National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

Background Information for Final Amendments

Summary of Public Comments and Responses

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National Emission Standards for Hazardous Air Pollutants
for Petroleum Refineries
Background Information for Final Rule

Summary of Public Comments and Responses

Contract No. EP-D-11-084

Work Assignment No. 3-08

U.S. Environmental Protection Agency

Office of Air Quality Planning and Standards

Sector Policies and Programs Division

Research Triangle Park, North Carolina 27711

September 2015

Disclaimer

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LIST OF ABBREVIATIONS, ACRONYMS AND UNITS OF MEASURE

AB2588	Air Toxics "Hot Spots" Information and Assessment Act
Admin.	Administrative
AEGL	acute exposure guideline levels
AERMOD	air dispersion model used by the HEM–3 model
AFPM	American Fuel & Petrochemical Manufacturers
AMEL	alternative means of emission limitation
AMOS	ample margin of safety
AMP	alternative monitoring plan
APCD	air pollution control devices
API	American Petroleum Institute
AQMD	Air Quality Management District
ARB	Air Resources Board
Ass'n	association
ASTM	American Society for Testing and Materials
ATSDR	Agency for Toxic Substances and Disease Registry
BAAQMD	Bay Area Air Quality Management District
BLD	bag leak detectors
BP	British Petroleum
Btu	British thermal units
BWON	Benzene Waste Operations NESHAP
CA	corrective action
CAA	Clean Air Act
CAA	corrective action analysis
CalEPA	California EPA
CASRN	Chemical Abstract Services Registry Number
CCU	catalytic cracking units
CCV	Continuing Calibration Verification
C_{cz}	combustion zone combustibles concentration
CDC	Centers for Disease Control
C_{dil}	combustibles concentration dilution parameter
CE	combustion efficiency
CEMS	continuous emissions monitoring system
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
cert.	certiorari (writ or order by which higher court reviews decision of lower court)
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CGA	cylinder gas audit
CH_4	methane
CHIEF	Clearinghouse for Inventories and Emissions Factors
CHPAC	Children's Health Protection Advisory Committee
Cir.	Circuit Court
CO	carbon monoxide
CO_2	carbon dioxide

CO_2e	carbon dioxide equivalents
COMS	continuous opacity monitoring system
CPMS	continuous parameter monitoring system
CRU	catalytic reforming units
CVS	closed-vent system
D.C.	District of Columbia
DCS	distributed control system
DCU	delayed coking units
DE	destruction efficiency
DIAL	Differential Absorption Light Detection and Ranging
dL	deciliters
DNA	deoxyribonucleic acid
DOT	Department of Transportation
dscf	dry standard cubic feet
DTSC	Department of Toxic Substances Control
EBU	enhanced biological unit
ECHO	Enforcement and Compliance History Online
e.g.	exempli gratia (for example)
EIA	Economic Impact Assessment
EJ	environmental justice
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ERPG	emergency response planning guidelines
ERRRNSPS	Electronic Reporting and Recordkeeping Requirements for the New Source Performance Standards Rulemaking
ERT	Electronic Reporting Tool
ESP	electrostatic precipitator
etc.	et cetera (and so forth)
ETV	Environmental Technology Verification
FCCU	fluid catalytic cracking units
FQPA	Food Quality Protection Act
FR	Federal Register
ft	feet
ft^3	cubic feet
FTIR	Fourier transform infrared spectroscopy
GC	gas chromatograph
GEAE	Generic Ecological Assessment Endpoint
GHG	greenhouse gases
GHGRP	Greenhouse Gas Reporting Program
GP	General Provisions
g	grams
gr	grains
H_2S	hydrogen sulfide
HAP	hazardous air pollutants
HCl	hydrogen chloride

HCN	hydrogen cyanide
HEM-3	Human Exposure Model, Version 1.1.0
HF	hydrogen fluoride
HFC	highest fenceline concentration
HIA	Health Impact Assessment
HON	Hazardous Organic NESHAP
HQ	hazard quotient
hr	hour
HRVOC	highly reactive volatile organic compounds
ICR	Information Collection Request
id.	idem (the same)
i.e.	id est (that is)
IQ	intelligence quotient
IRIS	Integrated Risk Information System
IS	Internal Standard
ISO	International Organization for Standardization
IST	inherently safer technologies
kg	kilograms
km	kilometers
L	liters
L&E	Locating and Estimating Air Emissions from Sources of Benzene
LACEEN	Los Angeles Community Environmental Enforcement Network
lb	pounds
LDAR	leak detection and repair
LDEQ	Louisiana Department of Environmental Quality
LEL	lower explosive limit
LFL	lower flammability limit
LFL_{cz}	combustion zone lower flammability limit
LFL_{dil}	lower flammability limit dilution parameter
m^3	cubic meters
M325A	Method 325A
M325B	Method 325B
MACT	maximum achievable control technology
MDL	method detection limit
MFC	measured fenceline concentration
mg	milligrams
min	minutes
MIR	maximum individual risk
ml	milliliters
MMbbl	million barrels
mmBtu	million British thermal units
MOA	mode of action
MOE	margin of exposure
MON	Miscellaneous Organic NESHAP
mph	miles per hour
MPV	miscellaneous process vent

MSS	maintenance, startup and shutdown
MTBE	methyl tert-butyl ether
NAAQS	National Ambient Air Quality Standards
NAS	National Academy of Sciences
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFS	near-field interfering source
ng	nanograms
NHV	net heating value
NHV_{cz}	combustion zone net heating value
NHV_{dil}	net heating value dilution parameter
NHV_{vg}	net heating value of the vent gas
Ni	nickel
NIST	National Institute of Standards and Technology
No.	number
NOAA	National Oceanic and Atmospheric Administration
NOAEL	no-observed-adverse-effect level
NOCS	notification of compliance status
non-PBT	not persistent, bioaccumulative and toxic
NOx	nitrogen oxides
NPS	National Park Service
NRC	National Research Council
NRDC	Natural Resources Defense Council
NSPS	new source performance standards
NTP	National Toxicology Program
O_2	oxygen
O_3	ozone
OAQPS	Office of Air Quality Planning and Standards
ODW	Office of Drinking Water
OEHHA	Office of Environmental Health Hazard Assessment
OEL	open-ended line
OGI	optical gas imaging
OHEA	Office of Health and Environmental Assessment
OMB	Office of Management and Budget
OMMP	Operating, Monitoring, and Maintenance Plan
OOC	out of control
OSC	off-site source contribution
OSHA	Occupational Safety and Health Administration
OTM	other test method
PAH	polycyclic aromatic hydrocarbons
PB-HAP	hazardous air pollutants known to be persistent and bioaccumulative in the environment
PBM	Perimeter Boundary Monitoring
PBT	persistent, bioaccumulative, and toxic
PFTIR	passive Fourier transform infrared spectroscopy
PM	particulate matter

$PM_{2.5}$	particulate matter 2.5 micrometers in diameter and smaller
PM_{10}	particulate matter 10 micrometers in diameter and smaller
POM	polycyclic organic matter
ppb	parts per billion
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
ppmw	parts per million by weight
PRA	Paperwork Reduction Act
PRD	pressure relief devices
PRV	pressure relief valves
PS	Performance Specification
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSM	Process Safety Management
PTE	potential to emit
P/V	pressure/vacuum
PVC	polyvinyl chloride
QA/QC	quality assurance/quality control
RATA	relative accuracy test audit
RC	root cause
RCA	root cause analysis
REL	reference exposure level
REM	Refinery Emissions Model
RfC	reference concentration
RfD	reference dose
RIA	Regulatory Impact Analysis
RMP	Risk Management Plan
RQ	reportable quantity
RTC	response to comments
RTR	residual risk and technology review
RV	relief valves
RWET	Refinery Wastewater Emission Tool
SAB	Science Advisory Board
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SCR	selective catalytic reduction
s	seconds
SO_2	sulfur dioxide
SOF	Solar Occultation Flux
SOx	sulfur oxides
SRP	sulfur recovery plant
SRU	sulfur recovery units
SS	startup and shutdown
SSM	startup, shutdown and malfunction

STERPP	Storage Tank Emission Reduction Partnership Program
TAB	total annual benzene
TAC	Texas Administrative Code
tbl.	table
TCEQ	Texas Commission on Environmental Quality
Tex.	Texas
TexasAQS	Texas Air Quality Study
THC	total hydrocarbons
TOSHI	target organ-specific hazard index
tpy	tons per year
TRI	Toxics Release Inventory
TRS	total reduced sulfur
UB	uniform background
UF	uncertainty factor
UF-H	intraspecies (human) uncertainty factor
URE	unit risk estimate
U.S.	United States
U.S.C.	United States Code
USW	United Steelworkers
USWS	U.S. Weather Service
UV	ultraviolet
UV-DOAS	ultraviolet differential optical absorption spectroscopy
v.	versus
VE	visible emissions
VOC	volatile organic compounds
VOHAP	volatile organic hazardous air pollutant
vol.	volume
WGS	wet gas scrubber
ΔC	concentration difference between the highest measured concentration and the lowest measured concentration
°F	degrees Fahrenheit
$	dollars
µg	micrograms
%	percent

1.0 Introduction/Comment Period Extension

The U.S. Environmental Protection Agency (EPA) promulgated national emissions standards for hazardous air pollutants (NESHAP) pursuant to the Clean Air Act (CAA) section 112(d)(2) and (3) for petroleum refineries located at major sources in three separate rules. The first of which was promulgated on August 18, 1995 in 40 CFR, subpart CC (also referred to as Refinery MACT 1) and regulates miscellaneous process vents, storage vessels, wastewater, equipment leaks, gasoline loading racks, marine tank vessel loading and heat exchange systems. The second rule was promulgated on April 11, 2002 in 40 CFR subpart UUU (also referred to as Refinery MACT 2) and regulates process vents on catalytic cracking units (CCU, including fluid catalytic cracking unit (FCCU)), catalytic reforming units (CRU), and sulfur recovery units (SRU). Finally, on October 28, 2009, the EPA promulgated maximum achievable control technology (MACT) standards for heat exchange systems which were not originally addressed in Refinery MACT 1. This same rulemaking included updating cross-references to the General Provisions in 40 CFR part 63.

Section 112(f)(2) of the CAA requires the EPA to determine for each CAA section 112(d) source category if promulgation of additional standards is required "in order to provide an ample margin of safety to protect the public health." The EPA may also impose a more stringent emission standard to prevent adverse environmental effect if such action is justified in light of costs, energy, safety, and other relevant factors. Section 112(d)(6) of the CAA requires the EPA to review NESHAPs and to revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less frequently than every 8 years. On September 27, 2012, a lawsuit was filed which alleged that the EPA missed statutory deadlines to perform review and revise, as necessary, the Refinery MACT 1 and 2. The EPA has completed both a technology and risk review of Refinery MACT 1 and 2 to fulfill its obligations under 112(f)(2) and 112(d)(6). The EPA proposed amendments as a result of these reviews on June 30, 2014. In addition to the proposed amendments relative to the Petroleum Refinery MACT 1 and 2, the EPA also proposed amendments to the refinery new source performance standards (40 CFR part 60 subparts J and Ja) to address technical corrections and clarifications raised in a 2008 industry petition for reconsideration. These were addressed in the proposed rulemaking because they affect sources included within the Refinery MACT 1 and 2 amendments. The proposed amendments include new standards for storage vessels, delayed coking units (DCU), flares, fenceline monitoring of fugitive emissions sources and FCCU.

The proposal provided a 60-day comment period ending on August 29, 2014. Upon request, the EPA extended the comment period for an additional 60 days ending October 28, 2014. During the comment period, the EPA held two public hearings on July 16, 2014 in Wilmington, CA and on August 5, 2014 in Galena Park, TX, to provide the public the opportunity to present data, views, or arguments concerning the proposed amendments. The EPA received 202,650 comments (including those from mass mail campaigns and public hearing) on the proposed amendments from refiners, industry, trade associations, and consultants, state and local environmental and health departments, environmental groups, private citizens and other interested parties during the comment period. These comments were reviewed and it was determined that there were 201 unique and substantive comments. All of the comment letters, including transcripts of the public hearings, have been placed in the docket for this rulemaking (Docket No. EPA-HQ-2010-0682). Key comment summaries and EPA responses are included in the preamble of this rulemaking package. This document includes a summary of the other substantive comments received and written responses from the EPA.

2.0 Risk Assessment

2.1 Emissions Data

2.1.1 Actual emissions and release characteristics

Comment 1: Several commenters expressed concerns that U.S. refineries are receiving greater quantities of unconventional crudes including tar sands, oil shale and tight oil, and the impacts of this shift in raw material has not been incorporated into the health risk assessment for this rulemaking, thus making it unlawfully incomplete, and arbitrary and capricious.

The commenters claimed that the use of these unconventional crudes poses a number of additional environmental, health and safety risks relative to standard conventional crude oil. The risks that they outlined include:

- Higher risk of refinery accidents: Tar sands and tight oil are more corrosive than conventional crude oil, which increases the risk of refinery accidents and raises the potential for significant additional air emissions during upsets and accidents.
- Increases in air pollution & associated health impacts: The chemicals used to dilute and blend tar sands contain highly volatile and sometimes toxic organic chemicals at much higher concentrations than conventional crude oil. Tar sands also contain many toxic constituents including heavy metals, such as lead, at much higher concentrations than in conventional crude oil.[1] The much heavier, denser tar sands crude requires greater use of heaters, boilers, hydro-treating, coking, cracking and greater hydrogen use, all of which creates greater emissions of smog- and soot-forming pollutants and toxic chemicals.[2] Tight oil has an unusually high flashpoint and Reid Vapor Pressure leading to potentially double the emissions of many light organic hazardous air pollutants (HAP) such as benzene from storage and handling.
- Irreversible Climate Damage: Carbon pollution from extracting and upgrading tar sands can be 3 to 5 times greater than for conventional crude oil. Over the course of production

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[1] R.F. Meyer, E.D. Attanasi, and P.A. Freeman, Heavy Oil and Natural Bitumen Resources in Geological Basins of the World, U.S. Geological Survey Open-File Report 2007-1084, 2007, p. 14, Table 1; http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf.

[2] Excerpt from Phyllis Fox Report to NRDC, July 1, 2013.

(well-to-tank), tar sands release 80% more global warming pollution than the U.S. average refined crude.[3,4]

- Other environmental & community impacts: Tar sands processing releases strong odors due to the higher levels of sulfur compounds, particularly noxious mercaptans. Exposure to mercaptans may cause irritation of the skin, eyes, and upper respiratory tract, and mercaptans negatively affect the central nervous system. Refining tar sands also leads to roughly 50% more petroleum coke, [Lattanzio CRS Report, 2014] which is a hazardous by-product that in some cases is stored in open piles creating a serious health hazard.

The commenter concluded that the EPA neglected to consider the many serious impacts to refinery emissions from unconventional crude oil including tar sands and Bakken crude, both of which are relatively new types of crude oil and yet are already in significant and increasing use at U.S. refineries. Unconventional crude oil refining is likely to significantly increase volatile HAP as well as heavy metals, polycyclic aromatic hydrocarbons **(**PAH), and other HAP, resulting in significant health impacts to refinery fence-line communities.

Response 1: First, the types of control systems used to limit the emissions from petroleum refinery process units are essentially independent of the types of crude processed. The EPA finds that the same MACT requirements would be needed to ensure sources using these unconventional crude slates are achieving the MACT emissions limitations. For example, delayed coking units are commonly used to process heavy crudes into lighter distillates (gasoline or diesel fuel). The MACT standards that we are finalizing for delayed coking units would apply to units processing unconventional heavy crude oils exactly the same as to units processing conventional heavy crudes. Thus, the MACT standards will help to limit the emissions from refineries regardless of the type of crude oil processed.

Second, the precise impact of different crude slates is very difficult to project, because it is difficult to predict how much of each type of unconventional oil will be processed and which conventional crude slates will be replaced. Heavy and sour crude oils are already processed in the U.S. If crude oil produced from tar sands replaces these heavy sour crudes, there may be very little difference in the amount of upgrading equipment used or the amount of emissions from this shift in crude feedstocks. Even if significant quantities of unconventional crude oil are processed in U.S. refineries, the fuel standards and the refinery MACT requirements will limit HAP (and sulfur) releases from refineries and subsequent petroleum product use. For example, hydrotreaters are commonly used to remove sulfur and heavy metals from petroleum intermediate streams. This processing will help to ensure emissions from downstream refinery processes are similar to those processing sweeter crudes. As such, there is significant uncertainty

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[3] Richard K. Lattanzio, Congressional Research Service report: Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions, March 10, 2014. This source also reports a 17% increase in GHGs from tar sands v. conventional crude over the lifecycle, including the use of the fuel in vehicles.

[4] Jessica P. Abella and Joule A. Bergerson, Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration Environ. Sci. Technol., 2012, 46 (24), pp 13037-13047 DOI: 10.1021/es3018682

as to whether these unconventional crudes will really cause any appreciable increase in refinery HAP emissions.

With respect to climate impacts, we consider these comments to be beyond the scope of this rulemaking, particularly as many of the impacts cited relates to upstream production and processing that occurs prior to the petroleum refinery.

At this time, we cannot scientifically defend revisions to refinery-specific emission inventories in an effort to estimate health risk assessments for some future time with assumed changes in crude slates. Furthermore, we consider that any changes in crude slate that actually do occur in the future will have a relatively small impact on refinery HAP emissions because the MACT control requirements we are finalizing will adequately control the refinery HAP emissions, and these changes would not alter our conclusion that the risks from petroleum refineries are acceptable.

Comment 2: Two commenters stated that emissions are over-stated because of the use of the section 114 information collection request (ICR) data collection effort in 2011 and the refinery emissions protocol document. Both commenters provided specific objections related to the EPA's requirements for preparing the emissions inventory for use in risk modeling, stating that the inventory approach required to be used tended to over-estimate the refinery's emissions, citing a critique of the EPA's risk analysis entitled "Refinery Air Emission Metrics" by Jess A. McAngus and Erin Valley of Spirit Environmental LLC which compared ICR inventory estimates to the Toxic Release Inventory (TRI) data. Commenters also state that there were unsupported adjustments made to the ICR data including increasing the hydrogen cyanide **(**HCN) emissions for FCCUs in the emissions inventory by a factor of 10 for those sites that did not provide actual stack test data.

Several commenters stated that many significant emission reductions have occurred since 2010 and those changes should have been reflected in the emission estimates and risk modeling. Most significant are the reductions anticipated due to new source performance standards **(**NSPS) Ja. One commenter stated other changes that should also have been reflected in the emission basis for the risk modeling include the following:

- The EPA states that the floor for the proposed delayed coker work practice standard is based on eight such units having to meet a 2 pounds per square inch gauge **(**psig) pressure limit. The risk input should reflect that limit, not their 2010 emissions. Furthermore, the South Coast Air Quality Management District **(**SCAQMD) has a rule in place that requires all 8 DCUs in that District to meet a 2 psig limit by late 2017 and those units should have been modelled on that basis as well.
- Consent decrees specifically addressing flares, a focus of this proposal, have been put in place since 2010 for six Marathon petroleum refineries, the Shell Deer Park Refinery, the Flint Hills Port Arthur Refinery, the Countrymark Indiana Refinery and the British Petroleum **(**BP) Whiting Refinery. The reductions in flaring and other emissions resulting from these and other refinery consent decrees should be reflected in the baseline emission and risk estimates.

One commenter also added that emissions of volatile organic compounds (VOC) and toxic air contaminants have been reduced through current and previous emission control efforts, such as state regulations. The commenter provided California's Air Toxics "Hot Spots" Information and Assessment Act (AB2588) process as an example, which reduced toxic emissions and risk such that most refineries pose risks that are already less than 10-in-1 million. The commenter recommended that the EPA should recognize all efforts to reduce emissions into the agency's analysis on a regional level. This will allow the EPA the opportunity to incorporate updated emissions data and cost information to determine if implementation of the NESHAPs on a local level is reasonable and feasible.

Response 2: The commenter's objections to the 2011 ICR data collection efforts and emissions inventory protocol have been noted and we appreciate the commenter's submission of the ICR data and emissions inventory in spite of their objections. We prepared the Refinery Protocol to provide guidance to refinery owners or operators to use the best available, site-specific data when developing their emissions inventory, to ensure that all emission sources are included in the inventory, and that there is a consistent set of emission factors that all respondents use if no site-specific emissions data were available. We disagree that the refinery emissions protocol would lead to overly conservative emissions estimates for the inventory. If site-specific emissions data were available, sites were to use these data preferentially over the default factors. The default factors provided in the Protocol were developed from the best data available at the time.

While TRI reporting is required, there is no uniform set of requirements for refinery owners or operators to follow in developing those emissions inventories. The idea that the TRI emission estimates are more accurate and complete than the inventories produced for the ICR effort is not supported by the facts. The Refinery Protocol included methodologies and emission factors for sources that have been historically omitted from emission inventory estimates and it is precisely because of the Refinery Protocol document that we consider the ICR inventories to be more thorough, consistent and complete than the TRI data.

We acknowledge that we increased the emission inventory estimated for hydrogen cyanide based on the emissions test data results from the ICR testing. We determined that the HCN emissions factor we provided in the Refinery Protocol, while likely be greater than what refineries used for TRI reporting, which understated the actual HCN emissions. Therefore, we increased the HCN emissions based on an updated HCN emissions factor derived from more recent ICR source test data. An added advantage of requiring facilities to use the Refinery Protocol factors when no site-specific emissions data are available is that, if we determine a specific emissions factor is inaccurate, it is relatively simple and straight forward to adjust the ICR emissions inventory appropriately. We strongly disagree with the commenter's assertion that this adjustment was somehow "arbitrary" as the revised HCN emissions factor was based on a greater quantity and quality of data than the original factor provided in the Refinery Protocol. We note that, subsequent to the ICR effort, many refiners have increased their HCN emission estimates in TRI reports.

We also disagree with commenters that our risk assessment was overly conservative in light of emission reductions purported future emission reductions. While we appreciate the fact that some refineries have entered into consent decrees for their flares, we note that the refinery Protocol recommended that flare emission control efficiencies of 98 percent should be used, so the flare emissions inventory provided in response to the ICR already reflects the improvement in flare performance expected as a result of these consent decrees (as well as the proposed operating limits for flares).

We routinely assess the impacts of a rule based on the information available at the time and it is impossible to continually revise the baseline emissions and emissions reductions based on on-going changes in the industry. While the commenters only discuss cases they expect would reduce future emissions, we also know that there have been some significant refinery expansions that were completed since 2010, and these changes would increase baseline emissions. We performed the analysis based on the 2010 data set because it was the most recent and complete data set available by which to assess health risks resulting from refinery emissions.

Even if, for the sake of argument, the emissions inventory developed using the emissions Protocol resulted in a conservative emissions inventory, this only strengthens the conclusion that risks are acceptable since the risks determined using those "conservative" emissions inventory are less than 100-in-1 million.

Comment 3: Several commenters stated that the EPA underestimates exposure because emissions are underreported and underestimated. The commenters noted that for the risk assessment for the refineries rule, the EPA evaluated (1) the emissions reported to the agency pursuant to the 2011 Petroleum Refinery ICR as sources "actual" emissions based on some tests and some estimation, and (2) the emissions the EPA estimates that the existing standards currently allow sources to emit, which it describes as "allowable" emissions, based on the REM. According to the commenters, both data sets are incomplete and undercount emissions, causing the EPA to significantly underestimate the resulting risk they cause in its risk analysis.

According to one commenter, the ICR emissions inventory significantly underestimates emissions because the emission inventory is largely calculated from emission factors and engineering judgment and it is well documented that emission factors underestimate emissions for a variety of reasons including inherent bias in the factors themselves and the inability to account for equipment malfunctions and environmental conditions. The commenter cited a variety of Differential Absorption Light Detection and Ranging (DIAL) studies and other studies to support the assertion that emission factors understate emissions, particularly for fugitive sources. Furthermore, the commenter suggested that there is evidence that facilities did not use the emission factors as directed or applied them incorrectly and the EPA has recognized some of these problems in the technology review component of this rulemaking and made some adjustments.

Another commenter similarly stated that a Texas Air Quality Study (TexasAQS) found large volumes of unreported airborne organic chemicals (see: http://www.utexas.edu/research/ceer/texaqsII/visitors.htm, and TexasAQS II Field Study at: http://www.tceq.state.tx.us/airquality/research/texaqs/texaqs_data.html). One of the early phases of the first TexasAQS found that VOC and air toxics concentrations in the Houston area above the major oil refineries were on average 6X-12X higher than those that were being reported by the refineries in the annual emissions inventory (EI) submitted to the Texas Commission on Environmental Quality (TCEQ). The TCEQ, scientists with the Texas AQS, and industrial officials concluded that the large volumes of unreported VOCs and air toxics were being released through four plant processes: flares, process vents, fugitive leaks, and cooling towers. The commenter stated that the significant under-reporting of VOC and air toxics indicates that the EPA needs stronger rules for more accurate VOC/HAP monitoring that that the EPA needs to require more reductions in refinery HAP, particularly from elevated flares.

In conclusion, the commenters stated that the EPA's risk analysis underestimates exposure because it relied on inaccurate data and assumptions to calculate and model the total amount of HAP emissions released by petroleum refineries every year, both in terms of the so-called "actual" and "allowable" emissions. For this reason alone, the EPA should find the level of current health risk to be "unacceptable," and set standards under 112(f)(2) to assure the requisite "ample margin of safety to protect public health" from additional emission points at refineries (including wastewater treatment, equipment leaks, FCCUs and process vents), to reduce these emissions.

Response 3: We used the best and most robust facility-specific HAP emissions inventory available to us, which was the 2011 ICR, in performing the analysis for the proposed rule. We conducted a thorough and exhaustive review of the data submitted through the ICR and we followed up on source-specific information on a facility-by-facility basis, as documented in the "Emissions Data Quality Memorandum and Development of the risk Model Input File" (see Docket Item No. EPA-HQ-2010-0682-0076). In addition, we took steps ahead of issuing the 2011 ICR to make sure that facilities could, as accurately, as practicable as possible, estimate their HAP emissions for purposes of responding to the inventory portion of that ICR. We prepared a Refinery Protocol to provide guidance to refinery owners or operators to use the best available, site-specific data when developing their emissions inventory, to ensure all emission sources are included in the inventory, and that the agency has a consistent set of emission factors that all respondents use if no site-specific emission data were available. If site-specific emissions data were available sites were to use these data preferentially over the default factors. We developed default factors provided in the protocol from best data available at the time.

The ICR-submitted information for allowable emissions did not include emission estimates for all HAP and all emission sources. Consequently, we used the REM to estimate allowable emissions. The REM relies on model plants that vary based on throughput capacity. Each model plant contains process-specific default emission factors, adjusted for compliance with the Refinery MACT 1 and 2 emission standards.

Regarding the findings of the TCEQAQS, we promulgated new MACT standards in 2010 for heat exchange systems to reduce emissions from cooling towers. Based on TCEQ and other studies, we proposed and are finalizing significant new operating and monitoring requirements for flares to ensure flares are achieving the required control efficiency. We also note that we proposed and are finalizing fenceline monitoring requirements in part to ensure the fugitive emissions inventory that we used in the risk modeling file are an accurate representation of actual refinery emissions.

If the industry commenters are correct, then the emissions inventory used in the risk assessment overstates the emissions and the risk conclusion is conservative. If the emissions inventory used in the risk assessment understates the emissions, then the fenceline monitoring and corrective action requirements will ensure refineries reduce their emissions to levels comparable to their emissions inventory and the surrounding communities would be protected to acceptable risk levels.

Comment 4: One commenter stated that a detailed review of the EPA's risk assessment by ENVIRON Corporation was commissioned by American Petroleum Institute (API) and they attached a copy of this report to their comment (Attachment A-1 to 0583). This risk modeling assessment was performed for the 33 refineries reported by the EPA that have the highest cancer and chronic noncancer risk to assist API in verifying the EPA's risk estimates and to identify key risk-drivers at those facilities for further review by API and member companies and correcting data if warranted. The commenter summarized key findings as follows:

- While modeled results are consistent with the EPA's judgment in its proposed rule that refinery risks are "acceptable," certain potential data issues were identified that, once corrected, will lower risk estimates for the highest-risk refineries and others.
- For certain refineries, the EPA modeled emission-outlier sources that overestimated actual emissions, sources that were mislocated or incorrectly extended offsite, or calculated maximum risks at nonresidential locations, causing risks to be misstated.
- For certain refineries, the EPA's risk modeling does not reflect corrected emission inventory data, causing risks to be overstated.
- Correction of data errors, if present, and re-modeling of risk by the EPA using corrected data is warranted. For example, using corrected data from companies, the Human Exposure Model, Version 1.1.0 (HEM-3) was used to re-calculate risk for the two refineries with the highest EPA-reported facility-wide cancer risk, correcting modeled cancer risk from 67-in-1 million to 15-in-1 million for one refinery, and from 67-in-1 million to 13-in-1 million for the other.

A few commenters (Western Refining and Northern Tier Energy) confirmed the errors found by ENVIRON and stated they would resubmit their corrected emissions data using the EPA's tool.

The commenters stated that there are serious technical issues in the EPA's risk modeling for refineries that greatly overstate the risk. Consequently, the EPA's modeling does not provide a credible basis to evaluate refinery risk or to substantiate any purported risk reduction benefits to be derived from the proposed rulemaking.

Response 4: We note that most of the issues noted by the commenters are issues with the emissions inventory files that were submitted to the EPA. We appreciate the commenters' review of the emission sources that were driving high risk results and the emissions inventory corrections submitted by various refineries. While a detailed modeling analysis of the revised emissions received during the comment period is not possible, the EPA risk modelers and engineers performed a screening analysis of these emissions revisions to determine their potential impact on the source category risk estimates. We estimate that the source category chronic cancer MIR based on actual emissions may be closer to 40-in-1 million as compared to the 60-in-1 million predicted by the initial risk modeling. Since allowable emissions are primarily based on model plant emissions, the model predicted chronic cancer maximum individual risk (MIR) of 100-in-1 million does not change based on the submitted emissions revisions. Other risk metrics changes (i.e., incidence, populations in risk bins, multipathway and ecological analyses) were not quantified but would likewise be expected to show some minor reductions from those presented in the draft risk assessment report.

Comment 5: A commenter stated that for decades, communities have faced substantial amounts of uncontrolled "off-the-books" pollution during periods of startup, shutdown, and malfunction (SSM). Another commenter stated that the EPA's emission estimates, developed to support its assessment of risks, are incomplete because they do not adequately account for the fact that HAP releases during malfunctions or maintenance (which are regular events at most refineries) are often much higher than emissions during "normal" operations, and are either under-reported or not reported at all. Commenters cited some specific examples from the ICR Component 1 when thousands of pounds of HAP were released during upset or malfunction events such as piping failure or leaks which occurred over a few minutes or many days, respectively, to support this argument. The commenter stated that the EPA must revise its risk-analysis of allowable emissions to account for these problems.

One of the commenters added that refineries release millions of pounds of emissions during SSM periods each year. According to the commenter, data from Texas shows that SSM emissions are a severe public health problem. Between 2009 and 2013 Texas refineries alone released nearly 1 million pounds of HAP. The commenter pointed out that while facilities reported more than 100,000 pounds of HAP emissions in Component 1 of the EPA's ICR, 96.77% of these emissions were attributable to the 43 Texas and Louisiana refineries. It seems unlikely that the other 103 refineries across the country accounted for less than 5% of startup, shutdown, and malfunction pollution.

A commenter also added that a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.

The commenters stated that it is not clear from the record that the EPA considered these hazardous events in its risk review of whether to require stronger standards, including leak detection and repair (LDAR) requirements, or the total and acute risks that communities near refineries are exposed to. The commenters stated that the EPA needs to account for the fact that upsets or repair events may not even be treated as a reportable malfunction or maintenance event. The commenters requested that the EPA should further require facilities to install the most responsive monitoring available on the release of emissions from pressure relief devices, control devices, bypass lines and flares.

Response 5: We agree that SSM emissions can be significant and that these releases, particularly when directed straight to the atmosphere rather than to a flare or other control device can quickly exceed emissions from routine operations. While large release events can significantly impact a facility's annual emissions, we disagree with the commenter that these large events are frequent. The commenters note that “upset events” are frequent, but the large “upset events” that significantly alter a facilities annual emissions only make up a small portion of the total “upset events.” Based on our review of the TCEQ incident database, many of these large release events had to do with sulfur dioxide (SO_2) emissions and only a few had significant HAP emissions. Thus, we do not characterize large releases that may occur once every 3 to 5 years to be “frequent.”

Episodic malfunction events cannot be predicted so it is impossible to estimate the location and quantity of these emission events for direct inclusion into the risk assessment. However, since we are now allowing a limited number of these events from pressure relief devices and flares, we performed a screening level analysis for the risks from these non-routine emissions. To estimate emissions for chronic risk calculations, emissions data was extracted from the EPA ICR in Component 1 of the survey. We summed the HAP emissions from all individual events at each facility, since chronic inhalation risk depends on the total quantity of emissions released over a year and is independent of the release time. This screening level analysis indicated we can expect these emissions to contribute up to about 2-in-1 million to the chronic cancer MIR. Noncancer risks resulting from these emissions are expected to remain well below 1. To estimate potential risks for acute events, we examined both the quantity and duration of each event such that higher mass emitted in a shorter time period has an increased potential for an acute impact. Acute risks from these events estimated a Hazard Index based on the REL of up to 14 from emissions of benzene. In all cases the acute exposure guideline levels (AEGL) levels are well below 1. It is important to note that the estimated acute risk assume a catastrophic release such that all the emissions from an event are emitted during a single hour time period (for more detail on this analysis, see Appendix 13 of the Final Residual Risk Assessment for the Petroleum Refining Source Sector in Docket No. EPA-HQ-OAR-2010-0682).

We also proposed revisions to the MACT requirements to eliminate “off-the-books” emissions (by reducing these events and making refinery owners or operators report these emissions when they do occur). In the final rule, we revised the monitoring requirements for bypass lines from the proposal, but we are retaining the requirements to estimate and report the emissions released during control system bypasses. We have also revised the requirements for pressure relief devices (PRD) from what was proposed, but we are still requiring that facility owners or operators determine the quantity of emissions released and report these emissions to the EPA. We proposed significant monitoring requirements for flares and we are finalizing these monitoring requirements with minor revisions from what was proposed. Finally, we proposed fenceline monitoring requirements to more quickly identify leaks and other fugitive emissions and to ensure the emission inventories provided to the EPA were reasonably accurate. As such, we proposed significant enhancements in the monitoring and reporting requirements petroleum refineries to limit and report emissions for these “upset events” and we are finalizing these enhanced monitoring and reporting requirements (with some revisions from proposal) in the final rule.

Comment 6: One commenter stated that emission totals for the petroleum refinery sector were underestimated and requested the that EPA detail their plans for future Information Collection Requests, new stack tests, and technology and risk as well as applicability review for petroleum refineries that are minor sources. The commenter explained that some of these refineries are minor sources because of third party lease agreements and argued that these business agreements allow sources to remain exempt from the Sector Rule proposal when if considered one entire source would constitute a major source. The commenter also inquired whether co-located recycling facilities processing motor oil or animal fats that are used to produce diesel fuel on a refinery's campus, but not included on their permit would be addressed through future rulemakings (e.g., ICR, stack test, residual risk and technology review (RTR)).

Response 6: At this time, we do not have any plans to conduct an additional, detailed ICR for the petroleum refining source category. With respect to business agreements, 40 CFR part 63 includes a specific definition for a "facility." If contiguous plants are not under a common ownership or control, then they are separate facilities, and if they are minor (area) sources for HAP emissions, then they are not subject to the Refinery MACT 1 and 2. We do not have specific plans to develop standards for area source petroleum refineries, but we may consider the need for such standards in the future. For our refinery risk assessment, we conducted a facility-wide risk assessment and did not necessarily limit the risk assessment to refinery MACT 1 and 2 emission sources, so co-located sources at a refinery facility were included in the risk assessment.

2.1.2 Allowable emissions

Comment 1: The EPA received comments in support of and against the use of allowable emissions in the risk assessment.

Those in support of the use of allowable emissions stated that facility emission estimates rely on outdated emissions factors which undercount emissions. Another commenter concern was that using actual emissions from a single point in time could underestimate risk from the source category. Commenters also stated that the use of allowable emissions allows the EPA to consider the potential health risks under the existing standards and added that using allowable emissions is consistent with the basis of the major source HAP thresholds and the basis of issuing air quality permits. Some of the commenters supporting the use of allowable emissions estimates, however, did not agree with the use of the REM to develop the allowable emissions estimates asserting that it is not representative of best available data.

On the other hand, those against the use of allowable emissions argued that the EPA's consideration of "MACT allowable emissions" is arbitrary and not authorized under the law. The commenter stated that section 112(f)(1)(A) requires EPA to report to Congress on "methods of calculating the risk to public health remaining, or likely to remain, from sources subject to regulation under this section after the application of standards under subsection (d) of this section." Because a risk assessment based on allowable emissions would not reflect risk that remains or is likely to remain, it is not permissible under the statute. Further, section 112(f)(1)(C) requires the EPA also to report on "the actual health effects with respect to persons living in the vicinity of" affected sources. These requirements clearly signal that Congress expected EPA to focus on actual risk and not hypothetical risk in implementing the requirements of section 112(f). Thus, it is not reasonable for EPA to construe section 112(f) as authorizing the Agency to conduct risk assessments based on hypothetical "MACT allowable" emissions.

The commenter added that EPA has failed to provide any reasoned explanation for why risk assessments based on actual emissions estimates are inadequate, nor has the EPA provided data or analyses indicating that its current methodology results in negative bias. Further, there is no rational basis for EPA to conclude that allowable emissions are reasonably likely to occur, making them irrelevant to its risk analysis. EPA has provided no data demonstrating that affected sources actually do emit at levels significantly higher than the actual data show for any significant period of time. Nor has EPA shown that emissions will systematically and consistently increase across the industry such that allowable emissions would be a reasonable basis for conducting a risk assessment. The commenter noted that there is already significant conservatism in the EPA's risk assessment methodology, including the use of the REM, for establishing health benchmarks and in the dispersion model.

