1.00)
999 or less (3,784 or less)	31.8 (1.25)

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

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

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 65 mm H_2O (2.5 in. H_2O).

(3) As an alternative to paragraph (f)(1) of this section, you may use the procedure in § 63.425(i) of this chapter.

§ 60.504a Monitoring requirements.

(a) *Monitoring requirements for thermal oxidation systems complying with the combustion zone temperature operating limit.* Install, operate, and maintain a CPMS for measuring the combustion zone temperature as specified in paragraphs (a)(1) through (5) of this section.

(1) Install the temperature CPMS in the combustion (flame) zone or in the exhaust gas stream as close as practical to the combustion burners in a position that provides a representative temperature of the combustion zone of the thermal oxidation system.

(2) The temperature CPMS must be capable of measuring temperature with an accuracy of ±1 percent over the normal range of temperatures measured.

(3) The temperature CPMS must be capable of recording the temperature at least once every 5 minutes and calculating hourly block averages that include only those 5-minute periods in which liquid product was loaded into gasoline cargo tanks.

(4) At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor.

(5) Conduct calibration checks at least annually and conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor.

(b) *Monitoring requirements for vapor recovery systems.* Install, calibrate, operate, and maintain a CEMS for measuring the concentration of TOC in the atmospheric vent from the vapor recovery system as specified in paragraphs (b)(1) and (2) of this section. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the vapor recovery system.

(1) The requirements of Performance Specification 8 of appendix B to this part, or, if the CEMS uses a flame ionization detector, Performance Specification 8A of appendix B to this part, the quality assurance requirements in Procedure 1 of appendix F to this part, and the procedures under § 60.13 must be followed for installation, evaluation, and operation of the CEMS. For CEMS certified using Performance Specification 8A of appendix B, conduct the RATA required under Procedure 1 according to the requirements in § 60.503a(d). As required by § 60.503a(b)(3), conduct annual performance evaluations of each TOC CEMS according to the requirements in § 60.503a(d). Conduct accuracy determinations quarterly and calibration drift tests daily in accordance with Procedure 1 in appendix F.

(2) The span value of the TOC CEMS must be approximately 2 times the applicable emission limit.

(c) *Monitoring requirements for flares and thermal oxidation systems for which flare monitoring alternative is provided.* Install, operate, and maintain CPMS for flares used to comply with the emission limitations in § 60.502a(c)(3), including monitors used for gasoline and total liquid product loading rates, following the requirements specified in § 63.671 of this chapter as specified in paragraphs (c)(1) through (3) of this section and conduct visible emission observations as specified in paragraph (c)(4) of this section.

(1) Substitute "pilot flame or flare flame" for each occurrence of "pilot flame."

(2) You may elect to determine compositional analysis for net heating value with a continuous process mass spectrometer without the use of a gas

chromatograph. If you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) You must meet the requirements in § 63.671(e)(2) of this chapter. You may augment the minimum list of calibration gas components found in § 63.671(e)(2) with compounds found during a pre-survey or known to be in the gas through process knowledge.

(ii) Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(iii) For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component's net heating value of flare vent gas (NHV_{vg}).

(iv) You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(v) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(vi) You must meet applicable requirements in Performance Specification 9 of appendix B to this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in section 10.1 of Performance Specification 9 and performing the periodic calibration requirements listed for gas chromatographs in table 13 to part 63, subpart CC, of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to part 63, subpart CC.

(vii) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Equation 1 to paragraph (c)(2)(vii)

Where:

C_m = Average instrument response (ppm).
C_a = Certified cylinder gas value (ppm).

(3) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you may choose to use the CE of net heating value (NHV) measured versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE. The CE for NHV at any calibration level must not differ by more than 10 percent from the certified cylinder gas value. The CE for NHV must be calculated using the following equation:

$$CE = \frac{NHV_{measured} - NHV_a}{NHV_a} \times 100$$

Equation 2 to paragraph (c)(3)

Where:

$NHV_{measured}$ = Average instrument response (Btu/scf)
NHV_a = Certified cylinder gas value (Btu/scf).

(4) If visible emissions are observed for more than one continuous minute during normal duties, visible emissions observation using Method 22 of appendix A–7 to this part must be conducted for 2 hours or until 5-minutes of visible emissions are observed.

(d) *Pressure CPMS requirements.* The owner or operator shall install, operate, and maintain a CPMS to measure the pressure of the vapor collection system to determine compliance with the standard in § 60.502a(h) as specified in paragraphs (d)(1) through (4) of this section.

(1) Install a pressure CPMS (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline cargo tank. If necessary to obtain representative loading pressures, install pressure CPMS for each loading rack.

(2) Check the calibration of the pressure CPMS at least annually. Check the calibration of the pressure CPMS following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor.

(3) At least quarterly, visually inspect components of the pressure CPMS for integrity, oxidation and galvanic corrosion, unless the system has a redundant pressure sensor.

(4) The output of the pressure CPMS must be reviewed each operating day to ensure that the pressure readings fluctuate as expected during loading of gasoline cargo tanks to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired within 24 hours or prior to the next gasoline cargo tank loading, whichever time period is longer.

(e) *Limited alternative requirements for vapor recovery systems.* If the CEMS used for measuring the concentration of TOC in the atmospheric vent from the vapor recovery system as specified in paragraph (b) of this section requires maintenance such that it is off-line for more than 15 minutes, you may follow the requirements in paragraphs (e)(1) and (2) of this section and monitor product loading quantities and regeneration cycle parameters as an alternative to the monitoring requirement in paragraph (b) for no more than 240 hours in a calendar year.

(1) Determine the quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS going off-line and select the smallest of these values as your

product loading quantity operating limit.

(2) Determine the vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS going off-line. You must operate vapor recovery system desorption cycles as specified in paragraphs (e)(2)(i) through (iii) of this section.

(i) The vacuum pressure for each desorption cycle must be at or above the average vacuum pressure from the past 10 desorption cycles. Note: a higher vacuum means a lower absolute pressure.

(ii) Purge gas quantity used for each desorption cycle must be at or above the average quantity of purge gas used from the past 10 desorption cycles.

(iii) Duration of the vacuum/purge cycle for each desorption cycle must be at or above the average duration of the vacuum/purge cycle used from the past 10 desorption cycles.

§ 60.505a Recordkeeping and reporting.

(a) *Recordkeeping requirements.* For each affected facility listed under § 60.500a(a), keep records as specified in paragraphs (a)(1) through (9) of this section, as applicable, for a minimum of five years unless otherwise specified in this section. These recordkeeping requirements supersede the requirements in § 60.7(b).

(1) For each thermal oxidation system used to comply with the emission limitations in § 60.502a(b)(1) or (c)(1) by monitoring the combustion zone temperature as specified in § 60.502a(b)(1)(ii) or (c)(1)(ii), for each pressure CPMS used to comply with the requirements in § 60.502a(h), and for each vapor recovery system used to comply with the emission limitations in § 60.502a(b)(2) or (c)(2), maintain records, as applicable, of:

(i) The applicable operating or emission limit for the continuous monitoring system (CMS). For combustion zone temperature operating limits, include the applicable date range the limit applies based on when the performance test was conducted.

(ii) Each 3-hour rolling average combustion zone temperature measured by the temperature CPMS, each 5-minute average reading from the pressure CPMS, and each 3-hour rolling average TOC concentration (as propane) measured by the TOC CEMS.

(iii) For each deviation of the 3-hour rolling average combustion zone temperature operating limit, maximum loading pressure specified in § 60.502a(h), or 3-hour rolling average TOC concentration (as propane), the start date and time, duration, cause, and the corrective action taken.

(iv) For each period when there was a CMS outage or the CMS was out of control, the start date and time, duration, cause, and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(v) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check. For TOC CEMS, include the type of CEMS used (*i.e.,* flame ionization detector, nondispersive infrared analyzer) and an indication of whether methane is excluded from the TOC concentration reported in paragraph (a)(1)(ii) of this section.

(vi) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) is used, also keep records of:

(A) The quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS outage.

(B) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS outage.

(C) The quantity of liquid product loaded in gasoline cargo tanks for each adsorption cycle while using the alternative.

(D) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles for each desorption cycle while using the alternative.

(2) For each flare used to comply with the emission limitations in § 60.502a(c)(3) and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii), maintain records of:

(i) The output of the monitoring device used to detect the presence of a pilot flame as required in § 63.670(b) of this chapter for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame was present when gasoline vapors were routed to the flare for a minimum of 5 years. The record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in paragraphs (a)(2)(ii)(A) and (B) of this section, as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 of appendix A–7 to this part, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of appendix A–7 to this part were not conducted for the full 2-hour period, the record must include the date, the start and end time of the visible emissions observation, and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) Each 15-minute block period during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) of this chapter when liquid product is being loaded into gasoline cargo tanks for at least 15-minutes identifying the specific operating limit that was not met.

(iv) The 15-minute block average cumulative flows for flare vent gas or the thermal oxidation system vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under § 63.670(i) of this chapter, along with the date and start and end time for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas, thermal oxidation system vent gas, or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii), the required minimum supplemental gas flow rate (winter and summer, if applicable) and the actual monitored supplemental gas flow rate for the 15-

minute block. Retain the supplemental gas flow rate records for a minimum of 5 years.

(v) The flare vent gas compositions or thermal oxidation system vent gas specified to be monitored under § 63.670(j) of this chapter. Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If an NHV_{vg} analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years. If you demonstrate your gas streams have consistent composition using the provisions in § 63.670(j)(6) of this chapter as specified in § 60.502a(c)(3)(vii), retain records of the required minimum ratio of gasoline loaded to total liquid product loaded and the actual ratio on a 5-minute block basis. If applicable, you must retain records of the required minimum gasoline loading rate as specified in § 60.502a(c)(3)(vii) and the actual gasoline loading rate on a 5-minute block basis for a minimum of 5 years.

(vi) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n) of this chapter, as applicable.

(vii) All periods during which the owner or operator does not perform monitoring according to the procedures in § 63.670(g), (i), and (j) of this chapter or in § 60.502a(c)(3)(vii) and (viii) as applicable. Note the start date, start time, and duration in minutes for each period.

(viii) An indication of whether ''vapors displaced from gasoline cargo tanks during product loading'' excludes periods when liquid product is loaded but no gasoline cargo tanks are being loaded or if liquid product loading is assumed to be loaded into gasoline cargo tanks according to the provisions in § 60.502a(c)(3)(i), records of all time periods when ''vapors displaced from gasoline cargo tanks during product loading'', and records of time periods when there were no ''vapors displaced from gasoline cargo tanks during product loading''.

(ix) If you comply with the flare tip velocity operating limit using the one-time flare tip velocity operating limit compliance assessment as provided in § 60.502a(c)(3)(ix), maintain records of the applicable one-time flare tip velocity operating limit compliance assessment for as long as you use this compliance method.

(x) For each parameter monitored using a CMS, retain the records specified in paragraphs (a)(2)(x)(A) through (C) of this section, as applicable:

(A) For each deviation, record the start date and time, duration, cause, and corrective action taken.

(B) For each period when there is a CMS outage or the CMS is out of control, record the start date and time, duration, cause, and corrective action taken.

(C) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check.

(3) The gasoline cargo tank vapor tightness documentation required under § 60.502a(e)(1) for each gasoline cargo tank loading at the affected facility shall be kept on file at the terminal in either a hardcopy or electronic form available for inspection. The documentation shall include, at a minimum, the following information:

(i) Test title: Annual Certification Test—EPA Method 27 or Railcar Bubble Leak Test Procedure.

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

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

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

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

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

(4) Records of each instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502a(e)(1) was not provided or available in the terminal's records. These records shall include, at a minimum:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) Records of each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 60.501a, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system. These records shall include, at a minimum:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(ii) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(6) A record [list, summary description, or diagram(s) showing the location] of all equipment in gasoline service at the collection of equipment at a bulk gasoline terminal affected facility and at the loading rack affected facility. A record of each leak inspection and leak identified under §§ 60.503a(a)(2) and 60.502a(j) as specified in paragraphs (a)(6)(i) through (iv) of this section:

(i) For each leak inspection, keep the following records:

(A) An indication if the leak inspection was conducted under § 60.502a(j) or § 60.503a(a)(2).

(B) Leak determination method used for the leak inspection.

(ii) For leak inspections conducted with Method 21 of appendix A–7 to this part, keep the following additional records:

(A) Date of inspection.

(B) Inspector name.

(C) Monitoring instrument identification.

(D) Identification of all equipment surveyed and the instrument reading for each piece of equipment.

(E) Date and time of instrument calibration and initials of operator performing the calibration.

(F) Calibration gas cylinder identification, certification date, and certified concentration.

(G) Instrument scale used.

(H) Results of the daily calibration drift assessment.

(iii) For leak inspections conducted with OGI, keep the records specified in section 12 of appendix K to this part.

(iv) For each leak detected during a leak inspection or by audio/visual/olfactory methods during normal duties, record the following information:

(A) The equipment type and identification number.

(B) The date the leak was detected, the name of the person who found the leak, the nature of the leak (*i.e.,* vapor or liquid), and the method of detection (*i.e.,* audio/visual/olfactory, Method 21 of appendix A–7 to this part, or OGI).

(C) The dates of each attempt to repair the leak and the repair methods applied in each attempt to repair the leak.

(D) The date of successful repair of the leak, the method of monitoring used to confirm the repair, and if Method 21 of appendix A–7 to this part is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A–7. If OGI is used to confirm the repair, keep video footage of the repair confirmation.

(E) For each repair delayed beyond 15 calendar days after discovery of the leak, record ''Repair delayed'', the reason for the delay, and the expected date of successful repair. The owner or operator (or designate) whose decision it was that repair could not be carried out in the 15-calendar-day timeframe must sign the record.

(F) For each leak that is not repairable, the maximum instrument reading measured by Method 21 of appendix A–7 to this part at the time the leak is determined to be not repairable, a video captured by the OGI camera showing that emissions are still visible, or a signed record that the leak is still detectable via audio/visual/olfactory methods.

(7) Records of each performance test or performance evaluation conducted on the affected facility and each notification and report submitted to the Administrator. For each performance test, include an indication of whether liquid product loading is assumed to be loaded into gasoline cargo tanks or periods when liquid product is loaded but no gasoline cargo tanks are being loaded are excluded in the determination of the combustion zone temperature operating limit according to the provision in § 60.503a(c)(8)(ii).

(8) Records of all 5-minute time periods during which liquid product is loaded into gasoline cargo tanks or assumed to be loaded into gasoline cargo tanks and records of all 5-minute time periods when there was no liquid product loaded into gasoline cargo tanks.

(9) Any records required to be maintained by this subpart that are submitted electronically via the EPA's Compliance and Emissions Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated authority or the EPA as part of an on-site compliance evaluation.

(b) *Reporting requirements for performance tests and evaluations.* Within 60 days after the date of completing each performance test and each CEMS performance evaluation required by this subpart, you must submit the results following the procedures specified in paragraph (e) of this section. As required by § 60.8(f)(2)(iv), you must include the value for the combustion zone temperature operating parameter limit set based on your performance test in the performance test report. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) and performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test or performance evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT and performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test or performance evaluation must be included as an attachment in the ERT or an alternate electronic file.

(c) *Reporting requirements for semiannual report.* You must submit to the Administrator semiannual reports with the applicable information in paragraphs (c)(1) through (7) of this section by the dates specified in paragraph (d) of this section following the procedure specified in paragraph (e) of this section. For this subpart, the semiannual reports supersede the excess emissions and monitoring systems performance report and/or summary report form required under § 60.7. Beginning on July 8, 2024, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (e). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(1) Report the following general facility information:

(i) Facility name.

(ii) Facility physical address, including city, county, and State.

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places.

(iv) The following information for the contact person:

(A) Name.

(B) Mailing address.

(C) Telephone number.

(D) Email address.

(v) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI.

(vi) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(vi).

(2) For each thermal oxidation system used to comply with the emission limitations in § 60.502a(b)(1) or (c)(1) by monitoring the combustion zone temperature as specified in § 60.502a(b)(1)(ii) or (c)(1)(ii), for each pressure CPMS used to comply with the requirements in § 60.502a(h), and for each vapor recovery system used to comply with the emission limitations in § 60.502a(b)(2) or (c)(2) report the following information for the CMS:

(i) For all instances when the temperature CPMS measured 3-hour rolling averages below the established operating limit or when the vapor collection system pressure exceeded the maximum loading pressure specified in § 60.502a(h) when liquid product was being loaded into gasoline cargo tanks or when the TOC CEMS measured 3-hour rolling average concentrations higher than the applicable emission limitation when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average combustion zone temperature, average pressure, or 3-hour rolling average TOC concentration during the deviation. For TOC concentration, indicate whether methane is excluded from the TOC concentration.

(D) A unique identifier for the CMS.

(E) The make, model number, and date of last calibration check of the CMS.

(F) The cause of the deviation and the corrective action taken.

(ii) For all instances that the temperature CPMS for measuring the combustion zone temperature or pressure CPMS was not operating or was out of control when liquid product was loaded into gasoline cargo tanks, or the TOC CEMS was not operating or was out of control when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the CMS.

(D) The make, model number, and date of last calibration check of the CMS.

(E) The cause of the deviation and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(F) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) is used, report either an indication that there were no deviations from the operating limits when using the limited alternative or report the number of each of the following types of deviations that occurred during the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(*1*) The number of adsorption cycles when the quantity of liquid product loaded in gasoline cargo tanks exceeded the operating limit established in § 60.504a(e)(1). Enter 0 if no deviations of this type.

(*2*) The number of desorption cycles when the vacuum pressure was below the average vacuum pressure as specified in § 60.504a(e)(2)(i). Enter 0 if no deviations of this type.

(*3*) The number of desorption cycles when the quantity of purge gas used was below the average quantity of purge gas as specified in § 60.504a(e)(2)(ii). Enter 0 if no deviations of this type.

(*4*) The number of desorption cycles when the duration of the vacuum/purge cycle was less than the average duration as specified in § 60.504a(e)(2)(iii). Enter 0 if no deviations of this type.

(3) For each flare used to comply with the emission limitations in § 60.502a(c)(3) and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii), report:

(i) The date and start and end times for each of the following instances:

(A) Each 15-minute block during which there was at least one minute when gasoline vapors were routed to the flare and no pilot flame was present.

(B) Each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Additionally, report the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(C) Each 15-minute period for which the applicable operating limits specified in § 63.670(d) through (f) of this chapter were not met. You must identify the specific operating limit that was not met. Additionally, report the information in paragraphs (c)(3)(i)(C)(*1*) through (*3*) of this section, as applicable.

(*1*) If you use the loading rate operating limits as determined in § 60.502a(c)(3)(vii) alone or in combination with the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii), the required minimum ratio and the actual ratio of gasoline loaded to total product loaded for the rolling 15-minute period and, if applicable, the required minimum quantity and the actual quantity of gasoline loaded, in gallons, for the rolling 15-minute period.

(*2*) If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii), the required minimum supplemental gas flow rate and the actual supplemental gas flow rate including units of flow rates for the 15-minute block.

(*3*) If you use parameter monitoring systems other than those specified in paragraphs (c)(3)(i)(C)(*1*) and (*2*) of this section, the value of the net heating value operating parameter(s) during the deviation determined following the methods in § 63.670(k) through (n) of this chapter as applicable.

(ii) The start date, start time, and duration in minutes for each period when ‘‘vapors displaced from gasoline cargo tanks during product loading’’ were routed to the flare or thermal oxidation system and the applicable monitoring was not performed.

(iii) For each instance reported under paragraphs (c)(3)(i) and (ii) of this section that involves CMS, report the following information:

(A) A unique identifier for the CMS.

(B) The make, model number, and date of last calibration check of the CMS.

(C) The cause of the deviation or downtime and the corrective action taken.

(4) For any instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502a(e)(1) was not provided or available in the terminal's records, report:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) For each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 60.501a, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system, report:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(ii) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, or not properly connected).

(iii) Cargo tank identification number.

(6) Report the following information for each leak inspection required under §§ 60.502a(j)(1) and 60.503a(a)(2) and each leak identified under § 60.502a(j)(2).

(i) For each leak detected during a leak inspection required under §§ 60.502a(j)(1) and 60.503a(a)(2), report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21 of appendix A–7 to this part).

(C) The total number and type of equipment for which leaks were detected.

(D) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(E) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(F) The total number and type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8).

(ii) For leaks identified under § 60.502a(j)(2), report:

(A) The total number and type of equipment for which leaks were identified.

(B) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(C) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(D) The total number and type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8).

(iii) The total number of leaks on the delay of repair list at the start of the reporting period.

(iv) The total number of leaks on the delay of repair list at the end of the reporting period.

(v) For each leak that was on the delay of repair list at any time during the reporting period, report:

(A) Unique equipment identification number.

(B) Type of equipment.

(C) Leak determination method (OGI, Method 21 of appendix A–7 to this part, or audio, visual, or olfactory).

(D) The reason(s) why the repair was not feasible within 15 calendar days.

(E) If applicable, the date repair was completed.

(7) If there were no deviations from the emission limitations, operating parameters, or work practice standards, then provide a statement that there were no deviations from the emission limitations, operating limits, or work practice standards during the reporting period. If there were no periods during which a CMS (including a CEMS or CPMS) was inoperable or out-of-control, then provide a statement that there were no periods during which a CMS was inoperable or out-of-control during the reporting period.

(d) *Timeframe for semiannual report submissions.* (1) The first semiannual report will cover the date starting with the date the source first becomes an affected facility subject to this subpart and ending with the last day of the month five months later. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to September 30. The first semiannual report must be submitted on or before the last day of the month two months after the last date covered by the semiannual report. In this example, the first semiannual report would be due November 30.

(2) Subsequent semiannual reports will cover subsequent 6 calendar month periods with each report due on or before the last day of the month two months after the last date covered by the semiannual report.

(e) *Requirements for electronically submitting reports.* For reports required to be submitted following the procedures specified in this paragraph (e), you must submit reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (e)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data are not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (e).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Gasoline Distribution Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group, and all other files should also be flagged to the attention of the Gasoline Distribution Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(f) *Claims of EPA system outage.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(g) *Claims of force majeure.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (g)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the

affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

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

■ 6. Section 63.420 is amended by

■ a. Revising paragraphs (a) introductory text, (a)(1) introductory text, (a)(2), (b) introductory text, (b)(1) introductory text, (b)(2), (c) introductory text, (c)(2), (d) introductory text, (d)(2), (g), (i), and (j); and

■ b. Adding paragraph (k).

The revisions and addition read as follows:

§ 63.420 Applicability.

(a) Prior to May 8, 2027, the affected source to which the provisions of this subpart apply is each bulk gasoline terminal, except those bulk gasoline terminals meeting either of the criteria listed in paragraph (a)(1) or (2) of this section. No later than May 8, 2027, the affected source to which the provisions of this subpart apply is each bulk gasoline terminal located at a major source as defined in § 63.2.

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

* * * * *

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

(b) Prior to May 8, 2027, the affected source to which the provisions of this subpart apply is each pipeline breakout station, except those pipeline breakout stations meeting either of the criteria listed in paragraph (b)(1) or (2) of this section. No later than May 8, 2027, the affected source to which the provisions of this subpart apply is each pipeline breakout station located at a major source as defined in § 63.2.

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

* * * * *

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

(c) Prior to May 8, 2027, a facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 1.0 but greater than or equal to 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

* * * * *

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(l)(4).

(d) Prior to May 8, 2027, a facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

* * * * *

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(l)(5).

* * * * *

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

* * * * *

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with §§ 63.646, 63.648, 63.649, 63.650, and 63.660 is not subject to the standards in this subpart, except as specified in § 63.650.

(j) Notwithstanding any other provision of this subpart, the December 14, 1995, compliance date for existing facilities in §§ 63.424(e) and 63.428(a), (l)(4)(i), and (l)(5)(i) is stayed from December 8, 1995, to March 7, 1996.

(k) Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station must comply with the standards in this part at all times. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 7. Section 63.421 is amended by:

■ a. Revising the introductory text and the definitions of ''Bulk gasoline terminal'' and ''Flare'';

■ b. Adding in alphabetical order a definition for ''Gasoline'';

■ c. Revising the definition of ''Pipeline breakout station'';

■ d. Adding in alphabetical order a definition for ''Submerged filling''; and

■ e. Revising the definition for ''Thermal oxidation system''.

The revisions and additions read as follows:

§ 63.421 Definitions.

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

Bulk gasoline terminal means:

(1) Prior to May 8, 2027, any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

(2) On or after May 8, 2027, any gasoline facility which receives gasoline by pipeline, ship, barge, or cargo tank and subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities and has a gasoline throughput greater than 20,000 gallons per day (75,700 liters per day). Gasoline throughput shall be the maximum calculated design throughput for the facility as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

* * * * *

Flare means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 4.0 pounds per square inch (27.6 kilopascals) or greater, which is used as a fuel for internal combustion engines.

* * * * *

Pipeline breakout station means:

(1) Prior to May 8, 2027, a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

(2) On or after May 8, 2027, a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline to other facilities. *Pipeline breakout stations* do not have loading racks where gasoline is loaded into cargo tanks. If any gasoline is loaded into cargo tanks, the facility is a bulk gasoline terminal for the purposes of this subpart provided the facility-wide gasoline throughput (including pipeline throughput) exceeds the limits specified for bulk gasoline terminals.

* * * * *

Submerged filling means the filling of a gasoline cargo tank through a submerged fill pipe whose discharge is no more than the 6 inches from the bottom of the tank. Bottom filling of gasoline cargo tanks is included in this definition.

Thermal oxidation system means an enclosed combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures. *Thermal oxidation systems* emit pollutants through a conveyance suitable to conduct a performance test.

* * * * *

■ 8. Revise § 63.422 to read as follows:

§ 63.422 Standards: Loading racks.

(a) You must meet either the requirements in paragraph (a)(1) or (2) of this section, as applicable in paragraph (d) of this section.

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

(2) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in § 60.502a of this chapter except for paragraphs (b) and (j) of that section and shall comply with the provisions in paragraphs (b) through (c) of this section. For purposes of this section, the term ''gasoline loading rack affected facility'' used in § 60.502a means ''the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.'' For purposes of this subpart, the term ''vapor-tight gasoline cargo tanks'' used in § 60.502a(e) of this chapter shall have the meaning given in § 63.421. As an alternative to the pressure monitoring requirements in § 60.504a(d) of this chapter, you may comply with the requirements specified in § 63.427(f).

(b) You must meet either the emission limits in paragraph (b)(1) or (2) of this section, as applicable in paragraph (d) of this section.

(1) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded.

(2) You must comply with the provisions in § 60.502a(c) of this chapter for all loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart, not just those that are modified or reconstructed.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall discontinue loading any cargo tank that fails vapor tightness according to the test requirements in § 63.425(f), (g), and (h) until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(1) The tank truck or railcar gasoline cargo tank has been repaired, retested, and subsequently passed either the annual certification test described in § 63.425(e) or the railcar bubble test described in § 63.425(i); or

(2) For each gasoline cargo tank failing the test in § 63.425(f) at the facility, the cargo tank meets the test requirements in either § 63.425(g) or (h); or

(3) For each gasoline cargo tank failing the test in § 63.425(g) at the facility, the cargo tank meets the test requirements in § 63.425(h).

(d) Each owner or operator shall meet the requirements in this section as expeditiously as practicable, but no later than the dates provided in paragraphs (d)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, each owner or operator shall meet the requirements in paragraphs (a)(1), (b)(1), and (c) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraphs (a)(1) and (b)(1) of this section no longer apply and each owner or operator shall meet the requirements in paragraphs (a)(2), (b)(2), and (c) of this section.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, each owner or operator shall meet the requirements in paragraphs (a)(1), (b)(1), and (c) of this section upon startup. Beginning no later than May 8, 2027, paragraphs (a)(1) and (b)(1) of this section no longer apply and each owner or operator shall meet

the requirements in paragraphs (a)(2), (b)(2), and (c) of this section.

(3) For facilities that commenced construction after June 10, 2022, each owner or operator shall meet the requirements in paragraphs (a)(2), (b)(2), and (c) of this section upon startup or July 8, 2024, whichever is later.

(e) As an alternative to § 60.502(h) and (i) or § 60.502a(h) and (i) of this chapter as specified in paragraph (a) of this section, the owner or operator may comply with paragraphs (e)(1) and (2) of this section.

(1) The owner or operator shall design and operate the vapor processing system, vapor collection system, and liquid loading equipment to prevent gauge pressure in the railcar gasoline cargo tank from exceeding the applicable test limits in § 63.425(e) and (i) during product loading. This level is not to be exceeded when measured by the procedures specified in § 60.503(d) of this chapter during any performance test or performance evaluation conducted under § 63.425(b) or (c).

(2) No pressure-vacuum vent in the bulk' gasoline terminal's vapor processing system or vapor collection system may begin to open at a system pressure less than the applicable test limits in § 63.425(e) or (i).

■ 9. Revise § 63.423 to read as follows:

§ 63.423 Standards: Storage vessels.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel according to the requirements in paragraph (a)(1) or (2) of this section, as applicable in paragraph (c) of this section.

(1) Equip each gasoline storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in § 60.112b(a)(1) through (4) of this chapter, except for the requirements in § 60.112b(a)(1)(iv) through (ix) and (a)(2)(ii) of this chapter.

(2) Equip each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in § 60.112b(a)(2)(ii) of this chapter if such storage vessel does not currently meet the requirements in paragraph (a)(1) of this section.

(b) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel according to the requirements in paragraphs (b)(1) of this section and, if a floating roof is used, either paragraph (b)(2) or (3) of this section, as applicable in paragraph (c) of this section.

(1) Equip, maintain, and operate each gasoline storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in § 60.112b(a)(1) through (4) of this chapter, except for the requirements in § 60.112b(a)(1)(iv) through (ix) of this chapter. Alternatively, you may elect to equip, maintain, and operate each affected gasoline storage vessel with a design capacity greater than or equal to 75 m^3 according to the requirements in subpart WW of this part as specified in § 60.110b(e)(5) of this chapter.

(2) Equip, maintain, and operate each internal floating control system to maintain the vapor concentration within the storage vessel above the floating roof at or below 25 percent of the lower explosive limit (LEL) on a 5-minute rolling average basis without the use of purge gas. This standard may require additional controls beyond those specified in paragraph (b)(1) of this section. Compliance with this paragraph (b)(2) shall be determined using the methods in § 63.425(j). A deviation of the LEL level is considered an inspection failure under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2) and must be remedied as such. Any repairs made must be confirmed effective through re-monitoring of the LEL and meeting the level in this paragraph (b)(2) within the timeframes specified in § 60.113b(a)(2) or § 63.1063(e), as applicable.

(3) Equip, maintain, and operate each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m^3 with fitting controls as specified in § 60.112b(a)(2)(ii) of this chapter.

(c) Each gasoline storage vessel at bulk gasoline terminals and pipeline breakout stations shall be in compliance with the requirements of this section as expeditiously as practicable, but no later than the dates provided in paragraphs (c)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, each gasoline storage vessel shall meet the requirements in paragraph (a) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraph (a) of this section no longer applies and each gasoline storage vessel shall meet the requirements in paragraphs (b)(1) and (2) of this section no later than May 8, 2027. If applicable, the fitting controls required in paragraph (b)(3) of this section must be installed the next time the storage vessel is completely emptied and degassed, or by May 8, 2034, whichever occurs first.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, each gasoline storage vessel shall meet the requirements in paragraph (a) of this section upon startup. Beginning no later than May 8, 2027, paragraph (a) of this section no longer applies and each gasoline storage vessel shall meet the requirements in paragraphs (b)(1) and (2) of this section no later than May 8, 2027. If applicable, the fitting controls required in paragraph (b)(3) of this section must be installed the next time the storage vessel is completely emptied and degassed, or by May 8, 2034, whichever occurs first.

(3) For facilities that commenced construction after June 10, 2022, each owner or operator shall meet the requirements in paragraph (b) of this section upon startup or July 8, 2024, whichever is later.

■ 10. Revise § 63.424 to read as follows:

§ 63.424 Standards: Equipment leaks.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall implement a leak detection and repair program for all equipment in gasoline service according to the requirements in paragraph (b) or (c) of this section, as applicable in paragraph (e) of this section and minimize gasoline vapor losses according to paragraph (d) of this section.

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

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

(2) Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (b)(3) of this section.

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

by which each repair is expected to be completed.

(4) As an alternative to compliance with the provisions in paragraphs (b)(1) through (3) of this section, owners or operators may implement an instrument leak monitoring program that has been demonstrated to the Administrator as at least equivalent.

(c) Comply with the requirements in § 60.502a(j) of this chapter except as provided in paragraphs (c)(1) through (3) of this section.

(1) The frequency for optical gas imaging (OGI) monitoring shall be semiannually rather than quarterly as specified in § 60.502a(j)(1)(i).

(2) The frequency for Method 21 monitoring of pumps and valves shall be semiannually rather than quarterly as specified in § 60.502a(j)(1)(ii)(A) and (B).

(3) The frequency of monitoring of pressure relief devices shall be semiannually and within 5 calendar days after each pressure release rather than quarterly and within 5 calendar days after each pressure release as specified in § 60.502a(j)(4)(i).

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

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

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

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

(e) Compliance with the provisions of this section shall be achieved as expeditiously as practicable, but no later than the dates provided in paragraphs (e)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, meet the requirements in paragraphs (b) and (d) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraph (b) of this section no longer applies and facilities shall meet the requirements in paragraphs (c) and (d) of this section no later than May 8, 2027.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, meet the requirements in paragraphs (b) and (d) of this section upon startup. Beginning no later than May 8, 2027, paragraph (b) of this section no longer applies and facilities shall meet the requirements in paragraphs (c) and (d) of this section no later than May 8, 2027.

(3) For facilities that commenced construction after June 10, 2022, meet the requirements in paragraph (c) and (d) of this section upon startup or July 8, 2024, whichever is later.

■ 11. Section 63.425 is amended by:

■ a. Revising paragraphs (a) through (d), (e)(1), (f) introductory text, and (f)(1);

■ b. Revising equation term ''N'' in the equation in paragraph (g)(3);

■ c. Revising paragraph (h); and

■ d. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.425 Test methods and procedures.

(a) *Performance test and evaluation requirements.* Each owner or operator subject to the emission standard in § 63.422(b)(1) or § 60.112b(a)(3)(ii) of this chapter shall comply with the requirements in paragraph (b) of this section. Each owner or operator subject to the emission standard in § 63.422(b)(2) shall comply with the requirements in paragraph (c) of this section. Performance tests shall be conducted under representative conditions when liquid product is being loaded into gasoline cargo tanks and shall include periods between gasoline cargo tank loading (when one cargo tank is disconnected and another cargo tank is moved into position for loading) provided that liquid product loading into gasoline cargo tanks is conducted for at least a portion of each 5 minute block of the performance test. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(b) *Gasoline loading rack and gasoline storage vessel performance test requirements.* For gasoline loading racks subject to the requirements in § 63.422(b)(1) or gasoline storage vessels subject to the requirements in § 60.112b(a)(3)(ii) of this chapter:

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (b)(1)(i) or (ii) of this section.

(i) Use the test methods and procedures in § 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under § 60.503(b) of this chapter, or

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in § 63.7(f).

(2) The performance test requirements of § 60.503(c) of this chapter do not apply to flares defined in § 63.421 and meeting the flare requirements in § 63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in § 63.11(b) and § 60.503(a), (b), and (d) of this chapter, respectively.

(3) For each performance test conducted under paragraph (b)(1) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

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

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

(iii) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in § 63.422(b)(1) or § 60.112b(a)(3)(ii) of this chapter.

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

(c) *Gasoline loading rack performance test and evaluation requirements.* For gasoline loading rack sources subject to the requirements in § 63.422(b)(2):

(1) Conduct performance tests or evaluations on the vapor processing and collection systems according to the requirements in § 60.503a(a), (c) and (d) of this chapter.