Response 1: We evaluated both actual and allowable emissions and considered the risk results using both of these emissions estimates to assess whether risks are acceptable. When estimating the impacts of the proposed revisions, we generally assess those impacts based on the actual emissions estimates, but the risk acceptability decisions consider both the actual and allowable emissions.

We disagree with the commenter that suggests consideration of allowable emissions to be unauthorized by the CAA. We interpret section 112(f)(1)(A) to require the EPA to assess allowable emissions because these are the potential emissions and therefore the "risk to public health remaining, or likely to remain, from sources subject to regulation under this section after the application of standards under subsection (d) of this section." The record is replete with evidence that emissions from refinery MACT sources may be understated. The fenceline monitoring approach was proposed largely to address concerns that emissions, particularly from fugitive sources (storage tanks, wastewater treatment, and equipment leaks), are difficult to characterize and studies have shown measured emissions to be many times higher than inventory reported values (see EPA Docket Item No. EPA-HQ-OAR-2010-0682-0210). As such, the commenter is mistaken in their assertion that the EPA did not provide any data in the record to suggest that the actual emissions may be understated and that an assessment of risk using allowable emissions is reasonable.

Comment 2: Some commenters stated that the EPA's method to develop allowable emissions estimates, including the use of the REM, is not representative of best available data and resulted in understated emissions, and provided specific criticisms of the flare and wastewater allowable emissions estimates.

Flares

The commenter stated that the EPA's estimate of allowable HAP emissions from flares significantly underestimates exposure because the REM is based on the following incorrect factually incorrect premises and thus the EPA must revise the REM.

- The EPA incorrectly used permit limits exceeding the assumed 98% flaring efficiency for facilities in Louisiana which biased the estimates for these facilities. Additionally, commenters disagreed that 98% efficiency is appropriate for allowables as an EPA analysis of data provided by petroleum refiners concluded that the average flare achieves approximately 93.9% destruction efficiency.

- Some facilities calculated emissions based on the combustion of natural gas, not refinery flare gas identifying the Murphy Oil permit as an example. The commenter further stated that refinery flare gas has significantly higher HAP concentrations than natural gas (as seen by the benzene concentration in the data the EPA collected from the passive Fourier transform infrared spectroscopy (PFTIR) tests).
- The REM used an emission factor of 0.14 pounds per million British thermal units **(**mmBtu) of VOC for some facilities from AP-42. This emissions factor is four times lower than EPA's proposed revision of the AP-42 emissions factor to 0.55 lb/mmBtu VOCs. According to the commenter, the EPA must assume that benzene and organic HAP releases were also under-estimated by the same amount and that the EPA's earlier risk estimate must be increased by a factor of four.
- The REM emission factor purports to account for all flaring emissions, but the underlying permits and emission factors in the EPA's Emission Estimation Protocol for Petroleum Refineries state that SSM events may not be incorporated. The EPA's attempt to account for the uncertainty in the data by applying a multiplier of three to the modeled emissions cannot correct for the structural errors in the EPA's model.
- The commenter stated that the EPA's recent consent decrees recognize that flaring emissions are proportional to the refinery's Nelson Complexity Index. The complexity of the U.S. Refineries increased nearly 12% between 2002 and 2010, warranting a corresponding 12% increase in flare emissions.

Wastewater

The commenter stated that the EPA's underlying assumptions about wastewater treatment systems are factually incorrect and that the EPA has severely underestimated the allowable emissions from petroleum refinery wastewater systems for the following reasons.

- The EPA's 2011 ICR for the Petroleum Refining industry shows that the average benzene concentration and wastewater production rates are much higher than the assumptions used to estimate allowable emissions. The commenter noted that benzene loading rates were derived from a 1998 document, Locating and Estimating Air Emissions Sources of Benzene (L&E document), which used data from the EPA's ICR for the original MACT 1 regulations for petroleum refineries issued in 1994.
- The EPA uses two contradicting models to estimate the control efficiency for wastewater treatment system pollution controls. To estimate allowable emissions, the EPA assumed 92% control efficiency, significantly higher than the average 86.5% control efficiency assumed in the Technology Review for Industrial Wastewater Collections and Treatment Operations at Petroleum Refineries. The commenter stated that EPA required five facilities to conduct emissions testing to determine the control efficiency of their biological treatment units and that EPA must use this data to inform its analysis of the allowable emissions from wastewater treatment facilities.

The commenter stated that the EPA must address these problems, remodel the allowable emissions from petroleum refineries, and then recalculate the risk posed by refineries.

Response 2: We disagree with the commenter that the allowable emission estimates are understated. We did note in the documentation of the allowable emissions estimates that "allowable emissions" are very difficult to estimate from several of the refinery emissions sources, including flares and wastewater.

Regarding our allowable emission estimates for flares, we based them on permit application limits, which reflect the "allowable" emissions requested for these flares. The available data supports the validity of the emission factors developed for the REM model. For example, we have measurements of 1,3-butadiene in the flare plume from the PFTIR data. We estimated 1,3-butadiene emissions for four refinery flares at three refineries using the data set for which the new VOC emissions factors were developed. The flare emissions factor for 1,3-butadiene developed from these data yields an identical emissions factor as used in the REM model. This suggests that the commenter's claim that HAP emissions should be 4 times higher based on the new VOC factor is unfounded. It also suggests that concerns that refinery fuel gas contains more HAP than natural gas may not be a significant issue either.

The commenter suggested that the PFTIR data shows more benzene in refinery fuel gas than in natural gas. We note that there is typically very little benzene in refinery fuel gas (or other C6+ hydrocarbons, which are liquid at ambient temperatures). Only one facility measured benzene in its refinery fuel gas. Assuming 98 percent combustion efficiency, the emission factor developed for this unit would be an order of magnitude lower than the REM emission factor for benzene. This again appears to support the relative accuracy and conservatism in the REM flare emissions factors.

It is difficult to set a maximum allowable quantity of gas that can be flared, so this is the key uncertainty in the analysis and this is why a factor of 3 was applied to the basic REM flare estimates so as to account for these potentially higher volumes of gas that could be flared. We note that the Greenhouse Gas Reporting Program (GHGRP) requires all refineries to report flare emissions including emissions that occur from SSM events. Flare emissions have not increased significantly over the 4 year reporting period, and the factor of 3 emissions is considered to be sufficient to account for any increased flaring due to increases in refinery complexity.

We agree with commenters that studies have shown that many refinery flares are operating less efficiently than 98 percent. Prior to proposing this rule, we conducted a flare ad hoc peer review to advise our consideration of factors affecting flare performance (see discussion in the June 30, 2014, proposal at 70 FR 36905). However, we disagree with the commenters that the risk analysis should consider this level of performance since the existing MACT standard does not allow it. For purposes of the risk analysis, we evaluate whether it is necessary to tighten the existing MACT standard in order to provide an ample margin of safety. Thus, in reviewing whether the existing standards provide an ample margin of safety, we review the level of emissions the MACT standards allow. In the present case, we considered the level of performance assumed in establishing the MACT standard for purposes of determining whether the MACT standard provides an ample margin of safety. However, we did recognize that facilities were experiencing performance issues with flares and that many flares were not meeting the performance level established at the time we promulgated the MACT standard. Thus, we proposed, and are finalizing, revisions to the flare operating requirements to ensure that flares used as control devices meet the required performance level. These provisions are consistent with the EPA's goals to improve the effectiveness of our rules.

Regarding the wastewater data in the ICR, in our initial review of these data, we determined that there were discrepancies that made the data unusable. For example, some facilities reported concentrations exceeding 1,000,000 parts per million by weight **(**ppmw), which is impossible. We were unable to quality assure the data prior to the time we were obligated to issue our proposed rule, and determined in light of these deficiencies it was more appropriate to utilize the L&E document factors. The data collected from the ICR efforts has been reviewed in more detail since proposal. As discussed in Chapter 9.2 of this response to comments (RTC), we performed an analysis of the facilities that submitted a complete data set (meaning values for flow, benzene, and total organic HAP), and calculated the average flow factor, flow-weighted average benzene concentration, and flow-weighted average HAP concentration. We applied these factors to the model plants used in the technology review and for 5 of the 6 model plants, the benzene loading rates determined from the L&E document factors were higher than the loadings derived from the 2011 ICR factors. While there are still issues with the 2011 ICR data for wastewater, this analysis indicates that the L&E document factors provided a reasonably conservative estimate for the allowable emissions from petroleum refinery wastewater treatment systems. The analysis of the ICR wastewater data has been added to the refinery docket EPA-HQ-OAR-2010-0682.

We also reviewed the ICR "source test" data for wastewater treatment systems. Based on these data, the control efficiencies of the wastewater treatment systems that were evaluated exceeded the 92 percent control efficiency used in the allowable emission estimate suggesting the allowable emissions estimates were appropriately conservative. As described in further detail in Section 9.2 of this document, we consistently used a control efficiency of approximately 92 percent for the enhanced biological treatment unit in both the allowables emissions estimate and the technology reviews, which we note is different from the overall collection and treatment system control efficiency. For some model plants in both the risk assessment and technology review, wastewater collection system controls are not required and the emissions from the collections system reduces the overall control efficiency of the system.

Comment 3: One commenter stated that EPA's inventory of hydrogen cyanide emissions underestimates these emissions from FCCUs. The commenter noted that EPA used the same factor to estimate "actual" and "allowable" emissions of HCN. The commenter attached a report from Dr. Phyllis Fox that, according to the commenter, explains that both actual and allowable emissions of HCN were underestimated for two main reasons:

- The underlying FCCU stack test show that HCN emissions are highly variable between process units. Based on only 9 stack tests, EPA found an HCN emission rate that ranged from 114 to 22,100 lb/MMbbl. With such a small sample size and such a high level of variability, EPA must use a conservative uncertainty factor to characterize "actual" emissions from all 203 FCCUs in use at refineries.
- The existing MACT standards do not regulate HCN emissions from the FCCUs, and the existing carbon monoxide (CO) standard actually leads to higher HCN emissions as CO is reduced.

In light of these issues, the commenter stated that HCN emissions at many FCCUs could be greater than the highest measured HCN emissions, from Hovensa, of 22,000 lb/MMbbl. The resulting target organ-specific hazard index (TOSHI) from inhalation exposure to "MACT-allowable" HCN emissions from FCCU's could be much greater than the TOSHI significance threshold of 1.

To fulfill the agency's duty to assess health risks from all emitted pollutants, prevent all unacceptable risk, and assure an "ample margin of safety to protect public health," as section 112(f)(2) requires, EPA must evaluate the HCN data and evidence provided in the Fox Report and set standards that will assure limits on HCN for the first time. EPA must also do so, as "developments" and ensure it is limiting all emitted HAPs as *National Lime Association* makes clear that the CAA requires.

Response 3: We agree that the HCN emissions were highly variable and we adjusted reported HCN emissions by a factor of 10 to account for the magnitude of emissions we saw in the stack test data.[5] Fortunately, we also had actual HCN stack test data for a number of FCCU and we modeled these emissions directly. Based on our consideration of risks associated with HCN emissions, we did not identify any facilities that had unacceptable HCN emissions.

We disagree that the existing CO limit leads to higher HCN emissions. As discussed in greater detail in our response to comments regarding HCN emissions in the preamble to the final rule, we consider the control strategy used by the best performing facilities is the use of complete combustion as defined by reducing CO emissions to 500 parts per million by volume **(**ppmv). Combustion theory suggests that partial combustion FCCU with no post-combustion device would have true uncontrolled (high) HCN emissions. The only data we have available is for facilities that have CO concentrations at or below 500 ppmv, so all of these emissions are for controlled units. The poor correlation between CO and HCN emissions below CO levels of 500 ppmv merely confirms the idea that CO limits are needed. In any event, since all FCCU must meet the 500 ppmv CO limit, the 9 source tests that are available should be representative of the allowable emissions from controlled, complete combustion units. This, combined with our augmentation of reported HCN emissions for risk modeling of FCCU HCN emissions, provides us adequate confidence that the actual or allowable emissions for FCCU HCN do not result in unacceptable risk.

2.1.3 Revisions submitted for the emissions data set

Comment 1: Commenters encouraged EPA to incorporate all corrections of the model input data provided by facilities and to re-evaluate the source category risk. One commenter provided suggested data revisions to the risk modeling file for 33 facilities. Seventeen facilities submitted detailed revisions in the EPA data revisions spreadsheet tool.

Response 1: Due to the limited time and resources available for completing the final rulemaking, the EPA was unable to remodel the entire source category risk. Additionally, information was

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[5] The Refinery Emission Protocol emission factor for HCN from FCCU was also revised by a factor of 10 in April, 2015.

provided by a commenter for 33 facilities that was incomplete and would have required additional follow-up with each of the facilities in order to revise the risk modeling file. However, 17 facilities provided revisions in the EPA data revisions tool. Of those 17 facilities, 13 of them provided emission data revisions. EPA post processed the risk for four of these facilities because they were the four highest MIR risk facilities. The fifth highest facility did not submit any emission revisions. Since their MIR risk will remain the same and the top-four MIR values are reduced below the fifth facility, the fifth facility will now be the new highest MIR facility. No additional post-processing of the remaining nine facilities will change the overall risk picture. By examining the specific pollutant contributions to the MIR we can adjust each pollutant risk by the ratio of the revised emissions versus the ICR emissions. A revised facility risk is then estimated by substituting the revised pollutant risks in place of the ICR pollutant modeled risks. The approach assumes that the reductions are spread evenly across the sources emitting that specific pollutant and that the facility maximum risks will still be located at the MIR location.

Other revisions submitted included deleting emission units that are no longer in service and moving the coordinates of emission points to more accurately reflect their actual location in the facility.

2.2 EPA overestimated human health risks

2.2.1 Modeling assumptions overestimate risk

Comment 1: Modeling assumptions are overly conservative and erroneous: One commenter argued that EPA has overstated the risk associated with refinery emissions because EPA's modeling assumptions are overly conservative**.** Regarding chronic risk estimates, the commenter describes EPA's methodology including the MIR based on the unit risk estimate (URE) of each HAP. The commenter points out that the URE is an upper bound estimate and may overestimate both the individual risk levels and the total estimated number of cancer cases.

Regarding acute risk estimates, the commenter again described EPA's methodology and underscores that the accuracy of the acute inhalation exposure assessment depends on the simultaneous occurrence of independent factors that may vary greatly, such as hourly emission rates, meteorology and human activity patterns. The commenter noted that EPA conservatively assumes that individuals remain for 1 hour at the point of maximum ambient concentration. The commenter further contends that EPA amplified its conservative approach, by claiming that the maximum hourly emission rate data collected in the ICR was inadequate, and instead estimating hourly emissions based on reported annual emissions, multiplied by "escalation factors" ranging from 10 to 60 times the annual emissions. According to the commenter, this the escalation factor methodology reflects EPA's arbitrary and excessively conservative attempt to assign an emission variability factor to each source type, which deviates from past RTR rulemakings.

Response 1: Uncertainty and the potential for bias are inherent in all risk assessments, including those performed for this rulemaking. Although uncertainty exists, our approach, which uses conservative tools and assumptions, ensures that our decisions are appropriately health protective and environmentally protective. A brief discussion of the uncertainties in the RTR emissions datasets, dispersion modeling, inhalation exposure estimates and dose-response relationships can be found in the proposal for this rulemaking [79 FR 36879]. Regarding the comment that we amplified our conservative approach by using refinery-specific hourly emission rate factors to estimate acute risks, we note that we derived process specific factors based on our knowledge of refinery processes. We intended to refine the default factor of 10 that is applied to the average hourly rate produced by dividing annual emissions by annual hours (8760 hours) that has been used in many other source categories to produce a more realistic value, not to add to the conservancy of the analysis. We did not, as the commenter asserts, use values from 10 to 60 to predict hourly rates. In fact, for many processes, our refinery specific factor was much less than 10; for example, we applied hourly multipliers of 2 to estimate maximum hourly rates for fugitives, FCCU, SRU, chemical processes and miscellaneous process vents. For storage and wastewater emissions sources, we used a value of 4; it was only in the case of cyclic and semi-regenerative catalytic reformers, and delayed cokers that we applied a factor greater than 10; in these processes, emissions, as reported on an annual basis, only occur for very limited periods of time. We used the number of hours in the venting cycle and the variability of emissions expected over the cycle to develop a factor specific to each type of process. For example, semi-regenerative reformers only vent a few weeks a year during regeneration. Our factor of 60 was intended to account for the period of time that they vent, and for variability over the venting period. Therefore, we do not agree that our approach was arbitrary or excessively conservative as it considers the variability of various types of emissions sources in petroleum refining and it is based on the actual venting characteristics of these sources. As we discussed in the proposal, we elected not to simply model reported hourly emissions as these values were often left blank or appeared to be reported in units other than those asked for in the ICR and we were not confident in the quality of these data. A more thorough discussion of these uncertainties is included in the Final *Residual Risk Assessment for the Petroleum Refining Source Sector in support of the September 2015 Risk and Technology Review Final Rule*, in Docket No. EPA-HQ-OAR-2010-0682 .

Comment 2: Unit risk estimates are too conservative: One commenter expressed concerns with EPA’s assumptions concerning benzene, naphthalene, and other polycyclic organic matter (POM) unit risk values, and stated that the unit risk factors are extremely conservative adding to the conservatism of the risk analysis. The commenter claimed that the EPA singled out benzene and naphthalene by attributing to them 98% of the MIR resulting from equipment leaks and storage tanks.

Regarding benzene, the commenter stated that the inhalation unit risk value developed under EPA’s IRIS program is a range of values (2.2 x 10^{-6} to 7.8 x 10^{-6}) and that EPA has gone on record stating that each estimate has equal scientific plausibility[6]. Several commenters asserted that EPA’s risk assessment utilizes the upper end of this range, biasing towards a greater cancer risk for each micrograms (µg)/ cubic meters (m^3) of exposure to this substance, rather than utilizing the entire range. If the lower end of the range were used, commenters stated that the resulting cancer risk estimates may have been 3-4 times lower than those shown in the report. One of the commenters noted that EPA often defaults to a more conservative approach when estimating risk, therefore utilizing the conservative upper end toxicity value; however, it would be beneficial to see a balanced approach, demonstrating the range of potential cancer risk,

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[6] http://www.epa.gov/iris/subst/0276.htm

especially when actions are being required by the refinery sector on the basis of the risk calculations.

Regarding naphthalene, one commenter stated that for several years, industry and EPA have been working together to resolve the question of whether naphthalene has been inappropriately classified as a possible or reasonably anticipated human carcinogen. The commenter asserted that EPA’s analysis of the possible risk associated with exposure to naphthalene does not take into account the most recent scientific information. According to the commenter, the naphthalene URE used in EPA’s risk analysis originates from California EPA’s Office of Environmental Health Hazard Assessment (OEHHA), which was established based upon National Toxicology Program (NTP) studies. The commenter noted that EPA dropped its own URE value that same year, citing a lack of evidence on naphthalene carcinogenicity in humans, and furthermore that current research by the National Research Council (NRC) has called into question the NTP studies (in which the animals were dosed at concentrations exceeding the Maximum Tolerated Dose resulting in inflammation incidence near 100%, suggesting that cytotoxicity played a significant role in the tumor responses [NRC comments submitted to EPA's IRIS Docket; August 20, 2014]). The commenter contended that the evidence used to support the URE adopted by OEHHA is irrelevant to actual human risk, that the California EPA URE is outdated and that therefore the validity of classifying naphthalene as a human carcinogen is highly questionable. The commenter also points out that, as a result of the NRC work, EPA is performing another IRIS program review of naphthalene carcinogenicity and derivation of cancer risk, which is delayed, but which will consider all the experimental evidence on naphthalene published over the past several years. Many commenters concluded that, in light of the latest experimental evidence on naphthalene, use of the OEHHA URE is overly conservative and mischaracterizes the human risk posed by naphthalene. Specifically, the conclusion that naphthalene carries more weight than benzene (22% vs 21%) in driving the cancer risk should be reviewed, according to the commenters. One commenter asserted that, at a minimum, recognition of this uncertainty and the work underway to resolve this uncertainty should have been addressed in the preamble, in an effort to provide a balanced representation of the potential risk attributed to naphthalene.

Response 2: EPA’s chemical-specific toxicity values are derived using risk assessment guidelines and approaches that are well established and vetted through the scientific community, and follow rigorous peer review processes.[7] The RTR program gives preference to EPA values for use in risk assessments and uses other values, as appropriate, when those values are derived with methods and peer review processes consistent with those followed by the EPA. The approach for selecting appropriate toxicity values for use in the RTR program has been endorsed by the Science Advisory Board.[8]

The commenter is correct that for benzene the high end of the reported cancer URE range (7.8E-06 per µg/m^3) was used in our assessments to provide a conservative estimate of potential cancer risks. Use of the high end of the range provides risk estimates that are approximately 3.5 times

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[7] Integrated Risk Information System (IRIS). IRIS Guidance document available at http://www.epa.gov/iris/backgrd.html

[8] http://yosemite.epa.gov/sab/sabproduct.nsf/0/b031ddf79cffded38525734f00649caf!OpenDocument&TableRow=2.3#2

higher than use of the equally plausible low end value (2.2E-06 per µg/m^3). If the estimated benzene–associated risks exceed 1-in-1-million, we would also evaluate the impact of using the low end of the URE range on our risk results. For the petroleum refineries source categories, the maximum individual risk for all carcinogens was estimated to be up to 60-in-1-million with benzene contributing 21% to the cancer incidence in exposed population. Estimating the cancer risk using the low end URE value for benzene would change the maximum individual risk to be up to 50-in-1-million for these source categories (i.e., driven by pollutants in addition to benzene) and would reduce the incidence by less than 6%, which would not impact our risk-based decisions. We have updated the risk assessment report for the final rulemaking to provide this information.

The commenter is correct that the EPA used the unit risk factor for naphthalene derived by OEHHA, which is considered by the EPA to be the best available value and most appropriate for use in RTR assessments. The derivation of OEHHA's naphthalene unit risk is based on a well conducted 2 year NTP bioassay showing clear evidence of carcinogenic activity in rats. We disagree with the commenter that the EPA dropped its own URE citing a lack of evidence on naphthalene carcinogenicity in humans. EPA did not drop the URE from the naphthalene IRIS assessment. This assessment, which was last revised in 1998, does not include a URE. Based on the 1996 Proposed Guidelines for Carcinogen Risk Assessment, the EPA determined that the human carcinogenic potential of naphthalene via the oral or inhalation routes "cannot be determined" at this time based on human and animal data; however, the naphthalene assessment also states that there is suggestive evidence (observations of benign respiratory tumors and one carcinoma in female mice only exposed to naphthalene by inhalation).[9]

Several commenters noted the ongoing assessment of naphthalene in the IRIS Program, which will consider the more recent studies sponsored by the Naphthalene Research Council, and suggested consideration of those studies alone as a reason to add greater uncertainty to the current cancer risk conclusions regarding naphthalene. EPA will not prejudge or presuppose the outcome of that ongoing assessment, or the relative merits of any particular set of studies; to do so would be premature and counterproductive to the established IRIS Process. EPA will continue to use the current cancer assessment for naphthalene.

2.2.2 Risk assessment is too broad in scope

Comment 1: Facility-wide emissions and risks should not be considered: One commenter stated that EPA is not authorized to consider total facility emissions in conducting risk assessments for particular source categories According to the commenter, the CAA requires EPA to conduct residual risk determinations on a category-by-category basis, citing the substance and timing required in section 112(f), in particular language in section 112(f)(2)(A) referring to "*emissions from a source in the category or subcategory.*" The commenter asserted that nothing in the text

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[9] National Toxicology Program (NTP). (1992) Technical Report on the Toxicology and Carcinogenesis Studies of Naphthalene (CAS No. 91-20-3) in B6C3F1 Mice. (Inhalation Studies). DHHS, PHS, NIH, Rockville, MD. https://ntp.niehs.nih.gov/ntp/htdocs/lt_rpts/tr410.pdf

of the statute indicates that EPA may combine multiple source categories into a single risk assessment and therefore EPA does not have the authority to consider emissions from any sources other than those in the source category or subcategory under review at that time. The commenter further argued that it is not reasonable to construe these provisions as authorizing EPA to consider emissions from entire facilities in conducting risk assessments, because Congress clearly envisioned that full implementation of the MACT program would take longer than eight years (which, according to the commenter, would be impossible for facilities that contain sources in a category where the eight-year deadline precedes the adoption of MACT standards for other sources at these facilities). For these reasons, the commenter concluded there is no practical way to use combined source categories for purposes of conducting the risk assessment, and thus the statute cannot reasonably be construed as authorizing EPA to do so.

Response 1: We disagree that examining facility-wide risk in a risk assessment conducted under section 112(f) exceeds the EPA's authority. The development of facility-wide risk estimates provides additional information about the potential cumulative risks in the vicinity of the RTR sources, as one means of informing the ample margin of safety step of our risk analysis for the RTR source categories in question.

Section 112(f)(2) of the CAA expressly preserves our use of the two-step process for developing standards to address residual risk and interpret "acceptable risk" and "ample margin of safety" as developed in the Benzene NESHAP (54 FR 38044, September 14, 1989). In the Benzene NESHAP, the EPA rejected approaches that would have mandated consideration of background levels of pollution in assessing the acceptability of risk, concluding that "…comparison of acceptable risk should not be associated with levels in polluted urban air. With respect to considering other sources of risk from benzene exposure and determining the acceptable risk level for all exposures to benzene, EPA considers this inappropriate because only the risk associated with the emissions under consideration are relevant to the regulation being established and, consequently, the decision being made." (54 FR 38044, 38061, September 14, 1989).

Although not appropriate for consideration in the determination of acceptable risk, we note that background risks or contributions to risk from sources outside the source category under review could be one of the relevant factors considered in the ample margin of safety determination, along with cost and economic factors, technological feasibility, and other factors. Background risks and contributions to risk from sources outside the facilities under review were not considered in the ample margin of safety determination for these source categories, mainly because of the significant uncertainties associated with emissions estimates for such sources. Our approach here is consistent with the approach we took regarding this issue in the Hazardous Organic NESHAP (HON) RTR (71 FR 76603, December 21, 2006), which the court upheld in the face of claims that the EPA had not adequately considered background *(NRDC v. EPA*, 529 F.3d 1077 (D.C. Cir. 2008)).

2.3 EPA underestimated human health risks

2.3.1 Modeling methodology understates risks

Comment 1: Deposition methodology understates metal toxicity: One commenter stated that particulates have an inversely proportionate bonding to particle size, with 99% of toxic metal gases like lead and mercury in an effluent stack adhered to particles less than 2 microns in size. According to the commenter, the deposition models attempt to show the general location where something that "went up" actually "comes down" as a deposited particle. The commenter further explained that, in these computer models, a "reflection coefficient" is a user-adjustable factor that "floats" very small particles and with artificially high values, small particles that go up do not come down. The commenter argued that the use of this reflection coefficient could enable modeling demonstrations to hide the bulk of the metal toxicity and requested that the EPA provide valid guidance for the use of these types of coefficients to ensure the models will to accurately project the real health impacts on the public.

Response 1: EPA disagrees with the commenter that the modeling methodology employed for the analysis underestimates risks. The commenter is concerned that the mass of the plume is not being made available for exposure at receptor locations at the surface. In determining downwind ambient concentrations the HEM-3 model treats each emitted pollutant (including metals) as a gaseous pollutant and thus does not account for potential removal of mass in the particle phase by contacting objects on the surface or settling. By modeling the pollutant only as a gas, the plume is brought to the ground for potential exposure at receptor locations by simple dispersion (movement of the plume by the wind and atmospheric stability). Although the emitted metals are particulates, at such low ambient concentrations the plume will behave more like a gas and EPA believes this approach will most realistically simulate the path of the plume as it travels downwind from the facility. This approach, in some situations, may result in an over-prediction of ambient concentrations (i.e., health protective).

Comment 2: Centroid location representing exposed population understates risk: Two commenters objected to EPA's estimation of chronic exposure at the census block centroid instead of at the facility property line or location of the maximum exposed individual. Commenters noted that census blocks can be geographically large and the population distribution within the blocks are not necessarily homogenous and thus this approach understates risk. Furthermore, commenters stated that, except for lead, EPA made no effort to move receptor points closer to the facility to assess chronic or cancer risk, even where local residents live nearer to a facility than the census block centroid. According to the commenter, this conflicts with the recommendation of the Science Advisory Board (SAB), which has urged EPA to consider "specific locations of residences" [SAB May 2010]. The commenter stated that taking geographic variation out of the equation fails to properly account for exposure to the "individual most exposed to emissions" as required by section 112(f)(2)(A), and fails to provide an accurate estimate of risk. The commenter stated that EPA's failure to adjust receptor points for residents living on the fenceline is particularly inexcusable given that the HEM-AERMOD system allows for such an adjustment, and that such an adjustment was appropriately made for the estimation of acute health risks [79 FR 36890]. The commenter concluded that, having recognized that the maximum exposed individual for acute risks is likely present at the fence-line, EPA cannot justify failing to analyze cancer and other chronic health effects in a similar manner.

Response 2: In a national-scale assessment of lifetime inhalation exposures and health risks from facilities in a source category, it is appropriate to identify exposure locations where it may be reasonably expected that an individual will spend a majority of his or her lifetime. In determining chronic risks, it is appropriate to use census block information on where people actually reside, rather than points at the property line, to locate the estimation of exposures and risks to individuals living near such facilities. Census blocks are the finest resolution available as part of the nationwide population data (as developed by the US Census Bureau); on average, a census block is comprised of approximately 40 people and about 10 households. In the EPA risk assessments, the geographic centroid of each census block containing at least one person is used to represent the location where all the people in that census block live. The census block centroid with the highest estimated exposure then becomes the location of maximum exposure, and the entire population of that census block is assumed to experience the maximum individual risk. In some cases, because actual residence locations may be closer to or farther from facility emission points, this may result in an overestimate or underestimate of the actual annual concentrations (although there is no systematic bias for average levels). Given the relatively small dimensions of census block in densely-populated areas, there is little uncertainty introduced by using the census block centroids in lieu of actual residence locations. There is the potential for more uncertainty when the census block are larger, although there is still no systematic bias. The EPA concludes that the most appropriate locations at which to estimate chronic exposures and risks are the census block centroids because: 1) census blocks are the finest resolution available in the national census data; 2) facility fence lines do not typically represent locations where chronic exposures are likely (i.e., people do not typically live at the fence line of facilities); and 3) there is no bias introduced into the estimate of MIR by using census block centroid locations. In its peer review of the methodologies used to estimate risks as part of the RTR rulemaking efforts, the EPA's SAB endorsed this approach.[10]

In addition to the approach described above, the EPA recognizes that where a census block centroid is located on industrial property or is large and the centroid is less likely to be representative of the block's residential locations, the block centroid may not be the appropriate surrogate. For these source categories, as described in the Draft Residual Risk Assessment for the Petroleum Refining Source Sector (May 2014) in Docket Item No. EPA–HQ–OAR–2010–0682-0225, in cases where a census block centroid was within 300 meters of any emission source (and therefore possibly on facility property), we viewed aerial images of the facility to determine whether the block centroid was likely located on facility property. Likewise, we examined aerial image of all large census blocks within one kilometer of any emission source. If the block

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[10] U.S. Environmental Protection Agency, Office of the Administrator Science Advisory Board. Review of EPA's draft entitled, "Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies – MACT I Petroleum Refining Sources and Portland Cement Manufacturing." EPA-SAB-10-007. May 7, 2010. http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.

centroid did not represent the residential locations within that block, we relocated it to better represent them and/or we added receptors for residences nearer to the facility than the centroid. For these source categories, we added several receptors for census blocks where the centroid location was not representative of the residential locations. Appendix 7 of the risk assessment document cited above provides additional information on these changes.

2.3.2 Cancer unit risk estimates, non-cancer reference doses and acute benchmarks used by EPA understate risks

Comment 1: Cancer unit risk estimates and chronic non-cancer reference concentrations used are not protective or based on the most up-to-date science: One commenter stated that EPA failed to use the best available reference values for a number of key HAPs including benzene, and thus underestimated risk from these pollutants.

Regarding cancer risk, the commenter recommended using the cancer potency values as published by the California EPA (CalEPA). The commenter performed a comparison of the CalEPA values and those used by the EPA and claimed for some HAP (including 1,3 butadiene, benzene, Cadmium Compounds, and Chromium VI Compounds) the UREs are at least 57% lower. The commenter also stated an emissions weighted analysis of the different potency values used by EPA versus those recommended by CalEPA shows that cancer risk may have been two times higher had EPA utilized up-to-date factors. Similarly, another commenter stated that California's OEHHA has developed a more stringent cancer inhalation unit risk value for benzene and if this number had been used with the proposed 9 µg/m^3 fenceline action level, the lifetime risk would be close to 260-in-1 million.

Regarding non-cancer chronic risk, the commenter also recommended that the EPA use the chronic inhalation reference concentrations (RfC) published by California EPA. The commenter claimed, that EPA's RfC for some HAP (including benzene, toluene, manganese, mercury (elemental), and nickel) are less protective than those published by CalEPA by at least a factor of 3. Likewise, another commenter stated that California's OEHHA finalized new and revised benzene and nickel reference exposure levels (REL) which are more stringent than those used in the residual risk assessment. One commenter further explained that the new OEHHA acute REL for benzene is 27 µg/m^3, is nearly equal to the value EPA used for the chronic RfC. The commenter noted that the EPA proposed a fenceline action level of 9 µg/m^3 would exceed the California chronic REL by a factor of three.

Regarding risks from lead exposure, one commenter stated that EPA should utilize the best science on assessing children's health risk of exposure to lead, rather than consider only the 2008 Lead National Ambient Air Quality Standards (NAAQS). The commenter stated that EPA must address and incorporate the best currently available information on children's exposure, including the Children's Health Protection Advisory Committee (CHPAC) recommendation[11] of lowering the lead standards to 0.02 µg/m^3 from the current EPA NAAQS level of 0.15 µg/m^3.

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[11] Letter from Dr. Melanie A. Marty, Chair, Children's Health Protection Advisory Comm., to Administrator Stephen L. Johnson, (June 16, 2008), http://www2.epa.gov/sites/production/files/2014-05/documents/61608.pdf

According to the commenter, the Centers for Disease Control (CDC) has now recognized that there is no safe level of exposure, and has replaced the now outdated 10 µg/dL standard with a recognition that action is required at the reference level of 5 µg/deciliters (dL).[12]The commenter concluded that because EPA relies on the lead NAAQS in its proposed residual risk rule, EPA has not met the legal standard of section 112(f)(2), noting that the residual risk standards are designed to do more than just replicate other statutory protections, such as those provided by the NAAQS. The commenter argued that, if Congress had intended EPA simply to replicate the NAAQS or some other different CAA requirement in its section 112(f)(2) residual risk rulemaking, the section 112(f)(2) requirement would become redundant for any hazardous air pollutant that also has any relationship to any other regulated pollutant. Furthermore, according to the commenter, for any ambiguity on this question, statutory construction requires a reading of section 112(f)(2) that preserves its independent value and meaning.

Response 1: EPA's chemical-specific toxicity values are derived using risk assessment guidelines and approaches that are well established and vetted through the scientific community, and follow rigorous peer review processes.[13] The RTR program gives preference to EPA values for use in risk assessments and uses other values, as appropriate, when those values are derived with methods and peer review processes consistent with those followed by the EPA. The approach for selecting appropriate toxicity values for use in the RTR Program has been endorsed by the SAB.[14]

The commenter recommended that EPA use California OEHHA's new toxicity values for several chemicals and provided some references for the approaches used to derive those values. The EPA scientists reviewed the information provided by the commenter regarding the California values and concluded that further information is needed to evaluate the scientific basis and rationale for the recent changes in California OEHHA risk assessment methods. The EPA will work on gathering the necessary information to conduct an evaluation of the scientific merit and the appropriateness of the use of California OEHHA's new toxicity values in the agency decisions. Until the EPA has completed its evaluation, it is premature to determine what role these values might play in the RTR process. Therefore, EPA did not use the new California OEHHA toxicity values as part of this current rulemaking.

We disagree with the comment that the use of the lead NAAQS does not sufficiently protect children. While recognizing that lead has been demonstrated to exert "a broad array of deleterious effects on multiple organ systems," the lead NAAQS targets the effects associated with relatively lower exposures and associated blood lead levels, specifically nervous system effects in children including cognitive and neurobehavioral effects (73 FR 66976). EPA establishes the NAAQS at a level to protect sensitive sub-populations, such as children and

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[12] CDC, What do Parents Need to Know to Protect Their Children?, http://www.cdc.gov/nceh/lead/acclpp/blood_lead_levels.htm

[13] Integrated Risk Information System (IRIS). IRIS Guidance documents available at http://www.epa.gov/iris/backgrd.html

[14]http://yosemite.epa.gov/sab/sabproduct.nsf/0/b031ddf79cffded38525734f00649caf!OpenDocument&TableRow=2.3#2

pregnant women. The 2008 decision on the lead NAAQS was informed by an evidence-based framework for neurocognitive effects in young children. In applying the evidence-based framework, we focused on a subpopulation of U.S. children, those living near air sources and more likely to be exposed at the level of the standard; to the same effect see 73 FR 67000/3--"The framework in effect focuses on the sensitive subpopulation that is the group of children living near sources and more likely to be exposed at the level of the standard. The evidence-based framework estimates a mean air-related intelligence quotient (IQ) loss for this subpopulation of children; it does not estimate a mean for all U.S. children"; 73 FR 67005/1--"the air-related IQ loss framework provides estimates for the mean air-related IQ loss of a subset of the population of U.S. children, and there are uncertainties associated with those estimates. It provides estimates for that subset of children likely to be exposed to the level of the standard, which is generally expected to be the subpopulation of children living near sources who are likely to be most highly exposed." In addition, in reviewing and sustaining the lead primary NAAQS, we note that the D.C. Circuit specifically noted that the rule was targeted to protect children living near lead sources: "EPA explained that the scientific evidence showing the impact of lead exposure in young children in the United States led it 'to give greater prominence to children as the sensitive subpopulation in this review' and to focus its revision of the lead NAAQS on the 'sensitive subpopulation that is the group of children living near [lead emission] sources and more likely to be exposed at the level of the standard.' Given the scientific evidence on which it relied, the EPA's decision to base the revised lead NAAQS on protecting the subset of children likely to be exposed to airborne lead at the level of the standard was not arbitrary or capricious." Coalition of Battery Recyclers, 604 F. 3d at 618.

As noted in the risk assessment document, there is no RfD or other comparable chronic health benchmark value for lead compounds. In 1988, the EPA's IRIS program reviewed the health effects data regarding lead and its inorganic compounds and determined that it would be inappropriate to develop an reference dose (RfD) for these compounds, stating:

> *A great deal of information on the health effects of lead has been obtained through decades of medical observation and scientific research. This information has been assessed in the development of air and water quality criteria by the Agency's Office of Health and Environmental Assessment (OHEA) in support of regulatory decision-making by the Office of Air Quality Planning and Standards (OAQPS) and by the Office of Drinking Water (ODW). By comparison to most other environmental toxicants, the degree of uncertainty about the health effects of lead is quite low. It appears that some of these effects, particularly changes in the levels of certain blood enzymes and in aspects of children's neurobehavioral development, may occur at blood lead levels so low as to be essentially without a threshold. The Agency's RfD Work Group discussed inorganic lead (and lead compounds) at two meetings (07/08/1985 and 07/22/1985) and considered it inappropriate to develop an RfD for inorganic lead.*

The EPA's IRIS assessment for lead and compounds (inorganic) (c 7439-92-1) can be found at http://www.epa.gov/iris/subst/0277.htm.

With regard to the information identified by the commenters, much of this information was similar to information available at the time of the 2008 NAAQS decision. For example, in 2005, the CDC recognized the evidence of adverse health effects in children with blood lead levels below 10 µg/dL, and that there is no safe level of blood lead in young children (CDC, 2005). The commenter also cites a benchmark analysis by California OEHHA that was completed during the time of the last lead NAAQS review (Carlisle and Dowling, 2007). The quantitative relationship from this analysis is a correlation of 1 IQ point change with a 1.0 µg/dL change in blood lead is actually a substantially smaller change in IQ per µg/dL blood lead than the slope of 1.75 IQ points per µg/dL blood lead used in the evidence-based framework that the Administrator relied upon in his 2008 decision on a revised level for the lead NAAQS in 2008 (73 FR 66964). Regarding the CHPAC, a recommendation on the level and averaging time for the revised NAAQS referenced by the commenter was made to EPA in January of this year in the context of the current NAAQS review and the same comment was made and considered in the 2008 review, that concluded with the current lead NAAQS.

The commenter also makes the legal argument that the primary NAAQS provides an "adequate" margin of safety, but that section 112 (f)(2) requires that a residual risk standard provide an "ample" margin of safety, reasoning from this that a NAAQS cannot just substitute as the measure for evaluating acceptability of risk and that some greater level of protection is required. We do not accept the commenter's argument. The EPA is considering the primary NAAQS for lead -- which incorporates an adequate margin of safety -- in determining whether risks (taken together with cancer and other non-cancer health risks) from air-borne lead from petroleum refinery facilities are acceptable or unacceptable. Thus, to the extent the commenter's argument rests on the difference between 'adequate' and 'ample' margin of safety, the argument is misplaced. Margin-of-safety determinations for this rule are conducted separately, in accord with the two-step framework set forth in the Benzene NESHAP and the en banc opinion in Vinyl Chloride. See not only Vinyl Chloride, 824 F. 2d at 1165, 1166 but *NRDC v. EPA*, 902 F. 2d 962, 973-74 (D.C. Cir. 1990) (distinguishing the NAAQS process, whereby the margin of safety analysis is incorporated as part of the standard without a two-step analysis, from residual risk determinations).[15] Using that framework, with its consideration of costs, cost-effectiveness, technological feasibility, and other factors set out in the Benzene NESHAP, at proposal we did not identify any additional controls beyond those that would need to be implemented to ensure an acceptable level of risk with an ample margin of safety. The EPA thus disagrees with the commenter that section 112 (f)(2) standards must be more stringent than a primary NAAQS as a matter of law.

Comment 2: Acute benchmark concentrations used are not protective or based on the most up-to-date science: A commenter claimed that the acute reference value used to evaluate benzene exposure is two orders of magnitude too high, leading to a very significant underestimation of the acute non-cancer health hazards of benzene emissions from refineries. Two commenters noted that the EPA used an acute REL of 1.3 mg/m^3, while California EPA's OEHHA uses a

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[15] The court was referring to the predecessor provision to the current section 112 (f), but its analysis is equally applicable to the revised provision.

value of 0.027 milligrams (mg)/m^3 based on the latest science.[16] One commenter explained that since developmental toxicity may occur in response to just one exposure during a specific window of susceptibility, the acute REL is intended to be health-protective with respect to infrequent one-hour exposures.

Notwithstanding EPA's decision not to use the California OEHHA benzene REL, one commenter expressed gratification to see that EPA has increased its reliance on the California RELs to address acute exposures in the residual risk assessments and urged EPA to continue to use the RELs for these assessments.

Another commenter stated that they have expressed concerns in the past with EPA's use of AEGL or Emergency Response Planning Guidelines (ERPG) values to address acute exposures in the residual risk assessments. The commenter asserted that these limits were developed for accident release emergency planning and are not appropriate for assessing daily human exposure scenarios (and also cited EPA's December 2002 document, "A Review of the Reference Dose and Reference Concentration Processes," in which EPA stated that the primary purpose of the AEGL program is to develop guidelines for once-in-a-lifetime short-term exposures to airborne concentrations of acutely toxic chemicals). The commenter argued therefore that the AEGL values are not meant to evaluate the acute impacts from routine emissions that occur over the life of a facility and, unlike the RfCs for chronic exposures, the AEGLs and ERPGs do not include adequate safety and uncertainty factors that can be relied upon to protect the public from the adverse effects of exposure to toxic air pollutants. The commenter concluded that the use of AEGLs or ERPGs in residual risk assessments is not appropriate and does not ensure that public health is adequately protected from the acute impacts of HAP exposure. Likewise, according to one commenter, EPA recognizes that many pollutants creating acute risks are pollutants for which it has no reference value [Draft Risk Assessment. tbl. 2.6-3 at 27-28.] and for that reason, the EPA looks at inappropriate values that are not health-protective (i.e., the AEGLs and ERPGs) designed only for emergency exposure response.[17]

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[16] CalEPA Table of Reference Exposure Levels, Guidelines for conducting health risk assessments under the Air Toxics Hot Spots Program, May 2014, http://www.oehha.ca.gov/air/allrels.html; EPA Dose-Response Values for Chronic Inhalation Exposure, as reported in the Draft Risk Assessment for the Petroleum Refining Source Sector (Doc. ID -0225), Table 2.6-2.

[17] The AEGL values (and Emergency Response Planning Guidelines (ERPG) values, which EPA also should not use) were created for emergency exposure scenarios. Levels defined for "once-in-a-lifetime, short-term exposures" and "emergency" chemical releases or accidents, 76 F R at 52,772, are not appropriate tools to measure long-term, lifetime acute exposure risk. As the Science Advisory Board has explained: The incorporation of the available California Reference Exposure Levels (RELs) for the assessment of acute effects is a conservative and acceptable approach to characterize acute risks. . . . The Panel has some concern with the use of the Acute Exposure Guidelines Limits (AEGLs) and Emergency Response Planning Guidelines (ERPGs) . . . . AEGL-2 and ERPG-2 values should never be used in residual risk assessments because they represent levels that if exceeded could cause serious or irreversible health effects. Sci. Adv. Bd., Review of EPA's draft entitled, "Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies - MACT I Petroleum Refining Sources and Portland Cement Manufacturing," EPA-SAB-10-007 at 6 (May 07, 2010)) ("SAB May 2010"), EPA-HQ-OAR-2010-0682-0103 (emphasis added). The AEGL and ERPG numbers would be expected to underestimate risk. Using these numbers is likely to discount or cloak the level of risk to the maximum exposed

Response 2: We disagree with the comment that the EPA should adopt the California OEHHA acute REL for benzene. The EPA has an approach for selecting appropriate health benchmark values and in general, this approach places greater weight on the EPA derived health benchmarks than those from other agencies. The approach favoring EPA benchmarks (when they exist) has been endorsed by the SAB,[18] and ensures values most consistent with well-established and scientifically-based EPA policy. The EPA is currently evaluating the most appropriate use for the California OEHHA derived reference doses. This evaluation on the appropriateness of these values in the context of the RTR Program and EPA science policy is necessary prior to using these references doses.

The EPA does not rely exclusively upon AEGL or ERPG values for assessment of acute exposures. Rather, the EPA's approach is to consider various acute health effect reference values (see 79 FR 37857), including the California REL, in assessing the potential for risks from acute exposures. To better characterize the potential health risks associated with estimated acute exposures to HAP, and in response to a key recommendation from the SAB's peer review of the EPA's RTR risk assessment methodologies,[19] we generally examine a wider range of available acute health metrics (e.g., RELs, AEGLs) than we do for our chronic risk assessments. This is in response to the SAB's acknowledgement that there are generally more data gaps and inconsistencies in acute reference values than there are in chronic reference values. In some cases, when Reference Value Arrays[20] for HAP have been developed, we consider additional acute values (i.e., occupational and international values) to provide a more complete risk characterization. As discussed in the preamble to the proposed rule (79 FR 37857), the exposure guidelines EPA considers depends on which exposure guidelines are available for the various hazardous air pollutants emitted. The EPA uses AEGL and ERPG values (when available) in conjunction with REL values (again, when available) to characterize potential acute health risks. However, it is often the case that HAP do not have all of these acute reference benchmark values. In these instances, the EPA describes the potential acute health risk in relation to the acute health values that are available. Importantly, when interpreting the results, we are careful to identify the benchmark being used and the health implications associated with any specific benchmark being exceeded.

Comment 3: Non-cancer reference values should assume no safe level of exposure, similar to cancer risk values, to avoid understating risks from non-carcinogens: One commenter asserted that the EPA must recognize that chronic (non-cancer) risk-causing pollutants have no safe level

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individual. These values are therefore not appropriate for rely on as health-protective in a section 112(f)(2) residual risk analysis. They simply do not provide sufficient protection for health.

[18] The SAB peer review of RTR Risk Assessment Methodologies is available at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf

[19] Ibid.

[20] U.S. EPA. (2009) Chapter 2.9 Chemical Specific Reference Values for Formaldehyde in Graphical Arrays of Chemical-Specific Health Effect Reference Values for Inhalation Exposures (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–09/061, and available on-line at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=211003*.

of exposure, noting that the National Academy of Sciences (NAS) recommends that cancer and chronic non-cancer risk assessment use the same approach in order to address the fact that very low levels of non-carcinogen exposures can pose health risks. The commenter noted that the use of RfDs for dose-response risk assessments of chronic non-cancer health effects may significantly underestimate risk, because the NAS defines the RfD or RfC as a dose "likely to be without an appreciable risk of deleterious effects" over a lifetime of exposure.

The commenter identified what they see as the problems with traditional toxicology as the basis for risk assessments, including the presumption that health effects are related to dose, and that a dose can be found for virtually all chemicals where no effect is found. The commenter claimed that the greatest public health threat of chemicals is for fetal exposure, meaning that the dose may be less important than the timing, and furthermore that for some toxic chemicals, the clinical effect can actually increase as the chemical concentration decreases, meaning that there is no safe level of exposure. For example, the commenter noted that a 2009 statement by the Endocrine Society stated that "[e]ven infinitesimally low levels of exposure, indeed, any level of exposure at all, may cause endocrine or reproductive abnormalities, particularly if exposure occurs during a critical developmental window. Surprisingly, low doses may even exert more potent effects than higher doses."[21] The commenter also noted that a recent panel of twelve national endocrine disruptor specialists recently stated that "[for] every chemical that we looked at that we could find a low-dose cutoff, if it had been studied at low doses it had an effect at low doses."[22] Finally, the commenter cited a report published in The New England Journal of Medicine, regarding the toxicity of volatilized compounds from oil, which states that: "Mutagenic effects theoretically can result from a single molecular DNA alteration. Regulatory prudence has led to the use of "one-hit models" for mutagenic end points, particularly cancer, in which every molecule of a carcinogen is presumed to pose a risk."[23]

Response 3: Chronic noncancer dose response values used in the RTR program, including those derived by EPA and similar authoritative agencies (e.g., Agency for Toxic Substances and Disease Registry (ATSDR) and CalEPA) represent chronic exposure levels that are intended to be health-protective. Those values are derived using an approach that is intended not to underestimate risk in the face of uncertainty and variability. When there are gaps in the available information, uncertainty factors (UFs) are applied to derive reference values that are intended to be protective against appreciable risk of deleterious effects. Uncertainty factors are commonly default values[24] (e.g., factors of 10 or 3) used in the absence of compound-specific data; where

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[21] Endocrine Society, Scientific Statements, https://www.endocrine.org/endocrine-press/scientific-statements.

[22] Vandenberg L, et al. Hormones and endocrine-disrupting chemicals: low-dose effects and nonmonotonic dose responses. Endocrine Rev; doi:10.1210/er.2011-1050 [online 14 Mar 2012].

[23] Goldstein B, Osofsky H, Lichtveld M. The Gulf Oil Spill N Engl J Med 2011; 364:1334-1348 April 7, 2011.

[24] According to the NRC report *Science and Judgment in Risk Assessment* (NRC, 1994) "[Default] options are generic approaches, based on general scientific knowledge and policy judgment, that are applied to various elements of the risk-assessment process when the correct scientific model is unknown or uncertain." The 1983 NRC report *Risk Assessment in the Federal Government: Managing the Process* defined *default option* as "the option chosen on the basis of risk assessment policy that appears to be the best choice in the absence of data to the contrary" (NRC,

data are available, data-derived extrapolation factors may also be developed using compound-specific information. When data are limited, more assumptions are needed and more default factors are used. Thus there may be a greater tendency to overestimate risk—in the sense that further study might support development of reference values that are higher (i.e., less potent) because fewer default assumptions are needed. However, for some pollutants there is some slight possibility that risks may be underestimated. With regard to consideration of a potential vulnerability of a specific lifestage, including time period before conception, the EPA includes this information in its derivation of cancer and noncancer toxicity assessments. For example, prenatal developmental studies in rodents, when available, are regularly considered in IRIS toxicity assessments and data are then extrapolated to predict effects in humans. As mentioned above in this response, in some instances, the available literature is unavailable for a robust characterization of risk during a specific lifestage and in that case the potential susceptibilities are accounted for by applying the appropriate uncertainty factors.

The EPA agrees with the NAS that the recommendations on harmonization of cancer and noncancer approaches are important issues in risk assessment and EPA incorporates NAS recommendations as feasible. The NAS has agreed with the EPA, specifically on the derivation methodology of RfCs and RfDs , that the available scientific information does not always allow for assessment derivation issues to be fully considered and it has reviewed and supported the approaches currently used in the derivation of the RfCs and RfDs. The NAS has also recognized that many of the recommended changes for the IRIS Program will need to be incorporated over a number of years and further recommend continuation of the development of assessments as the recommendations are implemented (i.e., the process should not be halted until all recommendations can be enacted). As such, improvements will be made over time and existing assessments will need to be used in the interim. Further, EPA has a legal obligation to proceed with regulatory action based on the best, currently available tools.

The commenter states that there are problems associated with traditional toxicology presumption that health effects are related to dose, however the commenter does not provide any information to consider an alternative paradigm to risk assessment that would not include an analysis of dose response relationships in the risk assessment process.

The commenter provided a reference to support the statement that there is no safe level of exposure and that for fetal exposure, the dose may be less important than the timing, and furthermore that for some toxic chemicals, the clinical effect can actually increase as the chemical concentration decreases. The review article on hormones and endocrine-disrupting chemicals focuses on a broad category of chemicals that appear to act at low concentrations. We disagree with the interpretation of the commenter on the referenced review. First, the authors of

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1983a, p. 63). Therefore, default options are not rules that bind the agency; rather, the agency may depart from them in evaluating the risks posed by a specific substance when it believes this to be appropriate. In keeping with EPA's goal of protecting public health and the environment, default assumptions are used to ensure that risk to chemicals is not underestimated (although defaults are not intended to overtly overestimate risk). See EPA 2004 *An examination of EPA Risk Assessment Principles and Practices,* EPA/100/B-04/001 available at: http://www.epa.gov/osa/pdfs/ratf-final.pdf.

the review article do not conclude that there is no safe level of exposure for chemicals in general, not even for endocrine disruptors. We disagree with the comment that clinical effect increases as dose of the chemical decreases; rather, the authors of the review conclude that the effect of low doses of these group of chemicals cannot be predicted by effects observed at high doses, and they encourage investigators to make changes in chemical testing approaches to identify potential endocrine disruptors. We concluded that the review article does not provide information that is relevant to this regulatory action.

We agree with the comment that the regulatory community, including the EPA, should use conservative approaches to evaluate cancer risks especially when considering cancer risks to early life stages. When chemical-specific data is available on which age or life-stage specific risk estimates or potencies can be determined, default age dependent adjustment factors can be applied when assessing cancer risk for early-life exposures to chemicals which cause cancer through a mutagenic mode of action (MOA). With regard to other carcinogenic pollutants for which early-life susceptibility data are lacking, it is the Agency's long-standing science policy position that use of the linear low-dose extrapolation approach (without further adjustment) provides adequate public health conservatism in the absence of chemical-specific data indicating differential early-life susceptibility or when the mode of action is not mutagenicity.[25] The basis for this methodology is provided in the 2005 Supplemental Guidance.[26]

Comment 4: The EPA inappropriately and unlawfully treated risk as zero for some pollutants: One commenter stated that EPA underestimates health risks by not using the best available information on pollutants and by treating various types of risk as zero even when the science shows risk is present. The commenter asserted that just because EPA has not yet developed a risk function for a pollutant, type of exposure, or type of risk, does not mean risk does not exist and can be ignored. The commenter suggested that EPA develop default approaches to support the evaluation of risk from chemicals which lack chemical-specific data. One of the approaches detailed by the commenter is the inclusion of an uncertainty factor to account for the additional risk that a HAP likely causes, until such time as EPA does have a reference value to use. The commenter added that if a default approach is not developed, the EPA should at a minimum engage in the interim in a qualitative assessment of the additional, missing risks, and account for them in its analysis. The commenter stated that EPA must include the risk from all HAP to satisfy their legal obligation under section 112(f)(2) to prevent unacceptable risk and ensure an "ample margin of safety to protect public health."

The commenter also argued that some pollutants continue to have no reference values over 20 years after the CAA was amended and that the IRIS review process has been bogged down for many pollutants.[27] One commenter asserted that, for pollutants currently under IRIS assessment,

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[25] Id.

[26] U.S. EPA. (2005), *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens*. EPA/630/R-03/003F. Washington, DC. Available online at: *http://www.epa.gov/cancerguidelines/guidelines-carcinogen-supplement.htm.*

[27] The commenter cites to U.S. Gov't Accountability Office, GAO-12-42, Chemical Assessments: Challenges Remain with EPA's Integrated Risk Information System Program 17-18 (2011).

the EPA must use the best available scientific information from the IRIS review during current rulemakings.[28] At minimum, commenters concluded that the EPA must account for the lack of reference values or the lack of an up-to-date final IRIS assessment rather than not including any consideration of health risks caused by such pollutants.

Finally, according to the commenter, the EPA violated the notice and comment requirements by not providing public notice of all HAPs for which it did not evaluate cancer, chronic non-cancer, acute, or multipathway risk. The commenter contended that this prevented commenters from having a meaningful opportunity to present data to EPA that may be useful in EPA's evaluation of the risk from pollutants for which EPA is currently treating as zero risk.

Response 4: This issue was addressed by the EPA's SAB in its May 7, 2010 response to the EPA Administrator.[29] In that response, the SAB panel recommended that, for HAP that do not have dose-response values from the EPA's list, the EPA should consider and utilize, as appropriate, additional sources for such values that have undergone adequate and rigorous scientific peer review. The SAB panel further recommended that the inclusion of additional sources of dose-response values into the EPA's list should be adequately documented in a transparent manner in any residual risk assessment case study. We agree with this approach and have considered other sources of dose-response data when conducting our risk determinations under RTR. However, in some instances no sources of information beyond the EPA's list are available. Compounds without health benchmarks are typically those without significant health effects compared to compounds with health benchmarks, and in such cases we assume the compounds will have a negligible contribution to the overall health risks from the source category. For a tabular summary of HAPs that have dose response values for which an exposure assessment was conducted, refer to Table 3.1-1 of the "Final Residual Risk Assessment for the Petroleum Refining Source Sector", Docket ID No. EPA-HQ-OAR-2010-0682.

The EPA agrees that it is important to develop toxicity values for all HAP utilizing all credible and relevant toxicity information. The need to update assessments with newly available data as well as the need to complete toxicological assessments for all HAP lacking dose-response assessments increases the importance of Agency activities to streamline and fully utilize the EPA's already overloaded IRIS program. To that end, the EPA has always prioritized for IRIS assessments those HAP without dose-response values but with the greatest potential for public exposure. As a result of this prioritization, while not all HAP may have scientifically accepted dose-response values that can be used in residual risk assessments, it is clear that the vast majority of HAP which might carry the potential to significantly impact the results of residual risk assessments do, in fact, have credible dose-response values. Thus, while we are not yet at the point where all HAP have dose-response values, we are generally capable of deriving reasonable risk estimates for those HAP which dominate the risks from any one source category. In the course of each residual risk assessment, should we encounter HAP without dose-response values which carry the potential to create significant risks, we shall clearly point those out as

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[28] Integrated Risk Information System (IRIS); Announcement of 2012 Program, 77 FR 26,751 (May 7, 2012).

[29] The SAB peer review of RTR Risk Assessment Methodologies is available at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.

uncertainties and target them for future IRIS assessments. In general, we strive to strike a balance in our assessments, meaning that while some factors likely lead to underestimates of risk, others likely lead to underestimates of risk. We conclude that the risk assessment for this source category is sufficient to support a decision on the acceptability of the risk and ample margin of safety.

Comment 5: The EPA did not rely on the latest science and underestimated risk by not adequately accounting for pre-natal and early life exposures: One commenter stated that EPA's cancer risk assessment for refineries does not adequately account for early-life exposure or the greater risk to and susceptibility of children. According to the commenter, EPA must account for increased early-life susceptibility by applying age-dependent adjustment factors for all carcinogens emitted by a source category. The commenter noted that EPA has restricted its application of age-dependent adjustment factors to those HAPs included in EPA's list of carcinogens that act by a mutagenic mode of action.[30] The commenter pointed out that EPA's 2005 Guidelines recognized that updates would be needed if more data became available,[31] and claimed that such data are now available from the NAS and OEHHA, yet the EPA has not issued such updates to implement age-dependent adjustment factors for all carcinogens.[32]

Regarding pre-natal cancer risk, the commenter noted that EPA's risk assessment does not take into account increased susceptibility to carcinogens due to pre-natal exposures, even for known-to-be mutagenic carcinogens, and that EPA must do so for these as well as for all carcinogens.[33] The commenter argued that despite EPA's own recognition that exposures of concern include pre-conception exposures of both parents through adolescence, it has not developed adjustment factors for pre-natal exposures.[34,35] This omission from EPA's 2005 Guidelines was noted by

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[30] Draft Risk Assessment (-0225) at 29-30; See EPA, "Guidelines for Carcinogen Risk Assessment," EPA/630/P-03/001F, at 1-19 to 1-20 (Mar. 2005), http://www.epa.gov/raf/publications/pdfs/CANCER_GUIDELINES_FINAL_3-25-05.PDF; EPA, "Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens," EPA/630/R-03/003F (2005), http://www.epa.gov/raf/publications/pdfs/childrens_supplement_final.pdf.

[31] See EPA, 2005 Supp. Guidance at 21, 31 ("EPA expects to expand this Supplemental Guidance to specifically address modes of action other than mutagenicity when sufficient data are available and analyzed.").

[32] Cal. EPA, OEHHA, TSD for Cancer Potency Factors, supra note 313. EPA should also update the 2005 Guidelines to fully reflect current science as described in OEHHA's 2009 review of the scientific literature on increased susceptibility to carcinogens from early life exposures

[33] Draft Risk Assessment (-0225) at 29 (noting that EPA applied factors only to known mutagens to account for "children aged 0-1" but not younger than that).

[34] EPA 2005 Guidelines for Carcinogen Risk Assessment, EPA/630/P-03/001F, at 1-16.

[35] EPA, 2005 Supp. Guidance at 4-5, 14 & tbl. 1a (A-1) (discussing research on human and animal cancer risks from prenatal exposure).

NAS.[36] The commenter recommended that EPA use the OEHHA methods and adjustment factors, as well as procedures to assess exposure during fetal development, to account for pre-natal susceptibility and exposures.[37,38,39] According to the commenter, OEHHA specifically discusses the use of a 10X adjustment factor for cancer risk to account for pre-natal (third trimester) to age 2 exposures, and the EPA should consider using this same factor.[40]

Regarding non-cancer risk, another commenter asserted that exposure to toxic agents in the intrauterine stage of life has one of the most important, potentially irreversible impacts on life-long health, but EPA's rules are insufficient to protect human health at the critical stage of embryonic development. Most of EPA's IRIS toxicity threshold values (reference concentrations and doses) used for chronic non-cancer risk assessment do not incorporate the latest science on increased susceptibility of children and, according to the commenter, EPA must consult and apply child-specific reference values, where available.[41] The commenter argued that until the IRIS values fully account for the increased risk caused by early-life exposure to an emitted pollutant, the EPA should use the OEHHA child-specific reference doses or benchmarks available to assess chronic non-cancer health risk from ingestion for certain pollutants. The commenter asserted that EPA should also assess such risk from inhalation by using standard methods to translate these values into child-specific reference concentrations to assess inhalation-based risk.

Where child-specific reference values are unavailable, the commenter asserted that EPA must consult science on early exposure impacts and use an additional default or uncertainty factor. Until EPA has child-specific or child-based reference values available for a given pollutant, the EPA should apply a default or uncertainty factor of at least 10, according to the commenter, to account for increased risk from early-life exposures for non-cancer risk in this rulemaking and

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[36] NAS 2009, supra note 264, at 112-13; see also id. at 112, 196 (noting that it is a "missing" default that EPA recognizes in utero carcinogenic activity, but fails to take account of it or calculate any risk for it as "EPA treats the prenatal period as devoid of sensitivity to carcinogenicity").

[37] See Cal. EPA, OEHHA, "Technical Support," supra note 313, App. J: "In Utero and Early Life Susceptibility to Carcinogens: The Derivation of Age-at-Exposure Sensitivity Measures" conducted by OEHHA's Reproductive and Cancer Hazard Assessment Branch, .http://oehha.ca.gov/air/hot_spots/2009/AppendixJEarly.pdf.

[38] Id. App. J at 7-8 & tbl. 1

[39] See Cal. EPA, Air Toxics Hot Spots Program Risk Assessment Guidelines: Technical Support Document for Exposure Assessment and Stochastic Analysis at 1-6 to 1-7 (Aug. 27, 2012) ("OEHHA 2012 Guidelines"), http://www.oehha.ca.gov/air/hot_spots/tsd082712.html.

[40] See id.; 2014 Air Toxics Hot Spots Program Guidance Manual, supra note 121, at 2.

[41] OEHHA has explained why child-specific reference doses or values are needed and provided a list of chemicals. See, e.g., Cal. EPA, OEHHA, "Prioritization of Toxic Air Contaminants - Children's Environmental Health Protection Act" (Oct. 2001), http://oehha.ca.gov/air/toxic_contaminants/pdf_zip/SB25%20TAC%20prioritization.pdf; Cal. EPA, OEHHA, "Development of Health Criteria for School Site Risk Assessment Pursuant to Health and Safety Code 901(g): Identification of Potential Chemical Contaminants of Concern at California School Sites, Final Report" (June 2002), http://oehha.ca.gov/public_info/public/kids/pdf/ChildHealthreport60702.pdf.

other risk assessments. The commenter noted that this would be consistent with the NAS recommendation on the need for EPA to use default factors to account for greater risk[42], with the science developed and considered by OEHHA, and with the 10X factor enacted by Congress in the Food Quality Protection Act. The Food Quality Protection Act (FQPA) enacted, a Ten-fold Margin of Safety, or "10X factor." Specifically, the Act provided that "an additional tenfold margin of safety for the pesticide chemical residue and other sources of exposure shall be applied for infants and children to take into account potential pre- and post-natal toxicity and completeness of the data with respect to exposure and toxicity to infants and children." [43] Congress's recognition of the need to use this default factor provides a model that EPA should consider and incorporate into its residual risk assessment, according to the commenter. The commenter stated that it would be appropriate and within EPA's authority under CAA section 112(f)(2) to determine that EPA must use a children's ten-fold margin of safety factor, to fulfill the CAA's "margin of safety" requirement.

Response 5: We disagree with the comment that this risk assessment underestimates risk to children and lacks consideration of early-life susceptibility. We acknowledge that population subgroups, including children, may have a potential for risk that is greater than the general population due to greater relative exposure and/or greater susceptibility to the toxicant. The assessments we undertake to estimate risk account for this potential vulnerability. With respect to exposure, the risk assessments we perform implicitly account for this greater potential for exposure by assuming lifetime exposure, in which populations are conservatively presumed to be exposed to airborne concentrations at their residence continuously, 24 hours per day for a full lifetime, including childhood. With regard to children's potentially greater susceptibility to non-cancer toxicants, the assessments rely on EPA (or comparable) hazard identification and dose-response values which have been developed to be protective for all subgroups of the general population, including children.

For example, a review[44] of the chronic reference value process concluded that the EPA's RfC derivation processes adequately considered potential susceptibility of different subgroups with specific consideration of children, such that the resultant RfC values pertain to the full human population "including sensitive subgroups," a phrase which is inclusive of childhood. With respect to cancer, the EPA uses the age-dependent adjustment factor approach referred to by the commenter, but limits the use of those factors only to carcinogenic pollutants that are known to act via mutagenic mode of action, in contrast to the OEHHA approach, which uses them across the board for all carcinogens regardless of MOA. In lieu of chemical-specific data on which age or life-stage specific risk estimates or potencies can be determined, default age dependent adjustment factors can be applied when assessing cancer risk for early-life exposures to

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[42] NAS 2009, supra note 264, at 190-93, 203.

[43] 21 U.S.C. 346a(b)(2)(C) (requiring that, in establishing, modifying, leaving in effect, or revoking a tolerance or exemption for a pesticide chemical residue, "for purposes of clause (ii)(I) an additional tenfold margin of safety for the pesticide chemical residue and other sources of exposure shall be applied" to protect infants and children).

[44] U.S. EPA. A Review of the Reference Dose and Reference Concentration Processes. U.S. Environmental Protection Agency, Risk Assessment Forum, Washington, DC, EPA/630/P-02/002F, 2002.

chemicals which cause cancer through a mutagenic MOA. With regard to other carcinogenic pollutants for which early-life susceptibility data are lacking, it is the Agency's long-standing science policy position that use of the linear low-dose extrapolation approach (without further adjustment) provides adequate public health conservatism in the absence of chemical-specific data indicating differential early-life susceptibility or when the mode of action is not mutagenicity.[45] The basis for this methodology is provided in the 2005 Supplemental Guidance.[46]

We also disagree with the comment that the risk assessment for these source categories did not consider the groups that may be most at-risk (e.g., pregnant women and children). When the EPA derives exposure reference concentrations and URE for hazardous air pollutants, it also considers the most sensitive populations identified in the available literature, and importantly, these are the values used in our risk assessments.[47] With regard to consideration of a potential vulnerability of a specific lifestage, including time period before conception, the EPA includes this information in its derivation of cancer and noncancer toxicity assessments. For example, a prenatal developmental studies in rodents, when available, are regularly considered in IRIS toxicity assessments and data are then extrapolated to predict effects in humans. In some instances, the available literature is unavailable for a robust characterization of risk during a specific lifestage and in that case the potential susceptibilities are accounted for by applying the appropriate uncertainty factors.

We disagree with the general comment that the EPA should adopt the Cal OEHHA child-protective scientific approach on for deriving health benchmarks. The EPA has an approach for selecting appropriate health benchmark values and in general, this approach places greater weight on the EPA derived health benchmarks than those from other agencies. The approach of favoring EPA benchmarks (when they exist) has been endorsed by the SAB,[48] and ensures use of values most consistent with well-established and scientifically-based EPA science policy. The EPA is currently evaluating the most appropriate use for the Cal OEHHA child-specific reference doses. We note that there are currently no such values for HAP inhalation, therefore the current utility may be limited to persistent and bioaccumulative (PB)-HAP, which may be associated with non-negligible ingestion exposures. This evaluation on appropriateness of these values in the context of the RTR Program and EPA science policy is necessary prior to using these child-specific RfD.

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[45] Id.

[46] U.S. EPA. (2005), *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens*. EPA/630/R-03/003F. Washington, DC. Available online at: *http://www.epa.gov/cancerguidelines/guidelines-carcinogen-supplement.htm.*

[47] US EPA. (2002). A review of the reference dose and reference concentration processes. EPA/630/P-02/002F. Risk Assessment Forum, Washington, DC. Available online at *http://www.epa.gov/raf/publications/pdfs/rfd-final.pdf*

[48] The SAB peer review of RTR Risk Assessment Methodologies is available at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf

The estimated risks must also be considered in the context of the full set of assumptions used for this risk assessment. Our unit risk estimates for hazardous air pollutants are considered a plausible upper-bound estimate with an appropriate age dependent adjustment; actual potency is likely to be lower and could be as low as zero. Our chronic noncancer reference values have been derived considering the potential susceptibility of different subgroups, with specific consideration of children. In addition, an extra 10X uncertainty factor is not needed in the RfC/RfD methodology because the currently available factors are considered sufficient to account for uncertainties in the database from which the reference values are derived. After considering these and other factors, we continue to consider the risks from emissions after application of the revisions to the NESHAP for these source categories to provide an ample margin of safety (consistent with the Benzene NESHAP framework).

The EPA disagrees with the commenter in that a children's default safety factor of 10 or more should be added to EPA's reference values. In response to the 10X factor enacted by Congress in the FQPA (1996)[49] to the EPA non-cancer reference value derivation, the Agency evaluated their methods for considering children's risk in the development of reference values. As part of their response, the U.S. EPA (i.e. the Science Policy Council and Risk Assessment Forum) established the RfD/RfC Technical Panel to develop a strategy for implementing the FQPA and examine the issues relative to protecting children's health and application of the 10X safety factor. One of the outcomes of the Technical Panel's efforts was an in depth review of a number of issues related to the RfD/RfC process (U.S. EPA 2002). The most critical aspect in the derivation of a reference value pertaining to the FQPA has to do with variation between individual humans and is accounted for by a default uncertainty factor (UF-H) when no chemical-specific data are available. EPA reviewed the default UF for inter-human variability and found the EPA's default value of 10 adequate for all susceptible populations, including children and infants. The EPA also recommended the use of chemical-specific data in preference to default uncertainty factors when available (US EPA, 1994, 2011) and is developing Agency guidance to facilitate consistency in the development and use of data-derived extrapolation factors for RfCs and RfDs (U.S EPA, 2011). Additionally, the EPA also applies a database uncertainty factor (UF-D) which is intended to account for the potential for deriving an under protective RfD/RfC as a result of an incomplete characterization of the chemical's toxicity. In addition to the identification of toxicity information that is lacking, review of existing data may also suggest that a lower reference value might result if additional data were available.

In conclusion, an additional uncertainty factor is not needed in the RfC/RfD methodology because the currently available factors are considered sufficient to account for uncertainties in the database from which the reference values are derived (and does not exclude the possibility that these uncertainty factors may be decreased or increased from the default value of 10).

2.3.3 Additional pollutants and health effects should be considered

Comment 1: Additional pollutants to those considered pose serious health risks: Commenters described the health effects including asthma and other respiratory diseases, IQ loss and other

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[49] US Environmental Protection Agency, Pesticide: Regulating Pesticides. The Food Quality Protection Act (FQPA). 1996. Available at http://www.epa.gov/pesticides/regulating/laws/fqpa/backgrnd.htm.

developmental impacts, cancer, heart disease, birth defects and other reproductive system impacts, kidney, liver and other organ damage, and even premature death they claimed result from toxic air pollutants emitted by refineries and asserted they must be reduced. The pollutants referenced by the commenters include: benzene, toluene, carbonyl sulfide, 1,3-butadiene, ethyl benzene, mixed xylenes, n-hexane, hydrogen sulfide (H_2S), hydrogen chloride (HCl), HCN, hydrogen fluoride (HF), PAHs (POM), mercury (including methylmercury), naphthalene, non-mercury metals (arsenic, beryllium, cadmium, lead, hexavalent chromium, manganese, nickel, and selenium), formaldehyde, acetaldehyde, SO_2, nitrogen oxides (NOx), particulate matter 2.5 micrometers in diameter and smaller ($PM_{2.5}$), VOCs as precursors to ozone (O_3), and methane (CH_4). Another commenter supported the need for public health impacts research data on all chemicals, including determination and annual reporting of all carcinogenic, neurological, non-carcinogenic, bio-cumulative, and physical and developmental public health impacts. Another commenter stated that HF is not addressed in the rule, but the risks from HF are catastrophic risks if something goes wrong which the commenter noted has happened several times in Corpus Christi.

The commenters provided information on risks from specific emissions and pollutants. One commenter stated that there is clear evidence of harm from direct emissions of sulfur dioxide, nitrogen oxide and VOCs, and further noted that these pollutants are precursors to O_3 and $PM_{2.5}$, which also pose a significant threat to human health (including increased risk of cardiovascular, respiratory, other acute and chronic systemic damage, and potentially cancer). Another commenter stated that although EPA's rule targets section 112-listed HAPs, refineries emit vast quantities of other pollutants, including criteria pollutants that can negatively interact with and exacerbate the impacts of HAP exposure. Of gravest concern, according to the commenter, are the numerous studies that have documented a wide range of adverse health impacts from exposure to $PM_{2.5}$.