(2) The first performance test or performance evaluation of the continuous emissions monitoring system (CEMS) shall be conducted within 180 days of the date affected source begins compliance with the requirements in § 63.422(b)(2). A previously conducted performance test may be used to satisfy this requirement if the conditions in paragraphs (c)(2)(i)

through (v) of this section are met. Prior to conducting this performance test or evaluation, you must continue to meet the monitoring and operating limits that apply based on the previously conducted performance test.

(i) The performance test was conducted on or after May 8, 2022.

(ii) No changes have been made to the process or control device since the time of the performance test.

(iii) The operating conditions, test methods, and test requirements (*e.g.,* length of test) used for the previous performance test conform to the requirements in paragraph (c)(1) of this section.

(iv) The temperature in the combustion zone was recorded during the performance test as specified in § 60.503a(c)(8)(i) of this chapter and can be used to establish the operating limit as specified in § 60.503a(c)(8)(ii) through (iv) of this chapter.

(v) The performance test demonstrates compliance with the emission limit specified in § 63.422(b)(2).

(3) For loading racks complying with the mass loading emission limit in § 60.502a(c)(1) of this chapter, subsequent performance tests shall be conducted no later than 60 calendar months after the previous performance test.

(4) For loading racks complying with the concentration emission limit in § 60.502a(c)(2) of this chapter, subsequent performance evaluations of CEMS for the vapor collection and processing system shall be conducted no later than 12 calendar months after the previous performance evaluation.

(d) *Gasoline storage vessel requirements.* The owner or operator of each gasoline storage vessel subject to the provisions of § 63.423 shall comply with § 60.113b of this chapter and, if applicable, the provisions in paragraph (j) of this section. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (d)(1) or (2) of this section, as applicable.

(1) If the gasoline storage vessel is subject to the provision in § 63.423(a) or the provision in § 63.423(b) and a control device other than a flare is used for the gasoline storage vessel, the owner or operator shall also comply with the requirements in paragraph (b) of this section.

(2) If the gasoline storage vessel is subject to the provision in § 63.423(b) and a flare is used as the control device for the gasoline storage vessel, you must comply with the requirements in § 60.502a(c)(3) of this chapter as indicated in paragraphs (d)(2)(i) and (ii) of this section rather than the requirements in § 60.18(e) and (f) of this chapter as specified in § 60.113b(d) of this chapter.

(i) At § 60.502a(c)(3)(i) of this chapter, replace ''vapors displaced from gasoline cargo tanks during product loading'' with ''vapors from the gasoline storage vessel.''

(ii) Section 60.502a(c)(3)(vi) through (ix) of this chapter does not apply.

(e) * * *

(1) *Method 27 of appendix A–8 to part 60 of this chapter.* Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 millimeters (mm) of water (H_2O) (18 inches (in.) H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. Each owner or operator shall implement the requirements in paragraph (e)(1)(i) or (ii) of this section, as applicable in paragraph (e)(1)(iii) of this section.

(i) The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in the second column of table 1 to this paragraph (e)(1).

(ii) The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in the third column of table 1 to this paragraph (e)(1).

(iii) Compliance with the provisions of this section shall be achieved as expeditiously as practicable, but no later than the dates provided in paragraphs (e)(1)(iii)(A) and (B) of this section.

(A) For facilities that commenced construction on or before June 10, 2022, meet the requirements in paragraph (e)(1)(i) of this section prior to May 8, 2027, and meet the requirements in paragraph (e)(1)(ii) of this section no later than May 8, 2027.

(B) For facilities that commenced construction after June 10, 2022, meet the requirements in paragraph (e)(1)(ii) of this section upon startup or July 8, 2024, whichever is later.

TABLE 1 TO PARAGRAPH (e)(1)—ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)]	Allowable pressure change (Δ p) in 5 minutes at any time, mm H_2O (in. H_2O)
9,464 or more (2,500 or more)	25 (1.0)	12.7 (0.50)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	19.1 (0.75)	76 (3.0)
5,677 to 3,785 (1,499 to 1,000)	51 (2.0)	25.4 (1.00)	89 (3.5)
3,784 or less (999 or less)	64 (2.5)	31.8 (1.25)	102 (4.0)

* * * * *

(f) *Leak detection test.* The leak detection test shall be performed using Method 21 of appendix A–7 to part 60 of this chapter. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph (f).

(1) The instrument reading that defines a leak is 10,000 ppm (as propane). Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

* * * * *

(g) * * *

(3) * * *

N = 5-minute continuous performance standard at any time from the fourth column of table 1 to paragraph (e)(1) of this section, inches H_2O.

* * * * *

(h) *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27 in appendix A to part 60 of this chapter. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2O), gauge. The maximum allowable 5-minute pressure change (Δ p) which shall be met at any time is shown in the fourth column of table 1 to paragraph (e)(1) of this section.

* * * * *

(j) *LEL monitoring procedures.* Compliance with the vapor concentration below the LEL level for internal floating roof storage vessels at § 63.423(b)(2) shall be determined based on the procedures specified in paragraphs (j)(1) through (5) of this section. If tubing is necessary to obtain the measurements, the tubing must be non-crimping and made of Teflon or other inert material.

(1) LEL monitoring must be conducted at least once every 12 months and at other times upon request by the Administrator. If the measurement cannot be performed due to wind speeds exceeding those specified in paragraph (j)(3)(iii) of this section, the measurement must be performed within 30 days of the previous attempt.

(2) The calibration of the LEL meter must be checked per manufacturer specifications immediately before and after the measurements as specified in paragraphs (j)(2)(i) and (ii) of this section. If tubing will be used for the measurements, the tubing must be attached during calibration so that the calibration gas travels through the entire measurement system.

(i) Conduct the span check using a calibration gas recommended by the LEL meter manufacturer. The calibration gas must contain a single hydrocarbon at a concentration corresponding to 50 percent of the LEL (*e.g.,* 2.50 percent by volume when using methane as the calibration gas). The vendor must provide a Certificate of Analysis for the gas, and the certified concentration must be within ±2 percent (*e.g.,* 2.45 percent—2.55 percent by volume when using methane as the calibration gas). The LEL span response must be between 49 percent and 51 percent. If the span check prior to the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced. If the span check after the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced, and the measurements must be repeated.

(ii) Check the instrumental offset response using a certified compressed gas cylinder of zero air or an ambient environment that is free of organic compounds. The pre-measurement instrumental offset response must be 0 percent LEL. If the LEL meter does not meet this requirement, the LEL meter must be recalibrated or replaced.

(3) Conduct the measurements as specified in paragraphs (j)(3)(i) through (iv) of this section.

(i) Measurements of the vapors within the internal floating roof storage vessel must be collected no more than 3 feet above the internal floating roof.

(ii) Measurements shall be taken for a minimum of 20 minutes, logging the measurements at least once every 15 seconds, or until one 5-minute average as determined according to paragraph (j)(5)(ii) of this section exceeds the level specified in § 63.423(b)(2).

(iii) Measurements shall be taken when the wind speed at the top of the tank is 5 mph or less to the extent practicable, but in no case shall measurements be taken when the sustained wind speed at top of tank is greater than the annual average wind speed at the site or 15 mph, whichever is less.

(iv) Measurements should be conducted when the internal floating roof is floating with limited product movement (limited filling or emptying of the tank).

(4) To determine the actual vapor concentration within the storage vessel, the percent of the LEL ''as the calibration gas'' must be corrected according to one of the following procedures. Alternatively, if the LEL meter used has correction factors that can be selected from the meter's program, you may enable this feature to automatically apply one of the correction factors specified in paragraphs (j)(4)(i) and (ii) of this section.

(i) Multiply the measurement by the published gasoline vapor correction factor for the specific LEL meter and calibration gas used.

(ii) If there is no published correction factor for gasoline vapors for the specific LEL meter used, multiply the measurement by the published correction factor for butane as a surrogate for determining the LEL of gasoline vapors. The correction factor must correspond to the calibration gas used.

(5) Use the calculation procedures in paragraphs (j)(5)(i) through (iii) of this section to determine compliance with the LEL level.

(i) For each minute while measurements are being taken, determine the one-minute average reading as the arithmetic average of the corrected individual measurements (taken at least once every 15 seconds) during the minute.

(ii) Starting with the end of the fifth minute of data, calculate a five-minute rolling average as the arithmetic average of the previous five one-minute readings determined under paragraph (j)(5)(i) of this section. Determine a new five-minute average reading for every subsequent one-minute reading.

(iii) Each five-minute rolling average must meet the LEL level specified in § 63.423(b)(2).

■ 12. Section 63.427 is amended by revising paragraphs (a) introductory text, (a)(3), (b), and (c) and adding paragraphs (d), (e), and (f) to read as follows:

§ 63.427 Continuous monitoring.

(a) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(1) shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in paragraph (a)(1), (2), (3), or (4) of this section, except as allowed in paragraph (a)(5) of this section.

* * * * *

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

* * * * *

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

(c) Except as provided in paragraph (f) of this section, each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall install, calibrate, certify, operate, and maintain a CMS as specified in § 60.504a(a) through (d) of this chapter, as applicable. You may use the limited alternative monitoring methods as specified in § 60.504a(e) of this chapter, if applicable.

(d) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall operate the vapor processing system in a manner consistent with the minimum and/or maximum operating parameter value or procedures described in §§ 60.502a(a) and (c) and 60.504a(a) and (c) of this chapter. Operation of the vapor processing system in a manner that constitutes a period of excess emissions or failure to perform procedures required shall constitute a deviation of the emission standard in § 63.422(b)(2).

(e) Each owner or operator of gasoline storage vessels subject to the provisions of § 63.423 shall comply with the monitoring requirements in § 60.116b of this chapter, except records shall be kept for at least 5 years. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (e)(1) or (2) of this section, as applicable.

(1) If the gasoline storage vessel is subject to the provision in § 63.423(a) or if the gasoline storage vessel is subject to the provision in § 63.423(b) and a control device other than a flare is used for the gasoline storage vessel, the owner or operator shall also comply with the requirements in paragraph (a) of this section.

(2) If the gasoline storage vessel is subject to the provision in § 63.423(b) and a flare is used as the control device for the affected gasoline storage vessel, you must comply with the monitoring requirements in § 60.504a(c) of this chapter.

(f) As an alternative to the pressure monitoring requirements in § 60.504a(d) of this chapter, you may comply with the pressure monitoring requirements in § 60.503(d) of this chapter during any performance test or performance evaluation conducted under § 63.425(c) to demonstrate compliance with the provisions in § 60.502a(h) of this chapter.

■ 13. Revising § 63.428 to read as follows:

§ 63.428 Recordkeeping and reporting.

(a) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by December 16, 1996, whichever is later. Affected sources that are major sources on December 16, 1996, and plan to be area sources by December 15, 1997, shall include in this notification a brief, non-binding description of and schedule for the action(s) that are planned to achieve area source status.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records in either hardcopy or electronic form of the test results for each gasoline cargo tank loading at the facility for at least 5 years as specified in paragraphs (b)(1) through (3) of this section. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records for at least 5 years as specified in paragraphs (b)(4) and (5) of this section.

(1) Annual certification testing performed under § 63.425(e) and railcar bubble leak testing performed under § 63.425(i); and

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

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

(i) Name of test: Annual Certification Test—Method 27 (§ 63.425(e)(1)); Annual Certification Test—Internal Vapor Valve (§ 63.425(e)(2)); Leak Detection Test (§ 63.425(f)); Nitrogen Pressure Decay Field Test (§ 63.425(g)); Continuous Performance Pressure Decay Test (§ 63.425(h)); or Railcar Bubble Leak Test Procedure (§ 63.425(i)).

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

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

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

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

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

(4) Records of each instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502(e)(1) or § 60.502a(e)(1) of this chapter, as applicable, was not provided or available in the terminal's records. These records shall include, at a minimum:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) Records of each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 63.421, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system. These records shall include, at a minimum:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped or improperly connected.

(ii) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(1) shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under § 63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

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

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

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

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

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

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

(4) Keep written procedures required under § 63.8(d)(2) on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you shall keep previous (*i.e.,* superseded) versions

of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action shall be included in the plan as required under § 63.8(d)(2).

(d) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall keep records as specified in paragraphs (d)(1) through (4) of this section, as applicable, for a minimum of five years unless otherwise specified in this section:

(1) For each thermal oxidation system used to comply with the emission limitations in § 63.422(b)(2) by monitoring the combustion zone temperature as specified in § 60.502a(c)(1)(ii) of this chapter, for each pressure CPMS used to comply with the requirements in § 60.502a(h) of this chapter, and for each vapor recovery system used to comply with the emission limitations in § 63.422(b)(2), maintain records, as applicable, of:

(i) The applicable operating or emission limit for the CMS. For combustion zone temperature operating limits, include the applicable date range the limit applies based on when the performance test was conducted.

(ii) Each 3-hour rolling average combustion zone temperature measured by the temperature CPMS, each 5-minute average reading from the pressure CPMS, and each 3-hour rolling average total organic compounds (TOC) concentration (as propane) measured by the TOC CEMS.

(iii) For each deviation of the 3-hour rolling average combustion zone temperature operating limit, maximum loading pressure specified in § 60.502a(h) of this chapter, or 3-hour rolling average TOC concentration (as propane), the start date and time, duration, cause, and the corrective action taken.

(iv) For each period when there was a CMS outage or the CMS was out of control, the start date and time, duration, cause, and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(v) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check. For TOC CEMS, include the type of CEMS used (*i.e.,* flame ionization detector, nondispersive infrared analyzer) and an indication of whether methane is excluded from the TOC concentration reported in paragraph (d)(1)(ii) of this section.

(vi) TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, also keep records of:

(A) The quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS outage.

(B) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS outage.

(C) The quantity of liquid product loaded in gasoline cargo tanks for each adsorption cycle while using the alternative.

(D) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles for each desorption cycle while using the alternative.

(2) For each flare used to comply with the emission limitations in § 63.422(b)(2) and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii) of this chapter, maintain records of:

(i) The output of the monitoring device used to detect the presence of a pilot flame as required in § 63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when gasoline vapors were routed to the flare for a minimum of 5 years. The record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in paragraphs (d)(2)(ii)(A) and (B) of this section, as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 of appendix A–7 to part 60 of this chapter, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of appendix A–7 to part 60 of this chapter were not conducted for the full 2-hour period, the record must include the date, the start and end time of the visible emissions observation, and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) Each 15-minute block period during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) when liquid product is being loaded into gasoline cargo tanks for at least 15-minutes identifying the specific operating limit that was not met.

(iv) The 15-minute block average cumulative flows for the thermal oxidation system vent gas or flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under § 63.670(i), along with the date and start and end time for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the thermal oxidation system vent gas, flare vent gas, or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required supplemental gas flow rate (winter and summer, if applicable) and the actual monitored supplemental gas flow rate for the 15-minute block. Retain the supplemental gas flow rate records for a minimum of 5 years.

(v) The thermal oxidation system vent gas or flare vent gas compositions specified to be monitored under § 63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHV_{vg} analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years. If you demonstrate your gas streams have consistent composition using the provisions in § 63.670(j)(6) as specified in § 60.502a(c)(3)(vii) of this chapter, retain records of the required minimum ratio of gasoline loaded to total liquid product loaded and the actual ratio on a 15-minute block basis.

If applicable, you must retain records of the required minimum gasoline loading rate as specified in § 60.502a(c)(3)(vii) and the actual gasoline loading rate on a 15-minute block basis for a minimum of 5 years.

(vi) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n), as applicable.

(vii) All periods during which the owner or operator does not perform monitoring according to the procedures in § 63.670(g), (i), and (j) or in § 60.502a(c)(3)(vii) and (viii) of this chapter as applicable. Note the start date, start time, and duration in minutes for each period.

(viii) An indication of whether ''vapors displaced from gasoline cargo tanks during product loading'' excludes periods when liquid product is loaded but no gasoline cargo tanks are being loaded or if liquid product loading is assumed to be loaded into gasoline cargo tanks according to the provisions in § 60.502a(c)(3)(i) of this chapter, records of all time periods when ''vapors displaced from gasoline cargo tanks during product loading'', and records of time periods when there were no ''vapors displaced from gasoline cargo tanks during product loading''.

(ix) If you comply with the flare tip velocity operating limit using the one-time flare tip velocity operating limit compliance assessment as provided in § 60.502a(c)(3)(ix) of this chapter, maintain records of the applicable one-time flare tip velocity operating limit compliance assessment for as long as you use this compliance method.

(x) For each parameter monitored using a CMS, retain the records specified in paragraphs (d)(2)(x)(A) through (C) of this section, as applicable:

(A) For each deviation, record the start date and time, duration, cause, and corrective action taken.

(B) For each period when there is a CMS outage or the CMS is out of control, record the start date and time, duration, cause, and corrective action taken.

(C) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check.

(3) Records of all 5-minute time periods during which liquid product is loaded into gasoline cargo tanks or assumed to be loaded into gasoline cargo tanks and records of all 5-minute time periods when there was no liquid product loaded into gasoline cargo tanks.

(4) Keep written procedures required under § 63.8(d)(2) on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you shall keep previous (*i.e.,* superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action shall be included in the plan as required under § 63.8(d)(2).

(e) Each owner or operator of storage vessels subject to the provisions of this subpart shall keep records as specified in § 60.115b of this chapter, except records shall be kept for at least 5 years. Additionally, for each storage vessel complying with the provisions in § 63.423(b)(2), keep records of each LEL monitoring event as specified in paragraphs (e)(1) through (9) of this section.

(1) Date and time of the LEL monitoring, and the storage vessel being monitored.

(2) A description of the monitoring event (*e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2); re-monitoring due to high winds; re-monitoring after repair attempt).

(3) Wind speed at the top of the storage vessel on the date of LEL monitoring.

(4) The LEL meter manufacturer and model number used, as well as an indication of whether tubing was used during the LEL monitoring, and if so, the type and length of tubing used.

(5) Calibration checks conducted before and after making the measurements, including both the span check and instrumental offset. This includes the hydrocarbon used as the calibration gas, the Certificate of Analysis for the calibration gas(es), the results of the calibration check, and any corrective action for calibration checks that do not meet the required response.

(6) Location of the measurements and the location of the floating roof.

(7) Each measurement (taken at least once every 15 seconds). The records should indicate whether the recorded values were automatically corrected using the meter's programming. If the values were not automatically corrected, record both the raw (as the calibration gas) and corrected measurements, as well as the correction factor used.

(8) Each 5-minute rolling average reading.

(9) If the vapor concentration of the storage vessel was above 25 percent of the LEL on a 5-minue rolling average basis, a description of whether the floating roof was repaired, replaced, or taken out of gasoline service.

(f) Each owner or operator complying with the provisions of § 63.424 shall keep records of the information in paragraphs (f)(1) and (2) of this section.

(1) Each owner or operator complying with the provisions of § 63.424(b) shall record the following information in the logbook for each leak that is detected:

(i) The equipment type and identification number;

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

(iii) The date the leak was detected and the date of each attempt to repair the leak;

(iv) Repair methods applied in each attempt to repair the leak;

(v) ''Repair delayed'' and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak;

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

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

(2) Each owner or operator complying with the provisions of § 63.424(c) or § 60.503a(a)(2) of this chapter shall keep records of the following information:

(i) Types, identification numbers, and locations of all equipment in gasoline service.

(ii) For each leak inspection conducted under § 63.424(c) or § 60.503a(a)(2) of this chapter, keep the following records:

(A) An indication if the leak inspection was conducted under § 63.424(c) or § 60.503a(a)(2) of this chapter.

(B) Leak determination method used for the leak inspection.

(iii) For leak inspections conducted with Method 21 of appendix A–7 to part 60 of this chapter, keep the following additional records:

(A) Date of inspection.

(B) Inspector name.

(C) Monitoring instrument identification.

(D) Identification of all equipment surveyed and the instrument reading for each piece of equipment.

(E) Date and time of instrument calibration and initials of operator performing the calibration.

(F) Calibration gas cylinder identification, certification date, and certified concentration.

(G) Instrument scale used.

(H) Results of the daily calibration drift assessment.

(iv) For leak inspections conducted with OGI, keep the records specified in section 12 of appendix K to part 60 of this chapter.

(v) For each leak that is detected during a leak inspection or by audio/visual/olfactory methods during normal duties, record the following information:

(A) The equipment type and identification number.

(B) The date the leak was detected, the name of the person who found the leak, nature of the leak (*i.e.,* vapor or liquid) and the method of detection (*i.e.,* audio/visual/olfactory, Method 21 of appendix A–7 to part 60 of this chapter, or OGI).

(C) The date of each attempt to repair the leak and the repair methods applied in each attempt to repair the leak.

(D) The date of successful repair of the leak, the method of monitoring used to confirm the repair, and if Method 21 of appendix A–7 to part 60 of this chapter is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A–7 to part 60. If OGI is used to confirm the repair, keep video footage of the repair confirmation.

(E) For each repair delayed beyond 15 calendar days after discovery of the leak, record ''Repair delayed'', the reason for the delay, and the expected date of successful repair. The owner or operator (or designate) whose decision it was that repair could not be carried out in the 15-calendar day timeframe must sign the record.

(F) For each leak that is not repairable, the maximum instrument reading measured by Method 21 of appendix A–7 to part 60 of this chapter at the time the leak is determined to be not repairable, a video captured by the OGI camera showing that emissions are still visible, or a signed record that the leak is still detectable via audio/visual/olfactory methods.

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall keep the following records for each deviation of an emissions limitation (including operating limit), work practice standard, or operation and maintenance requirement in this subpart.

(1) Date, start time, and duration of each deviation.

(2) List of the affected sources or equipment for each deviation, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(3) Actions taken to minimize emissions.

(h) Any records required to be maintained by this subpart that are submitted electronically via the U.S. Environmental Protection Agency (EPA) Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated authority or the EPA as part of an on-site compliance evaluation.

(i) Records of each performance test or performance evaluation conducted and each notification and report submitted to the Administrator for at least 5 years. For each performance test, include an indication of whether liquid product loading is assumed to be loaded into gasoline cargo tanks or periods when liquid product is loaded but no gasoline cargo tanks are being loaded are excluded in the determination of the combustion zone temperature operating limit according to the provision in § 60.503a(c)(8)(ii) of this chapter. If complying with the alternative in § 63.427(f), for each performance test or performance evaluation conducted, include the pressure every 5 minutes while a gasoline cargo tank is being loaded and the highest instantaneous pressure that occurs during each loading.

(j) Prior to November 4, 2024, each owner or operator of an affected source under this subpart shall submit performance test reports to the Administrator according to the requirements in § 63.13. Beginning on November 4, 2024, within 60 days after the date of completing each performance test and each CEMS performance evaluation required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). As required by § 63.7(g)(2)(iv), you must include the value for the combustion zone temperature operating parameter limit set based on your performance test in the performance test report. If the monitoring alternative in § 63.427(f) is used, indicate that this monitoring alternative is being used, identify each loading rack that loads gasoline cargo tanks at the bulk gasoline terminal subject to the provisions of this subpart, and report the highest instantaneous pressure monitored during the performance test or performance evaluation for each identified loading rack. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) and performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test or performance evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT and performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(k) The owner or operator must submit all Notification of Compliance Status reports in PDF format to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead.

(l) Prior to May 8, 2027, each owner or operator of a source subject to the requirements of this subpart shall submit reports as specified in paragraphs (l)(1) through (5) of this section, as applicable.

(1) Each owner or operator subject to the provisions of § 63.424 shall report to the Administrator a description of the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under § 63.424(b)(4), the report shall contain a full description of the program.

(i) In the case of an existing source or a new source that has an initial startup date before December 14, 1994, the report shall be submitted with the notification of compliance status required under § 63.9(h), unless an extension of compliance is granted under § 63.6(i). If an extension of compliance is granted, the report shall be submitted on a date scheduled by the Administrator.

(ii) In the case of new sources that did not have an initial startup date before December 14, 1994, the report shall be submitted with the application for approval of construction, as described in § 63.5(d).

(2) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual

report to the Administrator the following information, as applicable:

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

(ii) Periodic reports as specified in § 60.115b of this chapter; and

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

(3) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with § 63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

(i) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under § 63.425(b)(3). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

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

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

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

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

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

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

(D) The date of successful repair.

(4) Each owner or operator of a facility meeting the criteria in § 63.420(c) shall perform the requirements of this paragraph (l)(4), all of which will be available for public inspection:

(i) Document and report to the Administrator not later than December 16, 1996, for existing facilities, within 30 days for existing facilities subject to § 63.420(c) after December 16, 1996, or at startup for new facilities the methods, procedures, and assumptions supporting the calculations for determining criteria in § 63.420(c);

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

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

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

(5) Each owner or operator of a facility meeting the criteria in § 63.420(d) shall perform the requirements of this paragraph (l)(5), all of which will be available for public inspection:

(i) Document and report to the Administrator not later than December 16, 1996, for existing facilities, within 30 days for existing facilities subject to § 63.420(d) after December 16, 1996, or at startup for new facilities the use of the emission screening equations in § 63.420(a)(1) or (b)(1) and the calculated value of E_T or E_P;

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

(iii) At any time following the notification required under paragraph (l)(5)(i) of this section, and prior to any of the parameters being exceeded, the owner or operator may notify the Administrator of modifications to the facility parameters. Each such notification shall document any expected HAP emission change resulting from the change in parameter.

(m) On or after May 8, 2027, you must submit to the Administrator semiannual reports with the applicable information in paragraphs (m)(1) through (8) of this section following the procedure specified in paragraph (n) of this section.

(1) Report the following general facility information:

(i) Facility name.

(ii) Facility physical address, including city, county, and State.

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places.

(iv) The following information for the contact person:

(A) Name.

(B) Mailing address.

(C) Telephone number.

(D) Email address.

(v) The type of facility (bulk gasoline terminal or pipeline breakout station).

(vi) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI.

(vii) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (m)(1)(vii).

(2) For each thermal oxidation system used to comply with the emission limit in § 60.502a(c)(1) of this chapter by monitoring the combustion zone temperature as specified in § 60.502a(c)(1)(ii), for each pressure CPMS used to comply with the requirements in § 60.502a(h), and for each vapor recovery system used to comply with the emission limitations in § 60.502a(c)(2), report the following information for the CMS:

(i) For all instances when the temperature CPMS measured 3-hour rolling averages below the established operating limit or when the vapor collection system pressure exceeded the maximum loading pressure specified in § 60.502a(h) of this chapter when liquid product was being loaded into gasoline cargo tanks or when the TOC CEMS measured 3-hour rolling average concentrations higher than the applicable emission limitation when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average combustion zone temperature, average pressure, or 3-hour rolling average TOC concentration during the deviation. For TOC concentration, indicate whether methane is excluded from the TOC concentration.

(D) A unique identifier for the CMS.

(E) The make, model number, and date of last calibration check of the CMS.

(F) The cause of the deviation and the corrective action taken.

(ii) For all instances that the temperature CPMS for measuring the combustion zone temperature or pressure CPMS was not operating or out of control when liquid product was loaded into gasoline cargo tanks, or the TOC CEMS was not operating or was out of control when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the CMS.

(D) The make, model number, and date of last calibration check of the CMS.

(E) The cause of the deviation and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(F) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, report either an indication that there were no deviations from the operating limits when using the limited alternative or report the number of each of the following types of deviations that occurred during the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(*1*) The number of adsorption cycles when the quantity of liquid product loaded in gasoline cargo tanks exceeded the operating limit established in § 60.504a(e)(1) of this chapter. Enter 0 if no deviations of this type.

(*2*) The number of desorption cycles when the vacuum pressure was below the average vacuum pressure as specified in § 60.504a(e)(2)(i) of this chapter. Enter 0 if no deviations of this type.

(*3*) The number of desorption cycles when the quantity of purge gas used was below the average quantity of purge gas as specified in § 60.504a(e)(2)(ii) of this chapter. Enter 0 if no deviations of this type.

(*4*) The number of desorption cycles when the duration of the vacuum/purge cycle was less than the average duration as specified in § 60.504a(e)(2)(iii) of this chapter. Enter 0 if no deviations of this type.

(3) For each flare used to comply with the emission limitations in § 60.502a(c)(3) of this chapter and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii), report:

(i) The date and start and end times for each of the following instances:

(A) Each 15-minute block during which there was at least one minute when gasoline vapors were routed to the flare and no pilot flame was present.

(B) Each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Additionally, report the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(C) Each 15-minute period for which the applicable operating limits specified in § 63.670(d) through (f) were not met. You must identify the specific operating limit that was not met. Additionally, report the information in paragraphs (m)(3)(i)(C)(*1*) through (*3*) of this section, as applicable.

(*1*) If you use the loading rate operating limits as determined in § 60.502a(c)(3)(vii) of this chapter alone or in combination with the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum ratio and the actual ratio of gasoline loaded to total product loaded for the rolling 15-minute period and, if applicable, the required minimum quantity and the actual quantity of gasoline loaded, in gallons, for the rolling 15-minute period.

(*2*) If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum supplemental gas flow rate and the actual supplemental gas flow rate including units of flow rates for the 15-minute block.

(*3*) If you use parameter monitoring systems other than those specified in paragraphs (m)(3)(i)(C)(*1*) and (*2*) of this section, the value of the net heating value operating parameter(s) during the deviation determined following the methods in § 63.670(k) through (n) as applicable.

(ii) The start date, start time, and duration in minutes for each period when ''vapors displaced from gasoline cargo tanks during product loading'' were routed to the flare or thermal oxidation system and the applicable monitoring was not performed.

(iii) For each instance reported under paragraphs (m)(3)(i) and (ii) of this section that involves CMS, report the following information:

(A) A unique identifier for the CMS.

(B) The make, model number, and date of last calibration check of the CMS.

(C) The cause of the deviation or downtime and the corrective action taken.

(4) For any instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502a(e)(1) of this chapter was not provided or available in the terminal's records, report:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) For each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 63.421, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system, report:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(ii) The type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(6) Report the following information for each leak inspection required and each leak identified under § 63.424(c) and § 60.503a(a)(2) of this chapter.

(i) For each leak detected during a leak inspection required under § 63.424(c) and § 60.503a(a)(2) of this chapter, report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21).

(C) The total number and type of equipment for which leaks were detected.

(D) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(E) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(F) The total number and types of equipment that were placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(ii) For leaks identified under § 63.424(c) by audio/visual/olfactory methods during normal duties report:

(A) The total number and type of equipment for which leaks were identified.

(B) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(C) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(D) The total number and type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(iii) The total number of leaks on the delay of repair list at the start of the reporting period.

(iv) The total number of leaks on the delay of repair list at the end of the reporting period.

(v) For each leak that was on the delay of repair list at any time during the reporting period, report:

(A) Unique equipment identification number.

(B) Type of equipment.

(C) Leak determination method (OGI, Method 21, or audio/visual/olfactory).

(D) The reason(s) why the repair was not feasible within 15 calendar days.

(E) If applicable, the date repair was completed.

(7) For each gasoline storage vessel subject to requirements in § 63.423, report:

(i) The information specified in § 60.115b(a) or (b) of this chapter or deviations in measured parameter values from the plan specified in § 60.115b(c) of this chapter, depending upon the control equipment installed, or, if applicable, the information specified in § 63.1066(b).

(ii) If you are complying with § 63.423(b)(2), for each deviation in LEL monitoring, report:

(A) Date and start and end times of the LEL monitoring, and the storage vessel being monitored.

(B) Description of the monitoring event, *e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2); re-monitoring due to high winds; re-monitoring after repair attempt.

(C) Wind speed in miles per hour at the top of the storage vessel on the date of LEL monitoring.

(D) The highest 5-minute rolling average reading during the monitoring event.

(E) Whether the floating roof was repaired, replaced, or taken out of gasoline service. If the floating roof was repaired or replaced, also report the information in paragraphs (m)(7)(ii)(A) through (D) of this section for each re-monitoring conducted to confirm the repair.

(8) If there were no deviations from the emission limitations, operating parameters, or work practice standards, then provide a statement that there were no deviations from the emission limitations, operating parameters, or work practice standards during the reporting period. If there were no periods during which a continuous monitoring system (including a CEMS or CPMS) was inoperable or out-of-control, then provide a statement that there were no periods during which a continuous monitoring system was inoperable or out-of-control during the reporting period.

(n) Each owner or operator of an affected source under this subpart shall submit semiannual compliance reports with the information specified in paragraph (l) or (m) of this section to the Administrator according to the requirements in § 63.13. Beginning on May 8, 2027, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, you must submit all subsequent semiannual compliance reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

■ 14. Section 63.429 is amended by revising paragraph (c) introductory text and adding paragraph (c)(5) to read as follows:

§ 63.429 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 15. Table 1 to subpart R of part 63 is revised to read as follows:

TABLE 1 TO SUBPART R OF PART 63—GENERAL PROVISIONS APPLICABILITY TO THIS SUBPART

Reference	Applies to this subpart	Comment
63.1(a)(1)	Yes.	
63.1(a)(2)	Yes.	
63.1(a)(3)	Yes.	
63.1(a)(4)	Yes.	
63.1(a)(5)	No	Section reserved.
63.1(a)(6)	Yes.	
63.1(a)(7) through (9)	No	Sections reserved.
63.1(a)(10)	Yes.	
63.1(a)(11)	Yes.	
63.1(a)(12)	Yes.	
63.1(b)(1)	No	This subpart specifies applicability in § 63.420.
63.1(b)(2)	Yes.	
63.1(b)(3)	Yes	Except this subpart specifies additional reporting and recordkeeping for some large area sources in § 63.428. These additional requirements only apply prior to the date the applicability equations are no longer applicable.
63.1(c)(1)	Yes.	
63.1(c)(2)	Yes	Some small sources are not subject to this subpart.
63.1(c)(3)	No	Section reserved.
63.1(c)(4)	No	Section reserved.
63.1(c)(5)	Yes.	
63.1(c)(6)	Yes.	
63.1(d)	No	Section reserved.
63.1(e)	Yes.	

TABLE 1 TO SUBPART R OF PART 63—GENERAL PROVISIONS APPLICABILITY TO THIS SUBPART—Continued

Reference	Applies to this subpart	Comment
63.2	Yes	Additional definitions in § 63.421.
63.3(a)–(c)	Yes.	
63.4(a)(1) and (2)	Yes.	
63.4(a)(3) through (5)	No	Sections reserved.
63.4(b)	Yes.	
63.4(c)	Yes.	
63.5(a)(1)	Yes.	
63.5(a)(2)	Yes.	
63.5(b)(1)	Yes.	
63.5(b)(2)	No	Section reserved.
63.5(b)(3)	Yes.	
63.5(b)(4)	Yes.	
63.5(b)(5)	No	Section reserved.
63.5(b)(6)	Yes.	
63.5(c)	No	Section reserved.
63.5(d)(1)	Yes.	
63.5(d)(2)	Yes.	
63.5(d)(3)	Yes.	
63.5(d)(4)	Yes.	
63.5(e)	Yes.	
63.5(f)(1)	Yes.	
63.5(f)(2)	Yes.	
63.6(a)	Yes.	
63.6(b)(1)	Yes.	
63.6(b)(2)	Yes.	
63.6(b)(3)	Yes.	
63.6(b)(4)	Yes.	
63.6(b)(5)	Yes.	
63.6(b)(6)	No	Section reserved.
63.6(b)(7)	Yes.	
63.6(c)(1)	No	This subpart specifies the compliance date.
63.6(c)(2)	Yes.	
63.6(c)(3) and (4)	No	Sections reserved.
63.6(c)(5)	Yes.	
63.6(d)	No	Section reserved.
63.6(e)	No	See § 62.420(k) for general duty requirement.
63.6(f)(1)	No.	
63.6(f)(2)	Yes.	
63.6(f)(3)	Yes.	
63.6(g)	Yes.	
63.6(h)	No	This subpart does not require COMS; this subpart specifies requirements for visible emissions observations for flares.
63.6(i)(1) through (14)	Yes.	
63.6(i)(15)	No	Section reserved.
63.6(i)(16)	Yes.	
63.6(j)	Yes.	
63.7(a)(1)	Yes.	
63.7(a)(2)	Yes.	
63.7(a)(3)	Yes.	
63.7(a)(4)	Yes.	
63.7(b)	Yes.	
63.7(c)	Yes.	
63.7(d)	Yes.	
63.7(e)(1)	No	This subpart specifies performance test conditions.
63.7(e)(2)	Yes.	
63.7(e)(3)	Yes.	
63.7(e)(4)	Yes.	
63.7(f)	Yes.	
63.7(g)	Yes	Except this subpart specifies how and when the performance test and performance evaluation results are reported.
63.7(h)	Yes.	
63.8(a)(1)	Yes.	
63.8(a)(2)	Yes.	
63.8(a)(3)	No	Section reserved.
63.8(a)(4)	Yes.	
63.8(b)(1)	Yes.	
63.8(b)(2)	Yes.	
63.8(b)(3)	Yes.	
63.8(c)(1) introductory text	Yes.	
63.8(c)(1)(i)	No.	
63.8(c)(1)(ii)	Yes.	
63.8(c)(1)(iii)	No.	