Response 1: Section 112(f) of the CAA evaluates risks associated with emissions of hazardous air pollutants listed under section 112 (b)(1) or those added to this list under section 112(b)(2). The EPA does not regulate VOC, particulate matter, NOx or SO_2 under section 112 except to the extent that individual HAP are also VOC (e.g., benzene, toluene, xylene) or particulate matter (PM) (e.g., nickel, mercury). The pollutants are regulated under Title 1 of the CAA as NAAQS or precursors to the NAAQS.

The EPA conducted an assessment of the cumulative cancer risks from all emitted carcinogens and the cumulative noncancer hazard indices from all emitted non-carcinogens that are HAP affecting the same target organ system for both the source category emissions and the facility-wide emissions. To address the effect of mixtures of carcinogens, the individual cancer risks for the source categories were aggregated for all carcinogens. In assessing noncancer hazard from chronic exposures for pollutants that have similar modes of action or that affect the same target organ, we aggregated the hazard quotients (HQ) to provide a TOSHI. We further modeled whole-facility risks for both chronic cancer and non-cancer impacts to understand the risk contribution of the sources within the petroleum refineries source categories.

HF was included in both the inhalation and, along with six other environmental HAP, in the environmental screening analysis for these source categories. The average modeled concentration around each facility (i.e., the average concentration of all off-site data points in the modeling domain) did not exceed any human or ecological benchmarks. In addition, each individual modeled concentration (i.e., each off-site data point in the modeling domain) was below the human and ecological benchmarks for all facilities.

Comment 2: Hydrogen sulfide should be included in risk assessment: One commenter stated that EPA should include H_2S emissions in the technology and risk review as well as develop an actionable level and a national ambient air quality standard for H_2S. The commenter stated that there are health risks associated with H_2S including eye and respiratory irritations, nausea, dizziness, confusion and headache, which may disproportionality affect children.

Another commenter stated that there is a pending petition to list H_2S as a HAP, and EPA should grant that petition without further delay and regulate it at refineries.[50] The commenter added that the EPA's addition of H_2S reporting to the TRI, under the Emergency Planning and Community Right-to-Know Act (EPCRA), demonstrates EPA's acknowledgment of existing risk and further supports listing this compound as a HAP.[51]

Response 2: Section 112(f) of the CAA evaluates risks associated with emissions of hazardous air pollutants listed under section 112 (b)(1) or those added to this list under section 112(b)(2). H_2S is neither on the 112(b)(1) list nor has it completed the listing process under section 112(b)(2) as of the time of this analysis. If, in the future, H_2S, or any other HAP, is added to the list under section 112(b) (2) they will be included in all future risk analyses.

2.3.4 Additional emissions and source categories should be considered

Comment 1: EPA understates risk by ignoring emissions from upsets and malfunctions: One commenter stated that EPA must account for the acute, cancer, and chronic non-cancer health risks from emissions during upsets and malfunctions, instead of ignoring these risks, particularly since these emissions can be significantly higher than emissions at any other time of source operation. Ignoring these emission spikes is equivalent to treating additional health risk caused by exceedances as zero, according to the commenter.

Commenters added that EPA's own scientists stated that EPA may be underestimating actual maximum short-term emissions, through the use of low, short-term emissions factors and "data filtering" such that "accidental releases were dropped", thus also underestimating maximum health risk for the most-exposed person.[52] The commenter asserted that the dropping of all so-called "[a]ccidental releases" removes most of the maximum short-term emissions numbers that

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[50] Letter from Sierra Club et al. to U.S. EPA Administrator Jackson, Hydrogen Sulfide Needs Hazardous Air Pollutant listing under CAA Title III, (Mar. 25, 2009), available at http://www.texas.sierraclub.org/press/newsreleases/H2SLetterToEPA.pdf

[51] U.S. EPA, Lifting of Administrative Stay for Hydrogen Sulfide, 76 FR 64,022, 64,024 (Oct. 17, 2011), see also http://www.epa.gov/tri/lawsandregs/hydrogensulfide/indexf.html (last accessed Sept. 23, 2011)

[52] Risk Assessment App. 3, Ted Palma & Roy Smith, Analysis of data on short-term emission rates relative to long-term emission rates, at 3

the EPA must consider if it indeed wishes to fulfill the Act's requirement and its own interpretation of its responsibility.

Regarding the issue of accidental releases, commenters objected to the use of the term "accidental" since according to the commenters, many of these events can be prevented. The commenters also asserted that emissions from SSM are still lawful and thus should be considered to be part of the "allowable" emissions in the risk evaluation. In contrast to EPA policy, the commenters suggested that emissions from accidental releases must be evaluated even if they exceed the "allowable" emissions and are considered a violation of the standard. Commenters also stated that EPA did not say that it removed only emissions that were accidental releases that exceeded the level of emissions standards.

In support of their arguments, commenters noted that the SAB has also questioned how the risk from these emissions are addressed and has even criticized the EPA's estimation of maximum short-term emissions. Commenters expressed concern that EPA's method of calculating acute risk using a "worst-case" scenario is not actually representative of the "worst case" because it is ignores all malfunctions which exceed the standards. The commenter stated that EPA could simply use a more accurate factor (based on statistical methods and probability factors) to account for malfunctions for acute and other types of health risk, to close the gap and respond appropriately to the SAB's criticism of its current method.

The commenter noted that, to create representative factors to assess the health risk from malfunctions, EPA has information available or can collect information on major sources' malfunction and violation histories.[53] According to the commenter, EPA has already collected significant information on upset incidences as part of the Information Collection Request for this rulemaking [See ICR Component 1, at Part III] and the agency must evaluate and use them to address emission spikes at least to the extent reported by these existing sources. The commenter further noted that the Agency has already collected approximately two years' worth of this type of information from the TCEQ.[54] The commenters suggested that EPA should consider more of these data from TCEQ and other states that have delegated air programs, as facilities are required

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[53] See, e.g., EPA, Enforcement and Compliance History Online (ECHO), www.epa.gov/echo; Kelly Haragan, Envtl. Integrity Project, "Gaming the System: How Off-the-Books Industrial Upset Emissions Cheat the Public Out of Clean Air" (Aug. 2004), 1-2, 5, http://www.environmentalintegrity.org/news_reports/Report_Gaming_System.php (finding significant likelihood of an upset at refineries, chemical plants, gas plants and a carbon black plant, and finding that the resulting emissions release is many times higher than the amount of otherwise-reported annual emissions and that "releases from upsets actually dwarf a facility's routine emissions.").

[54] Palma & Smith memo at 2-3 ("The Texas Commission on Environmental Quality (TCEQ) collects emissions data using online reporting required of any facility releasing 100 pounds or more of a listed chemical (primarily ozone-forming VOCs) during a non-routine event. ... The database we utilized in our analysis was a subset of the TCEQ data covering emission events that occurred in an eight-county area in eastern Texas during a 756-day period between January 31, 2003 and February 25, 2005."); see Tex. Comm'n on Envtl. Quality, Search the Air Emission Event Report Database, http://www11.tceq.texas.gov/oce/eer/index.cfm.

to report malfunction releases to the states under EPA's existing regulations.[55] The commenter offered additional data with these comments, including: (1) EIP has created two major reports on upset or malfunction incident data that refineries reported to Texas and more recent follow-up letters summarizing data since 2012;[56] (2) Louisiana Bucket Brigade has compiled similar data from Louisiana reports by refineries to the state.[57]

Response 1: While we appreciate the additional information provided by the commenters about specific emissions events in violation of the standards, we disagree with the commenter that such emissions, whether or not they are caused by malfunction events, should be considered as part of the risk analysis. The purpose of the risk review is to evaluate whether the emission limits – the "standards promulgated pursuant to subsection (d)" not the non-compliance with those standards [section 112(f)(2)(A)] -- should be made more stringent to reduce the risk posed after compliance with the underlying MACT standard. To the extent that a source is violating the underlying MACT standard, no tightening of the emission standard under the residual risk rule will avoid or mitigate against such violations. In other words, a source that is violating the MACT emissions standard promulgated under section 112(d) would not be any more likely to be able to avoid such violations and comply with a different, presumably more stringent, standard promulgated under section 112(f). Such events are violations and subject to enforcement by the EPA, the States or citizens, and an action for injunctive relief is the most effective means to address such violations, whether or not they are caused by malfunctions if an emissions event poses a significant health or environmental risk.

While we agree with the commenter that the original standards did provide some relief for malfunctions, we proposed to remove those provisions from the MACT standard consistent with the Court's decisions in *Sierra Club*. Thus, at proposal, we evaluated risk based on the MACT standards as they would be modified to incorporate this revision. We continue to follow that approach for the final rule. Because we are finalizing standards that would apply to certain releases from flaring events and PRDs, we are evaluating emissions that would be allowed (i.e., that would not be a violation) during these events as part of our risk review.

We performed a screening level analysis to estimate the risks from these non-routine emissions (flaring events and PRDs). To estimate emissions for chronic risk calculations, emissions data was extracted from the EPA ICR in Component 1 of the survey. We summed the HAP emissions from all individual events at each facility, since chronic inhalation risk depends on the total quantity of emissions released over a year and is independent of the release time. This screening

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[55] See, e.g., 40 CFR 63.10(b) & (d); 40 CFR 63.655(g)(6)(i)-(ii) (pre-proposed rule) (requiring reporting of periods of "excess emission"); see also 40 CFR part 60 subpart J and Ja, 40 CFR part 63 subparts CC, UUU (other similar requirements)..

[56] Accident Prone, supra note 222; Letter from Eric Schaeffer, Environmental Integrity Project, Executive Director, to Inspector General Arthur Elkins, Environmental Protection Agency, Clean Air Act Enforcement of Excess Emissions and the Affirmative Defense (Apr. 23, 2012) [hereinafter EIP SSM Enforcement Letter] available at http://www.environmentalintegrity.org/news_reports/documents/EmissionEventLetter2009-2012FINAL_001.pdf

[57] Louisiana Bucket Brigade, Common Ground Reports I-IV.

level analysis indicated we can expect these emissions to contribute up to about 2-in-1 million to the chronic cancer MIR. Noncancer risks resulting from these emissions are expected to remain well below 1. To estimate potential risks for acute events, we examined both the quantity and duration of each event such that higher mass emitted in a shorter time period has an increased potential for an acute impact. Acute risks from these events estimated a Hazard Index based on the REL of up to 14 from emissions of benzene. While the analysis shows that there is a potential at these facilities for HQs exceeding 1 (benzene), because of the many uncertainties and the screening level nature of this analysis, we believe the potential for achieving a HQ=14 is low. In all cases the AEGL levels are well below 1. Further, it is important to note that the estimated acute risk assume a catastrophic release such that all the emissions from an event are emitted during a single hour time period (for more detail on this analysis, see Appendix 13 of the Final Residual Risk Assessment for the Petroleum Refining Source Sector in Docket No. EPA-HA-OAR-2010-0682)**.**

Comment 2: EPA understates risk by not accounting for cumulative risk from facility-wide emissions and multiple nearby sources impacting an area: One commenter asserted that in addition to performing a cumulative assessment from refineries alone, the EPA must perform a cumulative analysis which aggregates or adds the emissions for the most-exposed communities coming from: (1) the source category (including all individual sources within it); (2) facility-wide risk from collocated sources outside of this category; and (3) all other sources of toxic air pollution in the area.[58] The commenter stated that this is particularly important for the many communities containing refineries and other nearby sources of toxic air emissions such as: Wilmington, California, Port Arthur, Texas, and Delaware City, Delaware. The commenter noted that EPA has recognized this need in its recent risk report[59], yet has failed to propose any changes to the emission standards based on the combined exposure with any other sources. In support of their argument, the commenter also cited recommendations from the SAB and NAS which called for the incorporation of cumulative health risk into its residual risk analysis.

The commenter also noted that EPA has not used its calculated “facility-wide” risk for co-located sources to set standards, and it has ignored different sources across the street or in close proximity in its Draft Risk Assessment. In addition, the commenter claimed that EPA has provided no information on how it reached the “facility-wide” risk number.

The commenter recommended that EPA use the risk assessment results available for those source categories for which it has already performed a risk assessment review - such as those covered

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[58] We support EPA's recognition of the need to assess whether the maximum exposed individual is exposed to emissions from more than one source within each source category. We also appreciate that EPA has considered facility-wide risk in some way in this rulemaking. However, those assessments offer only part of the picture. And, even on both of these issues, EPA has provided very little information about what it included in such assessments, as discussed elsewhere in these comments. EPA just states numbers found for facility-wide risk, without explaining where those numbers came from, how they were calculated, or what emission sources they cover.

[59] U.S. EPA, “Concepts, Methods and Data Sources,” supra, at xxxii (defining a cumulative risk assessment as including “aggregate exposures by multiple pathways, media and routes over time, plus combined exposures to multiple contaminants from multiple sources”).

by the hazardous organic NESHAP and other chemical plant sources that are frequently located near refineries in its cumulative risk assessment. According to the commenter, the combined risk results for these sources near one another (not just co-located) would likely have higher overall risk than has been estimated for the most-exposed person near a refinery, and therefore stronger standards are needed under section 112(f)(2) for multiple emission points at refineries (not just storage vessels). Finally, the commenter suggested that EPA consider the existing research regarding health risk from toxic air pollution in urban communities nationwide[60] as well as the OEHHA cumulative assessment approach and apply a similar science-based approach in this residual risk assessment.[61]

In addition, one commenter noted that the NAS has recommended that EPA evaluate "background exposures and vulnerability factors," as well as use "epidemiologic and toxicologic evidence" in its risk assessments.[62] Rather than separating an environmental justice analysis and considerations of inequality from the risk assessment, considering these factors as part of the cumulative risk assessment - because of the increased vulnerability created - would be a more effective, meaningful, and scientific approach, according to the commenter. The commenter asserted that, in assessing a source category's emission contributions in affected communities and considering whether these contributions cause the most-exposed people to experience an unacceptable level of public health risk when combined with the existing baseline from past emissions, other HAP emissions, and the community's health status, EPA can describe and manage uncertainties, similar to many other analyses.[63]

The commenter concluded that the EPA must develop a data-driven approach to comprehensively model cumulative risk or impacts from multiple sources, EPA must incorporate

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[60] See, e.g., Rachel Morello-Frosch & Bill M. Jesdale, Envtl. Health Perspectives, Separate and Unequal: Residential Segregation and Estimated Cancer Risks Associated with Ambient Air Toxics in U.S. Metropolitan Areas, 114(3) Envtl. Health Perspectives 386 (2006) (assessing toxic air pollution cancer risk for 309 metropolitan areas encompassing 45,710 tracts); "National Air Toxics Program: The Integrated Urban Strategy," 64 FR 38,706, 38,738 (July 19, 1999).

[61] See, e.g., Cal. EPA, "Cumulative Impacts," supra.

[62] NAS 2009, supra note 264, at 221-23 (discussing Menzie et al. 2007 model); id. at 230 (discussing the role of epidemiology and surveillance data).

[63] See, e.g., 42 U.S.C. 7475(a)(3), 7503(a)(1) (requiring a localized, cumulative assessment of whether or not a new or modified source's additional emissions will cause an attainment area to deteriorate, or will make it difficult for a nonattainment area to make progress toward achieving the national ambient air quality standards); *New York v. EPA*, 443 F.3d 880, 883 n.1 (D.C. Cir. 2006) (citing *New York v. EPA*, 413 F.3d 3, 11-14 (D.C. Cir. 2005)); see also 40 CFR. 1508.27(b)(7) (requiring a consideration of "[w]hether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts"); see also 40 CFR. 1508.7; *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 930 (9th Cir. 2008) (applying 16 U.S.C. 1536(a)(2) to enforce the Endangered Species Act duty to ensure against jeopardy which includes the requirement to assess a newly proposed action in the context of all other impacts, and determine whether or not the specific action will "tip a species from a state of precarious survival into a state of likely extinction," or, where baseline conditions already jeopardize a species, whether it will "deepen[] the jeopardy by causing additional harm").

a default or uncertainty factor to adjust the degree to which each individual source category is contributing to the total risk experienced by the most-exposed individuals. For example, according to the commenter, for a source category in an area with up to 10 other HAP-emitting facilities, this default or uncertainty factor should equal at least 10, consistent with the common scientific use of this factor for other kinds of vulnerability.[64] This commenter suggested that wherever there is a history of other exposures or other source categories, the "unacceptable" level of cancer, non-cancer chronic, and acute risk from the source category must be adjusted downward (such that no single source category could constitute all acceptable risk, when the most-exposed person is exposed to many other source categories).

Response 2: We disagree with the claim that additional quantitative assessment of risks from sources outside the source category is required under the statute. Section 112(f) requires the EPA to perform a review of whether there is risk remaining from emissions from a source category after promulgation of the technology based MACT standards for that source category. To this end, the EPA conducts a comprehensive assessment of the risks associated with exposure to the HAPs emitted by the source category and supplements that with additional information that is available about other possible concurrent and relevant risks. While the incorporation of additional background concentrations from the environment in our risk assessments (including those from mobile sources and other industrial and area sources) could be technically challenging, they are neither mandated nor barred from our analysis. In developing the decision framework in the Benzene NESHAP currently used for making residual risk decisions, the EPA rejected approaches that would have mandated consideration of background levels of pollution in assessing the acceptability of risk, concluding that comparison of acceptable risk should not be associated with levels in polluted urban air (54 FR 38044, 38061, September 14, 1989). Although EPA rejected such approaches for considering the acceptable level of risk, EPA recognized in the Benzene NESHAP that background levels (including natural background) could be considered as part of EPA's ample margin of safety (AMOS) analysis, as appropriate and as available, along with other factors, such as cost and technical feasibility.

For the petroleum refinery source categories, the EPA conducted an assessment of the cumulative cancer risks from emitted carcinogens and the cumulative noncancer hazard indices from all emitted non-carcinogens affecting the same target organ system for both the source category emissions and the facility-wide emissions. While the emissions for the source category and whole facility emissions have been collected as part of the information data request and reviewed by project engineers and scientists, emissions data for sources outside of the refinery facility are not readily available at the level of detail and quality that is required for a refined risks analysis. Thus, because of uncertainties in this data we do not include the risks from stationary and mobile sources outside of the refinery in our facility-wide risk analysis.

The risk assessment modeling for the Refineries MACT accounted for the effects of multiple facilities within the source category that may be in close proximity when estimating concentration and risk impacts at each block centroid. When evaluating the risks associated with

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[64] For areas with more facilities, which cause an even greater level of health risk combined, the UF should be adjusted accordingly, i.e., 11-20 facilities would result in an UF of 20, and more than 20 would result in an UF of 100, so the source category's contribution is no higher than 1/100 of the threshold.

a particular source category we combined the impacts of all facilities within the same source category, and assessed chronic exposure and risk for all census blocks with at least one resident (i.e., locations where people may reasonably be assumed to reside rather than receptor points at the fenceline of a facility). The maximum individual risk considers the combined impacts of all sources in the category that may be in close proximity. We do not agree with the idea that we should apply an uncertainty factor related to the number of non-refinery facilities near a refinery. First and foremost, MIR is highly location-specific and neighboring facilities seldom have any significant contributions to the MIR posed from an individual facility. Second, given the geographic size of refineries and their emissions, it is non-scientific to suggest neighboring facilities can have such an additive impact on the MIR. When EPA considers the use of an uncertainty factor in a risk analysis, it only includes such factors that have been developed based on scientific data that support their use.

2.3.5 Multipathway risk assessment

Comment 1: Multipathway risk assessment is not sufficient and underestimates risks: One commenter supported performing a multipathway (i.e., non-inhalation-based) risk assessment but stated that EPA's multipathway analysis is deficient and could be improved by incorporating the following suggestions:

- Perform a multipathway (or non-inhalation) risk assessment assessing the "allowable" emissions.
- Assess the non-inhalation-based risk created by refineries' emissions of all hazardous air pollutants known to be persistent and bioaccumulative in the environment (PB-HAP) instead of restricting its multipathway risk screening assessment to the 14 contaminants identified in the 2004 Risk Assessment Guidance as PB-HAP.[65] The commenter specifically recommended the following compounds be included in the assessment: arsenic, hexavalent chromium, nickel, diethylhexylphthalate, beryllium, selenium, manganese and naphthalene. The commenter asserted that these pollutants have been shown to have a significant potential for deposition and retention within the environment and present a risk to nearby communities. The commenter cited the California OEHHA 2012 Guidelines for Exposure Assessment as the rationale for including these HAP in the assessment and recommended that EPA review and adopt the methods in these guidance documents. Specifically for naphthalene, the commenter stated that this compound has been demonstrated to be persistent and bioaccumulative and is a PAH, and as such must be considered in the POM category which is already listed as a PB-HAP.
- EPA must perform a proper multipathway assessment for lead in lieu of a reference value for multipathway risk rather than comparing the emissions to the National Ambient Air Quality Standards for lead (0.15 micrograms/m^3).
- EPA's table summarizing emissions and dose-response values suggests that the Agency did not evaluate the health risks at all from 2,2,4-trimethylpentane, phosphorus,

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[65] EPA, PB-HAP Compounds, Risk Assessment and Modeling - Air Toxics Risk Assessment Reference Library, Vol. I Tech. Resource Manual, Ch. 4 Air Toxics: Chemicals, Sources, and Emissions Inventories, at 4-10, Exhibit 4-2 (2004), http://www2.epa.gov/sites/production/files/2013-08/documents/volume_1_reflibrary.pdf.

dibutylphthalate, 3,3'-dimethylbenzidine, 3,3'-dimethoxybenzidine, N,Ndimethylanline, p-Phenylenadiamine. The risk from these compounds must be fully assessed.

- Consistent with the 2004 guidance document and OEHHA 2012 Guidelines, EPA must recognize the deposition of persistent HAPs as a source of soil contamination presenting a potentially significant route of exposure, particularly for children. The commenter argued that the EPA has been relying on outdated estimates of incidental soil ingestion exposures and EPA must update these values to ensure that it considers the urban child scenario in its multipathway risk assessment.[66] The risk assessment of exposure to soil contaminants should evaluate both direct exposure, hand-to-mouth, and indirect, object-to-mouth exposure as a study has found a statistically significant positive correlation between the frequency of object or food in mouth activity and blood lead levels, according to the commenter.[67] The commenter added that the 2011 update to EPA's Exposure Factors Handbook includes more recent studies and estimates of hand-to-mouth behavior, which must be used to assess risks from exposures to contaminated soils.[68]
- EPA's analysis shows that the highest level of multipathway risk, to which the most-exposed individual is exposed, may well be above the risk estimated from EPA's more refined multipathway case study of the Marathon Petroleum refinery, near Garyville in St. John the Baptist Parish, Louisiana.

Furthermore, the commenter stated that EPA must account for the aggregate impact of inhalation and multipathway cancer and chronic non-cancer risk by adding each type of similar risk together for all pollutants. The commenter stated that the purpose of the multipathway assessment is to allow EPA to look at a person's exposure overall - not just inhalation or other exposure pathways, in isolation. According to the commenter, failing to add up each type of risk in order to come up with a total cancer risk number and a total non-cancer number, and then a cumulative burden metric, makes EPA's overall risk assessment incomplete. The commenter asserted that because of these deficiencies, EPA's analysis underestimates health risks from refineries and thus EPA's proposed decision not to set residual risk standards for any part of this source category other than storage vessels is flawed.

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[66] As an additional problem, California's lead in soil standard is more stringent than EPA's due to more recent science on the harm of lead exposure. EPA has recognized that its standard is based on out-dated information about lead, that previously assumed children's blood-lead levels below 10.0 µg/dL was safe. EPA now admits that number is not protective, but has not updated its soil standard. See, e.g., "EPA fails to revise key lead-poisoning hazard standards," USA Today (Mar. 10, 2013), http://www.usatoday.com/story/news/nation/2013/03/10/epa-hasnot-revised-lead-hazard-standards-for-dust-and-soil/1971209 ("The EPA has not revised key hazard standards that protect children from lead poisoning since 2001, despite science showing harms at far lower levels of exposure than previously believed."); Children's Health Advisory Protection Comm., Letter to Administrator Jackson Regarding Childhood Lead Poisoning (Mar. 29, 2012), http://yosemite.epa.gov/ochp/ochpweb.nsf/content/chpac_childhood_lead_poison_letter.htm.

[67] Ko, S., Schaefer et al., Relationships of Video Assessments of Touching and Mouthing Behaviors During Outdoor Play in Urban Residential Yards to Parental Perceptions of Child Behaviors and Blood Lead Levels, 17 J. of Exposure Science and Environ. Epidemiology 47 (2007).

[68] EPA, Exposure Factors Handbook, 2011 Edition (http://cfpub.epa.gov/ncea/risk/recordisplay.cfm?deid=236252).

Response 1: Regarding the commenter's assertion that we did not base the multipathway risk assessment on allowable emissions, we believe it is reasonable for the multipathway risk assessment to be based on actual emissions for this source category, and not the allowable level of emissions that facilities are permitted to emit. The uncertainties associated with the multipathway screen along with uncertainties in the allowable emissions estimates would make a multipathway risk assessment based on allowable emissions highly uncertain. The ICR-submitted information for allowable emissions did not include emission estimates for all HAP and sources of interest. Consequently, we used our REM model to estimate allowable emissions. The REM model relies on model plants that vary based on throughput capacity. Each model plant contains process-specific default emission factors, adjusted for compliance with the Refinery MACT 1 and 2 emission standards. Basing the multipathway assessment on these modeled emissions along with the uncertainties inherent in the multipathway screening analysis would result in a risk estimate that is too uncertain to support a regulatory decision.

Naphthalene is not treated as a POM chemical in the multipathway analyses. Naphthalene is listed individually as a HAP under section 112(b) of the CAA. POM also is listed as a HAP under section 112(b) and is defined as organic compounds with more than one benzene ring and a boiling point greater than or equal to 100 degrees Celsius. Under this definition, naphthalene potentially could be considered as part of the POM listing. However, naphthalene is short-lived in environmental media due to its tendency to volatilize and biodegrade and, consequently, will not build up in environmental media over time.[69] It has a moderate affinity for lipids and will undergo short-term bioaccumulation is tissues; however, biochemical processes lead to its biodegradation and elimination. Because it is neither persistent nor bioaccumulative, we do not consider it a PB-HAP, and its inclusion as POM is inappropriate and would result in less accurate and less meaningful estimates of media concentrations and multipathway risk.

While we acknowledge we do not have screening values for some of the PB-HAP, we do not agree that this results in an inadequate multipathway assessment. In the Air Toxics Risk Assessment Reference Library,[70] we developed the current PB-HAP list considering all of the available information on persistence and bioaccumulation (see http://www2.epa.gov/fera/air-toxics-risk-assessment-reference-library-volumes-1-3), specifically Volume 1 Appendix D). This list considered HAP identified as PB-HAP by other EPA Program Offices (e.g., the Great Waters Program), as well as information from the persistent, bioaccumulative and toxic (PBT) profiler (see http://www.pbtprofiler.net/). This list was peer-reviewed by the SAB and found to be reasonable for use in the RTR program. Based on these sources and the available information on the persistence and bioaccumulation of other HAP, we do not believe that the potential for multipathway risk from other HAP rises to the level of the PB-HAP currently on the list.

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[69] US Agency for Toxic Substances and Disease Registry, 2005. Toxicological Profile for Naphthalene, 1-Methylnaphthalene, and 2-Methylnaphthalene. http://www.atsdr.cdc.gov/ToxProfiles/tp.asp?id=240&tid=43#bookmark08

[70] The Air Toxics Risk Assessment Reference Library provides information on the fundamental principles of risk-based assessment for air toxics and how to apply those principles in different settings (e.g., facility-specific) as well as strategies for reducing risk at the local level.

We have combined risk assessment results to the extent that it is appropriate to do so. We consider the effect of mixtures of carcinogens and use a TOSHI approach for our chronic noncancer assessments. We do not use a TOSHI approach for our acute analyses nor do we combine the results of our inhalation and multipathway assessments. The multipathway risk assessment conducted for proposal was a screening-level assessment followed by a more refined site-specific assessment. The screening assessment used highly conservative assumptions designed to ensure that facilities with results below the screening threshold values did not have the potential for multipathway impacts of concern. The screening scenario is a hypothetical scenario, and due to the theoretical construct of the screening model, exceedances of the thresholds are not directly translatable into estimates of risk or hazard quotients for these facilities. In situations where we have previously summed the inhalation and multipathway assessment results (e.g., secondary lead smelters), it was for two refined assessments, and still serves as a conservative overestimate of potential risks given that it is highly unlikely that the same receptor has the maximum results in both assessments. For the petroleum refinery source categories, the refined multipathway analysis predicts a potential lifetime cancer risk of 4-in-1 million to the maximum most exposed individual (MIR). The non-cancer HQ is predicted to be well below 1 for all target organs. The chronic inhalation cancer risk assessment estimated inhalation cancer risk around this same facility to be approximately 10-in-1 million, due in large part to emissions of naphthalene and 2-methylnaphthalene (both are not persistent, bioaccumulative, and toxic (non-PBT) HAP). Thus, although highly unlikely, if around this facility the person with the highest chronic inhalation cancer risk is also the same person with the highest individual multipathway cancer risk, then the combined, worst-case MIR for that facility could theoretically still be 10-in-1 million (risk estimates are expressed as 1 significant figure). While this refined assessment was performed on only a single facility, the results of this single refined analysis indicate that if refined analyses were performed for other sites, the risk estimates would consistently be lower than those estimated by the Tier II analysis. In addition, the risks predicted by the multipathway analyses at most facilities are considerably lower than the risk estimates predicted by the inhalation assessment, indicating that the inhalation risk results are in all likelihood the primary factor in our residual risk determination for this source category.

We disagree with the commenter that a separate multipathway risk assessment should have been performed for lead. As noted in previous responses, the NAAQS for lead was used as a health based standard in this review. It was not simply adopted mechanically, but rather is justified under the independent decision framework in section 112(f)(2). We note that the NAAQS for lead was set to protect, with an adequate margin of safety, the health of the most susceptible children and other potentially at-risk populations against an array of adverse health effects, most notably including neurological effects, particularly neurobehavioral and neurocognitive effects (which are the most effects to which children are most sensitive) (73 FR at 67007). We further note that in developing the NAAQS for lead, air-related multipathway effects were already taken into account. That is, as noted at 73 FR at 66971: “As was true in the setting of the current standard, multimedia distribution of and multipathway exposure to Pb that has been emitted into the ambient air play a key role in the Agency’s consideration of the Pb NAAQS.”

In addition, the EPA’s analysis addresses the cumulative, long-term impacts to individuals in the local affected communities from prior lead emissions. First, as part of the Risk and Exposure Assessment supporting the lead primary NAAQS, the EPA assessed the IQ loss associated with the cumulative environmental impact of long-term emissions in communities living near stationary sources of lead emissions, specifically lead smelters. See Lead Human Exposure and Health Risk Assessments for Selected Case Studies; Volume I Human Exposure and Health Risk Assessments 00 Full Scale; and Volume II: Appendices ((USEPA, 2007) (Office of Air Quality Planning and Standards, Research Triangle Park, NC EPA-432/R-07-014a and EPA-452/R-07-014b; see also 73 FR 66979-66983. The Risk and Exposure Assessment assessed exposure to lead from the inhalation route as well as the multiple ingestion pathways. Although the EPA relied primarily upon the evidence-based framework (i.e. epidemiological studies and related information) in developing the lead primary NAAQS, the EPA nonetheless found the air-related lead risk estimates from the Risk and Exposure Assessment to be generally supportive of that scientific evidence-based framework. (See 73 FR at 67003-04.)

The evidence-based framework used in developing the lead NAAQS is focused on children with total lead exposure closer to the current U.S. average (than the more highly lead exposed upper percentiles of the population), since these children will have greater response to each increment of air-related lead exposure than would children with higher overall blood lead levels. Other populations, including children with higher blood lead levels due to past exposures, will necessarily be accorded protection from air-related lead as well. (See EPA-HQ-OAR-2006-0735-5894 at page 13).

As noted in the risk assessment document, there is no RfD or other comparable chronic health benchmark value for lead compounds. In 1988, the EPA's IRIS program reviewed the health effects data regarding lead and its inorganic compounds and determined that it would be inappropriate to develop an RfD for these compounds, saying, "A great deal of information on the health effects of lead has been obtained through decades of medical observation and scientific research. This information has been assessed in the development of air and water quality criteria by the agency's Office of Health and Environmental Assessment (OHEA) in support of regulatory decision-making by the Office of Air Quality Planning and Standards (OAQPS) and by the Office of Drinking Water (ODW). By comparison to most other environmental toxicants, the degree of uncertainty about the health effects of lead is quite low. It appears that some of these effects, particularly changes in the levels of certain blood enzymes and in aspects of children's neurobehavioral development, may occur at blood lead levels so low as to be essentially without a threshold. The agency's RfD Work Group discussed inorganic lead (and lead compounds) at two meetings (07/08/1985 and 07/22/1985) and considered it inappropriate to develop an RfD for inorganic lead." The EPA's IRIS assessment for Lead and compounds (inorganic) (CASRN 7439-92-1), http://www.epa.gov/iris/subst/0277.htm.

Regarding incidental soil contamination, the EPA has estimated risks from both direct and indirect pathways. Direct routes of exposure include direct ingestion of soil and exposure through dermal contact. However, because it has been demonstrated in past analyses that exposure levels associated with dermal contact are but a small fraction of exposure levels associated with ingestion and inhalation pathways, dermal exposures were not assessed for this source category.

2.3.6 Recommendations for strengthening risk assessment

Comment 1: Suggestions for remedying claimed deficiencies in risk assessment: Several commenters claimed there are shortcomings in EPA's risk assessment, as detailed in above sections, and suggested improvements. These suggestions which have been included elsewhere in this chapter of the RTC are summarized in the following list:

- Assess and account for receptors with increased vulnerability such as children, seniors, pregnant woman, prenatal fetuses, persons with pre-existing health conditions, disabled and Environmental Justice Communities through the use of specific risk adjustment factors and reference values.
- Fully integrate the environmental justice analysis into the risk assessment and rulemaking set more protective standards.
- Assess and aggregate exposure from multiple pathways including by adding inhalation and non-inhalation-based cancer risks.
- Use a margin of exposure (MOE) framework for non-cancer impacts and adjust the target MOE according to known vulnerability factors.
- Account for exposure to multiple sources of multiple pollutants via multiple pathways to assess the total cumulative risk, and use the estimated impacts of these cumulative risks to shift the level of risk which triggers policy action.
- Reduce the acceptable lifetime cancer risk.
- Base risk assessments on the best available scientific research including incorporating recommendations from NAS and SAB.

Response 1: This compilation of suggestions for improving the perceived deficiencies in our residual risk assessment have been address in other responses in Sections 2.2 through 2.7 of this document. Further, it is important to note that the EPA's approach to performing risks assessments in support of residual risk program has been reviewed and supported by the SAB several times over the past 17 years. First, in 1998 they examined our analytical and policy approach for assessing residual risk from hazardous air pollutants emitted from stationary sources, followed by a second review in 2000 to verify that our application to a specific source category was consistent with the approved approach. A third SAB consultation in 2006 focused on development of emissions inventories for source categories and updated methods for characterizing human exposure and risks. Again in 2009, the SAB reviewed and supported our updated and expanded air toxics risk assessment methods, including our multipathway assessment, refinement of acute risk screening, and the methods of assessing potential environmental risk. We will continue to seek SAB consultation as our risk assessment methods develop and revise our approach as appropriate.

Comment 2: EPA must undertake a cumulative risk assessment: Many **c**ommenters stated that EPA needs to perform an up-to-date health risk and impact assessment of the cumulative effects refinery chemicals on communities and children. Commenters stated that this assessment should evaluate the combined impact of each type of risk from multiple pollutants and assess the total cumulative risk burden from all pollutants to make an ample margin of safety determination. The commenter noted that in the refineries risk assessment, EPA only assesses the combined impact of cancer risk and chronic non-cancer risk that operates on the same target organ, while the commenter argued that the EPA should assess the total and synergistic cancer risk and total chronic noncancer risk for different pollutants. In addition, the commenter noted that EPA should apply these same principles to create a mechanism for assessing the total acute risk to chemical mixtures, such as the TOSHI for chronic risk that aggregates the acute impacts on the same organ systems for all pollutants.

The commenter asserted that consistent with NAS recommendations, the EPA must create a metric to assess the total and cumulative risk burden, rather than only looking at each type of risk separately. After first assessing the total cancer, chronic non-cancer, and acute risks, for both inhalation and multipathway exposure, the commenter argued that EPA also must create a metric to assess the total risk. EPA must aggregate health risk for each pollutant, and each type of health risk, according to the commenter, to create a cumulative risk determination for the individual "most exposed" to emissions as section 112(f)(2) of the Act requires. The commenter asserted that without performing this cumulative assessment, EPA has failed to gather the information needed to assess whether the risk to public health is acceptable under section 112(f)(2).

Response 2: We have combined risk assessment results to the extent that it is appropriate to do so. We consider the effect of mixtures of carcinogens and use a TOSHI approach for our chronic noncancer assessments. We do not use a TOSHI approach for our acute analyses nor do we combine the results of our inhalation and multipathway assessments.

For the petroleum refinery source categories, the EPA conducted an assessment of the cumulative cancer risks from emitted carcinogens and the cumulative noncancer hazard indices from all emitted non-carcinogens affecting the same target organ system for both the source category emissions and the facility-wide emissions.