TABLE 1 TO SUBPART R OF PART 63—GENERAL PROVISIONS APPLICABILITY TO THIS SUBPART—Continued

Reference	Applies to this subpart	Comment
63.8(c)(2)	Yes.	
63.8(c)(3)	Yes.	
63.8(c)(4)	Yes.	
63.8(c)(5)	No	This subpart does not require COMS.
63.8(c)(6) through (8)	Yes.	
63.8(d)(1) and (2)	Yes.	
63.8(d)(3)	No	This subpart specifies CMS records requirements.
63.8(e)	Yes	Except this subpart specifies how and when the performance evaluation results are reported.
63.8(f)(1) through (5)	Yes.	
63.8(f)(6)	Yes.	
63.8(g)	Yes.	
63.9(a)	Yes.	
63.9(b)(1)	Yes.	
63.9(b)(2)	Yes	Except this subpart allows additional time for existing sources to submit initial notification. Section 63.428(a) specifies submittal by 1 year after being subject to the rule or December 16, 1996, whichever is later.
63.9(b)(3)	No	Section reserved.
63.9(b)(4)	Yes.	
63.9(b)(5)	Yes.	
63.9(c)	Yes.	
63.9(d)	Yes.	
63.9(e)	Yes.	
63.9(f)	No.	
63.9(g)	Yes.	
63.9(h)(1) through (3)	Yes	Except this subpart specifies how to submit the Notification of Compliance Status.
63.9(h)(4)	No	Section reserved.
63.9(h)(5) and (6)	Yes.	
63.9(i)	Yes.	
63.9(j)	Yes.	
63.9(k)	Yes.	
63.10(a)	Yes.	
63.10(b)(1)	Yes.	
63.10(b)(2)(i), (ii), (iv), and (v)	No	This subpart specifies recordkeeping requirements for deviations.
63.10(b)(2)(iii) and (vi) through (xiv)	Yes.	
63.10(b)(3)	Yes.	
63.10(c)(1)	Yes.	
63.10(c)(2) through (4)	No	Sections reserved.
63.10(c)(5) through (8)	Yes.	
63.10(c)(9)	No.	Section reserved.
63.10(c)(10) through (14)	Yes.	
63.10(c)(15)	No.	
63.10(d)(1)	Yes.	
63.10(d)(2)	No	This subpart specifies how and when the performance test results are reported.
63.10(d)(3)	No	This subpart specifies reporting requirements for visible emissions observations for flares.
63.10(d)(4)	Yes.	
63.10(d)(5)	No.	
63.10(e)(1)	Yes.	
63.10(e)(2) through (4)	No	This subpart specifies reporting requirements for CMS and continuous opacity monitoring systems.
63.10(f)	Yes.	
63.11(a) and (b)	Yes	Except these provisions no longer apply upon compliance with the provisions in §§ 63.422(b)(2) and 63.425(d)(2) for flares to meet the requirements specified in §§ 60.502a(c)(3) and 60.504a(c) of this chapter.
63.11(c), (d), and (e)	Yes	Except these provisions do not apply to monitoring required under § 63.425(b)(1) or (c)(1) and these provisions no longer apply upon compliance with the provisions in § 63.424(c).
63.12	Yes.	
63.13	Yes.	
63.14	Yes.	
63.15	Yes.	
63.16	Yes.	

Subpart BBBBBB—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

■ 16. Section 63.11081 is amended by revising paragraphs (c) and (f) to read as follows:

§ 63.11081 Am I subject to the requirements in this subpart?

* * * * *

(c) Gasoline storage tanks that are located at affected sources identified in paragraphs (a)(1) through (4) of this section, and that are used only for dispensing gasoline in a manner consistent with tanks located at a gasoline dispensing facility as defined in § 63.11132, are not subject to any of the requirements in this subpart. These tanks must comply with subpart CCCCCC of this part.

* * * * *

(f) If your affected source's throughput ever exceeds an applicable throughput threshold in the definition of ''bulk gasoline terminal'' or in item 1 in table 2 to this subpart, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold. If your bulk gasoline plant's annual average gasoline throughput ever reaches or exceeds 4,000 gallons per day, the bulk gasoline plant will remain subject to the vapor balancing requirements, even if the affected source annual average gasoline throughput later falls below 4,000 gallons per day.

* * * * *

■ 17. Section 63.11082 is amended by revising paragraph (a) to read as follows:

§ 63.11082 What parts of my affected source does this subpart cover?

(a) The emission sources to which this subpart applies are gasoline storage tanks, gasoline loading racks, vapor collection-equipped gasoline cargo tanks, and equipment components in vapor or liquid gasoline service that meet the criteria specified in tables 1 through 4 to this subpart.

* * * * *

■ 18. Revise § 63.11083 to read as follows:

§ 63.11083 When do I have to comply with this subpart?

(a) Except as specified in paragraphs (d) and (e) of this section, if you have a new or reconstructed affected source, you must comply with this subpart according to paragraphs (a)(1) and (2) of this section.

(1) If you start up your affected source before January 10, 2008, you must comply with the standards in this subpart no later than January 10, 2008.

(2) If you start up your affected source after January 10, 2008, you must comply with the standards in this subpart upon startup of your affected source.

(b) Except as specified in paragraphs (d) and (e) of this section, if you have an existing affected source, you must comply with the standards in this subpart no later than January 10, 2011.

(c) If you have an existing affected source that becomes subject to the control requirements in this subpart because of an increase in the daily throughput, as specified in § 63.11086(a) or in option 1 of table 2 to this subpart, you must comply with the standards in this subpart no later than 3 years after the affected source becomes subject to the control requirements in this subpart.

(d) All affected sources that commenced construction or reconstruction on or before June 10, 2022, must comply with the requirements in paragraphs (d)(1) through (5) of this section upon startup or on May 8, 2027, whichever is later. All affected sources that commenced construction or reconstruction after June 10, 2022, must comply with the requirements in paragraphs (d)(1) through (5) of this section upon startup, or on July 8, 2024, whichever is later.

(1) For bulk gasoline plants, the requirements specified in § 63.11086(a)(4) through (6).

(2) For storage vessels at bulk gasoline terminals, pipeline breakout stations, or pipeline pumping stations, the requirements specified in items 1(b), 2(c), and 2(f) in table 1 to this subpart and §§ 63.11087(g) and 63.11092(f)(1)(ii).

(3) For loading racks at bulk gasoline terminals, the requirements specified in items 1(c), 1(f), and 2(c) in table 2 to this subpart.

(4) For equipment leak inspections at bulk gasoline terminals, bulk gasoline plants, pipeline breakout stations, or pipeline pumping stations, the requirements in § 63.11089(c).

(5) For gasoline cargo tanks, the requirements specified in § 63.11092(g)(1)(ii).

(e) All affected sources that commenced construction or reconstruction on or before June 10, 2022, must comply with the requirements specified in items 2(d) and 2(e) in table 1 to this subpart upon startup or the next time the storage vessel is completely emptied and degassed, or by May 8, 2034, whichever occurs first. All affected sources that commenced construction or reconstruction after June 10, 2022, must comply with the requirements specified in items 2(d) and 2(e) in table 1 to this subpart upon startup, or on July 8, 2024, whichever is later.

■ 19. Revise § 63.11085 to read as follows:

§ 63.11085 What are my general duties to minimize emissions?

Each owner or operator of an affected source under this subpart must comply with the requirements of paragraphs (a) through (c) of this section.

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

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

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; and

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

(c) You must keep applicable records and submit reports as specified in §§ 63.11094(g) and 63.11095(d) or § 63.11095(e).

■ 20. Section 63.11086 is amended by:

■ a. Revising the introductory text and paragraph (a) introductory text;

■ b. Adding paragraphs (a)(4) through (6);

■ c. Revising paragraphs (b) and (c);

■ d. Removing and reserving paragraph (d); and

■ e. Revising paragraphs (e) and (i).

The revisions and additions read as follows:

§ 63.11086 What requirements must I meet if my facility is a bulk gasoline plant?

Each owner or operator of an affected bulk gasoline plant, as defined in § 63.11100, must comply with the requirements of paragraphs (a) through (j) of this section.

(a) Except as specified in paragraph (b) of this section, you must only load gasoline into storage tanks and cargo tanks at your facility by utilizing submerged filling, as defined in § 63.11100, and as specified in paragraph (a)(1), (2), or (3) of this section. The applicable distances in paragraphs (a)(1) and (2) of this section shall be measured from the point in the opening of the submerged fill pipe that is the greatest distance from the bottom of the storage tank. Additionally, for bulk gasoline plants with an annual average gasoline throughput of 4,000 gallons per day or more (calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365), you must only load gasoline utilizing vapor balancing as specified in paragraphs (a)(4) through (6) of this section.

* * * * *

(4) Beginning no later than the dates specified in § 63.11083, each bulk gasoline plant with an annual average gasoline throughput of 4,000 gallons per day or more shall be equipped with a vapor balance system between fixed roof gasoline storage tank(s) other than storage tank(s) vented through a closed vent system to a control device and incoming gasoline cargo tank(s) designed to capture and transfer vapors displaced during filling of fixed roof gasoline storage tank(s) other than storage tank(s) vented through a closed vent system to a control device. These lines shall be equipped with fittings that are vapor tight and that automatically and immediately close upon disconnection.

(5) Beginning no later than the dates specified in § 63.11083, each bulk gasoline plant with an annual average gasoline throughput of 4,000 gallons per day or more shall be equipped with a vapor balance system between fixed roof gasoline storage tank(s) other than storage tank(s) vented through a closed vent system to a control device and outgoing gasoline cargo tank(s) designed to capture and transfer vapors displaced during the loading of gasoline cargo tank(s). The vapor balance system shall be designed to prevent any vapors collected at one loading rack from passing to another loading rack.

(6) Beginning no later than the dates specified in § 63.11083, each owner or operator of a bulk gasoline plant subject to this subpart shall act to ensure that the following procedures are followed during all loading, unloading, and storage operations:

(i) The vapor balance system shall be connected between the cargo tank and storage tank during all gasoline transfer operations between a cargo tank and a fixed roof gasoline storage tank other than a storage tank vented through a closed vent system to a control device;

(ii) All storage tank openings, including inspection hatches and gauging and sampling devices shall be vapor tight when not in use;

(iii) No pressure relief device on a gasoline storage tank shall begin to open at a tank pressure less than 18 inches of water to minimize breathing losses;

(iv) The gasoline cargo tank compartment hatch covers shall not be opened during the gasoline transfer;

(v) All vapor balance systems shall be designed and operated at all times to prevent gauge pressure in the gasoline cargo tank from exceeding 18 inches of water and vacuum from exceeding 6 inches of water during product transfers;

(vi) No pressure vacuum relief valve in the bulk gasoline plant vapor balance system shall begin to open at a system pressure of less than 18 inches of water or at a vacuum of less than 6 inches of water; and

(vii) No gasoline shall be transferred into a cargo tank that does not have a current annual certification for vapor-tightness pursuant to the requirements in § 60.502a(e) of this chapter.

(b) Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the control requirements in paragraph (a) of this section but must comply only with the requirements in § 63.11085(b).

(c) You must perform a leak inspection of all equipment in gasoline service and repair leaking equipment according to the requirements specified in § 63.11089.

* * * * *

(e) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later unless you meet the requirements in paragraph (g) of this section. The Initial Notification must contain the information specified in paragraphs (e)(1) through (4) of this section. The notification must be submitted to the applicable U.S. Environmental Protection Agency (EPA) Regional Office and the delegated State authority, as specified in § 63.13.

(1) The name and address of the owner and the operator.

(2) The address (*i.e.,* physical location) of the bulk gasoline plant.

(3) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a), (b), and (c) of this section that apply to you.

(4) A brief description of the bulk gasoline plant, including the number of storage tanks in gasoline service, the capacity of each storage tank in gasoline service, and the average monthly gasoline throughput at the affected source.

* * * * *

(i) You must keep applicable records and submit reports as specified in §§ 63.11094 and 63.11095.

■ 21. Section 63.11087 is amended by revising paragraph (c) and adding paragraph (g) to read as follows:

§ 63.11087 What requirements must I meet for gasoline storage tanks if my facility is a bulk gasoline terminal, pipeline breakout station, or pipeline pumping station?

* * * * *

(c) You must comply with the applicable testing and monitoring requirements specified in § 63.11092(f).

* * * * *

(g) No later than the dates specified in § 63.11083, if your gasoline storage tank is subject to, and complies with, the control requirements of § 60.112b(a)(2), (3), or (4) of this chapter, your storage tank will be deemed in compliance with this section. If your gasoline storage tank is subject to the control requirements of § 60.112b(a)(1) of this chapter, you must conduct lower explosive limit (LEL) monitoring as specified in § 63.11092(f)(1)(ii) to demonstrate compliance with this section. You must report this determination in the Notification of Compliance Status report under § 63.11093(b). The requirements in paragraph (f) of this section do not apply when demonstrating compliance with this paragraph (g).

■ 22. Section 63.11088 is amended by revising the section heading and paragraph (d) to read as follows:

§ 63.11088 What requirements must I meet for gasoline loading racks if my facility is a bulk gasoline terminal?

* * * * *

(d) You must comply with the applicable testing and monitoring requirements specified in § 63.11092. As an alternative to the pressure monitoring requirements specified in § 60.504a(d) of this chapter, you may comply with the requirements specified in § 63.11092(h).

* * * * *

■ 23. Revise § 63.11089 to read as follows:

§ 63.11089 What requirements must I meet for equipment leak inspections if my facility is a bulk gasoline terminal, bulk gasoline plant, pipeline breakout station, or pipeline pumping station?

(a) Each owner or operator of a bulk gasoline terminal, bulk gasoline plant, pipeline breakout station, or pipeline pumping station subject to the provisions of this subpart shall implement a leak detection and repair program for all equipment in gasoline service according to the requirements in paragraph (b) or (c) of this section, as applicable based on the compliance dates specified in § 63.11083.

(b) Perform a monthly leak inspection of all equipment in gasoline service, as defined in § 63.11100. For this inspection, detection methods incorporating sight, sound, and smell are acceptable.

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

(2) Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (b)(3) of this section.

(3) Delay of repair of leaking equipment will be allowed if the repair is not feasible within 15 days. The owner or operator shall provide in the semiannual report specified in § 63.11095(c), the reason(s) why the repair was not feasible and the date each repair was completed.

(c) No later than the dates specified in § 63.11083, comply with the requirements in § 60.502a(j) of this chapter except as provided in paragraphs (c)(1) through (4) of this section. The requirements in paragraph (b) of this section do not apply when demonstrating compliance with this paragraph (c).

(1) The frequency for optical gas imaging (OGI) monitoring shall be annually rather than quarterly as specified in § 60.502a(j)(1)(i) of this chapter.

(2) The frequency for Method 21 monitoring of pumps and valves shall be annually rather than quarterly as specified in § 60.502a(j)(1)(ii)(A) and (B) of this chapter.

(3) The frequency of monitoring of pressure relief devices shall be annually and within 5 calendar days after each pressure release rather than quarterly and within 5 calendar days after each pressure release as specified in § 60.502a(j)(4)(i) of this chapter.

(4) Any pressure relief device that is located at a bulk gasoline plant or pipeline pumping station that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, but in no case more than 30 calendar days after a pressure release.

(d) You must comply with the requirements of this subpart by the applicable dates specified in § 63.11083.

(e) You must submit the applicable notifications as required under § 63.11093.

(f) You must keep records and submit reports as specified in §§ 63.11094 and 63.11095.

■ 24. Section 63.11092 is amended by:

■ a. Revising paragraphs (a)(1) introductory text and (b)(1)(i)(B)(*1*) introductory text;

■ b. Removing and reserving paragraph (b)(1)(i)(B)(*2*)(*iv*);

■ c. Revising paragraphs (b)(1)(i)(B)(*2*)(*v*) and (b)(1)(iii) introductory text;

■ d. Removing and reserving paragraph (b)(1)(iii)(B)(*2*)(*iv*);

■ e. Revising paragraphs (b)(1)(iii)(B)(*2*)(*v*) and (d) through (g); and

■ f. Adding paragraphs (h) and (i).

The revisions and additions read as follows:

§ 63.11092 What testing and monitoring requirements must I meet?

(a) * * *

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (a)(1)(i) or (ii) of this section, except as provided in paragraphs (a)(2) through (4) of this section.

* * * * *

(b) * * *

(1) * * *

(i) * * *

(B) * * *

(*1*) Carbon adsorption devices shall be monitored as specified in paragraphs (b)(1)(i)(B)(*1*)(*i*), (*ii*), and (*iii*) of this section.

* * * * *

(*2*) * * *

(*v*) The owner or operator shall document the maximum vacuum level observed on each carbon bed from each daily inspection and the maximum VOC concentration observed from each carbon bed on each monthly inspection, as defined in the monitoring and inspection plan, and any activation of the automated alarm or shutdown system with a written entry into a logbook or other permanent form of record. Such record shall also include a description of the corrective action taken and whether such corrective actions were taken in a timely manner, as defined in the monitoring and inspection plan, as well as an estimate of the amount of gasoline loaded.

* * * * *

(iii) Where a thermal oxidation system is used, the owner or operator shall monitor the operation of the system as specified in paragraph (b)(1)(iii)(A) or (B) of this section.

* * * * *

(B) * * *

(*2*) * * *

(*v*) The owner or operator shall document any activation of the automated alarm or shutdown system with a written entry into a logbook or other permanent form of record. Such record shall also include a description of the corrective action taken and whether such corrective actions were taken in a timely manner, as defined in the monitoring and inspection plan, as well as an estimate of the amount of gasoline loaded.

* * * * *

(d) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in paragraphs (d)(1) through (3) of this section.

(1) Operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the operating parameter value for the parameters described in paragraph (b)(1) of this section.

(2) In cases where an alternative parameter pursuant to paragraph (b)(1)(iv) or (b)(5)(i) of this section is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value.

(3) Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as appropriate, shall constitute a violation of the emission standard in § 63.11088(a).

(e) Each owner or operator of a bulk gasoline terminal subject to the emission standard in item 1(c) of table 2 to this subpart for loading racks must comply with the requirements in paragraphs (e)(1) through (4) of this section, as applicable.

(1) For each bulk gasoline terminal complying with the emission limitations in item 1 of table 3 to this subpart (thermal oxidation system), conduct a performance test no later than 180 days after becoming subject to the applicable emission limitation in table 3 and conduct subsequent performance tests at least once every 60 calendar months following the methods specified in § 60.503a(a) and (c) of this chapter. Prior to conducting this performance test, you must continue to meet the monitoring and operating limits that apply based on the previously conducted performance test. A previously conducted performance test may be used to satisfy this requirement if the conditions in paragraphs (e)(1)(i) through (v) of this section are met.

(i) The performance test was conducted on or after May 8, 2022.

(ii) No changes have been made to the process or control device since the time of the performance test.

(iii) The operating conditions, test methods, and test requirements (*e.g.,* length of test) used for the previous performance test conform to the requirements in paragraph (e)(1) of this section.

(iv) The temperature in the combustion zone was recorded during the performance test as specified in § 60.503a(c)(8)(i) of this chapter and can be used to establish the operating limit as specified in § 60.503a(c)(8)(ii) through (iv) of this chapter.

(v) The performance test demonstrates compliance with the emission limit specified in item 1(a) in table 3 to this subpart.

(2) For each bulk gasoline terminal complying with the emission limitations in item 1 of table 3 to this subpart (thermal oxidation system), comply with either the provisions in paragraph (e)(2)(i) or (ii) of this section.

(i) Install, operate, and maintain a CPMS to measure the combustion zone temperature according to § 60.504a(a) of this chapter and maintain the 3-hour rolling average combustion zone temperature when gasoline cargo tanks are being loaded at or above the operating limit set during the most recent performance test following the procedures specified in § 60.503a(c)(8) of this chapter. Valid operating data must exclude periods when there is no liquid product being loaded. If previous contents of the cargo tanks are known, you may also exclude periods when liquid product is loaded but no gasoline cargo tanks are being loaded provided that you excluded these periods in the determination of the combustion zone temperature operating limit according to the provisions in § 60.503a(c)(8)(ii) of this chapter.

(ii) Operate each thermal oxidation system in compliance with the requirements for a flare in § 60.502a(c)(3) of this chapter and the monitoring requirements in § 60.504a(c) of this chapter.

(3) For each bulk gasoline terminal complying with the emission limitations in item 2 of table 3 to this subpart (flare), install, operate, and maintain flare continuous parameter monitoring systems as specified in in § 60.504a(c) of this chapter.

(4) For each bulk gasoline terminal complying with the emission limitation in item 3 of table 3 to this subpart (carbon adsorption system, refrigerated condenser, or other vapor recovery system), install, operate, and maintain a continuous emission monitoring system (CEMS) to measure the total organic compounds (TOC) concentration according to § 60.504a(b) of this chapter and conduct performance evaluations as specified in § 60.503a(a) and (d) of this chapter. For periods of CEMS outages, you may use the limited alternative monitoring methods as specified in § 60.504a(e) of this chapter.

(f) Each owner or operator subject to the emission standard in § 63.11087 for gasoline storage tanks shall comply with the requirements in paragraphs (f)(1) through (3) of this section.

(1) If your gasoline storage tank is equipped with an internal floating roof,

(i) You must perform inspections of the floating roof system according to the requirements of § 60.113b(a) of this chapter if you are complying with option 2(b) in table 1 to this subpart, or according to the requirements of § 63.1063(c)(1) if you are complying with option 2(e) in table 1 to this subpart.

(ii) No later than the dates specified in § 63.11083, you must conduct LEL monitoring according to the provisions in § 63.425(j). A deviation of the LEL level is considered an inspection failure under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2) and must be remedied as such. Any repairs must be confirmed effective through re-monitoring of the LEL and meeting the levels in options 2(c) and 2(f) in table 1 to this subpart within the timeframes specified in § 60.113b(a)(2) or § 63.1063(e), as applicable.

(2) If your gasoline storage tank is equipped with an external floating roof, you must perform inspections of the floating roof system according to the requirements of § 60.113b(b) of this chapter if you are complying with option 2(d) in table 1 to this subpart, or according to the requirements of § 63.1063(c)(2) if you are complying with option 2(e) in table 1 to this subpart.

(3) If your gasoline storage tank is equipped with a closed vent system and control device, you must conduct a performance test and determine a monitored operating parameter value in accordance with the requirements in paragraphs (a) through (d) of this section, except that the applicable level of control specified in paragraph (a)(2) of this section shall be a 95-percent reduction in inlet TOC levels rather than 80 mg/l of gasoline loaded.

(g) The annual certification test for gasoline cargo tanks shall consist of the test methods specified in paragraph (g)(1) or (2) of this section. Affected facilities that are subject to subpart XX to part 60 of this chapter may elect, after notification to the subpart XX delegated authority, to comply with paragraphs (g)(1) and (2) of this section.

(1) *EPA Method 27 of appendix A–8 to part 60 of this chapter.* Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 millimeters (mm) of water (18 inches of water), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm of water (6 inches of water), gauge.

(i) The maximum allowable pressure and vacuum changes (Δ p, Δ v) for all affected gasoline cargo tanks is 3 inches of water, or less, in 5 minutes.

(ii) No later than the dates specified in § 63.11083, the maximum allowable pressure and vacuum changes (Δ p, Δ v) for all affected gasoline cargo tanks is provided in column 3 of table 2 in § 63.425(e). The requirements in paragraph (g)(1)(i) of this section do not apply when demonstrating compliance with this paragraph (g)(1)(ii).

(2) *Railcar bubble leak test procedures.* As an alternative to the annual certification test required under paragraph (g)(1) of this section for certification leakage testing of gasoline cargo tanks, the owner or operator may comply with paragraphs (g)(2)(i) and (ii) of this section for railcar cargo tanks, provided the railcar cargo tank meets the requirement in paragraph (g)(2)(iii) of this section.

(i) Comply with the requirements of 49 CFR 173.31(d), 179.7, 180.509, and 180.511 for the periodic testing of railcar cargo tanks.

(ii) The leakage pressure test procedure required under 49 CFR 180.509(j) and used to show no indication of leakage under 49 CFR 180.511(f) shall be a bubble leak test procedure meeting the requirements in

49 CFR 179.7, 180.505, and 180.509. Use of ASTM E515–95 (Reapproved 2000) or BS EN 1593:1999 (incorporated by reference, see § 63.14) complies with those requirements.

(iii) The alternative requirements in this paragraph (g)(2) may not be used for any railcar cargo tank that collects gasoline vapors from a vapor balance system and the system complies with a Federal, State, local, or Tribal rule or permit. A vapor balance system is a piping and collection system designed to collect gasoline vapors displaced from a storage vessel, barge, or other container being loaded, and routes the displaced gasoline vapors into the railcar cargo tank from which liquid gasoline is being unloaded.

(h) As an alternative to the pressure monitoring requirements in § 60.504a(d) of this chapter, you may comply with the pressure monitoring requirements in § 60.503(d) of this chapter during any performance test or performance evaluation conducted under § 63.11092(e) to demonstrate compliance with the provisions in § 60.502a(h) of this chapter.

(i) Performance tests conducted for this subpart shall be conducted under such conditions as the Administrator specifies to the owner or operator, based on representative performance (*i.e.,* performance based on normal operating conditions) of the affected source. Performance tests shall be conducted under representative conditions when liquid product is being loaded into gasoline cargo tanks and shall include periods between gasoline cargo tank loading (when one cargo tank is disconnected and another cargo tank is moved into position for loading) provided that liquid product loading into gasoline cargo tanks is conducted for at least a portion of each 5 minute block of the performance test. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

■ 25. Section 63.11093 is amended by revising paragraph (c) and adding paragraph (e) to read as follows:

§ 63.11093 What notifications must I submit and when?

* * * * *

(c) Each owner or operator of an affected bulk gasoline terminal under this subpart must submit a Notification of Performance Test or Performance Evaluation, as specified in subpart A to this part, prior to initiating testing required by this subpart.

* * * * *

(e) The owner or operator must submit all Notification of Compliance Status reports in PDF format to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead.

■ 26. Revise § 63.11094 to read as follows:

§ 63.11094 What are my recordkeeping requirements?

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station whose storage vessels are subject to the provisions of this subpart shall keep records as specified in paragraphs (a)(1) and (2) of this section.

(1) If you are complying with options 2(a), 2(b), or 2(d) in table 1 to this subpart, keep records as specified in § 60.115b of this chapter except records shall be kept for at least 5 years. If you are complying with the requirements of option 2(e) in table 1 to this subpart, you shall keep records as specified in § 63.1065.

(2) If you are complying with options 2(c) or 2(f) in table 1 to this subpart, keep records of each LEL monitoring event as specified in paragraphs (a)(2)(i) through (ix) of this section for at least 5 years.

(i) Date and time of the LEL monitoring, and the storage vessel being monitored.

(ii) A description of the monitoring event (*e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2); re-monitoring due to high winds; re-monitoring after repair attempt).

(iii) Wind speed at the top of the storage vessel on the date of LEL monitoring.

(iv) The LEL meter manufacturer and model number used, as well as an indication of whether tubing was used during the LEL monitoring, and if so, the type and length of tubing used.

(v) Calibration checks conducted before and after making the measurements, including both the span check and instrumental offset. This includes the hydrocarbon used as the calibration gas, the Certificate of Analysis for the calibration gas(es), the results of the calibration check, and any corrective action for calibration checks that do not meet the required response.

(vi) Location of the measurements and the location of the floating roof.

(vii) Each measurement (taken at least once every 15 seconds). The records should indicate whether the recorded values were automatically corrected using the meter's programming. If the values were not automatically corrected, record both the raw (as the calibration gas) and corrected measurements, as well as the correction factor used.

(viii) Each 5-minute rolling average reading.

(ix) If the vapor concentration of the storage vessel was above 25 percent of the LEL on a 5-minue rolling average basis, a description of whether the floating roof was repaired, replaced, or taken out of gasoline service.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions in items 1(e), 1(f), or 2(c) in table 2 to this subpart or bulk gasoline plant subject to the requirements in § 63.11086(a)(6) shall keep records in either a hardcopy or electronic form of the test results for each gasoline cargo tank loading at the facility as specified in paragraphs (b)(1) through (3) of this section for at least 5 years.

(1) Annual certification testing performed under § 63.11092(g)(1) and periodic railcar bubble leak testing performed under § 63.11092(g)(2).

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

(i) Name of test: Annual Certification Test—Method 27 or Periodic Railcar Bubble Leak Test Procedure.

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

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

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

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

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

(3) If you are complying with the alternative requirements in § 63.11088(b), you must keep records documenting that you have verified the vapor tightness testing according to the requirements of the Administrator.

(c) Each owner or operator subject to the equipment leak provisions of

§ 63.11089 shall prepare and maintain a record describing the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under § 63.11089(b), the record shall contain a full description of the program.

(d) Each owner or operator of an affected source subject to equipment leak inspections under § 63.11089(b) shall record in the logbook for each leak that is detected the information specified in paragraphs (d)(1) through (7) of this section.

(1) The equipment type and identification number.

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

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

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

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

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

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

(e) Each owner or operator of an affected source subject to § 63.11089(c) or § 60.503a(a)(2) of this chapter shall maintain records of each leak inspection and leak identified under § 63.11089(c) or § 60.503a(a)(2) as specified in paragraphs (e)(1) through (5) of this section for at least 5 years.

(1) An indication if the leak inspection was conducted under § 63.11089(c) or § 60.503a(a)(2) of this chapter.

(2) Leak determination method used for the leak inspection.

(3) For leak inspections conducted with Method 21 of appendix A–7 to part 60 of this chapter, keep the following additional records:

(i) Date of inspection.

(ii) Inspector name.

(iii) Monitoring instrument identification.

(iv) Identification of all equipment surveyed and the instrument reading for each piece of equipment.

(v) Date and time of instrument calibration and initials of operator performing the calibration.

(vi) Calibration gas cylinder identification, certification date, and certified concentration.

(vii) Instrument scale used.

(viii) Results of the daily calibration drift assessment.

(4) For leak inspections conducted with OGI, keep the records specified in section 12 of appendix K to part 60 of this chapter.

(5) For each leak detected during a leak inspection or by audio/visual/olfactory methods during normal duties, record the following information:

(i) The equipment type and identification number.

(ii) The date the leak was detected, the name of the person who found the leak, the nature of the leak (*i.e.,* vapor or liquid), and the method of detection (*i.e.,* audio/visual/olfactory, Method 21, or OGI).

(iii) The date of each attempt to repair the leak and the repair methods applied in each attempt to repair the leak.

(iv) The date of successful repair of the leak, the method of monitoring used to confirm the repair, and if Method 21 of appendix A–7 to part 60 of this chapter is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A–7. If OGI is used to confirm the repair, keep video footage of the repair confirmation.

(v) For each repair delayed beyond 15 calendar days after discovery of the leak, record ''Repair delayed'', the reason for the delay, and the expected date of successful repair. The owner or operator (or designate) whose decision it was that repair could not be carried out in the 15- calendar day timeframe must sign the record.

(vi) For each leak that is not repairable, the maximum instrument reading measured by Method 21 of appendix A–7 to part 60 of this chapter at the time the leak is determined to be not repairable, a video captured by the OGI camera showing that emissions are still visible, or a signed record that the leak is still detectable via audio/visual/olfactory methods.

(f) Each owner or operator of a bulk gasoline terminal subject to the loading rack provisions of item 1(c) of table 2 to this subpart or storage vessel provisions in § 63.11092(f) shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under § 63.11092(b) or (f). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the Notification of Compliance Status required under § 63.11093(b):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under § 63.11092(b) or (f); and

(ii) The following information when using a flare under provisions of § 63.11(b) to comply with § 63.11087(a):

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

(B) All visible emissions (VE) readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under § 63.11092(e)(3).

(3) Keep an up-to-date, readily accessible copy of the monitoring and inspection plan required under § 63.11092(b)(1)(i)(B)(*2*) or (b)(1)(iii)(B)(*2*).

(4) Keep an up-to-date, readily accessible record as specified in § 63.11092(b)(1)(i)(B)(*2*)(*v*) or (b)(1)(iii)(B)(*2*)(*v*).

(5) If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in § 63.11092(b), the owner or operator shall submit a description of planned reporting and recordkeeping procedures.

(g) Each owner or operator of a bulk gasoline terminal subject to the loading rack provisions of item 1(c) of table 2 to this subpart shall keep records specified in paragraphs (g)(1) through (3) of this section, as applicable, for at least 5 years unless otherwise specified.

(1) For each thermal oxidation system used to comply with the provisions in § 63.11092(e)(2)(i) by monitoring the combustion zone temperature, for each pressure CPMS used to comply with the requirements in § 60.502a(h) of this chapter, and for each vapor recovery system used to comply with the provisions in item 3 of table 3 to this subpart, maintain records, as applicable, of:

(i) The applicable operating or emission limit for the CMS. For combustion zone temperature operating limits, include the applicable date range the limit applies based on when the performance test was conducted.

(ii) Each 3-hour rolling average combustion zone temperature measured by the temperature CPMS, each 5-minute average reading from the pressure CPMS, and each 3-hour rolling average TOC concentration (as propane) measured by the TOC CEMS.

(iii) For each deviation of the 3-hour rolling average combustion zone temperature operating limit, maximum loading pressure specified in § 60.502a(h) of this chapter, or 3-hour rolling average TOC concentration (as propane), the start date and time, duration, cause, and the corrective action taken.

(iv) For each period when there was a CMS outage or the CMS was out of control, the start date and time, duration, cause, and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(v) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check. For TOC CEMS, include the type of CEMS used (*i.e.,* flame ionization detector, nondispersive infrared analyzer) and an indication of whether methane is excluded from the TOC concentration reported in paragraph (g)(1)(ii) of this section.

(vi) TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, also keep records of:

(A) The quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS outage.

(B) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS outage.

(C) The quantity of liquid product loaded in gasoline cargo tanks for each adsorption cycle while using the alternative.

(D) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles for each desorption cycle while using the alternative.

(2) For each thermal oxidation system used to comply with the provision in § 63.11092(e)(2)(ii) and for each flare used to comply with the provision in item 2 of table 3 to this subpart, maintain records of:

(i) The output of the monitoring device used to detect the presence of a pilot flame as required in § 63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when gasoline vapors were routed to the flare for a minimum of 5 years. The record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in paragraphs (g)(2)(ii)(A) and (B) of this section, as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 of appendix A–7 to part 60 of this chapter, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of appendix A–7 to part 60 of this chapter were not conducted for the full 2-hour period, the record must include the date, the start and end time of the visible emissions observation, and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) Each 15-minute block period during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) when liquid product is being loaded into gasoline cargo tanks for at least 15-minutes identifying the specific operating limit that was not met.

(iv) The 15-minute block average cumulative flows for the thermal oxidation system vent gas or flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under § 63.670(i), along with the date and start and end time for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the thermal oxidation system vent gas, flare vent gas, or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required supplemental gas flow rate (winter and summer, if applicable) and the actual monitored supplemental gas flow rate for the 15-minute block. Retain the supplemental gas flow rate records for a minimum of 5 years.

(v) The thermal oxidation system vent gas or flare vent gas compositions specified to be monitored under § 63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHV_{vg} analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years. If you demonstrate your gas streams have consistent composition using the provisions in § 63.670(j)(6) as specified in § 60.502a(c)(3)(vii) of this chapter, retain records of the required minimum ratio of gasoline loaded to total liquid product loaded and the actual ratio on a 15-minute block basis. If applicable, you must retain records of the required minimum gasoline loading rate as specified in § 60.502a(c)(3)(vii) and the actual gasoline loading rate on a 15-minute block basis for a minimum of 5 years.