Concerning comments that we should consider aggregate risks from multiple pollutants and sources, we note that we have done this to the extent it is appropriate to do so. We modeled whole-facility risks for both chronic cancer and non-cancer impacts to understand the risk contribution of the sources within the Petroleum Refinery source categories. The individual cancer risks for the source categories were aggregated for all carcinogens. In assessing noncancer hazard from chronic exposures for pollutants that have similar modes of action or (where this information is absent) that affect the same target organ, we aggregated the HQ. This process creates, for each target organ, a TOSHI, defined as the sum of hazard quotients for individual HAP that affect the same organ or organ system. Whole facility risks were estimated based on the 2011 ICR data obtained from facilities, which included emissions from all sources at the refinery, not just Refinery MACT 1 and 2 emission sources (e.g., emissions were included for combustion units and units subject to the Hazardous Organic NESHAP, if present at the refinery).

As described in the Draft Residual Risk Assessment for the Petroleum Refining Source Sector (Docket Item No. EPA-HQ-OAR-2010-0682-0225), we do not sum results of the acute noncancer inhalation assessment to create a combined acute risk number that would represent the total acute risk for all pollutants that act in a similar way on the same organ system or systems (similar to the chronic TOSHI). The worst-case acute screen is a conservative scenario. That is, the acute screening scenario assumes worst-case meteorology, peak emissions for all emission points occurring concurrently and an individual being located at the site of maximum concentration for an hour. Thus, as noted in Section 2.4 of the Draft Residual Risk Assessment for the Petroleum Refining Source Sector (Docket Item No. EPA-HQ-OAR-2010-0682-0225), "because of the conservative nature of the acute inhalation screening and the variable nature of emissions and potential exposures, acute impacts were screened on an individual pollutant basis, not using the TOSHI approach."

We did not combine the inhalation and multipathway risk assessment results for each pollutant because it is inappropriate to do so. The multipathway risk assessment conducted for proposal was a screening-level assessment followed by a more refined site-specific assessment. The screening assessment used highly conservative assumptions designed to ensure that facilities with results below the screening threshold values did not have the potential for multipathway impacts of concern. The screening scenario is a hypothetical scenario, and due to the theoretical construct of the screening model, exceedances of the thresholds are not directly translatable into estimates of risk or hazard quotients for these facilities. For the refined multipathway analysis, it is unlikely that the person with the highest chronic inhalation cancer risk is also the same person with the highest individual multipathway cancer risk. Also, in our experience, the risk estimates predicted by the multipathway analysis at most facilities are considerably lower than the risk estimated predicted by the inhalation assessment, indicating that the inhalation risk results are in all likelihood the primary factor in our residual risk determination.

2.4 Demographic Analysis / Environmental justice

Comment 1: Lower income, minority, less educated, non-English speaking and younger communities are disproportionately impacted by refinery emissions: One commenter stated that the emissions from the 149 petroleum refineries in 32 states pose serious harm to millions of Americans who live nearby or downwind of these facilities. The commenter noted that among the approximately 5.2 million people exposed to levels of carcinogens from refineries, fully half are from minority groups, one quarter of those exposed are under the age 17 and one in five had incomes below the poverty line. Furthermore, the commenter cited that one in four adults lacked a high school diploma and that one in ten had no one in the household over age 14 who spoke English. The commenter highlighted that a greater percentage of African-Americans, Hispanics and people living below the poverty line face an increased risk of cancer from exposure to emissions from refineries than do whites or those with higher incomes. Therefore, according to the commenter, as supported by EPA's own analysis the harm that communities are exposed to is not equal and a serious environmental and social injustice exists.[71] In particular the commenter noted, half of the people who currently face a cancer threat from refineries' pollution are racial minorities even though the U.S. population is only 28% minority. The commenter stated that of the approximate 4 million people who will still face an increased cancer threat from refineries after the proposed rule, more than 50% will be racial minorities, 31% will be African Americans, 24% will be Hispanic or Latino, and 22% will be people living below the poverty level. The

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[71] 79 FR 36937; Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries, EPA-HQ-OAR-2010-0682-0226

commenter stated that the disparity increases under the EPA's proposed rule.[72] The commenter concluded that the EPA must take stronger action than it has proposed to resolve the need for robust national air toxics standards and to reduce the socioeconomic disparity in environmental health impacts caused by U.S. refineries.

Another commenter stated that considerations of the cost/benefits to industry have been taken into account, while the costs to those living near the fenceline of refineries have not, noting that these populations often have a lower quality of health and do not have access to health insurance.

Response 1: With regards to the comment concerning unacceptability due to socioeconomic disparity, under Executive Order (EO) 12898, the EPA is directed to the greatest extent practicable and permitted by law, to make environmental justice (EJ) part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations in the United States. Consistent with EO 12898 and the Presidential Memorandum that accompanies it, the EPA's environmental justice policies promote justice by focusing attention and EPA efforts on addressing the types of environmental harms and risks that are prevalent among minority, low-income and indigenous populations. EO 12898 and the EPA's environmental justice policies do not mandate particular outcomes from an action, but they demand that decisions involving the action be informed by a consideration of EJ issues. With respect to this rule, the EPA found the overall level of risk from the source categories to be acceptable and to provide an ample margin of safety for all populations in close proximity to these sources, including minority and low-income populations.

Because minority groups make up a large portion of the population living near refineries, as compared with their representation nationwide, those groups would see a greater benefit from the implementation of the controls required by this rule. For example, we estimate that after implementation of the controls (*i.e.*, post-controls), about 1,000,000 fewer people will be exposed to cancer risks greater than 1-in-1 million (*i.e.,* 4,000,000 people). Further, we estimate that approximately half of those who risk would be reduced to below 1-in-1 million, or about 500,000 people, would be in a minority demographic group.

Comment 2: Specific examples of communities cited by commenters as having environmental justice concerns: Commenters expressed environmental justice concerns for several communities where people of low income, less education, and/or communities of color live within close proximity to a refinery fenceline, particularly for those living in Manchester, Pasadena, Galena Park, Baytown, Deer Park, Port Arthur, Beaumont, and Texas City which are located near the largest petrochemical complex in the nation. The commenter stated that these communities suffer the burdens of industry including health effects (e.g., higher than normal incidence of cancer,

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[72] Draft Residual Risk Assessment for the Petroleum Refining Source Sector, EPA-HQ-OAR-2010-0682-0225; Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries, EPA-HQ-OAR-2010-0682-0226; Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries Post Control Scenario at 8, EPA-HQ-OAR-2010-0682-0227.

asthma, chronic bronchitis, and other negative respiratory health outcomes) without enjoying the benefits (e.g., highly skilled and technical jobs).

Another commenter provided a report on the risks refineries pose to Pasadena, a city east of Houston,that has dozens of chemical plants and a refinery. The commenter stated community members from this area have issues with asthma and other health problems, but have limited access to health care outside of a single public clinic that serves a huge swath of this portion of the Houston Ship Channel. The commenter stated that it is especially important to strengthen rules considering the vulnerable demographics of the area combined with poor air quality in the region.

Additional commenters referenced a 2006 study by the University Of Texas School Of Public Health concluding that children living within 2 miles of the Houston Ship Channel, which is home to five oil refineries, have a 56 percent greater risk of leukemia than children living 10 miles away. One of these commenters also referenced a 2008 study published in the journal Environmental Science and Technology that found for residents of the eastern portion of the Houston Ship Channel, the greatest contributor to an increased risk of cancer is point-source emissions from petrochemical refineries. Another commenter stated that there are 86 schools in the Houston Independent School District which are in the top 5 percent of the most toxic schools in the nation according to reports by the Center for Health and Environmental Justice.

Response 2: We are not able to determine the baseline health status of individuals or communities in a national rulemaking. Individual privacy issues as they relate to health records and the costs that would be associated with such an analysis make the analysis infeasible. Through the EPA’s interim guidance on Environmental Justice and the Action Development Process, the agency is encouraging rule writers and policy makers to look at the whole range of factors that impact communities and population groups when crafting rules. The EPA is continuing to discuss and pilot approaches that are consistent with the agency’s responsibilities regarding environmental justice as outlined in EO 12898. In determining the need for tighter residual risk standards, the EPA strives to limit to no higher than 100-in-1 million the estimated cancer risk for persons living near a plant if exposed to the maximum pollutant concentration for 70 years and to protect the greatest number of persons to an individual lifetime risk of no higher than 1-in-1 million. Considerations are made for all people regardless of racial or socioeconomic status.

To examine the potential for any environmental justice issues that might be associated with the source categories, we performed a demographic analysis of the population close to the facilities. In this analysis, we evaluated the distribution of HAP-related cancer and non-cancer risks from petroleum refineries across different social, demographic, and economic groups within the populations living near facilities identified as having the highest risks. The methodology and the results of the demographic analyses are included in a technical report, *Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries,* available in the docket for this action (Docket Item Number EPA–HQ–OAR–2010–0682-0226). These results, for various demographic groups, are based on the estimated risks from actual emissions levels for the population living within 50 kilometers (km) of the facilities.

The results of the demographic analysis indicate that emissions from petroleum refineries expose approximately 5,000,000 people to a cancer risk at or above 1-in-1 million. Implementation of the provisions is expected to reduce the number of people estimated to have a cancer risk greater than 1-in-1 million due to HAP emissions from these sources from 5,000,000 people to about 4,000,000. Our analysis of the demographics of the population within 50 km of the facilities indicates potential disparities in certain demographic groups, including the African American, Other and Multiracial, Hispanic, Below the Poverty Level, and Over 25 without a High School Diploma. The population living within 50 km of the 142 petroleum refineries has a higher percentage of minority, lower income and lower education persons when compared to the nationwide percentages of those groups. For example, 50 percent are in one or more minority demographic group, compared to 28 percent nationwide. As noted above, approximately 5,000,000 people currently living within 50 km of a petroleum refinery have a cancer risk greater than 1-in-1 million. We would expect that half of those people are in one or more minority demographic groups.

Because minority groups make up a large portion of the population living near refineries, as compared with their representation nationwide, those groups would similarly see a greater benefit from the implementation of the controls. For example, we estimate that after implementation of the controls proposed in this action (*i.e.,* post-controls), about 1,000,000 fewer people will be exposed to cancer risks greater than 1-in-1 million (*i.e.,* 4,000,000 people). Further, we estimate that approximately 500,000 people no longer exposed to a cancer risk greater than 1-in-1 million would be in a minority demographic group.

Although the EPA's fenceline monitoring requirement is intended to ensure that owners and operators monitor, manage and, if necessary, reduce fugitive emissions of HAP, we also expect the collected fenceline data to help the EPA understand and identify emissions of benzene and other fugitive emissions that are impacting communities in close proximity to the facility. While currently-available emissions and monitoring data do not indicate that risks to nearby populations are unacceptable, we recognize that the collection of additional data through routine fenceline monitoring can provide important information to communities concerned with potential risks associated with emissions from fugitive sources. We note that the data we will collect on a quarterly basis may include exceedances of the fenceline action level that a facility could have addressed or could still be actively addressing at the time of the report. Requiring the electronic reporting of fenceline monitoring data on a quarterly basis will ensure that communities have access to data on benzene levels near the facility, which is directly relevant to the potential health risks posed by the facility. The requirements for fenceline monitoring and corrective action when fugitive emissions from a facility exceed the specified corrective action level will serve as an important backstop to protect the health of the populations surrounding the facility, including minority and low-income populations.

Comment 3: Recommendations for improvements to the environmental justice demographic analysis: Commenters made several recommendations for improvements to the environmental justice demographic analysis including:

- Performing an environmental justice analysis more similar to the recent work done on the definition of solid waste.

- Considering other factors in terms of the overall disproportionate impact on communities (e.g., a complete risk profile) including: susceptibility of the community, the number of children, vulnerable populations, higher disease rates, the ability of the community to participate in decision-making or receiving information, lack of information, language barriers, lack of social capital, the ability of the community to prepare for impacts (such as evacuation issues in emergencies), the ability of the community to recover from environmental insults such as the lack of health care and the lack of financial resources, the potential impacts of land use on the community, the availability of recreation and other enrichment opportunities, cumulative impacts (which is critically important and may include all of the above), the distribution of environmental burdens,; and the location of other potential sites of pollution (such as Superfund sites and hazardous waste facilities within the same community, and their compliance rates, particularly comparing facilities subjected to other regulations).
- Develop more conservative resulting emission standards because, according to the commenter, a California EPA screening tool which identifies California communities that are disproportionately burdened by multiple sources of pollution as determined by evaluating multiple pollutants and stressors in these communities shows that those identified as being threatened by the burden of serious pollution are located in the same locations as the majority of California's refineries.
- Consistent with NAS recommendations, the EPA should consider the use of socioeconomic factors as part of EPA's consideration of both vulnerability and variability, as core elements of the risk assessment.[73] According to the commenter, data describing these factors are available from the CDC's Environmental Public Health Tracking Program, the U.S. ATSDR, state and local health agencies, and academic researchers.
- Better account for other types of human variability such as genetics and baseline health status, as recommended by NAS and current science. According to the commenter, socioeconomic status has been shown to act as a proxy for other types of human variability to chemical risk that EPA has not adequately addressed in its draft risk assessment for the refineries rule.
- In addition to looking at the demographic census data on race, ethnicity, poverty level, and similar factors, EPA must assess the starting point or baseline overall health status of the affected individuals and communities using the best available data at a local and national level, including the baseline cancer levels, respiratory problems, and health problems associated with the toxic chemicals emitted by a source category. The commenter asserted that doing so would be consistent with the 1999 Residual Risk Report[74] and would also follow EPA's own statements (in the 2014 Second Integrated

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[73] NAS 2009, supra note 264, at 109-10 & tbl. 4-1 (describing the need to consider increased susceptibility due to prior and concurrent exposures; and to 'social and economic factors'); id. at 220-21 (describing ways to assess cumulative risk including by consideration of "epidemiologic concepts" and information, and by considering "what the burden of disease is in the context of simultaneous exposure to a number of stressors"); id. at 230 (discussing the role of epidemiology and surveillance data).

[74] U.S. EPA, "Residual Risk Report to Congress" at 42, 67 (Mar. 1999), EPA-453/R-99-00 (discussing factor of "overall health" and recognizing the need to consider sensitive subpopulations that "consist of a specific set of

Urban Air Toxics Report) that more work is needed to reduce excess cancer risks in urban areas that continue to face elevated risks [Second Integrated Urban Air Toxics Report, at xiv]. As an alternative, EPA could use a default factor to account for socioeconomic and other community-based stressors.

- Better communicate and document the findings of the analysis, as one commenter stated, the EPA has presented environmental justice numbers in the abstract, which makes it difficult for communities to understand the risk assessment and the EPA's findings.
- Conduct a demographic analysis on individuals projected to experience a risk greater than 1-in-1-million for cancer or an HQ above one and on individuals living within five kilometers of the facility, regardless of projected risk, consistent with the approach used for the Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks source category.
- EPA rule writers should consult with the EPA Office of Environmental Justice to develop criteria and specific guidance on how to interpret and apply the outcome of these types of analyses in the rulemaking process.

Response 3: The EPA continues to evaluate and refine environmental justice analysis, such as the proximity analysis performed for the Definition of Solid Waste. The draft EPA document *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* is currently undergoing SAB review. The Office of Air and Radiation is contributor to this draft document and cites numerous examples of EJ analysis performed in agency rulemakings. Environment justice considerations are a part of the rulemaking process; however, various factors influence the scope and complexity of an assessment. These factors may include, but are not limited to statutory mandates, data availability, resources and/or timeframe limitations.

For this rulemaking, the EPA conducted both pre- and post- control risk-based assessment with analysis of various socio-economic factors for populations living near petroleum refineries. While partially proximity-based, this assessment also uses air quality modeling HEM-3 to show a decrease in potential cancer risks for all populations. These reports can be found at the consolidated petroleum refinery rulemaking repository at: http://www.epa.giv/airtoxics/petref.html. In addition, the EPA's meaningful involvement activities included webinars, community calls and all day trainings held in San Francisco, California, New Orleans, Louisiana and Research Triangle Park, North Carolina. Additionally, we have held a number of meetings with community organizations on this rulemaking.

The commenter is correct that we performed the demographic analyses for the petroleum refinery source categories differently than we did for the October 2010 proposed RTR for the chrome source categories. We performed the demographic analyses for the chrome source categories using two approaches as examples of how such analyses might be developed, and invited public comment on the approaches used and the interpretations made from the results. In the first approach, we focused the analysis on the total populations residing within 5 km of each facility, regardless of their estimated risks, and examined the distributions across various demographic groups within those 5 km circles. That analysis was a "proximity" analysis in that it

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individuals who are particularly susceptible to adverse health effects because of physiological (e.g., age, gender, pre-existing conditions), socioeconomic (e.g., nutrition), or demographic variables, or significantly greater levels of exposure," based on various demographic factors).

considered only the distance from the emission sources to surrounding populations, and not the estimated risks to those populations.

In the second approach, we focused the analysis on the populations within 5 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater. We examined the distributions of those risks across various demographic groups. In each approach, we compared the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. We stated in the proposed rule for the chrome source categories that in future rules we planned to extend the analyses to cover the entire modeled domain for a facility (50 km radius) to capture all individuals with risks above 1-in-1 million or greater or non-cancer hazard indices of 1 or greater. We also stated that generally we have found that using a 5 km radius in the analysis will capture more than 90 percent of the individuals with cancer risks above 1-in-1 million.

In the February 2012 supplemental proposal for the RTR for the chrome source categories, our demographic analyses included populations within 50 km of each source (including those very near the sources) with risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater (77 FR 6628, Feb. 8, 2012). We did not include analyses using a 5 km radius in that supplemental proposal nor in the RTR proposal for the petroleum refinery source categories. Where a risk assessment has been performed, it is more informative to consider the demographics of all populations (including those beyond 5 km) with elevated risks than to limit the demographics analysis to populations located within 5 km of a facility. Where a risk assessment has been performed, these populations are identified, and the source parameters are taken into account. As discussed above, we have found that most exposure locations with the highest estimated risks are within 5 km of a facility, so extending the radius to 50 km has little impact on an analysis based on risks, but makes more sense because 50 km corresponds to the risk modeling radius and includes all populations with elevated risk estimates. We also note that we are working with the Office of Environmental Justice in an ongoing effort to develop new tools for considering environmental justice in rulemakings.

In the Urban Air Toxics Strategy Report to Congress we acknowledge that national rules and standards can address part of the risk to communities, but because the assessments did not include background risks or contributions to risk from sources outside the facilities more needs to be done at the community level with other tools available within the CAA and within state, local, and other federal programs. EPA is committed to our efforts to make a difference in communities of concern and developing an integrated strategy focusing work in communities with the most need for EPA’s assistance. We have been, and will continue to work in thousands of communities across the country. For example, through community-scale grants, we provided funding and technical support to the City of Philadelphia over a 2 year period in which we deployed numerous technologies in the South Philadelphia communities bordering a refinery to investigate how passive samplers and sensor based, stand-alone air measures can help improve information on air pollutant concentrations in areas that have many potential sources. The study has found that low cost passive samplers and sensors are effective in determining the origins of pollutants in communities that have a number of potential sources. Furthermore, these low cost passive sensors are able to determine emissions of multiple pollutants at low concentrations. Some of the information that resulted from this study is also discussed in Chapter 8. Over the next two years we will look for opportunities to enhance our partnership with communities to strengthen and improve their health – both environmental and economic. This effort to enhance coordination across our EPA programs and with other federal agencies will improve how we support community needs. We will focus on those communities where we think we have opportunities to leverage resources and actions to make a real difference. As we learn lessons on coordinating and focusing our efforts, we will use these lessons to help more communities in the future.

Comment 4: Consideration of environmental justice issues are outside the scope of EPA authority: One commenter stated that EPA's consideration of environmental justice issues are outside the scope of its authority under section 112(f). The commenter noted that section 112(f)(2)(A) expressly instructs EPA to impose additional emissions controls if needed to provide an ample margin of safety "to protect public health." Although the term "public health" is not defined in section 112 or in EPA's part 63 regulations, the commenter argued such a definition would not include non-health related demographic factors and EPA's analysis is, therefore, inapplicable to its statutory mandate to protect public health. The commenter provided an example of how this term is used in the context of EPA's NAAQS program. The commenter stated in this context, the term "public health" should be dictated by the meaning of the word "public" which, according to the commenter means "of, relating to, or affecting all of the people or the whole area of a nation or state" and "of or relating to people in general." These definitions emphasize, according to the commenter, that the word "public" should be construed expansively as describing the people as a whole, and not particular demographic segments.

The commenter further stated that EPA's established approach to assessing potential impacts on public health under the NAAQS program is consistent with this meaning. The EPA reasonably interprets the term "public health" to include consideration not only of potential impacts to the population as a whole, but also to sensitive subpopulations, according to the commenter, recognizing that the objective is to protect the group rather than any particular individual in the group. See, e.g., 71 Fed. Reg. 61144, 61145 fn. 2 (Oct. 17, 2006). The commenter asserts that sensitive subpopulations are identified according to their particular health-based sensitivities (e.g., asthmatics), rather than demographic classifications unrelated to particular health-based sensitivities. According to the commenter, with this backdrop, it would not be reasonable to construe the term "public health" as used in section 112(f) as allowing consideration of demographic classifications that bear no relationship to the potential health effects presented by the HAPs at issue for the given source category or subcategory.

Response 4: As noted above, the EPA is continuing to discuss and pilot approaches that are consistent with the agency's responsibilities regarding environmental justice as outlined in EO 12898. The EPA defines "environmental justice" to mean fair treatment and meaningful involvement of *all* people, and this definition represents a commitment to ensuring that EPA works to improve conditions affecting the public health of all Americans so that everyone has access to clean water, clean air and healthy communities.

As stated in the Benzene NESHAP ((54 FR 38044, 38061, September 14, 1989), in determining the need for residual risk standards, we strive to limit to no higher than approximately 1-in-10 thousand (100-in-1 million) the estimated cancer risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years and, in the ample margin of safety decision, to protect the greatest number of persons possible to an individual lifetime risk level of no higher than approximately 1-in-1 million. These considerations are made for all people, regardless of racial or socioeconomic status. However, in determining whether to require additional standards under section 112(f), these levels are not considered rigid lines, and we weigh the cancer risk values with a series of other health measures and factors in both the decision regarding risk acceptability and in the ample margin of safety determination. We also consider cost of controls in the ample margin of safety determination. While we analyzed the demographic makeup of the at-risk populations surrounding the facilities within the source categories addressed by this rulemaking, we ultimately concluded that the risks were acceptable for all population groups and protected public health with an ample margin of safety. Thus, while the results of our demographic analyses served to provide information about the demographic makeup of the populations exposed to the source category, the EPA did not base its decision solely on these analyses.

2.5 Ecological risk assessment

Comment 1: Additional pollutants should be considered in ecological risk assessment: One commenter noted that EPA acknowledged in the proposal that there are HAPs beyond the seven the agency evaluated in the environmental risk screening assessment that "may have the potential to cause adverse environmental effects" [79 FR 36898], stating that additional HAPs may be evaluated in the future "as modeling science and resources allow." The commenter strongly urged EPA to evaluate additional pollutants that are emitted by this source category, including arsenic and nickel, and ensure that measures are undertaken to reduce the public's exposure to them.

Response 1: The environmental screen focuses on the following seven environmental HAP: five PB-HAP – cadmium, dioxins/furans POM, mercury (both inorganic mercury and methyl mercury) and lead; and two acid gases - HCl, and HF. HAP that persist and bioaccumulate are of particular environmental concern because they accumulate in the soil, sediment and water. The five PB-HAP we evaluate as part of our screening analysis account for 99.8 percent of national PB-HAP emissions from all stationary sources (on a mass basis from the 2005 NEI). The acid gases, HCl and HF, were included due to their well-documented potential to cause direct damage to terrestrial plants. According to the 2005 NEI, HCl and HF account for about 99 percent (on a mass basis) of national acid gas emissions from stationary sources. The commenter did not provide any documentation to support the claim that arsenic and nickel air emissions from the petroleum refineries category cause adverse environmental effects. Therefore, we have not revised our environmental risk screen to include arsenic and nickel.

Comment 2: Refinements to the ecological risk assessment are needed to address region-specific impacts: The commenter stated that EPA has not adequately examined environmental, wildlife, and other ecological risks such as region-specific impacts to wildlife, including federally listed species under the Endangered Species Act, and aquatic resources in rivers and estuaries. For example, the commenter noted that EPA is legally required to assess impacts to endangered and threatened species, and yet EPA's assessment includes no discussion of potentially affected species located near refineries, much less any evaluation of the risks they face. The commenter stated that the EPA also says nothing about ESA consultation which, according to the commenter, provides further evidence that it has not considered or addressed its duty to prevent adverse environmental effects. The commenter asserted that EPA must assess potential endangered and threatened species near the existing sources in this source category.

The commenter provided specific details of the area of Anacortes, Washington and Cherry Point and cited numerous scientific studies showing environmental impacts in that area. This area has four large refineries near where the Nooksack and Skagit River deltas provide fertile salmon habitat. The commenter also note that shellfish and orcas – the latter listed as endangered under the Endangered Species Act – are of particular concern in the area. According to the commenter, recent research suggests that PAHs in streams are creating big problems for salmon. Furthermore, current research by the National Oceanic and Atmospheric Administration (NOAA) concerning storm water runoff and PAHs indicates regional species' sensitivity to PAH emissions from any source.[75] The commenter stated that EPA's assessment appears to look only at lakes, which is not giving EPA the full picture for impacts to salmon and orcas.

The commenter stated that it is also important to consider that air emissions from the Anacortes area refineries (and from the aluminum smelter that is also located there) significantly affect Olympic National Park. The commenter noted that emissions from the Anacortes sources (the Park Service was concentrated on the Tesoro Refinery) are the most significant source of haze impairment in the Olympics and presumably air toxics are deposited in Olympic lakes, rivers, and estuaries as well. It is unclear whether EPA has done an assessment of those impacts, according to the commenter.

The commenter further asserted that it is unclear if EPA's risk assessment documents analyzed particular existing problems and sensitivity to airborne emissions over time. According to the commenter, but it is difficult to tell from EPA's documentation what water bodies actually were modeled. The commenter asserted that the latest studies about mercury in Olympic National Park are available and EPA must consider these and other similar scientific research in this rulemaking in order to fulfill its legal duty to evaluate the adverse environmental effect of refineries' pollution under section 112(f)(2).

Response 2: The environmental risk screen is designed to be a conservatively protective screen that identifies potential adverse environmental effects from refinery air emissions to the most sensitive organisms, including threatened and endangered species. We evaluate four exposure media in the environmental risk screen: terrestrial soils, surface water bodies, fish consumed by wildlife, and air. Within these four exposure media, we evaluate nine Generic Ecological Assessment Endpoints (GEAEs). The GEAEs reflect the overall "health" of aquatic and terrestrial ecosystems and any important organisms that could be exposed in those ecosystems, including threatened and endangered species. Therefore, we did not conduct an ecological

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[75] See NOAA Northwest Fisheries Science Center, Polycyclic aromatic hydrocarbons, http://www.nwfsc.noaa.gov/research/divisions/efs/ecotox/pah.cfm and NOAA Northwest Fisheries Science Center, Stormwater science: ecological impacts, http://www.nwfsc.noaa.gov/research/divisions/efs/ecotox/ecoimpacts.cfm and publications cited there.

assessment that focused on specific species of organisms found in the Anacortes region as suggested by the commenter.

Specifically, the environmental risk screen includes the following conservative assumptions to ensure that adverse environmental effects to the most sensitive species are identified:

- Selection of species for the population-level assessments for PB-HAPs was based on those organisms that are likely to be the most sensitive and/or highly exposed due to bioaccumulation of the PB-HAP through aquatic and terrestrial food chains.
- For hydrogen fluoride, we evaluate the ecological endpoint for damage to plants, rather than fluorosis in livestock, because the HF concentrations at which fluorosis in livestock occur are higher than those at which plant damage begins.
- Where possible we used ecological benchmarks for each ecological assessment endpoint at no-observed-adverse-effect levels (NOAEL).
- In the Tier 1 screen for PB-HAP we use worst case meteorology and lake distance.
- As the commenter indicates, for PB-HAP we screen for adverse environmental effects primarily for lakes. In general, lentic bodies of water (lakes and ponds) accumulate higher levels of contaminants in both sediments and biota than lotic systems (rivers, streams). Therefore, if no potential adverse environmental effects are identified in lakes we would not expect there to be an adverse environmental effect on rivers/streams/estuaries.

We did not include background levels of pollutants, such as pollutants emitted from other non-refinery sources in the environmental risk screen as suggested by the commenter. Similar to the AMOS analysis for human health, background levels (including natural background) are not barred from the EPA's assessment of adverse environmental effects, and the EPA may consider them, as appropriate and as available, along with other factors, such as cost, economic impacts and technical feasibility. However, this assessment excludes background contributions because the available data are of insufficient quality upon which to base a meaningful analysis. We reviewed the information the commenter cited in their comments and found the following:

- The mercury study titled "Mercury in Fishes from 21 National Parks in the Western United States—Inter- and Intra-Park Variation in Concentrations and Ecological Risk" published by the U.S. Geological Survey does not draw any connection between mercury measurements and petroleum refinery facilities. In fact, the study cites the global nature of mercury pollution with sources as far away as China.
- The National Park Service (NPS) Western Airborne Contaminants Assessment Project Report also makes no mention of HAP emissions from petroleum refineries. The report cites regional agriculture and global emissions as the primary sources of airborne contaminants.
- The NOAA studies cited by the commenter focus on storm water runoff from roads, parking lots, and other impervious surfaces, not air emissions from petroleum refineries.
- The comments submitted by the National Park Service to EPA, Region 10 on February 15, 2013 are in regards to the Regional Haze program. The comments

related to Tesoro Refinery focus on NOx and SOx controls for improving visibility, not on HAP, which are the focus of this rule.

Based on our conservative environmental screening analysis, we do not expect adverse environmental effects, as defined in CAA section 112 (a)(7), as a result of HAP emissions from any sources addressed in this rulemaking. The EPA does not have information, nor did the commenter provide information to support the position that HAP emissions from facilities addressed in this rulemaking would result in environmental effects. Because our environmental risk screen does not indicate an environmental effect from this source category, we disagree with the commenter's statement that the EPA must engage in consultations (e.g., with the U.S. Fish & Wildlife Service and the National Marine Fisheries Service) under 16 U.S.C. 1536(a)(2).

2.6 Rule changes are not needed because risks are acceptable

Comment 1: Several commenters agreed that the EPA has correctly concluded that the proposed rule requirements protect the public with an ample margin of safety from refinery emissions. Other commenters noted that EPA found residual risks remaining after implementation of the MACT standards to be acceptable, and in light of the acceptability determination argued that the proposed changes to the rule are not justified. The commenters noted that the EPA's detailed emissions inventory assessment and risk modeling results demonstrated that, at every U.S. refinery, category-specific risks are below the EPA's presumptive limit of acceptable risk (i.e., cancer risk of less than 100-in-1 million).

The commenter noted that the estimated annual cancer incidence based on the maximum risk results is less than 1 case per year (0.3 and 0.6 cases per year based on actual and allowable emissions, respectively), and argued that this incidence is insignificant compared to the over 1,665,000 cases predicted to occur in 2014.[76] The commenter added that the proposed requirements (e.g., storage vessels, delayed coking units) would not affect maximum individual risk and would only result in an estimated 2 to 15 percent reduction in the conservatively estimated cancer incidence for the source category. The commenter claimed that such modest available reductions (2 to 15 percent) in theoretical upper-bound risk demonstrate that the existing standards are already providing an ample margin of safety.

The commenter further asserted that because risk was found to be acceptable, the agency must follow the requirements of section 112(d)(6) of the CAA when proposing actions to further increase the margin of public safety and thus must consider costs when issuing new controls of emissions. Commenters argued that proposed rule costs are estimated to be $20-40 billion. Due to these costs burdens, commenters recommended that EPA withdraw the proposed rule.

Commenters also stated in response to EPA's request for comment on whether to find the risks unacceptable, that there are flaws in the risk analysis based on actual and allowable emissions which the commenter believes if corrected would decrease the overall estimated risk.

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[76] http://seer.cancer.gov/statfacts/html/all.html

For these reasons, the commenter asserted that to be consistent with the finding of sufficient protection, EPA should retain the existing standards, as allowed by the FCAA.

Response 1: Regarding the comment that in light of the acceptability determination the proposed changes to the rule are not justified, we note that we also are required to ensure that the standards provide an ample margin of safety to protect public health. That analysis is separate from the acceptability analysis, and the determination of acceptability does not automatically lead us to conclude that the standards provide an ample margin of safety to protect public health.

In response to the comment on cost burden, as note elsewhere in this RTC, we are not finalizing the atmospheric PRD prohibition. While some facilities will need to implement additional prevention measures on some atmospheric PRD, we estimate that the costs of the final work practice standards to be reasonable.

We address various comments regarding commenter identified potential flaws in the estimation of actual and allowable in the risk assessment in Sections 2.1.1 (comment/response 2 and 4), 2.1.2 (comment/response 1), and 2.1.3.

Comment 2: <u>EPA's proposed changes are not demonstrably beneficial or cost effective</u>: Commenters stated that despite significant emission reductions and financial investments made by refiners over the last two decades coupled with the fact that both the 2008 and current RTR risk met the acceptability criteria, the EPA has proposed regulations which impose significant costs. According to the commenter, EPA has done so without demonstrating that such regulations are cost effective or justified by the factors specified in section 112(d)(6) of the CAA. The commenter added that EPA took no further action in its 2008 rulemaking after determining risk was acceptable. Another commenter also stated that EPA's analysis shows that the public health benefits from this rule, under best case scenarios, would be quite small even when based on the conservative assumptions, extrapolations and conclusions which are unsupported by science, making the projected benefits of these rules illusory.

One commenter stated that the balance of this proposal is not based on risk reduction and thus must be justified on other grounds and must be achievable and cost effective. Even where a change is claimed to be driven by judicial decisions, the commenter asserted that EPA must follow the provisions of the CAA in implementing the Court decision, which has not been done in many cases. The commenter provided the example that extending emission limitations derived for normal operation to maintenance, startup, and shutdown (MSS) periods may be the easiest regulatory path, but that approach is not required and is sometimes not cost effective or even feasible; alternative standards must be developed and implemented in such cases.

The commenter stated that although EPA's analysis has overstated the risk associated with refinery emissions, it does not affect the agency's conclusion that risk levels are acceptable and that only additional controls on small storage tanks are justified as a means to increase the ample margin of safety**.** The commenter noted that EPA evaluated the reduction in risk associated with a number of additional potential controls on storage vessels, equipment leaks, gasoline and marine loading racks, cooling towers and heat exchangers, wastewater collection and treatment systems, FCCUs, flares, and other refinery emissions sources. With the exception of changing the applicability threshold to include controls on small storage vessels, no controls were identified that cost-effectively reduced the levels of risk and – even in the case of storage vessels – the cost-effectiveness was largely driven by EPA's questionable assumption of credits associated with VOC recovery, according to the commenter.

Response 2: We maintain that the proposed rule is targeting significant, scientifically identified deficiencies in the current MACT standards that must be corrected to ensure that health risks are acceptable and to provide an ample margin of safety. Since 2008, we have new data documenting poor flare performance and the magnitude of emissions from decoking operations which have led to significant revisions that we are now including that were not in the 2008 rule. Additionally, we are required to make several other revisions to ensure the refinery MACT standards are consistent with the *Sierra Club v. EPA* decisions; another development since the 2008 rulemaking.

We note that this rulemaking includes both a technology review and a risk review. We only included the storage vessel requirements as part of our risk review (similar to the conclusions in the 2008 rulemaking). Given the advances in technology and practices since the 2008 rulemaking, the additional revisions we are making in the refinery MACT standards are appropriate and consistent with the CAA requirements in section 112. We disagree that the proposed amendments are not justified. We made several revisions to address SSM exemptions. These revisions are not only justified, but required by the CAA as determined in the *Sierra Club v. EPA* decision. We also revised existing MACT requirements or set new MACT, under the authority of 112 (c)(2) and (3) as we determined that the original MACT were deficient in achieving expected emission reductions or missing. For example, the DCU decoking operations had significant HAP emissions and contributed significantly to the overall cancer incidence from refineries was effectively exempted from MACT requirements. Therefore, we developed MACT requirements for DCU decoking operations. Similarly, minimal flare monitoring requirements were included in Refinery MACT 1 and 2, leading to the operation of flares with poor control efficiencies. Therefore, we determined that significant revisions were needed in these requirements. Our technology review also identified numerous issues with the ongoing performance and monitoring requirements for some control systems. These requirements were based in part on the technology review conducted under the New Source Performance Standards which found that the existing monitoring requirements were insufficient to ensure compliance at all times. For these reasons, we enhanced the monitoring requirement for FCCU and in addition to the current 30 percent opacity compliance option for subpart J, we are adding a 20% opacity 3-hour average operating limit. Consequently, even though we are not promulgating these specific requirements under the authority of section 112(f)(2), we maintain that significant revisions to Refinery MACT 1 and 2 are "necessary" to ensure refinery owners and operators are complying with the MACT requirements at all times.

2.7 Stronger standards are needed because risks are unacceptable

Comment 1: EPA must find the current health risk unacceptable and set protective standards with an adequate margin of safety: Many commenters argued that EPA underestimated risks and that the true level of risk is unacceptable. One of these commenters argued that the residual risk assessment should have found the risk from refinery pollution "unacceptable" and that EPA's rule will not protect communities with the “adequate margin of safety” required by the CAA. The commenter stated that outdated and inadequate science cannot estimate true risk. EPA’s risk analysis has failed to adequately account for early life exposure, multipathway exposure, and cumulative impacts from multiple source exposure, according to the commenter. The commenter further noted that EPA has also understated risk by ignoring emissions during unplanned SSM events and by ignoring hazardous air pollutants for which no reference value is established. As a result, the commenter asserted that the 100-in-1 million MIR is an underestimation.

The commenter asserted that 0.6 excess cancer cases per year – or at least 1 extra cancer case every other year – is one additional cancer case is too many. It is plainly unacceptable that EPA proposes to allow at least 1 new cancer case every other year, and 5 new, additional cancer cases every decade, in communities that have refineries, because Congress enacted the 1990 CAA Amendments to prevent cancer from toxic air pollution, and to do so especially in communities overburdened by such pollution.[77] According to the commenter, when EPA recognizes that at least 7 million people are exposed to extra cancer risk from refineries, it should plainly find this inhalation-based cancer risk, alone, to be unacceptable under section 112(f)(2). Another commenter noted that EPA has determined that the risks from petroleum refinery emissions are “acceptable”, however the commenter expressed serious concerns with MACT-allowable emission cancer risks are up to 100-in-1 million. Another commenter (who supports steps to reduce the use of flaring, including banning flaring and monitoring and reporting of flaring emissions to the public) added that even with the proposed improvements, only 18 percent more people will be protected, leaving nearly four million people breathing air that gives them an unacceptable risk of cancer, which is far from the only health risk they will continue to face.

According to the commenter, in addition to the reasons EPA identified as why risk could be considered unacceptable (79 FR 36940), the EPA should also find the current health risks to be unacceptable for the following reasons, which have been included in more detail elsewhere in this chapter:

- Underestimation of the cancer risk from inhalation particularly from early exposure.
- Underestimation of the cancer risk from multipathway exposure.
- Need to recognize that the combination of cancer, high chronic non-cancer and acute risks, together, create unacceptable risk.
- Need to recognize that the cumulative impacts and multiple source exposure from various sources, including refineries.
- EPA did not evaluate facility-wide risk based on “allowable” emissions, which would likely cause the presumptive acceptability benchmark for cancer to be exceeded. In addition, the chronic non-cancer risk EPA found is 4 (4 times EPA’s TOSHI threshold of 1). [79 FR 36937]
- There is a high population exposed to refineries’ risk (at least 7 million), and resulting incidence of cancer risk (at least one case every 1.5 years). There are 83 million people living within 50 km (approx. 31 miles) of refineries, with an additional risk of catastrophic exposure.

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[77] S. Rep. No. 101-228, at 128-29, 1990 U.S.C.C.A.N. at 3513-14.

- It is unjust and inconsistent with the Act's health protection purpose to allow the high health risks caused by refineries to fall disproportionately on communities of color and lower income communities who are least equipped to deal with the resulting health effects.
- The rule likely does not address all emissions, particularly fugitive emissions.

Response 1: We believe we have adequately estimated risk from these source categories and that the risk is acceptable. As discussed in previous responses, there are many aspects of the risk assessment that commenters disagreed with, and we are providing references to the responses to these comments here:

- Early life exposure: Chapter 2.3.2, 2.3.6
- Multipathway exposure: Chapter 2.3.5
- Cumulative risks and impacts from multiple source exposure: Chapter 2.3.4, 2.3.6
- Use of allowable emissions: Chapter 2.1.2, 2.3.5
- Non-cancer risk: 2.3.2, 2.3.5, 2.3.6
- Environmental justice concerns: 2.4
- Concerns over the inclusion of emissions from SSM events: 2.3.4

Comment 2: Risk is unacceptable even when less than 100-in-1 million: Many commenters disputed the acceptability criteria of 100-in-1 million for risk and stated that it should be lower, particularly when there is uncertainty built into the EPA's risk assessment, the EPA lacks necessary information on certain pollutants, and these rules affect people of color and poor people disproportionately. Since 1990, however, EPA has used this criteria. The commenter asserted that the EPA based the criteria on an unusual study of people's perceptions of their own risk from 1988, known as the Survey of Societal Risk (July 1988), rather than science.[78] EPA looked at an odd collection of risks, according to the commenter, such as dangers from driving a car, and found that "the presumptive level established for MIR [maximum individual risk of cancer] of approximately 1-in-10,000 is within the range for individual risk in the survey, and provides health protection at a level lower than many other risks common "in the world in which we live." [54 FR 38044, 38046 (Sept. 14, 1989).]

The commenter noted that EPA has failed to revisit or update this number for the decades, even though scientists have made breakthroughs on early-life exposure and children's vulnerability; biomonitoring and other data on adult body burdens of chemicals; the vulnerability of overburdened communities, including socioeconomic disparities; and on ways to analyze and control the impacts of pollutants on human health. The commenter listed numerous landmark policies concerning health risks since 1990 to substantiate the importance of the issue.

The commenter asserted that it is time for EPA scientists and policymakers to revisit the outdated assumption EPA makes regarding what level of cancer risk triggers policy

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[78] Benzene Rule Docket No. OAQPS 79-3, Part I, Docket Item X-B-1, EPA Air Docket (cited at Nat'l Emission Standards for Hazardous Air Pollutants; Benzene Emissions from Maleic Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants, 53 FR 28,496, at 28,512-13 (July 28, 1988)).

interventions. EPA's own policy regarding carcinogens recognizes that they have no safe threshold of exposure, according to the commenter. EPA has appropriately recognized that cancer risks add up to increase lifetime risk. Importantly, the commenter stated that EPA's presumption regarding cancer risk ignores the experience of communities exposed to multiple sources and types of sources of pollution. The commenter noted that even if some level of risk might otherwise be acceptable, that cannot be assumed to be true for communities exposed to more than one source that is causing that level of health risk. EPA has a responsibility to address the science on cumulative impacts and risk, according to the commenter, and update its assumptions accordingly, to acknowledge that cancer risks below 100-in-1 million cannot be presumed safe.

The commenter also argued that EPA should also reform how it evaluates chronic and acute hazard indices, in which a risk number below 1 does not result in policy changes or standards. The commenter suggests that EPA should instead factor in uncertainties and vulnerability factors that adjust the "acceptable level of risk." The commenter notes that this is currently done under the FQPA when EPA uses factors to determine a Target MOE and risks below this level warrant increased scrutiny and changes to allowable exposures.[79]

Response 2: The approximately 100-in-1 million benchmark was established in the Benzene NESHAP (54 FR 38044, September 14, 1989), which Congress specifically referenced in CAA section 112(f)(2)(B) . While this presumptive level provides a benchmark for judging the acceptability of MIR, it is important to recognize that it does not constitute a rigid line for making that determination. The EPA considers the specific uncertainties of the emissions, health effects and risk information for the source category in question when deciding whether the risk posed by that source category is acceptable. In addition, the source category-specific decision of what constitutes an acceptable level of risk is a holistic one; that is, the EPA considers all potential health impacts -- chronic and acute, cancer and non-cancer, and multipathway -- along with their uncertainties, when determining whether the source category presents an unacceptable risk.

We also note in this response, that EPA has addressed comments specifically related to the use of OEHHA toxicity values, early life exposure (including prenatal), cumulative impacts and risks, and the use of uncertainty and vulnerability factors in chapters 2.3.2 and 2.3.4 of this RTC document.

Comment 3: <u>Other rule decisions support claim that refinery risks are unacceptable</u>: One commenter noted that in other rules, EPA has found or is proposing to find similar or lower levels of risk to be unacceptable. For example, the commenter noted that in Secondary Lead Smelting, EPA found that health risks were "unacceptable" based partly on high chronic non-cancer risk (due to fugitive lead emissions) and partly on: "[t]he fact that maximum individual cancer risks due to actual emissions are above 1-in-1 million also contributes to our

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[79] See, e.g., EPA, Sulfuryl Fluoride; Proposed Order Granting Objections to Tolerances and Denying Request for a Stay, Proposed Rule, 76 FR 3422, 3427 (Jan. 19, 2011) (explaining use of MOE).

determination of unacceptability."[80] The commenter asserted that for petroleum refineries the maximum individual cancer risk due to actual emissions is well above 1-in-1 million, is underestimated (as explained in these comments), and the risk number based on allowable emissions is 100-in-1 million. Thus, the commenter argued that it would be inconsistent with its risk acceptability determination in Secondary Lead Smelting not to find risk in this case similarly unacceptable.

The commenter stated that EPA has long recognized that a combination of cancer and non-cancer risks can show unacceptable health risks, as stated as its policy in the current rulemaking.[81] The commenter notes that, in its proposed rule for Ferroalloys, EPA found that allowable cancer risk is 100-in-1 million and that cancer risk based on reported "actual" emissions is lower; EPA also found significant chronic non-cancer risks from manganese and mercury. EPA stated, according to the commenter, that the fact that "risks from allowable emissions are at the upper end of the range of acceptability ... combined with" high non-cancer risk, lead EPA to conclude that the current risk from Ferroalloys sources is "unacceptable."[82] EPA similarly found significant non-cancer risks here, as well as cancer risk at the "upper end" of the range EPA considers acceptable - and thus, the commenter asserts, should similarly find the health risks from refineries to be "unacceptable." Specifically, the commenter noted that EPA has found a high acute risk (HQ of 5 based on "actual" emissions) and high chronic non-cancer risk (TOSHI of 1), as well as multipathway risks that did not screen out, in a refined analysis for a single refinery (which EPA recognizes is not representative of the highest multipathway risk for any exposed individual).[83].

As another example, the commenter stated that EPA found in regard to the Wool Fiberglass source category that, although EPA's assessment of "actual" emissions did not create risk above 100-in-1-million (as is true with refineries), under the potential cancer risk EPA evaluated: "8,100 people would be exposed to risks greater than 100-in-1-million, 460,000 people would be exposed to risks of greater than 10-in-1-million, and over 7 million people would be exposed to cancer risks of greater than 1-in-1-million."[84] The commenter noted that regarding petroleum refineries, there are millions of people exposed to cancer risks above 1-in-1 million, about 100,000 exposed above 10-in-1 million, and EPA has found that based on allowable emissions, there is exposure at 100-in-1 million, based on inhalation risk alone. By contrast with Wool Fiberglass, where EPA found no other relevant health risks above its threshold, with petroleum

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[80] Secondary Lead Smelting, Final Rule, 77 FR 556, 563 (Jan. 5, 2012) (EPA has since granted the reconsideration petition of environmental petitioners on the issue of how EPA underestimated health risks in the secondary lead smelting risk assessment, and reconsideration remains pending).

[81] 79 FR at 36,899 ("the level of the MIR [maximum individual lifetime cancer risk] is only one factor to be weighed in determining acceptability of risks ... the Agency may find, in a particular case, that a risk that includes MIR less than the presumptively acceptable level is unacceptable in the light of other health risk factors.") (quoting Benzene Rule).

[82] Ferroalloys, Supplemental Proposed Rule, 79 FR 60,238, 60,269-70 (Oct. 6, 2014).

[83] 79 FR at 36,934-38. Risk Assessment (-0225).

[84] Wool Fiberglass, Proposed Rule, 76 FR 72,770, 72,801 (Nov. 25, 2011).

refineries EPA has found significant acute, chronic non-cancer, and multipathway risks, and there are many more people exposed to refinery risks, on top of the cancer risks, which all provide additional reasons for EPA to find petroleum refinery risk “unacceptable.”

In general, the commenter argued that it would be out of step with EPA’s interpretation of section 112(f)(2), and with the policy reflected in other EPA risk determinations, and thus “arbitrary” and “capricious”, for EPA not to find that the refineries risk is similarly unacceptable. According to the commenter, EPA must provide equal protection for people near air toxics sources. Because people living near refineries are disproportionately people of color and lower income people, the commenter notes that disparate treatment by EPA would be especially problematic and raise discrimination concerns under all applicable requirements for equal treatment and equal protection. The commenter also noted that EPA should not ignore the reality that communities near refineries face daily, and instead should find that their health risks are currently “unacceptable,” and set residual risk standards for to reduce those risks.

Response 3: We generally draw no bright lines of acceptability regarding cancer or noncancer risks from source category HAP emissions, and acknowledge that it is always important to consider the specific uncertainties of the emissions and health effects information regarding the source category in question when deciding exactly what level of cancer and noncancer risk should be considered acceptable. In addition, the source category-specific decision of what constitutes an acceptable level of risk should be a holistic one; that is, it should simultaneously consider all potential health impacts -- chronic and acute, cancer and noncancer, and multipathway -- along with their uncertainties, when determining the acceptable level of source category risk. The Benzene NESHAP decision framework of 1989 acknowledged this; in today’s world, such flexibility is even more imperative, because new information relevant to the question of risk acceptability is being developed all the time, and the accuracy and uncertainty of each piece of information must be considered in a weight-of- evidence approach for each decision. This relevant body of information is growing fast (and will continue to grow even faster), necessitating a flexible weight-of-evidence approach that acknowledges both complexity and uncertainty in the simplest and most transparent way possible. While this challenge is formidable, it is nonetheless the goal of the EPA’s RTR decision-making, and it is the goal of the risk assessment to provide the information to support the decision-making process.

Comment 4: <u>Technology developments require stronger standards:</u> One commenter stated that for both equipment leaks and wastewater, EPA has found that “developments” have occurred in practices, processes, and control technologies within the meaning of CFR 112(d)(6), but has not proposed to strengthen the existing standards for these emission points at all. [79 FR 36915 (leaks), 36919 (wastewater), 36920 (wastewater and leaks)] The commenter stated that it would be “unlawful, arbitrary, and capricious” for EPA not to set stronger standards for these emissions under section 112(d)(2)-(3).

In addition, the commenter noted that EPA has recognized that these sources drive the health risk EPA found under section 112(f)(2). [79 FR 36934] Therefore, under section 112(f)(2), EPA must reduce all unacceptable risk (which it has underestimated and should find to be unacceptable here), according to the commenter, and set stronger standards to assure an “ample margin of safety to protect public health” from these sources. EPA’s purely cost-based reasons for not updating the equipment leak and wastewater standards are both inconsistent with the text and purpose of the Act, according to the commenter, and are irrational based on the record showing that methods to reduce emissions from these sources are available, are in use, and are not cost-prohibitive. Further, the commenter argued that EPA should not use a cost-per-ton test to assess the value of HAP reductions because, as the reference exposure values show, the pollutants emitted by these sources are harmful at levels well below 1 ton, and even at the level of micrograms. The commenter asserted that EPA has no valid basis not to acknowledge that it is indeed valuable to public health to reduce less than 1 ton of benzene and the other air toxics emitted by these sources.

Response 4: For the Petroleum Refineries NESHAP, we are revising emissions controls for coking units, and storage and loading processes concurrently under both the CAA section 112(d)(6) technology review and the CAA section 112(f)(2) risk review. As noted in the preamble to the proposed rule (79 FR 36879), in keeping with the Benzene NESHAP two-step process for developing residual risk standards, in the risk review the EPA first examines risk acceptability and then considers whether the existing standards provide for an “ample margin of safety.” The two-step process does not conclude with a decision of acceptability. In the second step, the EPA determines whether the emissions standards provide an ample margin of safety, considering all of the health risks and other health information considered in the acceptability determination, as well as other relevant factors. While we proposed that the risks from the petroleum refineries source category are acceptable, we also found that the cancer risk estimates for 5,000,000 individuals in the exposed population were above 1-in-1 million, with an MIR of up to 60-in-1 million, based on actual emissions. We then proceeded to the ample margin of safety analysis. For this source category, we estimated what the risks would be if all of the petroleum refinery facilities adopted control measures to limit emissions from coking units, and storage and loading processes. We estimated that after implementation of the proposed controls, about 1,000,000 fewer people will be exposed to cancer risks greater than 1-in-1 million. Finding that the revised requirements would reduce cancer risks and considering the associated costs, economic impacts, and technological feasibility among other information, we proposed to revise the standards for these emissions sources under CAA section 112(f). The commenter has identified no flaw in our reasons or analysis under either section 112(d)(6) or 112(f)(2) for adopting the revised requirements.

3.0 Refinery Flares Control Device Provisions

Comment 1: Some commenters expressed support for the proposed flare operating requirements but other commenters suggested that the EPA needs to do more. Suggestions included: establishing direct emission limitations (release quantities, number of events, or other "hard caps"); requiring specific technologies such as flare gas recovery systems; requiring back-up power generation; and requiring root-cause analysis and reporting for flaring events. One commenter suggested that the EPA needs to ban emissions from routine flaring and minimize their use in other circumstances to protect people from these emissions.

Response 1: Flares are being used as air pollution control devices (APCD) to meet the Refinery MACT 1 control requirement for affected emissions sources such as miscellaneous process vents (MPVs), gasoline loading operations, marine vessel loading operations and storage vessels. The flare itself is not an affected emissions source within Refinery MACT 1. As such, we disagree with the commenter that we should ban emissions from routine flaring in the MACT rule. The commenters do not recommend similar actions to minimize or eliminate the use of thermal oxidizers, carbon absorbers or other control devices that may be employed to control HAP emissions from the affected emission sources at the petroleum refinery. Eliminating the routine use of flares as an acceptable APCD would only increase the use of these other types of APCD (at potentially significant cost) without any net emissions reductions from the refinery (provided that the flare is meeting the required control efficiency). Therefore, the flare operating requirements we are finalizing in this action are focused on those requirements necessary to ensure that refineries that use flares as APCD meet the MACT standards at all times when controlling HAP emissions. In other words, the flare operating requirements are being finalized to ensure that flares operate with appropriately high destruction efficiencies at all times when controlling HAP emissions.

Comment 2: Commenters stated that there are other non-conventional types of flares, such as pressure-assisted flares, ground flares, and enclosed flares, and recommended that the EPA set separate (or case-by-case) limits for these "other" flare types.

Response 2: We note that the types of flares referred to by the commenter are in most instances covered under the proposed definition of flare that we are finalizing in this action: "*Flare* means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this rule, the definition of flare includes, but is not necessarily limited to, air-assisted flares, steam-assisted flares and non-assisted flares." We also note that if the combustion device has an enclosed combustion chamber that uses a controlled volume of ambient air, then the device is a thermal oxidizer or incinerator and you must verify the control device achieves 98% destruction efficiency or 20 ppmv following the requirements in 40 CFR 63.645.

With respect to setting separate (or case-by-case) limits, commenters provided either insufficient information (i.e., pressure-assisted flares) or no additional information (i.e., ground flares and enclosed flares) for the agency to consider for use in developing separate limits, and therefore, we are not establishing separate limits for these types of non-conventional flares at this time. We note however that to the extent a flare owner or operator considers the final rule requirements too restrictive, the final rule includes provisions in 40 CFR 63.670(r) for owners or operators to test their flares and develop alternative operating limits on a case-by-case basis.

Comment 3: Several commenters recommended that emergency or standby flares should have separate standards.

Response 3: The commenter does not provide, and we are not aware of, any basis for revising the flares standards to provide separate, different limits for emergency or standby flares. If a gas stream containing HAP is required to be controlled under the Refinery MACT standards, then that control device must meet the applicable control efficiency requirements, regardless of whether that control device is used every day or once per year. Therefore, we are not establishing separate standards specifically for emergency or standby flares.

Comment 4: Several commenters recommended that temporary flares (flares on-site for less than 12 months) should not be subject to the flare requirements in subpart CC, but should comply only with the General Provisions (GP) requirements in 40 CFR 63.11.

Response 4: The EPA disagrees with the commenters. Subpart CC applies to the identified emission sources located at refineries and thus these emissions sources have been covered by the MACT since it was first promulgated. As noted in the previous response, if a gas stream containing HAP is required to be controlled under the Refinery MACT standards, then that control device must meet the applicable control efficiency requirements. We have determined that the GP requirements in 40 CFR 63.11 are not sufficient to ensure that refinery flares achieve the applicable HAP emissions control requirements. The commenters provided no reason, and we see no basis, to exclude temporary flares from the flaring requirements of subpart CC in this action.

Comment 5: Three commenters suggested that 98 percent flare gas recovery should be considered in compliance with the flare provisions.

Response 5: While we encourage the use of flare gas recovery systems, we disagree that this requirement would be consistent with the flare requirements in the MACT and we do not believe we should revise the MACT pursuant to section 112(d)(6) or (f)(2) to provide for this option. First, 98 percent flare gas recovery is not equivalent to the 98 percent destruction efficiency that forms the basis for the MACT flaring provisions. This is because 98 percent of the gas that is diverted away from the flare to a recovery system is not 100 percent controlled. The recovered flare gas is used in process heaters and/or boilers which should achieve a 98 percent destruction efficiency.

We acknowledge that emissions from process heaters and boilers can be measured, so it is possible to “prove” that these combustion devices are achieving greater than 98 percent destruction efficiency. If, for example, 99 percent recovery of flare gas is achieved and 99 percent control efficiency of the recovered flare gas is achieved, then the overall control efficiency of the recovery and control system would be 98 percent. However, we also have concerns about how a refiner could demonstrate compliance with this provision, if it were provided. Continuous emissions monitoring system (CEMS) would be needed on all individual process heaters and boilers receiving the recovered gas. Additionally, one would need to continuously determine the percentage of flare gas that is being recovered. Process gases are routinely recovered at certain process units as the standard practice. Therefore, there would be a need to identify only that fraction of the fuel gas that is actually recovered at the flare (or from the flare header system) that is in addition to the traditional process gases that are recovered. Finally, if a big flaring event occurs that overwhelms the flare gas recovery system, it is quite possible, for that day, month, or year (which ever averaging time was provided) that the flare gas system would not meet the targeted 98 overall system control efficiency. Therefore, the refinery owner or operator would likely need to install the appropriate flare monitoring systems even if a flare gas recovery option were provided in order to demonstrate compliance during large malfunction events. As we could identify no reasonable way a facility could demonstrate continuous compliance with the flare provisions using flare gas recovery efficiencies, we have not provided the suggested compliance alternative in the final rule.

Comment 6: Several commenters requested that the EPA require continuous PFTIR monitoring of flares to ensure they are achieving the targeted 98 percent destruction efficiency.

Response 6: Based on our understanding of the PFTIR testing method and our review of the PFTIR test data, we determined that it is technically infeasible to apply this technology on a continuous basis. First, the monitor must be appropriately positioned so that it receives infrared light signals from the flare exhaust plume. Shifts in wind directions would require manual repositioning of the monitoring system and it would be impossible to differentiate short shifts in wind speed or direction that cause the monitor to lose key carbon dioxide (CO_2) signals (used to calculate combustion efficiency) from poor combustion performance. The instrument would also have significant interferences from rain, snow, and fog that would generally yield no useable data during these events. In addition to technical infeasibility, we also note that there is an inadequate supply of PFTIR monitoring systems as well as highly trained and specialized personnel to operate these systems for every flare in the refining industry and that the cost of a continuous PFTIR monitoring requirement would be cost prohibitive considering the equipment necessary to process the data and the personnel needed to interpret the results. Lastly, no standardized EPA or industrial method for operating a continuous PFTIR monitoring system for flares currently exists. For all these reasons, we find that the suggested continuous PFTIR monitoring requirement is infeasible at this time. Further, we find that the operating and monitoring requirements that we are finalizing for flares are adequate to ensure that flares achieve the targeted 98 percent control efficiency at all times so that additional monitoring requirements are not needed to ensure compliance with the final standards.

Comment 7: Some commenters agreed with and supported the EPA’s conclusion that wind does not affect flare performance while other commenters disagreed with this assertion.

Response 7: We have extremely limited data to suggest that wind adversely impacts the combustion efficiency of flares, let alone the combustion efficiency of industrial-sized refinery flares. Commenters submitted no new data to otherwise support the assertion that wind does indeed affect flare performance and as such, we are unconvinced that changing our position from the proposal that no flare operating parameter(s) are needed to minimize wind effects on flare performance is warranted.

Comment 8: Several commenters noted that 10 years must be provided to comply with the proposed requirements for flares and PRDs, stating that the time is needed to install new flares so that PRDs will not be vented to the atmosphere and also to comply with the visible emissions and velocity limits during SSM events.

Response 8: The statute provides a maximum compliance period of 2 years for standards promulgated pursuant to CAA section 112(f)(2) and 3 years for standards promulgated pursuant to CAA section 112(d). We note that the final rule does not include a prohibition on venting PRD to the atmosphere, but instead establishes work practice standards for PRD releases that are not vented to a control device, and it includes separate emissions limitations in the form of work practice standards that apply to flaring events that exceed the smokeless capacity of the flare.

Comment 9: One commenter expressed concern that the proposed rules do not require refineries to install refinery flare gas recovery systems. They stated that the technology can be implemented with relatively small capital investments, that it has short pay back periods, and that it appears to them that most refineries would profit by implementing a strategy of utilizing flare gas recovery.

Response 9: The cost-effectiveness of a flare gas recovery system is a very site-specific determination based on the current amount of gas being flared and the ability to offset natural gas purchases with the recovered flare gas. Many facilities have installed flare gas recovery systems because of the favorable economics for their particular site-specific conditions. However, it is incorrect to assume that flare gas recovery systems would always be cost-effective in every application because it was cost-effective for certain applications. In response to this and other comments, however, we are requiring flares to minimize flaring during SSM events and we specifically identify installation of a flare gas recovery system as a means to reduce flaring.

3.1 Halogenated vent stream

3.1.1 Prohibition of halogenated vent streams

Comment 1: Several commenters suggested that while the EPA proposed a new requirement to prohibit the flaring of halogenated vent streams greater than 0.45 kilograms (kg)/hour (hr) (1 lb/hr), that no justification or analysis was provided for this newly proposed requirement in the preamble or elsewhere, that no explanation of the legal authority was given, and that no costs or emissions impacts were presented to determine if such standards are even necessary and that this violates the EPA’s obligations under section 307(d)(3) of the CAA as well as the Administrative Procedure Act. In addition, commenters suggested these newly proposed requirements raise significant safety concerns because they would apply under all operating circumstances, including start-up, shutdown, process upset, and malfunction and recommended based on all of these facts that the EPA remove this requirement from the rule. Commenters suggested that if the EPA really believes that the flaring of halogenated vent streams is an issue that the EPA address it in the future either through a new proposal or during the next technology review. A few commenters suggested that the ban on flaring a halogenated vent stream containing more than 1 lb/hr of halogen will significantly impact HF alkylation units, the catalytic reforming units, and the isomerization units at refineries because these three types of process units contain and/or use process streams with halogenated compounds. One commenter further stated that refineries already have incentives to minimize halogen concentrations due to metallurgy and corrosion concerns and that there is already a high level of care refiners take when processing these streams (as is evident by their company's use of scrubbing systems to remove halogenated species). They also stated that due to the solubility of halogens in water, they believe halogenated species will drop out with the liquid in the flare knock-out drum and not be released as an emission to the flare.

Response 1: First, we note that no refinery included dioxin emissions in their inventories for any of the refinery flares, which would indicate that halogens are not being combusted in the flare, and only a few reported HCl emissions from a flare. We are not, however, finalizing the ban on halogenated vent streams at this time because we did not include sufficient justification or include cost estimates for this proposed provision and we did not include any monitoring requirements to ensure compliance with this ban on halogenated vent streams. Also, we find that more emissions data, control technology information and cost information are needed to establish whether additional standards for halogenated vents are needed. Therefore, we are not finalizing the proposed halogenated vent gas prohibition for flares in this final rule.

3.1.2 Definition of halogenated vent stream

Comment 1: One commenter recommended clarifications to the definition of "Halogenated vent stream" should the EPA decide to promulgate the requirements to not flare halogenated vent streams in 40 CFR 63.670(a).

Response 1: As noted above, we are not finalizing the requirements proposed for flaring halogenated vent gas streams.

Comment 2: One commenter suggested three different alternative compliance options to the requirements to not flare halogenated vent streams in 40 CFR 63.670(a) that the Agency could make should they decide to finalize the aforementioned requirements.

Response 2: As noted above, we are not finalizing the requirements proposed for flaring halogenated vent gas streams.

3.2 Pilot flame requirement

Comment 1: A few commenters suggested that although most flares within the industry have multiple pilots, that the EPA revise the flare flame monitoring language in both Refinery MACT 1 and Refinery MACT 2 to make clear that the proposed standards only require one flare pilot flame be lit since this is consistent with the wording in the current General Provisions requirements at 40 CFR 63.11(b)(5).

Response 1: We note that the requirement in 40 CFR 63.670(b) is to "…operate each flare with a pilot flame present at all times." That is, the requirement is to operate with "a" pilot flame, which we interpret to mean at least one pilot flame must be present. The language proposed to be included in 40 CFR 63.670(g) includes the optional plural form in the event that a refinery owner or operator elects to monitor for a flame at multiple pilot locations. This may be done to help demonstrate that "a" pilot flame is present at all times. If one pilot goes out and the other does not, monitoring both pilots allows that refinery to demonstrate continuous compliance. If the owner or operator elects to monitor only one of the pilots and that pilot goes out, the refinery owner or operator may not be able to demonstrate compliance with the standard. Therefore, we are finalizing 40 CFR 63.670(b) as proposed, with the exception of no longer requiring an automated device to the relight the pilot (see Section 3.2.1 for more details).

Comment 2: A few commenters suggested that the EPA should allow alternatives to continuous pilot flame presence and monitoring for different flare sizes and type of flare operations that may not be continuous like those controlling emissions from batch operations or truck and railcar loading operations. The commenters suggested that the EPA should allow these intermittent type of operations to operate with no pilots until the need is triggered to operate the flare, and only require pilot monitoring when flares are actually receiving streams requiring control. On the other hand, one commenter suggested a variety of additional requirements for the EPA to consider that would strengthen the requirements for flare pilot flames. These suggested recommendations included pointing to the self-imposed industry requirements per API-537 which specify multiple requirements for stable pilot flame operation and re-ignition, removing the regulatory language "when regulated material is routed to the flare" to ensure that the pilot must be continuously lit, and adding a requirement that flare pilots must have a reliable fuel source separate from the flare vent gas as some pilot designs have the potential to use a portion of the flare vent gas as a slip stream fuel source.

Response 2: The first set of commenters appear to misunderstand the proposed rule. The proposed pilot flame requirements "...apply at all times when regulated material is routed to the flare," [40 CFR 63.670(b)]. In response to other comments, we have added the following definition of regulated material: *Regulated material* means any stream associated with emission sources listed in §63.640(c) required to meet control requirements under this subpart as well as any stream for which this subpart or a cross-referencing subpart specifies that the requirements for flare control devices in §63.670 must be met. If no "regulated material" is being discharged through the flare, there is no requirement to operate a pilot flame. Thus, the proposed rule would allow flares to operate with no pilots if no regulated material is routed to a flare, which appears in part to be what the first set of commenters are requesting, however we note that refiners still have a general duty to minimize emissions as required in 40 CFR 63.642(n). Also, we understand that some flares that are used on a discrete basis continually vent purge gas to the flare to prevent oxygen ingress into the flares. If refinery fuel gas is used as the flare's purge gas, then it is likely that the flare will always be in regulated material service and the rule would require that these flares operate continually with a pilot flame present. If the flare is purged using natural gas or nitrogen, these gas streams are not regulated HAP streams and the requirements in 40 CFR 63.670(b) would not apply during those times that only these streams without "regulated material" are used in the flare. We are not removing this phrase "when regulated material is routed to the flare" from this requirement as requested by one commenter because the flare is not a separate affected emissions source within the Refinery MACT rules – it is an APCD. Section 112 of the CAA only authorizes us to set standards for the control of HAP; natural gas or nitrogen do not contain HAP and we do not have the authority under section 112 to regulate these vent gas streams when they are not mixed with a HAP-containing vent gas. We consider the requirement to have a pilot flame present at all times is sufficient to ensure flare vent gas is ignited as it exits the flare and we do not consider it necessary to provide additional specifications to refinery owners or operators on how to operate their pilot flame system. We are finalizing this requirement as proposed.

3.2.1 Automated relight systems

Comment 1: Several commenters suggested that the EPA remove the proposed requirement that flares be equipped with automatic pilot re-ignition systems. The commenters state that the EPA's assumption that nearly all refinery flares are already equipped with an automated device to re-ignite the pilot flame is incorrect and rather, most refinery flares are equipped with manual re-ignition systems. The commenters point to the fact that it is very uncommon for a flare to lose all of its pilots and/or all pilot monitors and if that happens, there is already adequate redundancy for operators to be quickly alerted so they can manually re-ignite the pilot. Commenters also stated that past experience has shown auto re-ignition systems to be unreliable, and that there is a potential significant cost burden to the industry of $1.5-2.0 billion ($3-4 million per flare) to require a system that would provide little to no improvement in compliance assurance compared to manual re-ignition systems. One commenter added that the EPA has not identified what CAA provision authorizes this change or included any cost or associated emission reduction in the rule record or the Paperwork Reduction Act (PRA) Information Request Supporting Statement to support the proposed revisions.

One commenter suggested that if the goal of the proposed automatic pilot re-ignition system was to remove the possible delay of manual interaction to relight the pilots that the following re-wording should be considered: "The pilot system must be equipped with an automated device to relight the pilot(s) ***without human interaction*** if extinguished."

Another commenter suggested that the fact that the EPA proposed a requirement for a flare pilot automatic re-ignition system demonstrates that a pilot flame system will not be able to operate continuously. The commenter suggested that the rule needs to allow for a time gap to for automatic or manual relighting of the pilot flame if it were to go out.

Response 1: Our intent for an automated re-light system was to ensure that the pilots were re-lit as soon as practical. We proposed this requirement under CAA section 112(d)(2) and (d)(3) along with the other flare requirements. We expected most refineries had automated re-light systems so we did not attribute any costs to the proposed requirement. As noted in the previous response, we consider the requirement to have a pilot flame present at all times is sufficient to ensure flare vent gas is ignited as it exits the flare and we do not consider it necessary to provide additional specifications to refinery owners or operators on how to operate their pilot flame system. Therefore, we are not requiring in the final rule that all flares be equipped with automatic re-ignition systems. We agree with the commenter that suggested that even with automatic re-ignition there will be at least some small gap when the pilot is not lit once it goes out and the commenter recommended that the rule should address this. We are clarifying in 40 CFR 63.670(b) that one minute in any 15 minute block where a pilot flame is not present (when regulated material is routed to the flare) is a deviation of the standard and that deviations in different 15 minute blocks from the same event are considered separate deviations (such that failure to relight the pilot flame prior to the next 15-minute block will be a separate deviation).

3.2.2 Pilot monitoring requirements

Comment 1: One commenter stated that while the proposed regulation language at section 63.670(b) requires pilot flame monitoring, it has no requirements to monitor the presence of a flare flame or other such requirements that would indicate flare combustion.

Response 1: There are numerous other provisions in 40 CFR 63.670 that place requirements on the flare vent gas to ensure that the gas discharged by the flare is flammable. These provisions in conjunction with the pilot flame requirement will ensure proper performance of the flare.

Comment 2: One commenter suggested that reporting each instance when a pilot flame has gone out is unnecessary because many flares are designed with more than one pilot and can maintain a flame and safely operate even during periods when one of the pilots is not lit. The commenter further suggested the absence of a pilot flame does not indicate the absence of a flare flame or whether destruction of gases being routed to the flare is occurring.

Two commenters suggested alternatives to the options proposed for pilot flame monitoring. The commenters claimed that the ultraviolet beam sensor and infrared sensor options in the current proposal are not capable of distinguishing between the main flare flame and the pilot flame. The commenters identified an ionization detector, an ultrasonic (sound) detector, or possibly a flame rod as options that could make such a distinction.

Response 2: The commenter is misreading the proposed regulatory requirement. The requirement is to have “a” (i.e., at least one) flare pilot flame present at all times when regulated material is sent to the flare and to report “each period when regulated material is routed to a flare and a pilot flame is not present.” Thus, this reporting requirement would not require reporting of each instance when a single pilot went out if multiple pilots are used and monitored, but only those instances that all of the pilots were not lit.

We agree that most pilot flame monitors would likely read compliant if a flare flame is present even if the flare pilot goes out. We do not consider this to be a very realistic condition considering flare and flare pilot designs. However, even if it were to occur, we note the objective of these requirements is to ensure that an ignition source is always present to ignite and adequately combust the flare vent gases discharged to the flare. Thus, we do not consider it necessary to finalize a requirement for use of a monitoring system that can always delineate between the flare flame and the pilot flame at this time.

Comment 3: One commenter suggested that the proposed requirements in 40 CFR 63.671(a) should clearly limit Table 13 applicability to only the instrument types specified in that table and not apply those requirements to remote sensing monitors such as infrared and ultraviolet (UV) pilot monitors as well as visible emissions video monitors. One commenter similarly suggested that the EPA keep the flare flame monitoring language in the existing regulations at 40 CFR 63.644(a)(2) and 40 CFR 63.11(b)(5) and not convert the flare pilot monitors to continuous parameter monitoring system (CPMS) due to challenges associated with flare and process shutdown, accessing an elevated flare tip safely, and lost production time due to additional requirements with respect to performing CPMS quality assurance/quality control (QA/QC).

Response 3: Table 13 only applies to those CPMS that are listed in Table 13. We agree with the commenters that flare pilot monitoring systems need not be subject to the performance and quality control/quality assurance requirements in Table 13. For example, it is not necessary to determine a precise measurement of temperature (when using a thermocouple) to detect the presence of a flame, so it is not critical to have a temperature monitor that is accurate to ±1 percent as would be required if Table 13 applied. We have revised 40 CFR 63.671(a)(1) to add the clause "Except for CPMS installed for pilot flame monitoring…" and to include the word "applicable" (i.e., "**Except for CPMS installed for pilot flame monitoring**, all monitoring equipment must meet the **applicable** minimum accuracy…") to help clarify that the requirements in Table 13 are applicable only to those systems included in Table 13 and that they are not applicable to flare pilot flame monitoring systems. We are also excluding flare pilot monitoring systems from the out-of-control period requirements in 40 CFR 63.671(c) as these are not applicable for CPMS that are not required to meet the accuracy requirements in Table 13.

3.3 Visible emissions and velocity requirements

3.3.1 Need for visible emission limit

Comment 1: One commenter suggested that when the EPA promulgated the visible emissions requirements in the General Provisions in part 63, it provided no explanation for the foundation of this requirement in its proposed or final preamble and that this error was repeated when the EPA incorporated those requirements in the Refinery MACT 1 standards. The commenter claimed that now that the EPA is re-codifying and changing portions of these requirements they must support the legal and technical foundation for the requirement. Specifically, the commenter suggested that the EPA must provide an explanation for why it believes that daily opacity monitoring will better ensure VOC/HAP compliance and why elevated opacity would signify that the flare is not being properly maintained and operated for VOC/HAP control efficiency. In addition, with regard to the newly proposed daily observation requirements, the commenter stated that EPA must explain how it is supported under either sections 112(d)(6) or section 112(d)(2) and (3) in light of the fact that a daily Method 22 observation of flares is not currently in use as an industry practice.