(vi) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n), as applicable.

(vii) All periods during which the owner or operator does not perform monitoring according to the procedures in § 63.670(g), (i), and (j) or in § 60.502a(c)(3)(vii) and (viii) of this chapter as applicable. Note the start date, start time, and duration in minutes for each period.

(viii) An indication of whether ''vapors displaced from gasoline cargo tanks during product loading'' excludes periods when liquid product is loaded but no gasoline cargo tanks are being loaded or if liquid product loading is assumed to be loaded into gasoline cargo tanks according to the provisions in § 60.502a(c)(3)(i) of this chapter, records of all time periods when ''vapors displaced from gasoline cargo tanks during product loading'', and records of time periods when there were no ''vapors displaced from gasoline cargo tanks during product loading''.

(ix) If you comply with the flare tip velocity operating limit using the one-time flare tip velocity operating limit compliance assessment as provided in § 60.502a(c)(3)(ix) of this chapter, maintain records of the applicable one-time flare tip velocity operating limit compliance assessment for as long as you use this compliance method.

(x) For each parameter monitored using a CMS, retain the records specified in paragraphs (g)(2)(x)(A) through (C) of this section, as applicable:

(A) For each deviation, record the start date and time, duration, cause, and corrective action taken.

(B) For each period when there is a CMS outage or the CMS is out of control, record the start date and time, duration, cause, and corrective action taken.

(C) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check.

(3) Records of all 5-minute time periods during which liquid product is loaded into gasoline cargo tanks or assumed to be loaded into gasoline cargo tanks and records of all 5-minute time periods when there was no liquid product loaded into gasoline cargo tanks.

(h) Each owner or operator of a bulk gasoline terminal subject to the provisions in items 1(e), 1(f), or 2(c) in table 2 to this subpart or bulk gasoline plant subject to the requirements in § 63.11086(a)(6) shall maintain records of each instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502(e)(1) or § 60.502a(e)(1) of this chapter, as applicable, was not provided or available in the terminal's or plant's records for at least 5 years. These records shall include, at a minimum:

(1) Cargo tank owner and address.

(2) Cargo tank identification number.

(3) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(4) Date proper documentation was received or statement that proper documentation was never received.

(i) Each owner or operator of a bulk gasoline terminal or bulk gasoline plant subject to the provisions of this subpart shall maintain records for at least 5 years of each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, or, if applicable, not equipped with vapor collection or balancing equipment that is compatible with the terminal's vapor collection system or plant's vapor balancing system. These records shall include, at a minimum:

(1) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(2) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(3) Cargo tank identification number.

(j) Each owner or operator of a bulk gasoline plant subject to the requirements in § 63.11086(a)(6) shall maintain records for at least 5 years of instances when gasoline was loaded between gasoline cargo tanks and storage tanks and the plant's vapor balancing system was not properly connected between the gasoline cargo tank and storage tank. These records shall include, at a minimum:

(1) Date and time of gasoline loading between a gasoline cargo tank and a storage tank that was not properly connected.

(2) Cargo tank identification number and storage tank identification number.

(k) Each owner or operator of an affected source under this subpart shall keep the following records for each deviation of an emissions limitation (including operating limit), work practice standard, or operation and maintenance requirement in this subpart.

(1) Date, start time, and duration of each deviation.

(2) List of the affected sources or equipment for each deviation, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(3) Actions taken to minimize emissions in accordance with § 63.11085(a).

(l) Each owner or operator of a bulk gasoline terminal or bulk gasoline plant subject to the provisions of this subpart shall maintain records of the average gasoline throughput (in gallons per day) for at least 5 years.

(m) Keep written procedures required under § 63.8(d)(2) on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you shall keep previous (*i.e.,* superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action shall be included in the plan as required under § 63.8(d)(2).

(n) Keep records of each performance test or performance evaluation conducted and each notification and report submitted to the Administrator for at least 5 years. For each performance test, include an indication of whether liquid product loading is assumed to be loaded into a gasoline cargo tank or periods when liquid product is loaded but no gasoline cargo tanks are being loaded are excluded in the determination of the combustion zone temperature operating limit according to the provision in § 60.503a(c)(8)(ii) of this chapter. If complying with the alternative in § 63.11092(h), for each performance test or performance evaluation conducted, include the pressure every 5 minutes while a gasoline cargo tank is being loaded and the highest instantaneous pressure that occurs during each loading.

(o) Any records required to be maintained by this subpart that are submitted electronically via the EPA's Compliance and Emissions Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated authority or the EPA as part of an on-site compliance evaluation.

■ 27. Revise § 63.11095 to read as follows:

§ 63.11095 What are my reporting requirements?

(a) *Reporting requirements for performance tests.* Prior to November 4, 2024, each owner or operator of an affected source under this subpart shall submit performance test reports to the Administrator according to the requirements in § 63.13. Beginning on November 4, 2024, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedures specified in § 63.9(k). As required by § 63.7(g)(2)(iv), you must include the value for the combustion zone temperature operating parameter limit set based on your performance test in the performance test report. If the monitoring alternative in § 63.11092(h) is used, indicate that this monitoring alternative is being used, identify each loading rack that loads gasoline cargo tanks at the bulk gasoline terminal subject to the provisions of this subpart, and report the highest instantaneous pressure monitored during the performance test or performance evaluation for each identified loading rack. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file.

(b) *Reporting requirements for performance evaluations.* Prior to November 4, 2024, each owner or operator of an affected source under this subpart shall submit performance evaluations to the Administrator according to the requirements in § 63.13. Beginning on November 4, 2024, within 60 days after the date of completing each CEMS performance evaluation, you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). If the monitoring alternative in § 63.11092(h) is used, indicate that this monitoring alternative is being used, identify each loading rack that loads gasoline cargo tanks at the bulk gasoline terminal subject to the provisions of this subpart, and report the highest instantaneous pressure monitored during the performance test or performance evaluation for each identified loading rack. The results of performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or an alternate electronic file.

(c) *Reporting requirements prior to May 8, 2027.* Prior to May 8, 2027, each owner or operator of a source subject to the requirements of this subpart shall submit reports as specified in paragraphs (c)(1) through (3) of this section, as applicable.

(1) Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:

(i) For storage vessels, if you are complying with options 2(a), 2(b), or 2(d) in table 1 to this subpart, the information specified in § 60.115b(a), (b), or (c) of this chapter, depending upon the control equipment installed, or, if you are complying with option 2(e) in table 1 to this subpart, the information specified in § 63.1066.

(ii) For loading racks, each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility.

(iii) For equipment leak inspections, the number of equipment leaks not repaired within 15 days after detection.

(iv) For storage vessels complying with § 63.11087(b) after January 10, 2011, the storage vessel's Notice of Compliance Status information can be included in the next semi-annual compliance report in lieu of filing a separate Notification of Compliance Status report under § 63.11093.

(2) Each owner or operator of an affected source subject to the control requirements of this subpart shall submit an excess emissions report to the Administrator at the time the semiannual compliance report is submitted. Excess emissions events under this subpart, and the information to be included in the excess emissions report, are specified in paragraphs (c)(2)(i) through (v) of this section.

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

(ii) Each reloading of a non-vapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with § 63.11094(b).

(iii) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under § 63.11092(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(iv) [Reserved]

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

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

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

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

(D) The date of successful repair.

(3) Each owner or operator of a bulk gasoline plant or a pipeline pumping station shall submit a semiannual excess emissions report, including the information specified in paragraphs (c)(1)(iii) and (c)(2)(v) of this section, only for a 6-month period during which an excess emission event has occurred. If no excess emission events have occurred during the previous 6-month period, no report is required.

(d) *Reporting requirements for semiannual reports on or after May 8, 2027.* On or after May 8, 2027, you must submit to the Administrator semiannual reports with the applicable information in paragraphs (d)(1) through (9) of this section following the procedure specified in paragraph (e) of this section.

(1) Report the following general facility information:

(i) Facility name.

(ii) Facility physical address, including city, county, and State.

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places.

(iv) The following information for the contact person:

(A) Name.

(B) Mailing address.

(C) Telephone number.

(D) Email address.

(v) The type of facility (bulk gasoline plant with an annual average gasoline throughput less than 4,000 gallons per day; bulk gasoline plant with an annual average gasoline throughput of 4,000 gallons per day or more; bulk gasoline terminal with a gasoline throughput (total of all racks) less than 250,000 gallons per day; bulk gasoline terminal with a gasoline throughput (total of all racks) of 250,000 gallons per day or more; pipeline breakout station; or pipeline pumping station).

(vi) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI.

(vii) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (d)(1)(vii).

(2) For each thermal oxidation system used to comply with the provision in § 63.11092(e)(2)(i) by monitoring the combustion zone temperature, for each pressure CPMS used to comply with the requirements in § 60.502a(h) of this chapter, and for each vapor recovery system used to comply with the provisions in item 3 of table 3 to this subpart, report the following information for the CMS:

(i) For all instances when the temperature CPMS measured 3-hour rolling averages below the established operating limit or when the vapor collection system pressure exceeded the maximum loading pressure specified in § 60.502a(h) when liquid product was being loaded into gasoline cargo tanks or when the TOC CEMS measured 3-hour rolling average concentrations higher than the applicable emission limitation when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average combustion zone temperature, average pressure, or 3-hour rolling average TOC concentration during the deviation. For TOC concentration, indicate whether methane is excluded from the TOC concentration.

(D) A unique identifier for the CMS.

(E) The make, model number, and date of last calibration check of the CMS.

(F) The cause of the deviation and the corrective action taken.

(ii) For all instances that the temperature CPMS for measuring the combustion zone temperature or pressure CPMS was not operating or out of control when liquid product was loaded into gasoline cargo tanks, or the TOC CEMS was not operating or was out of control when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the CMS.

(D) The make, model number, and date of last calibration check of the CMS.

(E) The cause of the deviation and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter.

(F) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, report either an indication that there were no deviations from the operating limits when using the limited alternative or report the number of each of the following types of deviations that occurred during the use of the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter.

(*1*) The number of adsorption cycles when the quantity of liquid product loaded in gasoline cargo tanks exceeded the operating limit established in § 60.504a(e)(1) of this chapter. Enter 0 if no deviations of this type.

(*2*) The number of desorption cycles when the vacuum pressure was below the average vacuum pressure as specified in § 60.504a(e)(2)(i) of this chapter. Enter 0 if no deviations of this type.

(*3*) The number of desorption cycles when the quantity of purge gas used was below the average quantity of purge gas as specified in § 60.504a(e)(2)(ii) of this chapter. Enter 0 if no deviations of this type.

(*4*) The number of desorption cycles when the duration of the vacuum/purge cycle was less than the average duration as specified in § 60.504a(e)(2)(iii) of this chapter. Enter 0 if no deviations of this type.

(3) For each thermal oxidation system used to comply with the provision in § 63.11092(e)(2)(ii) and each flare used to comply with the provision in item 2 of table 3 to this subpart, report:

(i) The date and start and end times for each of the following instances:

(A) Each 15-minute block during which there was at least one minute when gasoline vapors were routed to the flare and no pilot flame was present.

(B) Each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Additionally, report the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(C) Each 15-minute period for which the applicable operating limits specified in § 63.670(d) through (f) were not met. You must identify the specific operating limit that was not met. Additionally, report the information in paragraphs (d)(3)(i)(C)(*1*) through (*3*) of this section, as applicable.

(*1*) If you use the loading rate operating limits as determined in § 60.502a(c)(3)(vii) of this chapter alone or in combination with the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum ratio and the actual ratio of gasoline loaded to total product loaded for the rolling 15-minute period and, if applicable, the required minimum quantity and the actual quantity of gasoline loaded, in gallons, for the rolling 15-minute period.

(*2*) If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum supplemental gas flow rate and the actual supplemental gas flow rate including units of flow rates for the 15-minute block.

(*3*) If you use parameter monitoring systems other than those specified in paragraphs (d)(3)(i)(C)(*1*) and (*2*) of this section, the value of the net heating value operating parameter(s) during the deviation determined following the methods in § 63.670(k) through (n) as applicable.

(ii) The start date, start time, and duration in minutes for each period when ''vapors displaced from gasoline cargo tanks during product loading'' were routed to the flare or thermal oxidation system and the applicable monitoring was not performed.

(iii) For each instance reported under paragraphs (d)(3)(i) and (ii) of this section that involves CMS, report the following information:

(A) A unique identifier for the CMS.

(B) The make, model number, and date of last calibration check of the CMS.

(C) The cause of the deviation or downtime and the corrective action taken.

(4) For any instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 63.11094(b) was not provided or available in the terminal's records, report:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) For each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 63.11100, not equipped with vapor collection or balancing equipment that is compatible with the terminal's vapor collection system or plant's vapor balancing system, or not properly connected to the terminal's vapor collection system or plant's vapor balancing system, report:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(ii) The type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(6) For each instance when gasoline was loaded between gasoline cargo tanks and storage tanks and the plant's vapor balancing system was not properly connected between the gasoline cargo tank and storage tank, report:

(i) Date and time of gasoline loading between a gasoline cargo tank and a storage tank that was not properly connected.

(ii) Cargo tank identification number and storage tank identification number.

(7) Report the following information for each leak inspection and each leak identified under § 63.11089(c) and § 60.503a(a)(2) of this chapter.

(i) For each leak detected during a leak inspection required under § 63.11089(c) and § 60.503a(a)(2) of this chapter, report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21).

(C) The total number and type of equipment for which leaks were detected.

(D) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(E) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(F) The total number and types of equipment placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(ii) For leaks identified under § 63.11089(c) by audio/visual/olfactory methods during normal duties report:

(A) The total number and type of equipment for which leaks were identified.

(B) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(C) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(D) The total number and type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(iii) The total number of leaks on the delay of repair list at the start of the reporting period.

(iv) The total number of leaks on the delay of repair list at the end of the reporting period.

(v) For each leak that was on the delay of repair list at any time during the reporting period, report:

(A) Unique equipment identification number.

(B) Type of equipment.

(C) Leak determination method (OGI, Method 21, or audio/visual/olfactory).

(D) The reason(s) why the repair was not feasible within 15 calendar days.

(E) If applicable, the date repair was completed.

(8) For each gasoline storage tank subject to requirements in item 2 of table 1 to this subpart, report:

(i) If you are complying with options 2(a), 2(b), or 2(d) in table 1 to this subpart, the information specified in § 60.115b(a) or (b) of this chapter or deviations in measured parameter values from the plan specified in § 60.115b(c) of this chapter, depending upon the control equipment installed, or, if you are complying with option 2(e) in table 1 to this subpart, the information specified in § 63.1066(b).

(ii) If you are complying with options 2(c) or 2(e) in table 1 to this subpart, for each deviation in LEL monitoring, report:

(A) Date and start and end times of the LEL monitoring, and the tank being monitored.

(B) Description of the monitoring event, *e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2) of this chapter; re-monitoring due to high winds; re-monitoring after repair attempt.

(C) Wind speed in miles per hour at the top of the tank on the date of LEL monitoring.

(D) The highest 5-minute rolling average reading during the monitoring event.

(E) Whether the floating roof was repaired, replaced, or taken out of gasoline service. If the floating roof was repaired or replaced, also report the information in paragraphs (d)(8)(ii)(A) through (D) of this section for each re-monitoring conducted to confirm the repair.

(9) If there were no deviations from the emission limitations, operating parameters, or work practice standards, then provide a statement that there were no deviations from the emission limitations, operating parameters, or work practice standards during the reporting period. If there were no periods during which a continuous monitoring system (including a CEMS or CPMS) was inoperable or out-of-control, then provide a statement that there were no periods during which a continuous monitoring system was inoperable or out-of-control during the reporting period.

(e) *Requirements for semiannual report submissions.* Each owner or operator of an affected source under this subpart shall submit semiannual compliance reports with the information specified in paragraph (c) or (d) of this section to the Administrator according to the requirements in § 63.13. Beginning on May 8, 2027, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, you must submit all subsequent semiannual compliance reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

■ 28. Revise § 63.11098 to read as follows:

§ 63.11098 What parts of the General Provisions apply to me?

Table 4 to this subpart shows which parts of the General Provisions apply to you.

■ 29. Section 63.11099 is amended by revising paragraphs (c) introductory text and (c)(5) to read as follows:

§ 63.11099 Who implements and enforces this subpart?

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 30. Section 63.11100 is amended by:

■ a. Revising the introductory text and the definitions of ''Bulk gasoline terminal'', ''Flare'', ''Gasoline'', ''Operating parameter value'', ''Pipeline breakout station'', and ''Pipeline pumping station;'' and

■ b. Adding in alphabetical order a definition for ''Thermal oxidation system''.

The revisions and addition read as follows:

§ 63.11100 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA), in subparts A, K, Ka, Kb, and XXa of part 60 of this chapter, or in subparts A, R, and WW of this part. All terms defined in both subpart A of part 60 of this chapter and subparts A, R, and WW of this part shall have the meaning given in subparts A, R, and WW of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

* * * * *

Bulk gasoline terminal means:

(1) Prior to May 8, 2027, any gasoline storage and distribution facility that receives gasoline by pipeline, ship or barge, or cargo tank and has a gasoline throughput of 20,000 gallons per day or greater. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

(2) On or after May 8, 2027, any gasoline facility which receives gasoline by pipeline, ship, barge, or cargo tank and subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities and has a gasoline throughput of 20,000 gallons per day (75,700 liters per day) or greater. Gasoline throughput shall be the maximum calculated design throughput for the facility as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

* * * * *

Flare means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 4.0 pounds per square inch (27.6 kilopascals) or greater, which is used as a fuel for internal combustion engines.

* * * * *

Operating parameter value means a value for an operating or emission parameter of the vapor processing system (*e.g.,* temperature) which, if maintained continuously by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with the applicable emission standard. The operating parameter value is determined using the procedures specified in § 63.11092(b) and (e).