Several commenters suggested that a smoking flare does not imply reduced combustion efficiency, that there is a potential conflict for demonstrating compliance between operating a flare close to the incipient smoke point and operating with no visible emissions, and that $PM_{2.5}$ is not a regulated pollutant under section 112 of the CAA and regulating these emissions in Refinery MACT 1 is inconsistent with the General Provisions requirements. To support their claims, the commenters point to the 1994 RTC for the General Provisions rulemaking, in which the EPA promulgated the flare requirements in 40 CFR 63.11. The commenters noted that the

RTC discusses the frequency of the Method 22 observations. The commenter also noted that the TCEQ flare study, which analyzed flare soot, found it to be elemental carbon and not PM containing HAP. The commenter also referenced the TCEQ operator training discussing proper flare operation and the visible emissions observation point as being outside the flame envelope, which is something the EPA should clarify in the rule.

One commenter suggested that flares with flare gas recovery systems, flares that only receive purge gas or sweep gas (with a daily average molecular weight of less than 20 grams (g)/mole), and flares that only receive high hydrogen streams have a low likelihood of smoking and should not be required to perform the daily Method 22 observation and monitoring for visible emissions.

Two commenters suggested that performing daily visible emissions observations using EPA Method 22 is overly burdensome and an unnecessary for refiners. To support this argument, the commenters point to the fact that flare smoking events are rare and unscheduled, that many flares now are equipped with flare gas recovery systems that minimize flaring and make routine flaring of regulated material more intermittent in nature, and that additional personnel and costs will be incurred unnecessarily when video cameras are already available and used by operators. Commenters further stated that flare test data show that visible emissions do not suggest poor destruction efficiency by the flare.

One commenter suggested that flares are not designed to adequately combust benzene and other aromatic hydrocarbons, especially when smoking and that evidence of smoking is extensive and is a big problem.

Response 1: We disagree with the commenter that we did not provide an explanation of the visible emissions standard when it was first established for flares and we find no record of this requirement being challenged on this ground in the 1994 RTC. We included that visible emissions requirement in the General Provisions as a means to ensure that flares were operating with destruction efficiencies of 98 percent of higher. In addition, for the present rulemaking we also provided the basis for this requirement in Section IV.A.3.b of the preamble to the proposed rule. As discussed in the proposal preamble, smoking flares indicate reduced combustion efficiency. Furthermore, as discussed in other comment responses, this requirement is part of a suite of flare requirements that ensure that the flare is well-operated as necessary to achieve the MACT requirements for affected emissions sources using flares as a control device.

We also think commenters clearly misunderstood how the TCEQ flare study PM measurements were taken and analyzed. The TCEQ made a concerted effort to obtain flare test data that were in compliance with the current General Provisions flaring requirements. Specifically, they state on page 49 of the final report that “A requirement of this study was that all data be obtained at flare operating points that comply with 40 CFR 60.18. A requirement of 40 CFR 60.18 is that flares be operated with no visible smoke emissions, except for periods not to exceed 5 minutes during any two consecutive hours.” This same requirement is also a requirement for refinery flares complying with Refinery MACT 1 and 2 standards at 40 CFR 63.11 and as such, the data collected from this study in no way supports the argument that the EPA should not limit smoking from flares because it was collected under this purview. However, even if the data in figure 12 of the “Appendix-Aerodyne Research Mobile Laboratory Particulate Measurements TCEQ 2010

Flare Study" were collected from flare flame smoke, it clearly shows that not just elemental carbon, but organics, which were not speciated and could contain HAP, are also emitted. Therefore, we conclude and continue to believe that it is appropriate to limit smoking of flares under the Refinery MACT standards.

In our review of the existing MACT requirements for flares, we found that there are very little or no on-going compliance requirements for the visible emissions limit. We agree that the 1994 RTC specifically stated that "This [no visible emissions] requirement was intended to provide a practical method for occasional observation. While this paragraph does not state the frequency that Method 22 must be applied, the EPA certainly did not intend for facilities to continuously, or even daily, monitor the flare to comply with the no visible emissions requirement." However, we now find that the lack of on-going monitoring requirements in the General Provisions to be a major stumbling block in our efforts to ensure refinery owners or operators are complying with the emission limitation "at all times." We disagree that performing a daily 5-minute EPA Method 22 observation is overly burdensome and we are finalizing these requirements as proposed. However, we also agree that daily EPA Method 22 monitoring for only 5 minutes during the day would not be as effective at ensuring continuous compliance with the visible emissions standard as "continuous" or "on-going periodic review" of video camera displays. Therefore, we are including in the final rule the use of video camera monitoring as an alternative to the proposed daily EPA Method 22 monitoring requirement.

3.3.2 Time allowed for visible emissions

Comment 1: Several commenters suggested that the proposed changes will force many flares to operate near the incipient smoke point and that in order to have enough time to fine-tune flare operations in the event the incipient smoke point is reached, the EPA should extend the not to exceed visible emissions requirements in 40 CFR 63.670(c) from a period of 5 minutes to 10 minutes during any 2 consecutive hours.

Several commenters suggested that allowing 5-minutes of smoking or visible emissions in a two-hour period from flares is unacceptable and that the EPA should prohibit visible emissions from flares altogether as flare smoking can release large volumes of HAP, toxic soot, and fine particulate matter emissions.

Response 1: Neither set of commenters provided data to support their position that a longer allowance period for visible emissions or that no allowance period should be provided. In the preamble to the proposed rule, we determined that a short allowance period was appropriate. It is unrealistic to suggest that flares can be effectively operated at high combustion efficiencies while never having a short period of visible smoke. Flare vent gas flow rates can change abruptly, and even with advanced steam flow controls, an abrupt increase in flare vent gas flow can cause a short period of smoking while steam system flow rates are adjusted. These adjustments should take no more than the 5-minutes, so we considered the historical 5-minute allowance to be reasonable and consistent with the best-performing flares.

We considered but rejected a visible emissions limit allowance of 10 minutes. Given the improved vent gas flow monitoring and steam system controls projected in our flare impact cost estimates, we determined that refinery owners and operators would be able to meet the flare operating limits without increased incidence of smoking.

Comment 2: Two commenters suggested that the EPA remove the requirement in 40 CFR 63.670(h) to extend the Method 22 observation period to 2 hours when visible emissions observations are made and occur at any point during the 5-minute period. The commenters suggested that there is no value added by this requirement, especially when other monitoring (e.g., video and/or operator observation, daily visible emissions (VE) check under state rules like TCEQ rule 111) occurs routinely, that some situations will arise where high flare venting occurs only for a short period of time, and that any instances of smoke emissions (greater than 5 minutes in 2 hours) are already reported as part of the semi-annual Title V deviation reports.

Response 2: We disagree with the commenter that there is no value to require an extended monitoring period of 2 hours in circumstances where visible emissions are observed and persist for at least one minute. The requirement is to operate with no visible emissions except for periods not to exceed 5 minutes during any 2 consecutive hours. Where visible emissions are observed for a period of at least one minute, it is important that the owner or operator tracks and documents whether there are a series of short 1 to 2 minute smoking events that occur sporadically over a period of 2 hours. The only possible means to demonstrate whether the source is in compliance with the no visible emissions requirement is to observe the flare flame over that 2 hour period. We note that in the final rule we have provided for the use of video camera surveillance monitoring as an alternative to EPA Method 22 monitoring.

3.3.3 Monitoring requirements for visible emissions

Comment 1: Several commenters suggested that the visible emissions monitoring requirements proposed at 40 CFR 63.670(h) not be finalized. Alternatively, they suggested that if these requirements are maintained, they should be revised and clarified, or that that the EPA allow a work practice type approach where use of a video camera or visual observation to monitor and manage visible emissions from flares in place of the EPA Method 22 monitoring requirements that were proposed. Commenters suggested that if the EPA does decide to maintain the visible emissions monitoring requirements that the EPA:

- Remove the initial visible emissions determination or clarify its intent of applying as just the first time that a flare becomes subject to the requirements at 40 CFR 63.670(h);
- Include only a simple requirement to maintain a record of the time and duration of any visible flare emissions and any greater than 5 minute occurrence in 2 hours be reported in the next periodic report;
- Clarify that two observers are not required given that rest periods are needed;
- Allow sources to stipulate that the 5 minute period has been exceeded in lieu of two or more hours of monitoring;
- Clarify that if a visible emission occurrence has been performed before the daily monitoring has been carried out that this counts for the daily observation;
- Allow a second tier of monitoring via Method 9 using a trained observer as follow-up to Method 22 observations where some level of visible emissions are noted;

- Adopt a similar approach to visible emissions as those in the TCEQ rule 30 TAC Chapter 111, Subchapter A- Visible Emissions and Particulate Matter, Division 1: Visible Emissions Rule section 111.111; and
- Allow some relief when weather inhibits observation.

Response 1: We are retaining the proposed EPA Method 22 observations but we have included an alternative to use video surveillance cameras provided that the cameras are installed at an appropriate vantage point where the camera would reasonably be expected to continuously record (at least one frame every 15 seconds) as well as output to a control room or other continuously manned location the video images of the flare and smoke generated from the flare. We confirm that the "initial visible emissions demonstration" is only for newly-affected flares and that the "subsequent visible emissions observations" pertains to all subsequent daily evaluations. We agree with the commenter that, if the 5-minute observation is extended to 2 hours and the observer has already observed 5 minutes of visible emissions, the observation period is complete and we note that this is already specified in Section 11.4.2 of Method 22. We also are clarifying that a single observer may be used to perform the 2 hour observation and that the observer is to observe the rest breaks required in Section 11.4.3 of Method 22 and must not include those rest breaks in the 2 hour observation period (as specified in Section 11.4.1 of Method 22).

The commenters appear to suggest that clarification is needed that, if a required 5-minute observation is needed prior to the "daily 5 minute observation" then the daily 5-minute observation is not needed. The basic requirement is that the visible emissions test must be conducted at least once per day using an observation period of 5 minutes. Any 5-minute observation period satisfies this requirement. We do not distinguish this as a "daily observation" separate from the requirement to monitor for 5 minutes if visible emissions are observed except to note that, even if you have satisfied your "daily observation" requirement, additional 5-minute observations are required when visible emissions are observed. Refinery owners and/or operators are required to record all periods of observed visible emissions and must report all 2-hour periods where the visible emissions were observed for more than 5 minutes in a given 2-hour period. Therefore, while any 5-minute observation of visible emissions satisfies the "daily observation" requirements, any new instance of visible emissions will require a new observation period, even if there was an exceedance period earlier in that day.

It is unclear why the commenter requests to perform Method 9 monitoring "as follow up to Method 22." Observer certification is more stringent for Method 9, and quantification of the opacity is not required. We consider the use of video surveillance as a more reasonable and more applicable alternative to direct Method 22 monitoring, and we have provided this as an alternative in the final rule, which should also address weather-related observation issues. We find that the proposed requirements are similar to those specified in TCEQ Title 30 Rule 111.111 except that they allow Method 9 and they do not require readings during process upsets. We consider that we have adopted an approach similar to that used in the TCEQ rule but we disagree with the provisions to exclude periods of upset from the visible emissions requirement.

Comment 2: A few commenters suggested that in order to encourage flare operation as close to the incipient smoke point a possible that the EPA should make changes and clarifications to the definition of visible emissions as it relates to the Method 22 procedure. Specifically, the commenters suggested that the language be revised to read: "Smoke emissions means visible emissions persisting beyond one flame length from the visible flame tip. Smoke occurring within the visible flame is not considered a smoke emission."

Response 2: We agree that black smoke within the flame envelope should not be considered visible emissions, but we note that EPA Method 22 already clarifies that "*Smoke emissions* means a pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission." Flame lengths can vary widely depending on the velocity of the release, and one flame length can be too far from the flame for the visible emissions observation. While we recognize that identifying the exact location where the flame ends is somewhat subjective, the commenters provided no data to support that EPA Method 22 needs to be amended. Therefore, we are not amending EPA Method 22 directly or as it applies to flares subject to the Refinery MACT 1standards.

Comment 3: Several commenters suggested that the additional burden to require refiners to have a visible emissions evaluator available for 2-hour daily checks and during any smoking incident is not reflected in the record or the Information Collection Supporting Statement. Commenters also stated that plant personnel's primary task should be to focus on alleviating the issues causing visible emissions at the flare rather than just performing a visual observation. Additionally, commenters suggested that the EPA clarify that personnel that are conducting Method 22 observations need not be certified as some situations could arise where flaring ceases before a certified individual is available to perform the visual observation.

Response 3: The daily check only requires 5-minute observations and these observations were included in the ICR burden estimate. EPA Method 22 does not require the same certification procedures as EPA Method 9, but rather, only requires that an observer be knowledgeable with procedures for determining the presence of visible emissions. The commenter did not provide any reason why it would be appropriate to waive this requirement and we believe it is important that an observer understand how to perform this type of monitoring. We clarify in this response that all that is required for personnel that will be expected to conduct the visible emissions observations is that they have read Method 22 and understand the basic requirements for visible "smoke emissions" monitoring for a flare. As noted elsewhere in this document, we are also including an option for refiners to use a video surveillance camera to conduct the visible emissions monitoring, which will eliminate the need to have a separate Method 22 observer. Observation via the video camera feed can be conducted readily throughout the day and will allow the operators of the flare to watch for visible emissions at the same time they are adjusting the flare operations.

Comment 4: One commenter supported the proposed visible emissions observation requirements while another commenter wanted the Agency to provide a webcam feature for citizens living near refineries to use and actually monitor refinery flares in real time. Another commenter wanted more information about flaring and air permits for the ExxonMobil Chalmette refinery, wanted the EPA to provide additional clarity on what was meant by "visible emissions" since it can be subjective, and wanted the EPA to provide state agencies with training regarding the no visible emissions requirement.

Response 4: While we are allowing an option for refinery owners and operators to use video surveillance cameras for visible emissions monitoring, we are not requiring them to provide public access to the video feed. Refiners must keep records of either their Method 22 observations or the continuous surveillance video records, but in general we would not require additional reporting for one option over what would be required for refiners opting to comply with the Method 22 observations. Regarding one commenter's request for more information about flaring and air permits for a specific refinery, we note that request is beyond the scope of this rulemaking. Information relating to permitting for individual facilities should be directed to the delegated air agency, e.g. the Louisiana Department of Environmental Quality in the case of ExxonMobil's Chalmette refinery.

We disagree that additional clarity is needed for the term "visible emissions" and that the EPA needs to provide state agencies with training regarding this requirement as no revisions to EPA Method 22 are being made in this action. The term "visible emissions" is the same as smoke emissions as defined in EPA Method 22: "*Smoke emissions* means a pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission." The EPA Method 22 is available online at: http://www.epa.gov/ttn/emc/promgate/m-22.pdf. Persons interested in understanding the method should read the method and the references cited in the method if more information is needed. Questions on EPA methods may also be directed to the Emission Measurement Center. A contact list is available online at: http://www.epa.gov/ttn/emc/staffdir.html.

3.3.4 Need for flare tip velocity requirement

Comment 1: Several commenters suggested that the EPA remove the flare tip velocity requirements from the rule altogether. To support this request, commenters suggested that flares operating at low velocities will achieve a high level of combustion efficiency due to the new flare combustion zone requirements and that at high exit velocities any lit flame which has sufficient heat content to support combustion will achieve the same result. Also, they suggested that if the maximum velocity was limited to only 400 feet (ft)/second (s) that new flare capacity would be needed which would increase flare purge gas rates as well as greenhouse gas emissions. One commenter suggested that it may be difficult for the EPA to remove the numerical requirements that have become conventionalized over time and as an alternative recommended that a new equation representing required heat content as a function of velocity be developed on a combustion zone heating value basis that has maximum of 600 British thermal units (Btu)/ standard cubic feet (SCF) at the high flare tip velocity end of 400 ft/s or greater.

Response 1: We disagree that we should abandon the flare tip velocity requirements. At high velocities, flare flame lift-off can occur leading to reduced combustion efficiencies and potentially complete loss of flame. Additionally, the flare tip velocity limits ensure that refiners operate their flares within a stable operating regime. The commenters provide no data to suggest that high flare combustion efficiencies are achievable for traditional, elevated flare tips at velocities over 400 ft/s as well as provide no data to suggest what the stable flare operating envelope would look like for elevated refinery flares operating above 400 ft/s. We do not expect that flare velocities will be over 400 ft/s under normal flaring events so we disagree that this requirement will cause refineries to have to build new flare capacity. However, as detailed later in this response to comment document, we are also implementing a work practice standard for these significant events to minimize their occurrence while also preventing the need to build new flares in efforts to prevent exceedances of the 400 ft/s flare velocity limits.

Comment 2: A few commenters suggested that the EPA revise the proposed standards for flare tip velocity to address pressure-assisted (or multi-stage ground) flares because they are designed to operate above the 400 ft/s regulatory threshold and that other new requirements related to visible emissions and SSM proposed in this rule will potentially drive facilities to consider this technology going forward. Other commenters suggested that the EPA remove the flare tip velocity equations for certain flare designs and operations altogether, particularly pressure-assisted flares and non-assisted flares. As an alternative, one commenter suggested that the EPA provide the ability for facilities to set site-specific flare tip velocity evaluations when the equations proposed in 40 CFR 63.670(d) are not appropriate.

Response 2: We do recognize that pressure-assisted flares have specially-designed flare tips capable of achieving high combustion efficiencies at high flare tip velocities and are in the process of reviewing alternative operating parameters for such installations on a site specific basis. We also note that we already proposed methods to allow refinery owners or operators to develop alternative operating parameters or limits, including, but not limited to, flare tip velocity limits.

3.3.5 Velocity limit and calculation method

Comment 1: Several commenters suggested that the EPA should reassess the flare tip velocity requirements for flares combusting low net heating value gases, particularly hydrogen, because the current requirements in the General Provisions provide a different flare tip velocity equation for flares that have a diameter of 3 inches or greater, are non-assisted, and have a hydrogen content of 8.0 percent (by volume) at 40 CFR 63.11(b)(6)(i)(A) and that flares combusting lots of hydrogen will not be able to achieve a sufficient net heating value to comply with any flare tip velocity limit other than 60 ft/s even though hydrogen flame stability at high tip velocities is well established.

Response 1: As described in Section 3.5.2 of this document, we are providing an allowance to use an effective net heating value of hydrogen of 1,212 Btu/scf. With this provision, we consider that the flare velocity equations will work effectively for flares that have high hydrogen content.

Comment 2: Several commenters suggested that the EPA revise the averaging time for demonstrating compliance with the flare tip exit velocity provisions from a 15-minute block average period to either a 1-hour or 3-hr block average and that the EPA revise the volumetric flow rate calculation requirements to be at standard conditions (pressure of 14.696 pounds per square inch absolute (psia) and temperature of 68 degrees Fahrenheit (°F)) and not actual conditions. To support these suggestions, commenters pointed out that the Texas highly reactive volatile organic compounds (HRVOC) Vent Gas Control rule under 30 TAC 115, Subchapter H, Division 1 [section 115.726(d)(4), 115.725(d)(6)], which is considered to be among the most stringent set of monitoring provisions for flares in the US, utilizes a 1-hr block average monitoring requirement, that facilities should not incur a violation when flare tip velocity requirements are exceeded because flares can handle highly variable and intermittent waste gas streams and use of flares in these situations is a proper emission control technique, and that the current exit velocity flare requirements in the General Provisions use standard conditions and not actual conditions.

Response 2: We disagree with the commenters' suggestion that the flare tip velocity should be evaluated on a 1-hour or 3-hour average. The primary purpose of the maximum velocity requirements is to ensure that flares are operated within a stable operating regime that prevents "flame lift off" or complete extinction of the flame if flare vent gas is released too fast. Even a small period of time of flame lift-off or extinction can make it impossible for a flare to achieve a 98 percent destruction efficiency over a 3-hour period (the typical testing period for other control devices used to control Refinery MACT organic HAP emissions). As the commenters noted, flares often receive highly variable and intermittent waste gas streams and using a 1-hour or 3-hour average can easily mask short term events when large quantities of gas may be expelled from a flare. For example, if a flare that receives a vent gas stream with a net heating value of 600 Btu/scf the V_{max} calculation would yield a maximum permitted velocity of 135 ft/s. If the event lasted approximately 30 minutes releasing vent gas at a velocities of 200 ft/s during two 15-minute periods but the flow rate was under 20 ft/s during the previous and subsequent two 15-minute periods, the average velocity would be 110 ft/s across the time period. However, during periods of the highest flow, it is likely that the combustion efficiency was reduced because the flame would be expected to have operated in an unstable regime and could potentially be completely extinguished. Due to potential flame stability issues at high flows (and the sharp reduction in combustion efficiencies that result from unstable flare flames), we find it critical that the flare tip velocity (as well as the other operating limits) are determined and adjusted as quickly as possible, which we determined to be based on the 15-minute block periods (due to time needed for compositional analysis determinations when using a gas chromatograph).

With respect to the comments stating that the flare tip velocity should be determined based on standard conditions, in our initial review of the historical 1985 flare efficiency report, we noted that the exit velocities were reported as "Actual Exit Velocity (ft/s)." There was a footnote indicating that the calculation was based on the open areas of the flare, but no other indication of how the flow volume was determined. Based on the table headings, we interpreted this to mean the reported velocities were determined based on the actual exit velocities (i.e., actual volumetric flow divided by the open area). We do note that 40 CFR 63.11(b)(7)(i) includes the following instructions: "The actual exit velocity of a flare shall be determined by dividing by the volumetric flow rate of gas being combusted (***in units of emission standard temperature and pressure***), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR part 60 of this chapter, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip" (emphasis added), lending credence to the commenter's suggestion. We reviewed the 1985 report again and found it very difficult to determine the actual basis of the "Actual Exit Velocity" calculation. Appendix D provides some detail regarding the orifice meter flow rate measurements. After our review of this equation, and understanding that orifice meters generally correlate to a mass flow rate, we agree that the volumetric flow rate was determined using a fixed molar volume correction factor (i.e., “standard conditions”) although it is impossible to tell from the report what conditions were used as “standard conditions.” In any event, based on our further examination, we agree with the commenter that for flare tip velocity should be determined based on the volumetric flow at standard conditions, consistent the procedures in 40 CFR 63.11(b)(7)(i), and we have revised the rule accordingly.

Comment 3: Several commenters suggested that flares that would be demonstrating compliance with the combustion efficiency parameter of combustion zone combustibles concentration (C_{cz}) using a total hydrocarbon (THC) analyzer would be constrained to a maximum flare tip velocity of 60 ft/s and that this would effectively eliminate the use of using a THC analyzer as a viable monitoring option for demonstrating compliance with the flare tip velocity requirements since you need to know the net heating value of the vent gas (NHV_{vg}). One commenter suggested that the EPA should add flexibility to the rule to allow for the use of process knowledge or engineering calculations to determine the NHV_{vg} for flare tip velocity compliance demonstrations when there is no continuous on-line monitor or monitor capable of determining NHV_{vg}.

Response 3: First, we are not finalizing operating limits related to C_{cz} or combustion zone lower flammability limit (LFL_{cz}). These operating limits were included primarily to provide more appropriate limit for flares with high hydrogen content. We have determined that these alternatives are no longer necessary given the adjusted net heating value for hydrogen of 1,212 Btu/scf included in the final rule. We agree with the commenter that facilities that elected to use the proposed THC monitoring option would have had to comply with the 60 ft/s flare tip velocity limit or they would have had to install a calorimeter to determine the net heating value of the vent gas. As such, the proposed THC monitoring option had limited utility and we have removed this monitoring option from the final rule.

Comment 4: One commenter suggested that the EPA clarify the language at 40 CFR 63.670(k)(1) by adding the word “exit” after cross sectional area of the flare tip.

Response 4: We are unclear how adding the word “exit” to the flare tip discussion further clarifies the discussion. Based on our review of the 1985 flare study, we understand that the proposed approach (to reduce the flow area based on obstructions in the flare tip) is consistent with the approach used in determining the “actual exit velocity” reported in the 1985 flare study. We also note that we have received comments from refinery owners or operators suggesting that, if these obstructions end before the flare tip “exit” (even if only by ¼ inch), than the flare tip “exit” should not be reduced by these obstructions. We disagree because this would not be consistent with the treatment of the data used to determine V_{max}. We specifically include in 40 CFR 63.670(k)(1) the obstructions in the flare tip that must be considered in determining the unobstructed cross-sectional area. We find that the description provided clearly reflects our intent and that including the word “exit” will actually lead to inappropriate determinations of the unobstructed cross-sectional area.

3.4 Flare SSM Issues

3.4.1 VE and velocity exclusions during SSM events

Comment 1: A few commenters suggested that the flare tip velocity and visible emissions limitations proposed by the EPA have not been achieved and are not achievable during periods of malfunction or emergencies, even by the best performing 12 percent of sources and that the EPA is significantly misapplying the D.C. Circuit Court ruling in *Sierra Club v. EPA*, 551F.3d1019 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (2010). Because of this, the commenters suggested that the EPA is required under section 112 to demonstrate that compliance with proposed flare standards is compliant with the statute for all operating conditions and that the EPA must either establish a numeric emission standard in accordance with section 112(d)(2)-(3) or, if that is not feasible, establish a work practice standard under section 112(h) that is achievable under these operating conditions.

Response 1: For the reasons provided in the preamble to the final rule, we are establishing work practice standards that would apply when a flare is operating above its smokeless capacity.

Comment 2: A few commenters suggested that flare tip velocities in excess of 400 ft/sec and/or the presence of smoke (visible emissions) do not indicate a reduced combustion efficiency from flares. The commenters suggested that available data demonstrate that HAP and VOC destruction efficiencies are maintained at emergency release velocities as long as a flame is present and the new combustion zone requirements are met; that the data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and result in higher combustion efficiency; that both literature searches and computational evaluations noted that smoke does not necessarily indicate a significantly inefficient combustion; that soot formation typically comprises less than 0.5 percent of unburned hydrocarbons; and that smoking flares can have a combustion efficiency of greater than 99 percent.

Another commenter suggested that when flares are releasing black smoke, it is an indicator of incomplete combustion, and based on their conversation with Houston city staff and at least one flare supplier, operating a flare in this smoking regime could lead to destruction efficiencies as low as 50 to 70 percent. The commenter also suggested that flares operating in this regime burn heavier aromatics less efficiently, which poses a greater potential for adverse health impacts on surrounding communities.

Response 2: The commenters do not provide any verifiable data to support their conclusion that gases discharged from a flare in excess of 400 ft/s (270 miles per hour (mph)) will remain in the combustion zone for sufficient time to ensure high combustion efficiencies or that these velocities will not lead to flame instability for conventional elevated flares. Even if the high velocity does not cause flame instability, there are no data to support claims for traditional elevated flare tips that “if a flame is present, combustion efficiencies are high.” While we agree that it may be possible to achieve high combustion efficiency when small quantities of smoke are produced for short time periods (hence the allowance to have 5 minutes of visible emissions in a two hour period), we agree with the commenter that suggests destruction efficiencies can become greatly reduced during periods of high velocities when large quantities of black soot are produced, as seen during “hydraulic load” events. We do not have direct emissions test data from large industrial flares during such an event, but based on the flame stability studies performed in the 1980s, we conclude that flame stability issues that produce significantly lower flare combustion efficiencies are likely to occur at flare tip velocities exceeding the limits provided in the rule and/or when significant black smoke is produced. Therefore, we are retaining the proposed limits on flare tip velocities and visible emissions. However, as noted previously, we are providing a work practice standard that apply specifically when the volumetric flow rate exceeds that smokeless capacity of the flare. Below the smokeless capacity of the flare, exceedances of the visible emission limits or flare tip velocity limits are a deviation of the standard. Above the smokeless capacity of the flare, exceedances of the visible emission limits or flare tip velocity limits triggers the work practice standard (i.e., root cause analyses and corrective actions with hard limits on these events that can occur in a 3-year period) as a means to reduce the frequency and magnitude of these events.

3.4.2 Other flare SSM issues

Comment 1: One commenter suggested that the loss of exemptions for periods of startup, shutdown, and upset conditions should drive refiners to make improvements in equipment integrity and operability, lead to better maintenance programs, and reduce breakdown conditions to diminish upset flaring.

Response 1: We agree that emissions limits that apply at all times encourage sources to maintain equipment and improve procedures to ensure proper operation.

Comment 2: One commenter suggested that the use of flares is a backdoor malfunction exemption that EPA must prohibit. The commenter claimed that the CAA requires that emissions standards apply at all times and prohibits exemptions for malfunction. The commenter claimed that the EPA’s proposal to allow facilities to route refinery fuel gas and miscellaneous process vent gas to flares caused by malfunctions would violate these requirements; that some gas routed to flares from process upsets comes from the FCCU and since the FCCU is subject to an independent limit on organic HAP that this illegally circumvents the applicable requirements; and that when refinery fuel gas that is normally burned in heaters and boilers is routed to a flare that the control efficiency decreases from a 99.9 percent control to 98 percent control efficiency.

Response 2: We disagree that the use of flares is a “backdoor” malfunction exemption. As the commenter recognizes, flares are a means of controlling emissions and, at the time the EPA promulgated Refinery MACT 1, the EPA determined that use of a flare meeting certain requirements in the General Provisions at 40 CFR 63.11 was an equivalent option to achieving a 98 percent control efficiency, the MACT floor level of control. We also note that the use of flares is specifically provided as an acceptable control device to comply with the organic HAP limits for FCCU in Refinery MACT 2. It is irrelevant whether the flare is receiving these organic HAP streams as a primary (routine) control device or as a back-up control system to other controls. We consider that flares operated in accordance with the requirements in the final rule will achieve the necessary MACT floor level of control and are acceptable control devices.

Therefore, we are not circumventing the MACT control requirements by allowing gases produced as a result of an upset or malfunction to be discharged to the flare.

With respect to heaters and boilers, we do not agree that all heaters and boilers achieve 99.9 percent control efficiency at all times or that the long-term average control efficiency for flares is only 98 percent. Combustion efficiencies in heaters and boilers are dependent on a variety of factors (fuel quality, air feed rates, burner design, etc.) and we have historically determined that these combustion controls achieve 98 percent control (or 20 ppmv total organic carbon). As with flares, the combustion efficiency may vary with time and the 98 percent control level was established as the minimum acceptable control efficiency over the performance test period (3-hour average). The flare requirements we are finalizing are designed to ensure flares meet this minimum combustion efficiency for any 3-hour average period, consistent with the MACT control requirements. It is clear from the flare performance test data that flares can achieve 99.9+ percent controls at certain times and we estimated that the long-term nationwide average control efficiency achieved by flares meeting the final flare requirements will be well-over 99 percent, which is equivalent to the combustion performance of process heaters and boilers.

3.5 Combustion zone operating limits (general, non-H2-olefin)

Comment 1: One commenter supported the EPA’s proposal on flares but suggested that additional improvements are required under sections 112(d) and (f) of the CAA. Specifically, the commenter suggested that the EPA: (1) require flares to achieve 98 percent control efficiency, (2) limit routine flaring (pursuant to sections 112(d)(2),(3) and (6)), and (3) require continuous monitoring of the flare gas in order to assure continuous compliance with all applicable limits.

Response 1: As discussed in the preamble and elsewhere in this section, we established the flare operating requirements and monitoring provisions in order to ensure flares are achieving the targeted 98 percent or higher destruction efficiency.

Regarding the request that the EPA limit “routine flaring,” we note that where Refinery MACT 1 and 2 allow the use of flares as a control option, they don’t specify this control device must be used to demonstrate compliance with the applicable MACT standards. In fact, refinery owners or operators can elect to use non-flare control devices (e.g., thermal oxidizers or other control systems) to demonstrate compliance with these same MACT standards and that these other non-flare control devices also have no “hard caps” or limits on their routine use. Therefore, we do not consider it appropriate under the MACT requirements to limit routine flaring to control Refinery MACT regulated gas streams.

Finally, as to the comment regarding continuous monitoring, the final rule generally requires continuous monitoring of flare gas in order to ensure continuous compliance with the applicable limits. We note that, as proposed, flare owners or operators may elect to use once every 8-hours grab samples for compositional analysis. We expect this alternative will only be used by “emergency only” flares that very seldom receive flare waste gas and owners or operators of these flares must still install continuous monitoring systems for determining flare vent gas flow rates. We also included a provision for flare owners or operators that have a consistent composition of flare vent gas (such as for gasoline loading racks) to determine, through an initial sampling program, a fixed net heating value of the flare vent gas to be used in the calculations. See the preamble to the final rule and Section 3.0 of this response to comment document for further discussion on this alternative. We determined that these alternatives are appropriate for these situations and will provide a means by which refinery owners or operators can demonstrate continuous compliance with the final operating limits for each 15-minute block average period.

Comment 2: One commenter suggested that the EPA should provide flexibility in monitoring of flow rates and composition for infrequently used flares and instead require that the flares be operated by trained and certified personnel when they need to be used.

Response 2: The operating limits apply to all flares that manage Refinery MACT regulated gas streams. We proposed alternative monitoring methods for flares, some of which were specifically targeted for flares that were not routinely used, such as the use of pressure monitoring systems and engineering calculations to determine flow rates and the use of grab samples to determine gas composition. We have finalized these monitoring alternatives and have also added an alternative for flares with a consistent composition of flare vent gas (such as for gasoline loading racks) to determine, through an initial sampling program, a fixed net heating value of the flare vent gas to be used in the calculations. We have determined that these alternatives are appropriate for these situations and will provide a means by which refinery owners or operators can demonstrate continuous compliance with the final operating limits for each 15-minute block average period, while helping to reduce the burden related to installing and operating a continuous monitoring system for a flare that receives waste gas only a few times a year or only once every few years. However, we disagree that a simple requirement to use “trained flare operators” is sufficient to ensure that these flares are achieving 98 percent control efficiencies at all times. We note that refineries currently use “trained flare operators” and it is not unusual to find flares being over-assisted. Without the necessary information on flare vent gas properties, as would be collected via the monitoring requirements in the final rule, a “trained flare operator” simply does not have information required to properly operate the flare.

Comment 3: A few commenters suggested that the rule language should be flexible enough to permit the use of direct combustion efficiency measurement as a potential future compliance option and that the EPA should allow use of an Alternative Monitoring Plan (AMP) for flare control and monitoring.

Response 3: We note that the General Provisions at 40 CFR 63.8(f) provide a mechanism by which refinery owners or operators can apply for an AMP. Therefore, if a technology becomes available by which refinery owners or operators can directly monitor flare combustion efficiency, refinery owners or operators can request to use this alternative monitoring method. We also note that we included provisions in 40 CFR 63.670(r) to provide a mechanism by which refinery owners or operators can establish different operating limits, which may also include different monitoring requirements.

Comment 4: Several commenters suggested that poor destruction efficiency from flares is not a widespread problem and that overly stringent combustion zone metrics could lead to unnecessary emissions of criteria air pollutants and greenhouse gas (GHG) from natural gas supplementation beyond what is necessary. The commenters also stated that the EPA needs to account for situations of poorly mixed steam in the combustion zone and that steam flow rate measurements could actually be lower at the flare tip than where they are being measured due to heat losses.

Response 4: We disagree that poor destruction efficiency from flares is not a widespread issue. Many companies that use flares to control emissions have become more cognizant of the fact that flares can be over-assisted and not achieve the intended destruction efficiencies. However, not all companies are required to continuously monitor the combustion zone characteristics of the flare and excessive quantities of steam or air can still be introduced in an effort to minimize smoking events or limit the visible flame from the flare. Additionally, and as discussed further in the preamble, we project that the flare operational and monitoring requirements being finalized have the potential to actually reduce excess emissions of both criteria air pollutants (i.e., VOC) and GHG.

Regarding the concerns about the introduction and monitoring of steam into the combustion zone, refinery owners or operators should place steam flow monitors at a location that is representative and also ensure they are efficiently operating flares in a manner where situations of poorly mixed steam in the combustion zone are minimized. For properly installed steam monitoring systems, we disagree that the steam flow rate would be lower at the flare tip due to heat losses because of the relatively high heat capacity and heat of vaporization of steam. Given the thermodynamic properties of steam, any heat losses between the representative measurement location and the flare tip will have a negligible effect on the quantity of steam actually introduced at the flare tip.

Comment 5: One commenter suggested that the EPA should encourage operation near the incipient smoke point and provide an option for operating at or just above that point regardless of the net heating value in the combustion zone.

Response 5: We disagree with the commenter that we should provide an option to operate at or near the incipient smoke point. First, without the detailed monitoring systems that we proposed and that we are requiring in this final rule, flare owners or operators will not have the information needed to determine if they are at or near the incipient smoke point. In other words, if no smoke is present, there would be no way to know if the system is being operated “near” the incipient smoke point. Alternatively, a flare owner or operator would have to operate at all times with some smoke present in the flame but not in the gas beyond the flame. This would be impossible given typical variations in flare gas flow rates, so incidence of smoking would be prevalent and likely in violation of the no visible emissions limitation.

Comment 6: Several commenters generally supported the proposed suite of flares provisions, use of combustion zone metrics instead of vent gas metrics, and the 15-minute sampling period proposed by the Agency.

Response 6: We appreciate the support for the proposal. We have retained several of aspects of the proposal noted by the commenter, such as use of combustion zone metrics and a 15-minute block average, but have modified the flare operating requirements as described in the preamble to the final rule.

3.5.1 Applicability (steam-assist only or all flares)

Comment 1: Several commenters suggested that the EPA should only apply the proposed flaring requirements at 40 CFR 63.670 and 63.671 to steam-assisted flares and that there is no justification for imposing the revised requirements on air-assisted, pressure assisted, and unassisted flares and that these flares should remain subject to the requirements at 40 CFR 63.11. In support, commenters suggested that the EPA has not collected adequate performance data on which to establish or justify limits for flares that are not steam-assisted; that the EPA has not properly considered the differences in design, waste gas composition, and use between these flare types and steam-assisted flares; and that the EPA has not properly evaluated the costs and benefits associated with the flare types that are not steam-assisted of meeting the limits derived from the steam-assisted flare dataset.