Pipeline breakout station means:

(1) Prior to May 8, 2027, a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

(2) On or after May 8, 2027, a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline to other facilities. *Pipeline breakout stations* do not have loading racks where gasoline is loaded into cargo tanks. If any gasoline is loaded into cargo tanks, the facility is a bulk gasoline terminal for the purposes of this subpart provided the facility-wide gasoline throughput (including pipeline throughput) exceeds the limits specified for bulk gasoline terminals.

Pipeline pumping station means a facility along a pipeline containing pumps to maintain the desired pressure and flow of product through the pipeline, and not containing gasoline loading racks or gasoline storage tanks other than surge control tanks.

* * * * *

Thermal oxidation system means an enclosed combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures. *Thermal oxidation systems* emit pollutants through a conveyance suitable to conduct a performance test.

* * * * *

■ 31. Table 1 to subpart BBBBBB of part 63 is revised to read as follows:

TABLE 1 TO SUBPART BBBBBB OF PART 63—APPLICABILITY CRITERIA, EMISSION LIMITS, AND MANAGEMENT PRACTICES FOR STORAGE TANKS

If you own or operate . . .	Then you must . . .
1. A gasoline storage tank meeting either of the following conditions:. (i) a capacity of less than 75 cubic meters (m^3); or .... (ii) a capacity of less than 151 m^3 and a gasoline throughput of 480 gallons per day or less. Gallons per day is calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365.	(a) Equip each gasoline storage tank with a fixed roof that is mounted to the storage tank in a stationary manner, and maintain all openings in a closed position at all times when not in use; and (b) No later than the dates specified in § 63.11083, all pressure relief devices on each gasoline storage tank must be set to no less than 18 inches of water at all times to minimize breathing losses.

TABLE 1 TO SUBPART BBBBBB OF PART 63—APPLICABILITY CRITERIA, EMISSION LIMITS, AND MANAGEMENT PRACTICES FOR STORAGE TANKS—Continued

If you own or operate . . .	Then you must . . .
2. A gasoline storage tank with a capacity of greater than or equal to 75 m^3 and not meeting any of the criteria specified in item 1 of this table.	Do the following: (a) Reduce emissions of total organic HAP or TOC by 95 weight-percent with a closed vent system and control device, as specified in § 60.112b(a)(3) of this chapter; or (b) Equip each internal floating roof gasoline storage tank according to the requirements in § 60.112b(a)(1) of this chapter, except for the secondary seal requirements under § 60.112b(a)(1)(ii)(B) and the requirements in § 60.112b(a)(1)(iv) through (ix) of this chapter; and (c) No later than the dates specified in § 63.11083, equip, maintain, and operate each internal floating roof control system to maintain the vapor concentration within the storage tank above the floating roof at or below 25 percent of the LEL on a 5-minute rolling average basis without the use of purge gas, which may require additional controls beyond those specified in item 2(b) of this table; and (d) Equip each external floating roof gasoline storage tank according to the requirements in § 60.112b(a)(2) of this chapter, except that the requirements of § 60.112b(a)(2)(ii) of this chapter shall only be required if such storage tank does not currently meet the requirements of § 60.112b(a)(2)(i) of this chapter; by the dates specified in § 63.11083, all external floating roofs must meet the requirements of § 60.112b(a)(2)(ii) of this chapter; or (e) Equip and operate each internal and external floating roof gasoline storage tank according to the applicable requirements in § 63.1063(a)(1) and (b), except for the secondary seal requirements under § 63.1063(a)(1)(i)(C) and (D), and equip each external floating roof gasoline storage tank according to the requirements of § 63.1063(a)(2) by the dates specified in § 63.11087(b) if such storage tank does not currently meet the requirements of § 63.1063(a)(1); by the dates specified in § 63.11083, all external floating roofs must meet the requirements of § 63.1063(a)(2); and (f) No later than the dates specified in § 63.11083, equip, maintain, and operate each internal floating roof control system to maintain the vapor concentration within the storage tank above the floating roof at or below 25 percent of the LEL on a 5-minute rolling average basis without the use of purge gas, which may require additional controls beyond those specified in item 2(e) of this table.
3. A surge control tank	Equip each tank with a fixed roof that is mounted to the tank in a stationary manner and with a pressure/vacuum vent with a positive cracking pressure of no less than 0.50 inches of water. Maintain all openings in a closed position at all times when not in use.

■ 32. Table 2 to subpart BBBBBB of part 63 is revised to read as follows:

TABLE 2 TO SUBPART BBBBBB OF PART 63—APPLICABILITY CRITERIA, EMISSION LIMITS, AND MANAGEMENT PRACTICES FOR LOADING RACKS

If you own or operate . . .	Then you must . . .
1. A bulk gasoline terminal loading rack(s) with a gasoline throughput (total of all racks) of 250,000 gallons per day, or greater (“large bulk gasoline terminal”). Gallons per day is calculated by summing the current day’s throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365.	(a) Equip your loading rack(s) with a vapor collection system designed and operated to collect the TOC vapors displaced from cargo tanks during product loading; and (b) Reduce emissions of TOC to less than or equal to 80 mg/l of gasoline loaded into gasoline cargo tanks at the loading rack; and (c) No later than the dates specified in § 63.11083, reduce emissions of TOC to the applicable limits in table 3 to this subpart. The requirements in item 1(b) do not apply when demonstrating compliance with this item; and (d) Design and operate the vapor collection system to prevent any TOC vapors collected at one loading rack or lane from passing through another loading rack or lane to the atmosphere; and (e) Limit the loading of gasoline into gasoline cargo tanks that are vapor tight using the procedures specified in § 60.502(e) through (j) of this chapter. For the purposes of this section, the term “tank truck” as used in § 60.502(e) through (j) means “gasoline cargo tank” as defined in § 63.11100; and (f) No later than the dates specified in § 63.11083, limit the loading of liquid product into gasoline cargo tanks using the procedures specified in § 60.502a(e) through (i) of this chapter and in § 63.11092(g) and (h). The requirements in item 1(e) do not apply when demonstrating compliance with this item.

TABLE 2 TO SUBPART BBBBBB OF PART 63—APPLICABILITY CRITERIA, EMISSION LIMITS, AND MANAGEMENT PRACTICES FOR LOADING RACKS—Continued

If you own or operate . . .	Then you must . . .
2. A bulk gasoline terminal loading rack(s) with a gasoline throughput (total of all racks) of less than 250,000 gallons per day. Gallons per day is calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365.	(a) Use submerged filling with a submerged fill pipe that is no more than 6 inches from the bottom of the cargo tank; and (b) Make records available within 24 hours of a request by the Administrator to document your gasoline throughput. (c) No later than the dates specified in § 63.11083, limit the loading of gasoline into gasoline cargo tanks that are vapor tight using the procedures specified in § 60.502a(e) of this chapter and in § 63.11092(g).

■ 33. Table 3 to subpart BBBBBB of part 63 is revised to read as follows:

TABLE 3 TO SUBPART BBBBBB OF PART 63—EMISSION LIMITATIONS AND REQUIREMENTS FOR LARGE BULK GASOLINE TERMINALS BASED ON CONTROL SYSTEM USED

If you operate . . .	Then you must . . .
1. A thermal oxidation system	(a) Reduce emissions of TOC to less than or equal to 35 mg/l of liquid product loaded into gasoline cargo tanks at the loading rack; and (b) Continuously meet the applicable operating limit as specified in § 63.11092(e)(2).
2. A flare	Operate the flare following the applicable requirements specified in § 60.502a(c)(3) of this chapter.
3. A carbon adsorption system, refrigerated condenser, or other vapor recovery system..	(a) Reduce emissions of TOC to less than or equal to 19,200 parts per million by volume as propane determined on a 3-hour rolling average considering all periods when the vapor recovery system is capable of processing gasoline vapors, including periods when liquid product is being loaded, during carbon bed regeneration, and when preparing the beds for reuse. (b) Operate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 63.4, the use of diluents to achieve compliance with a relevant standard based on the concentration of a pollutant in the effluent discharged to the atmosphere is prohibited.

■ 34. Table 4 to subpart BBBBBB of part 63 is added to read as follows:

TABLE 4 TO SUBPART BBBBBB OF PART 63—APPLICABILITY OF GENERAL PROVISIONS

Citation	Subject	Brief description	Applies to this subpart
§ 63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions, notifications.	Yes, specific requirements given in § 63.11081.
§ 63.1(c)(2)	Title V permit	Requirements for obtaining a title V permit from the applicable permitting authority.	Yes, § 63.11081(b) exempts identified area sources from the obligation to obtain title V operating permits.
§ 63.2	Definitions	Definitions for standards in this part	Yes, additional definitions in § 63.11100.
§ 63.3	Units and Abbreviations	Units and abbreviations for standards under this part ..	Yes.
§ 63.4	Prohibited Activities and Circumvention.	Prohibited activities; circumvention, severability	Yes.
§ 63.5	Construction/Reconstruction.	Applicability; applications; approvals	Yes.
§ 63.6(a)	Compliance with Standards/Operation & Maintenance Applicability.	General Provisions apply unless compliance extension; General Provisions apply to area sources that become major.	Yes.
§ 63.6(b)(1) through (4)	Compliance Dates for New and Reconstructed Sources.	Dates standards apply for new and reconstructed sources.	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§ 63.6(b)(6)	[Reserved].		

TABLE 4 TO SUBPART BBBBBB OF PART 63—APPLICABILITY OF GENERAL PROVISIONS—Continued

Citation	Subject	Brief description	Applies to this subpart
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources that Become Major.	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	No.
§ 63.6(c)(1) and (2)	Compliance Dates for Existing Sources.	Comply according to date in this subpart	No, § 63.11083 specifies the compliance dates.
§ 63.6(c)(3) and (4)	[Reserved].		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources that Become Major.	Area sources that become major must comply with major source standards by date indicated in this subpart or by equivalent time period (*e.g.,* 3 years).	No.
§ 63.6(d)	[Reserved].		
§ 63.6(e)(1)(i)	General duty to minimize emissions.	Operate to minimize emissions at all times; information Administrator will use to determine if operation and maintenance requirements were met.	No. *See* § 63.11085 for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as possible.	Owner or operator must correct malfunctions as soon as possible.	No.
§ 63.6(e)(2)	[Reserved].		
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) plan.	Requirement for SSM plan; content of SSM plan; actions during SSM.	No.
§ 63.6(f)(1)	Compliance Except During SSM.	You must comply with emission standards at all times except during SSM.	No.
§ 63.6(f)(2) and (3)	Methods for Determining Compliance.	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.
§ 63.6(g)(1) through (3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)(1)	Compliance with Opacity/VE Standards.	You must comply with opacity/VE standards at all times except during SSM.	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards.	If standard does not state test method, use EPA Method 9 for opacity in appendix A to part 60 of this chapter and EPA Method 22 for VE in appendix A to part 60 of this chapter.	No.
§ 63.6(h)(2)(ii)	[Reserved].		
§ 63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards.	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart.	No.
§ 63.6(h)(3)	[Reserved].		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date.	Must notify Administrator of anticipated date of observation.	No.
§ 63.6(h)(5)(i) and (iii) through (v).	Conducting Opacity/VE Observations.	Dates and schedule for conducting opacity/VE observations.	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with 30 6-minute averages.	No.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations.	Must keep records available and allow Administrator to inspect.	No.
§ 63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data from Performance Test.	Must submit COMS data with other performance test data.	No.
§ 63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9.	Can submit COMS data instead of EPA Method 9 results even if this subpart requires EPA Method 9 in appendix A of part 60 of this chapter, but must notify Administrator before performance test.	No.
§ 63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test.	To determine compliance, must reduce COMS data to 6-minute averages.	No.
§ 63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to § 63.8(e); COMS are properly maintained and operated according to § 63.8(c) and data quality as § 63.8(d).	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 (in appendix A to part 60 of this chapter) observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B to part 60 of this chapter, and data have not been altered.	No.

TABLE 4 TO SUBPART BBBBBB OF PART 63—APPLICABILITY OF GENERAL PROVISIONS—Continued

Citation	Subject	Brief description	Applies to this subpart
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all COMS, EPA Method 9 (in appendix A to part 60 of this chapter), and EPA Method 22 (in appendix A to part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance.	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard.	No.
§ 63.6(i)(1) through (14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§ 63.6(j)	Presidential Compliance Exemption.	President may exempt any source from requirement to comply with this subpart.	Yes.
§ 63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date.	Yes.
§ 63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time.	Yes.
§ 63.7(a)(4)	Force Majeure	Provisions for delayed performance tests due to force majeure.	Yes.
§ 63.7(b)(1)	Notification of Performance Test.	Must notify Administrator 60 days before the test	Yes.
§ 63.7(b)(2)	Notification of Re-scheduling.	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay.	Yes.
§ 63.7(c)	Quality Assurance (QA)/Test Plan.	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing.	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§ 63.7(e)(1)	Conditions for Conducting Performance Tests.	Performance test must be conducted under representative conditions.	No, § 63.11092(i) specifies conditions for conducting performance tests.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative.	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used.	Yes, except for testing conducted under § 63.11092(a) and (e).
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method.	Yes.
§ 63.7(g)	Performance Test Data Analysis.	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the notification of compliance status; keep data for 5 years.	Yes, except this subpart specifies how and when the performance test and performance evaluation results are reported.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements.	Subject to all monitoring requirements in standard	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance specifications in appendix B to part 60 of this chapter apply.	Yes.
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in § 63.11 apply	Yes.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§ 63.8(b)(2) and (3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§ 63.8(c)(1) introductory text	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§ 63.8(c)(1)(i)	Operation and Maintenance of CMS.	Must maintain and operate each CMS as specified in § 63.6(e)(1).	No.
§ 63.8(c)(1)(ii)	Operation and Maintenance of CMS.	Must keep parts for routine repairs readily available	Yes.
§ 63.8(c)(1)(iii)	Operation and Maintenance of CMS.	Requirement to develop SSM Plan for CMS	No.

TABLE 4 TO SUBPART BBBBBB OF PART 63—APPLICABILITY OF GENERAL PROVISIONS—Continued

Citation	Subject	Brief description	Applies to this subpart
§ 63.8(c)(2) through (8)	CMS Requirements	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test.	Yes.
§ 63.8(d)(1) and (2)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc..	Yes.
§ 63.8(d)(3)	CMS Quality Control Records.	Must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions.	No. This subpart specifies CMS records requirements.
§ 63.8(e)	CMS Performance Evaluation.	Notification, performance evaluation test plan, reports	Yes, except this subpart specifies how and when the performance evaluation results are reported.
§ 63.8(f)(1) through (5)	Alternative Monitoring Method.	Procedures for Administrator to approve alternative monitoring.	Yes.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test.	Procedures for Administrator to approve alternative relative accuracy tests for CEMS.	Yes.
§ 63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average.	Yes.
§ 63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§ 63.9(b)(1), (2), (4), and (5)	Initial Notifications	Submit notification of being subject to standard; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each.	Yes.
§ 63.9(b)(3)	[Reserved].		
§ 63.9(c)	Request for Compliance Extension.	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate.	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Sources.	Notification for new sources subject to special compliance requirements.	Yes.
§ 63.9(e)	Notification of Performance Test.	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test.	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications When Using CMS.	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative.	Yes, however, there are no opacity standards.
§ 63.9(h)(1) through (3), (5), and (6).	Notification of Compliance Status.	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after; when to submit to Federal vs. State authority.	Yes, except as specified in § 63.11095(c).
§ 63.9(h)(4)	[Reserved].		
§ 63.9(i)	Adjustment of Submittal Deadlines.	Procedures for Administrator to approve change when notifications must be submitted.	Yes.
§ 63.9(j)	Change in Previous Information.	Must submit within 15 days after the change	Yes.
§ 63.9(k)	Notifications	Electronic reporting procedures	Yes.
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source.	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years.	Yes.
§ 63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No. See § 63.11094(k) for recordkeeping requirements for deviations.
§ 63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment.	Yes.
§ 63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi) through (xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	Yes.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting initial notification and notification of compliance status.	Yes.
§ 63.10(b)(3)	Records	Applicability determinations	Yes.
§ 63.10(c)	Records	Additional records for CMS	No. This subpart specifies CMS records.

TABLE 4 TO SUBPART BBBBBB OF PART 63—APPLICABILITY OF GENERAL PROVISIONS—Continued

Citation	Subject	Brief description	Applies to this subpart
§ 63.10(d)(1)	General Reporting Requirements.	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results.	When to submit to Federal or State authority	No. This subpart specifies how and when the performance test results are reported.
§ 63.10(d)(3)	Reporting Opacity or VE Observations.	What to report and when	No.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	No.
§ 63.10(e)(1) and (2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; 2–3 copies of COMS performance evaluation.	No.
§ 63.10(e)(3)(i) through (iii)	Reports	Schedule for reporting excess emissions	No.
§ 63.10(e)(3)(iv) and (v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7) and (8) and 63.10(c)(5) through (13).	No.
§ 63.10(e)(3)(vi) through (viii).	Excess Emissions Report and Summary Report.	Requirements for reporting excess emissions for CMS; requires all of the information in §§ 63.8(c)(7) and (8) and 63.10(c)(5) through (13).	No.
§ 63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No. This subpart specifies COMS reporting.
§ 63.10(f)	Waiver for Recordkeeping/Reporting.	Procedures for Administrator to waive	Yes.
§ 63.11(a)	Applicability	Specifies applicability of control device and work practice requirements within § 63.11.	Yes.
§ 63.11(b)	Flares	Requirements for flares	Yes, except these provisions no longer apply for flares used to comply with the flare provisions in item 2 of table 3 to this subpart.
§ 63.11(c) through (e)	Alternative Work Practice for Monitoring Equipment for Leaks.	Requirements for using optical gas imaging for EPA Method 21 monitoring.	Yes, except these provisions do not apply to monitoring required under § 63.11092(a)(1)(i) or (e)(1) and these provisions no longer apply upon compliance with the provisions in § 63.11089(c).
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent.	Yes.
§ 63.14	Incorporations by Reference.	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.
§ 63.16	Performance Track Provisions.	Special reporting provision for Performance Track member facilities..	Yes.

[FR Doc. 2024–04629 Filed 5–7–24; 8:45 am]

BILLING CODE 6560–50–P