Response 1: First, while we acknowledge that there are limited new data for other flare types, we do not see any difference in the combustion efficiency curves between steam and unassisted flares when we consider the combustion zone properties, which is consistent with combustion zone theory. Furthermore, recent data clearly indicates that combustion efficiencies begin to deteriorate at combustion net heating values above 200 Btu/scf and that an operating limit of 200 Btu/scf in the flare vent gas (which is the combustion zone gas for unassisted flares), as currently provided in the General Provisions for unassisted flares, does not ensure that these flares will achieve an average destruction efficiency of 98 percent. Finally, the data that we do have on air-assisted flares clearly indicates that air-assisted flares can be over-assisted leading to poor combustion efficiencies. Therefore, we consider the available pool of data, which includes data for air, steam and unassisted flares, supports our conclusion that the combustion zone net heating value target for all flares must be significantly higher than 200 Btu/scf in order to ensure flares are achieving 98 percent control and that special provisions are also needed to ensure air-assisted flares are not over assisted.

Comment 2: A few commenters suggested that the EPA should clarify that refinery flares are only subject to the 40 CFR 63.670 and 63.671 requirements when they are receiving Group 1 Refinery MACT 1 or regulated Refinery MACT 2 vent streams. Specific examples of refinery flares that commenters listed that never receive Refinery MACT 1 or 2 regulated vent streams include: flares that receive fuel gas where there are no Group 1 emission points routed to that fuel gas system, dedicated acid gas flares, dedicated hydrogen plant flares, flares that are dedicated to non-HAP pressure storage (e.g. propane/butane spheres), and flares equipped with flare gas recovery systems where no flaring of “regulated material” is taking place.

Response 2: We consider that the rule is clear and we are confirming in this response that flares that do not receive any “regulated material” would not be subject to the new flare provisions in 40 CFR 63.670 and 63.671. We are adding a definition of “regulated material” to help clarify this phrase. Nonetheless, we are hesitant to provide definitive answers to specific examples provided by the commenter because there are potentials for “exceptions” to the general rule. For example, the new flare requirements would not generally apply if only Group 2 streams are controlled by the flare. However, if a refinery is using emissions averaging and is controlling a Group 2 stream using a flare, we consider that the flare must be in compliance with the new flare requirements in order to take emissions averaging credits. Similarly we expect that propane/butane spheres would not have sufficient HAP content to trigger Group 1 storage vessel control requirements, so we generally expect that flares dedicated to serving these vessels would not be subject to the new flare requirements. However, if the purity of these products in these tanks allows 2 to 4% HAP materials (depending on the applicable Group 1 storage vessel definitions), then this flare could be subject to the new flare requirements. Refinery owners or operators should carefully review the rule requirements and definitions to assess the applicability of the new provisions and are encouraged to submit an applicability determination for any flare for which they are uncertain whether the new flare requirements apply in a specific application.

We do note that we expect that most fuel gas systems would receive a Group 1 stream since any fuel gas recovery compressor that receives gas from a process unit in HAP service would be a Group 1 miscellaneous process vent had these gases not been recovered in the fuel gas system. Again, refinery owners or operators can submit an applicability determination for their specific fuel gas system to determine if there is any question as to whether the fuel gas system receives a Group 1 stream.

Comment 3: One commenter stated that available data strongly suggests that the 8% (vol.) rule for hydrogen rich flaring for unassisted flares works well for the chemical industry practices but that it may not work for hydrogen rich flaring in refineries.

Response 3: We are providing provisions to use 1,212 Btu/scf for the net heating value of hydrogen, which accounts for the flammability of hydrogen. While this provision does not directly allow gas streams with 8 percent hydrogen to comply with the rule regardless of the other constituents in the gas stream (e.g., 8 percent hydrogen in an otherwise inert gas stream would not have sufficient heat content to ensure high combustion efficiencies), it does greatly improve the correlation between combustion efficiency and combustion zone net heating value. Therefore, we are finalizing a provision to use 1,212 Btu/scf for the net heating value of hydrogen. The final rule is applicable to flares at petroleum refineries; we are not revising the requirements for flares in the chemical manufacturing industry or other industry sectors at this time.

Comment 4: One commenter raised a concern that the proposed flare requirements would become a template for future NSPS rule revisions and that these regulations may be misapplied to other source categories with flares or to flares controlling non-VOC vent streams.

Response 4: We are only applying these requirements to petroleum refinery flares at this time. If, in the future, we propose similar requirements for NSPS, the commenters can raise their concerns in the context of that rulemaking.

3.5.2 Selection of parameters & limits

Comment 1: A few commenters suggested that the EPA based the proposed combustion zone limits on an invalid data analysis (i.e., invalid use of CO_2 PFTIR signal wavelengths and invalid data acceptance criteria), that the one minute PFTIR data should not be used to establish combustion efficiency correlations because of temporary shifts in the flare plume due to changes in wind speed or direction, and that the emission limits should be set so as to provide an equal chance of false positives and negatives.

Response 1: We re-analyzed the data using the "approved" CO_2 signal wavelength when it was available. While the arguments provided by the commenters regarding the use of 1 minute average data are not compelling, we note that the flare gas composition data used to determine the NHV_{cz} is generally based on gas chromatography (GC) analysis, with cycle times of 10 to 15 minutes. Because the compositional analysis data are not available each minute, we compiled the data using approximate 15-minute run averages, as suggested by the commenters, and we then evaluated the impacts of different operating limits using the resulting run-average data set. Details of this analysis are provided in the memorandum entitled "Monte Carlo Analysis of Flare Performance Data" included in Docket ID No. EPA-HQ-OAR-2010-0682. This analysis essentially confirmed that the proposed operating limits were reasonable although we finalizing some revisions to the flare operating limits as described in the preamble to the final rule. We disagree that we should develop limits that provide an equal chance of false positives as false negatives because the operating limits are intended to ensure that all flares are achieving the targeted 98 percent destruction efficiency at all times rather than half of the flares meeting that target half of the time.

Comment 2: A few commenters suggested that the EPA should assign hydrogen a heating value of 1,212 Btu/scf to more accurately reflect its flammability in a net heating value (NHV) basis and that doing so is consistent with some recent flare consent decrees and will help reduce natural gas supplementation for facilities complying only with the NHV_{cz} metric.

Response 2: We evaluated the 15-minute average run data using the normal net heating value for hydrogen of 274 Btu/scf and the suggested value of 1,212 Btu/scf, which is based on a comparison of the lower flammability limit and the net heating value of hydrogen compared to light organic compounds. Based on our analysis, using the 1,212 Btu/scf value for hydrogen greatly improves the correlation between combustion efficiency and combustion zone net heating value. Therefore, we are finalizing a provision to use 1,212 Btu/scf for the net heating value of hydrogen. For more detail on the data analysis, see the memorandum entitled "Monte Carlo Analysis of Flare Performance Data" included in the Docket ID No. EPA-HQ-OAR-2010-0682.

Comment 3: One commenter supported the EPA's decision to not include perimeter assist air in the calculation of combustion zone metrics (i.e., NHV_{cz}, LFL_{cz}, and C_{cz}).

Response 3: We appreciate the support.

Comment 4: One commenter generally supported and urged the EPA to stand by the updated flare regulations.

Response 4: We appreciate the support. We are finalizing the requirements with revisions as described in the preamble to the final rule.

Comment 5: One commenter requested that the EPA provide actual refinery flare operating data that confirms that affected flares can achieve the proposed standards under the range of process conditions and control scenarios found in the refining industry.

Response 5: Many of the flare performance studies, such as those conducted at Marathon and Flint Hills Resources,[85, 86, 87] were conducted on actual industrial flares at petroleum refineries, which indicate affected flares can achieve the proposed requirements.

Comment 6: One commenter requested that the EPA formulate and provide the equation for calculating the combustibles concentration, C_{vg}, in proposed section 63.670(1)(6) to be used when a total hydrocarbon analyzer is used for total volumetric hydrocarbon concentration.

Response 6: At the time of proposal, we expected that a THC analyzer calibrated using propane would provide a direct measure of C_{vg}. However, we are not finalizing the use of C_{vg} operating limit because we are providing an allowance to use 1,212 Btu/scf as the net heating value for hydrogen. The C_{vg} parameter (as well as the lower flammability limit (LFL) parameter) was proposed largely to account for instances where the net heating value did not correlate well with combustion efficiency. With the hydrogen adjustment, the net heating value alone provided excellent correlation with combustion efficiency and the use of C_{vg} is no longer needed.

3.5.3 Allowance to use any parameter at any time

Comment 1: One commenter suggested that no flare monitoring system currently exists that is capable of both monitoring and simultaneous adjusting flare operations to ensure compliance with at least one of the three parameters in the combustion zone proposed by the EPA (i.e., NHV_{cz}, LFL_{cz}, and C_{cz}) for each measurement taken. The commenter further stated that while such an advanced control system may be possible to implement, it estimates a cost of such a system to be $850,000 and that the EPA has not justified such a cost, especially when recent consent decrees use values in the vent gas rather than the combustion zone gas.

Response 1: In the proposal, we reasoned that if a GC was used to determine gas composition, calculation of all three parameters would be straight forward and one could easily determine the parameter that would allow the most steam addition (the largest compliance margin). We are not finalizing the proposed approach but rather requiring refinery owners or operators to comply

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[85] Clean Air Engineering, Inc. 2010a. Performance Test of a Steam-Assisted Flare with Passive FTIR. Prepared for Marathon Petroleum Co., LLC, Texas Refining Division, Texas City, Texas. May. Available at: www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/mpc-txc.pdf.

[86] Clean Air Engineering, Inc. 2010b. Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR – Detroit. Prepared for Marathon Petroleum Co., LLC. Detroit Refinery, Detraoit, Michigan. November. Available at: www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/mpc-detroit.pdf.

[87] Clean Air Engineering, Inc. 2011. PFTIR Test of a Steam-Assisted Elevated Flares – Port Arthur. Prepared for Flint Hills Resources Port Arthur. LLC. Port Arthur Chemicals, Port Arthur, Texas. June 17. Available at http://www.regulations.gov/, Docket Item No. EPA-HQ-OAR-2010-0682-0167.

with the NHV_{cz} parameter using an adjusted net heating value of 1,212 Btu/scf for hydrogen. Under this requirement, we expect that most refinery owners or operators will incur monitoring costs for a calorimeter (costs for which were included at proposal) and a hydrogen analyzer (costs for which were not included at proposal) and have revised our cost projections for the final rule accordingly. As noted in previous responses, the LFL_{cz}, and C_{cz} parameters were proposed largely to account for instances where the net heating value did not correlate well with combustion efficiency. With the hydrogen adjustment, the combustion zone net heating value alone provided excellent correlation with combustion efficiency and the use of these other parameters is no longer needed.

Finally, we note that we are requiring monitoring of the flare vent gas with calculation of the combustion zone properties. This is consistent with recent consent decrees and it is thus far the only means by which the proper performance of the flares can be assured.

Comment 2: One commenter suggested that the EPA should give further consideration on how to apply the target combustion zone gas limits. To support this claim, the commenter referenced conditions of certain combustion zone gas mixtures that may meet some of the target combustion zone gas properties but not others and referenced the fact that certain combustion zone gas mixtures may meet the proposed criteria but that there now exists a potential conflict with the EPA flaring requirements in the General Provisions, specifically for NHV and streams with high hydrogen content.

Response 2: We proposed that compliance could be demonstrated with any of the operating limit formats (i.e., Btu, LFL, combustibles) at any time because we were aware that some operating parameters worked better under certain conditions while others worked better under other conditions. As provided in the preamble to the final rule, we have determined that using a net heating value of 1,212 Btu/scf for hydrogen, the combustion zone net heating value appears to work well for nearly all cases. We do not agree that the proposed requirements (many of which we are not finalizing) were or the final requirements we are promulgating are in conflict with the GP although they are more stringent than those in the GP. Importantly, refinery flares are not required to comply with both sets of provisions; they need to comply with the new monitoring requirements in 40 CFR 63.670 and 63.671 and are not subject to the requirements in the GP and we have added specific overlap provisions to clarify this point.

3.6 Dilution parameters for air-assisted flares (general, non-H2-olefin)

Comment 1: A few commenters suggested that the EPA did not evaluate or provide costs, burden evaluations, or demonstrations of cost effective control methodologies for the proposed air-assisted flare combustion control requirements that would require facilities to convert their air-assisted blower motors to continuous control systems and upgrade their electrical and digital control logic systems.

Response 1: First, we disagree that we did not project costs for control systems for air-assisted flares. See the memorandum entitled “Petroleum Refinery Sector Rule: Flare Impact Estimates” included as Docket Item No. EPA-HQ-OAR-2010-0682-0209. Second, while some retrofits may require new, adjustable blower motors, the adjustable blower motors, in addition to providing functionality needed to prevent over-assisting the flare, will reduce operating costs of the flare during lower flow events. We did not attempt to quantify or take credit for the cost savings associated with the air flow controllers. While individual applications may vary significantly from the average cost that we included for air-assisted flares, we consider that the nationwide estimate of the impacts for air-assisted flares is reasonable and we did not revise the cost estimates specific to air control systems for air-assisted flares.

Comment 2: A few commenters suggested that the EPA did not provide enough data analyses to demonstrate that air-assisted flares can be "over assisted." The commenters also stated that the proposed dilution factor approach, which considers both flare tip diameter and perimeter assist air flow rates to be critical parameters in flare combustion efficiency (CE) is not better correlated with CE than the stoichiometric air ratio approach, and that the EPA did not demonstrate that these sorts of occurrences are common or even occur in practice. Another commenter suggested that compliance with the proposed dilution parameters using the current variable frequency drive technology will require the minimum gas flow to the flare (and subsequently CO_2 emissions) to be increased as the air blowers must remain on at all times vent gas is being routed to the flare for purposes of equipment integrity and that this problem could be exacerbated with the proposed exit velocity and no visible emissions requirements.

One commenter suggested that the air-assisted flare monitoring parameters do not appear to have been extensively tested in practice because blowers are often not capable of performing fine adjustments in air assist rates and that the EPA should investigate alternatives to these proposed requirements to ensure air-assisted flares in routine service will obtain the combustion efficiency improvements being proposed in this rule.

Response 2: The performance data for air-assisted flares clearly demonstrate that air-assisted flares can be over-assisted (see Figure 5 in the memorandum entitled "Petroleum Refinery Sector Rule: Operating Limits for Flares" included as Docket Item No. EPA-HQ-OAR-2010-0682-0206). The ability of the dilution factor to align the data from flare tips of different diameters clearly suggests that the proposed parameters are better than the stoichiometric air ratio approach (see Figures 6 and 7 in the memorandum entitled "Petroleum Refinery Sector Rule: Operating Limits for Flares" included as Docket Item No. EPA-HQ-OAR-2010-0682-0206). The fact that the industry practice is to use a single speed blower fan as suggested by some commenters ensures poor combustion efficiencies at low flare vent gas flow rates. We do not understand how using a variable speed fan would increase the amount of vent gas that needs to be sent to the flare when the exact opposite is true. In fact, using a variable speed fan will lower electricity use by the facility during low vent gas flows and it would be the use of a single air blower rate that would require more supplemental gas flow to prevent over-dilution of the vent gas. We are finalizing the net heating value dilution parameter (NHV_{dil}) parameter requirements for air-assisted flares with limited revision from those proposed.

Comment 3: One commenter suggested that the EPA significantly change the final rule with respect to the proposed target dilution parameters for flares with perimeter assist air, particularly for the target dilution parameter limits proposed for air-assisted flares that meet Hydrogen-Olefin interaction criteria because there is no data currently available that support them. The commenter also suggested that the EPA allow flexibility in the rule for facilities to demonstrate compliance by using a stoichiometric ratio of 10:1 or less or allow facilities to operate air-assisted flares right at or above the incipient smoke point.

Response 3: We are not finalizing the hydrogen-olefin target parameters at this time. We are not allowing use of a set stoichiometric ratio of 10:1 because the flare performance data we have clearly suggests that a 10:1 stoichiometric ratio would not ensure combustion efficiencies anywhere near 98 percent for some flares (see Figure 6 in the memorandum entitled "Petroleum Refinery Sector Rule: Operating Limits for Flares" included as Docket Item No. EPA-HQ-OAR-2010-0682-0206). We have previously described issues with operating at or above the incipient smoke point in this response to comment document. We are finalizing the NHV_{dil} parameter requirements for air-assisted flares as proposed, except that we are not finalizing separate operating limits that were proposed to address concerns of reduced combustion efficiency when both hydrogen and olefins are present in the vent gas.

Comment 4: One commenter suggested that the EPA make some clarifications to the regulatory language at 40 CFR 63.670(n). Specifically, the commenter pointed out that the EPA should use an "or" rather than an "and" in the first paragraph since only one of the dilution parameters needs to be calculated for compliance in paragraph (f) of that section. The commenter also points out that while the units and equations used for NHV_{dil} and lower flammability limit dilution parameter (LFL_{dil}) at 40 CFR 63.670(n)(1) and n(2) are different than the NHV_{cz} and LFL_{cz} parameters presented at 40 CFR 630.670(m)(1) and m(2), that the definitions are the same and need revision. Lastly, the commenter also points out that combustibles concentration dilution parameter (C_{dil}) should be defined at 40 CFR 63.670(n)(3) and not C_{cz}.

Response 4: First, we are not finalizing the options to comply with the LFL_{cz} , C_{cz}, LFL_{dil}, or C_{dil} operating limits, so these revisions are no longer needed. We agree with the parameter definition revisions suggested by the commenter to fix the editorial error in the equation term descriptions. Therefore, we are revising the parameter description in 63.670(n)(1) to describe NHV_{dil} as the "Net heating value dilution parameter" rather than "Net heating value of the combustion zone gas."

3.7 H2-olefin interaction

3.7.1 Appropriateness of interaction criteria concept

Comment 1: Several commenters suggested that neither scientific literature nor the available flare test data support the EPA's claim of an adverse Hydrogen-Olefin Interaction on combustion efficiency and that the EPA should not finalize the more restrictive combustion zone operating limits for all flare types. To support their claims, commenters suggested that the EPA did not provide any evidence that the assumed hydrogen/olefin effect actually exists, that statistical analysis demonstrates that the EPA developed their limit based on random differences in data, that the PFTIR data analysis method of using the individual minute by minute data instead of the test average data is flawed and leads to invalid conclusions, and that proper analysis of the data demonstrates that the more stringent operating limits for hydrogen/olefin conditions cannot be supported.

Several commenters suggested that there is some evidence to support more stringent flare combustion zone limits for a narrowly defined high concentration propylene-only condition as outlined in some of the recent flare consent decrees and that the flare test data do not support more stringent operating limits for the proposed hydrogen/olefins criteria by the EPA. Additionally, one of the commenters suggested that if the EPA decides to proceed with the more restrictive target combustion zone limits for the hydrogen/olefins interaction cases that the final rule should not expand beyond an interaction between hydrogen and propylene.

Response 1: We disagree that the hydrogen-olefin interaction effect had not been demonstrated. The data presented in Figure 2 in the memorandum entitled “Petroleum Refinery Sector Rule: Operating Limits for Flares” (included as Docket Item No. EPA-HQ-OAR-2010-0682-0206) clearly indicated an early drop in combustion efficiency at relatively high combustion zone net heating values relative to the other data points. When using the minute-by-minute data, there were numerous data points meeting the hydrogen-olefin interaction criteria and the early degradation of combustion efficiencies was quite pronounced. When we analyze the run average data, we still see low combustion efficiencies above a combustion zone net heating value of 270 Btu/scf, and all of the lowest combustion efficiencies in this range are from runs that meet the hydrogen-olefin interaction criteria that we proposed. The reduced combustion efficiencies were clearly present at two different Marathon refineries; hydrogen olefin criteria were also present for one Flint Hills Resources flare, but this flare generally operated above the target combustion zone net heating value proposed for gas streams meeting the hydrogen-olefin interaction criteria.

Nonetheless, we acknowledge that the precise mechanism of the combustion efficiency degradation is not well known (e.g., is it limited to propylene or applicable to all light olefins) and we do not have additional data available to evaluate the ability of the proposed interaction criteria to predict poor combustion efficiency for other refinery flares outside of the data from which the criteria were developed. Therefore, at this time we have decided to not finalize the hydrogen-olefin interaction criteria. Based on our Monte Carlo assessment (see the memorandum entitled “Monte Carlo Analysis of Flare Performance Data” included in Docket ID No. EPA-HQ-OAR-2010-0682), we determined that the NHV_{cz} limit of 270 Btu/scf evaluated on a 15-minute average provided adequate assurance that all flares would meet an average destruction efficiency of 98 percent over a 3-hour period (the time period for which other conventional control systems must demonstrate compliance).

3.7.2 Selection of limits when interaction is present

Comment 1: One commenter suggested that the EPA misinterpreted Marathon Petroleum Company’s PFTIR flare testing resulting in errors in the proposed Olefins-Hydrogen operating limits. The commenter suggested these errors were that the EPA based the limits on all olefins rather than solely on propylene, that the limits are calculated in the combustion zone rather than the vent gas, that the limits are unbounded on the upper end, and that the limits do not take the relative amounts of hydrogen and olefins into account.

Response 1: We selected our hydrogen-olefin criteria so as to include the worst performing data when combustion zone net heating values were at or over 300 Btu/scf. Since combustion occurs in the combustion zone, we considered it most appropriate to base the criteria on the concentrations of these compounds in the combustion zone. Because we have a minimum concentration for each compound and a minimum combined concentration, we conclude that we did consider “relative amounts” of the hydrogen and olefins. At high concentrations of these compounds in the combustion zone, the net heating value of the combustion zone gas will be well above the proposed target (particularly now that we are providing 1,212 Btu/scf for the net heating value of hydrogen), so there is no need to establish an upper concentration limit. However, as noted previously, we are not finalizing separate standards for cases meeting the proposed hydrogen-olefin interaction criteria.

Comment 2: One commenter suggested that TCEQ investigations that form the bulk of the dataset on which the regulations are based show that 98% destruction efficiency is achieved by focusing on operation at the incipient smoke point and that while the EPA implies these flare regulations will cause operation on the lean side of the incipient smoke point, that that notion is not proven and that it is possible the numerical regulatory limits proposed by the EPA will mandate flare operation in the smoking region, especially for flares burning hydrogen and olefins, thereby resulting in greater particulate emissions and visible emissions above existing allowable limits.

Response 2: The TCEQ is one of seven flare studies evaluated, so it is not “the bulk of the dataset.” While visible emissions records were not always provided with the combustion efficiency data, the available data indicate that refinery flares were able to operate with no visible emissions at combustion zone net heating values well above 400 Btu/scf.

Comment 3: One commenter wanted clarification that in the special provisions for olefins and hydrogen in the combustion zone that diolefins are included and that unsaturated hydrocarbons such as aromatic compounds are not.

Response 3: As proposed, diolefins (e.g., 1,3-butadiene) were included in the olefins concentrations and aromatic compounds were not included. As noted previously, however, we are not finalizing these provisions.

Comment 4: One commenter suggested that while some of the data in the EPA flare dataset was collected at flares serving ethylene production units, that it is not representative of ethylene industry flaring or other olefin production flaring and that the proposed combustion zone parameters are not appropriate for flares outside of the petroleum refining source category. To further support this suggestion, the commenter notes that chemical industry flares combust a wide variety of hydrocarbon compounds, some of which have not been included in the flare dataset, and that flare tip sizes can range from 2” to 54” and larger in the chemical industry, whereas the refinery flare testing likely focused only on larger flare tips.

Response 4: As noted previously, we have not definitively concluded whether the poor combustion efficiencies identified in the performance test data are due to a general olefin-hydrogen interaction or a propylene-hydrogen interaction. More data are needed to determine if flares with high ethylene and hydrogen may have similar performance issues as the refinery flares tested, regardless of their size. In any event, we did not propose, nor are we finalizing, hydrogen-olefin requirements for the chemical industry as part of the Refinery Sector Rule.

3.7.3 Applicability (steam-assist only or all flares)

Comment 1: A few commenters suggested that the EPA should remove the requirements for air-assisted flares meeting the hydrogen/olefins interaction criteria to comply with the more stringent combustion zone and dilution parameter operating limits until actual data are obtained for air-assisted flares operating in this regime because these limits could be over-specified and result in operation of a smoking flare.

Response 1: We are not finalizing separate operating requirements for hydrogen-olefin interaction operating limits for steam-assisted, unassisted or air-assisted flares.

3.8 Flow rate monitoring requirements

Comment 1: One commenter suggested that the EPA should specifically allow all required CPMS outages for flare gas flow monitors due to activities required to comply with NSPS Ja as well as flow out-of-control periods due to required temperature and pressure correction instrument outages.

Response 1: The commenters did not identify and we are unaware of activities required to comply with subpart Ja that would cause a flare flow CPMS outage. We do not agree that we should allow flow CPMS outages when temperature and pressure monitoring systems are not functioning. We have revised the QA/QC requirements for pressure tap inspections and we are unaware of other issues that would cause monitoring system outages. We note that flare flow rates must be determined under “standard conditions” so the temperature and pressure monitoring systems are considered an integral part of the flare flow monitor for this application. Refinery owners or operators may employ redundant temperature and pressure monitors, if desired, to limit outages of these inputs needed to correct measured flow rates to standard conditions.

Comment 2: A few commenters suggested that if air-assisted flares are included in the final rule that the EPA should specifically allow for use of air blower motor speed and design curve air flow data as the basis for estimating assist-air flow rates as an alternative to having to install air-assist flow rate monitoring systems.

Response 2: Generally, we agree that air blower motor speeds and design air flow data can be used provided these have the required accuracy and the accuracy of the design curves are verified like other flow CPMS.

Comment 3: One commenter suggested that utilization of flare vent gas composition data from time periods before the 15-minute block periods with measured flow data as prescribed in the rule at section 63.670(l)(2) appears misleading and problematic and that an approach to use a continuous calorimeter in concert with a GC should be encouraged to avoid such problems.

Response 3: Based on the data we have reviewed, flow rates vary more significantly than compositions. Given the short time period for the operating limit, we considered that it would be more important to use a feed forward compliance approach to provide a means for owners or operators to be able to know the allowable steam to vent gas flow allowed within a given 15-minute time period, particularly when using a GC. The GC allows speciation of chemicals which may assist the refinery owner or operator in identifying and correcting discharges to the flare from, for example, PRD that are not properly seated that might go undetected when using a calorimeter. As such, we do not wish to discourage the use of GC, although we recognize the lag time of the GC analysis presents challenges with the control logic. In the final rule, we allow refinery owners or operators to comply with either the feed forward calculation that was proposed or a direct calculation procedures using the flow and composition results available for a given 15-minute block to calculate the vent gas and combustion zone gas properties during that 15-minute block period. While we expect that the direct method will be used primarily for flares equipped with calorimeters, we allow the owner or operator to elect either the feed-forward or the direct calculation methodology. The flare owner or operator must select which calculation method they will use and must use that method at all times.

Comment 4: One commenter suggested that if flow monitors are employed in concert with other monitors that will let refiners evaluate flare combustion zone gas characteristics, that the rule should allow for manual operation and not dictate automated responses, particularly when the relevant data is not synchronized based on delayed response times.

Response 4: The rule does not prohibit manual operation of the flare and refinery owners of operators can elect how to best control steam additions to prevent smoking while maintaining adequate net heating value in the combustion zone.

Comment 5: One commenter suggested that the proposed rules do not recognize infrequently used flares like NSPS Ja and that provisions should be made to reduce or eliminate the requirements for infrequently used flares.

Response 5: We disagree with the commenter. While we did not specifically define “emergency only” flares as we did in NSPS Ja nor limit the alternative grab sampling approach specifically to “emergency only” flares, these provisions were provided specifically to reduce the requirements for infrequently used flares.

3.8.1 Flow monitors

Comment 1: Several commenters suggested that the EPA flow monitor accuracy specifications are inconsistent with those in the South Coast Flare Rule and many Refinery Consent Decrees and that as indicated in their NSPS Ja Reconsideration Petition, it is unclear what “measurement sensitivity” means. Thus, in order to resolve the NSPS Ja reconsideration issue as well as to be consistent with recent consent decrees, the commenters recommended revising both the flare flow meter sensitivity specification and accuracy specification in Refinery MACT 1 Table 13 and in 40 CFR 60.106a(a)(6)(i)(B) of NSPS Ja to be consistent with the accuracy specification from the Shell Deer Park Consent Decree, Appendix 1.10, which specifies the required flare flow meter accuracy as “±20% of reading over the velocity range of 0.1-1 ft/s and ± 5% of reading over the velocity range of 1-250 ft/s.” One commenter similarly suggested that the accuracy requirements in Table 13 for flows less than 0.1 ft/s be set within 20% to be consistent with Petroleum Refinery consent decrees and the monitoring technology available today.

Response 1: We agree that the term "measurement sensitivity" is not a term that is commonly used in flow monitoring system's technical specification sheets. To be consistent with the terminology used by instrument vendors and used in Refinery MACT 1 and 2, we are revising Refinery NSPS Ja to replace the term "measurement sensitivity" with "accuracy." We agree that flares can normally operate at very high turndown rates. We also recognize that flares can have fairly large diameters. These two issues combined can cause some difficulties meeting the 10 cubic feet per minute (cfm) lower flow accuracy requirement. Therefore, we are revising the flow rate accuracy provisions specific for flares to provide an accuracy requirement of ±20% over the velocity range of 0.1-1 ft/s and ±5% for velocities exceeding 1 ft/s in 40 CFR 60.l07a(f)(l)(ii) and in Table 13 of subpart CC. Note, we believe that the commenter cited an incorrect paragraph in Refinery NSPS Ja. 40 CFR 60.106a(a)(6)(i)(B) pertains to gas flow measurements related to the sulfur recovery plant. We do not consider it appropriate to revise that accuracy requirements for these units. The accuracy requirement applies to normal flow ranges and these units do not normally operate at high turn down rates. Therefore, if a gas stream generally operates at low flow, the diameter of gas line, or at least the flow monitoring insert, should be sized appropriately to accurately determine these low flow volumes. Thus, we are only providing the dual range accuracy provisions for flares; all other flow monitoring systems must meet the lower flow limit accuracy of 10 cfm.

Comment 2: One commenter suggested that the EPA remove the annual calibration and QA/QC requirements for ultrasonic and optical flare gas flow monitors required in Refinery MACT 1 Table 13 and Refinery MACT 2 Table 41 because they can only be calibrated at the factory and not in the field. In lieu of such requirements, the commenter suggested that the EPA allow these flow monitors to use a monitoring plan that specifies following the manufacturer's recommendations instead.

Response 2: , While we recognize that ultrasonic and optical flare gas flow monitors are calibrated at the factory, there are techniques that manufacturers recommend to evaluate the accuracy of the instruments in the field on an ongoing basis and these calibration evaluations should be conducted periodically. To reduce the burden of these evaluations, we are changing calibration evaluation requirements to be biennially (every two years) rather than annually (or semi-annually as proposed in Table 41 of subpart UUU).

3.8.2 Engineering calculations (temp/press monitors)

Comment 1: Two commenters were supportive of the proposed language at 40 CFR 63.670(i)(4) that would allow use of engineering calculations in lieu of flow monitoring in some cases, especially where the molecular weight of the gas is known. One of those commenters raised the question of whether both pressure and temperature monitoring are required for each use of engineering calculations. This commenter also gave some specific examples where the final rule should allow engineering calculations where either pressure or temperature information is known, including but not limited to, calculations to determine the flow rate of steam though an orifice plate or a control valve, calculations of vent gas flow rate through a process control valve, and calculations of the air-assist flow rate using blower curves and actual operating conditions.

Response 1: All of the flow rate measurements or engineering estimates will need to be converted to "standard conditions" (68 degrees F and 1 atmosphere pressure). Depending on the information available for the engineering calculation, knowledge of system temperature and pressure may be needed.

3.9 Flare vent gas composition monitoring requirements

Comment 1: Several commenters suggested that 40 CFR 63.671(e)(3)(ii) assumes that there are heavy compounds present in flare gas which is an invalid assumption, that these species are treated as C5+ in the calculations and that because of this, this paragraph should deleted. If it is not deleted, commenters suggested that the EPA try and be consistent with state regulations like the TCEQ HRVOC which requires analysis of C1-C4 compounds and uses a C5+ grouping or that the EPA specify a concentration level at which the calibration range no longer needs to be extended.

Response 1: We agree with the commenter that very few if any C5+ compounds exist routinely in the flare vent gas. We are revising these calibration requirements to allow the use of n-pentane as a surrogate for all C5+ organics in the flare vent gas.

Comment 2: Some commenters suggested that the EPA should not require continuous GCs for all refinery flares as other more cost effective monitoring approaches are available that will achieve the same reductions in emissions, that both identifying leaks into the flare system and incremental steam savings and natural gas use savings from being able to fine tune flare operations isn't as practical as the EPA claims. The commenters stated that requiring sophisticated instrumentation like online GC on all flares has a disproportionate effect on small refineries. Other commenters generally supported the use of GCs on all refinery flares, suggesting it would increase operational awareness of real-time flaring events and give refiners a better understanding of the true emission potential of the gas being flared.

Response 2: We are not requiring all flares to install a GC. At proposal, we considered that many refineries would elect to use a GC in order to evaluate all compliance options. Because we are finalizing only the NHV_{cz} operating limit (with the provision allowing use of 1,212 Btu/scf for the net heating value of hydrogen for determining compliance), we consider it more likely now that refinery owners or operators will elect to install a calorimeter along with a hydrogen analyzer than we did at proposal. The advantage of this monitoring technique is quicker response times, which helps to improve process control of the flare. While the full GC monitor would provide additional data for both compliance and troubleshooting purposes, it is no longer needed to allow a means to demonstrate compliance with any of the three proposed flare operating parameters and the longer response time, which generally provides only one reading per 15 minute period, causes lag in process control of the flare. The final rule allows either the use of a GC or a calorimeter and, if a calorimeter is used, provides the refinery owner or operator the option to also install a hydrogen analyzer in order to take advantage of the provision to use 1,212 Btu/scf for the net heating value of hydrogen for determining compliance.

Comment 3: A few commenters suggested that the EPA add a definition for "Pipeline Natural Gas" and that in lieu of using the default composition laid out in 40 CFR 63.670(j)(5) that the

EPA allow periodic sampling results (e.g., weekly, every six months, or annually) of pipeline natural gas to be used as an alternative.

Response 3: The term we use in the regulations is "pipeline quality natural gas." We do not consider it necessary to add a definition for this term as it is a common term used to refer to natural gas that meets certain specifications for interstate distribution. When this term is used in the regulations, it generally refers to purchased natural gas (i.e., natural gas purchased from local natural gas suppliers), and we are clarifying this intent in the final rule. We agree that periodic sampling is a reasonable alternative to using the default composition provided in the proposal, and we are including this allowance in the final rule. Since we are finalizing only the NHV_{cz} operating limit, we are only providing a default net heating value for natural gas rather than providing a default composition. Considering all of these revisions, we are finalizing 40 CFR 63.670(j)(5) as follows "Direct compositional **or net heating value** monitoring is not required for **purchased ("**pipeline quality**")** natural gas streams. **The composition of purchased** ~~In lieu of monitoring the composition of a pipeline quality~~ natural gas **streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any** ~~stream, the following composition can be used for~~ **purchased** ~~pipeline quality~~ natural gas stream **can be assumed to be 920 Btu/scf**."

Comment 4: One commenter suggested that the EPA should allow the use of any standard reference text or Internet site to obtain the LFL for any component that is not listed on Table 12.

Response 4: We are not finalizing the option to comply with a LFL_{cz} operating parameter. Therefore, it is not necessary for refiners to determine the LFL for purposes of the flare requirement revisions to Refinery MACT 1.

Comment 5: One commenter suggested that the proposed calculation for C_{vg} does not reflect combustibility because normalizing the calculation to propane penalizes C1 and C2 compounds and that the EPA should explain the basis for reporting results as volume percent as propane v. volume percent as methane.

Response 5: At this time we are not finalizing requirements that include this calculation.

Comment 6: Several commenters suggested that the calibration requirements for on-line GC in Table 13 should be modified to allow the approach used in the Texas HRVOC regulations, specifically in 30 TAC 115.725(d)(2)(A)(i). Specifically, commenters suggested that in order to compensate for the significant GC downtime associated with calibrations over the wide range of compounds specified in the proposal, the EPA should permit variations from Appendix B, PS9 by allowing a multi-point calibration quarterly rather than monthly and by allowing a mid-level calibration once per week instead of daily.

Response 6: We have already permitted variations from Performance Specification 9 by allowing for calibration using surrogate compounds instead of every compound expected to be in the stream. While we do not fully agree with the Texas HRVOC regulatory approach, we do agree that if a mid-level calibration check is performed daily, it provides enough assurance of proper operation to allow for quarterly multi-point calibration checks in this application. We have updated Table 13 accordingly.

Comment 7: One commenter wanted the EPA to clarify in what instances 40 CFR 63.670(d) and (f) are not "applicable" from the following regulatory text at 40 CFR 63.670(j): "The owner or operator shall determine the concentration of individual components in the flare vent gas using either the methods provided in paragraphs (j)(1) or (j)(2) of this section, to assess compliance with the operating limits in paragraph (e) of this section and, if applicable, paragraphs (d) and (f) of this section." Also, the commenter pointed out that "continuously" is not defined in paragraphs 40 CFR 63.670(j)(3) or (4) and that while it is defined in (j)(1) as occurring at least once every 15 minutes it may not need to be defined for Btu analyzers or THC monitors as they can probably measure continuously.

Response 7: The "as applicable" reference in Paragraph 63.670(j) is intended to refer to the fact that it is not necessary to determine NHV_{vg} for flare tip velocity if the owner or operator elects to comply with the 60 ft/s velocity limit in (d)(1). Similarly, since paragraph 63.670(f) is only applicable for air-assisted flares with perimeter assist air that provision would not be applicable within the meaning of paragraph (j) for flares that do not have perimeter assist air. With respect to continuous, 40 CFR 63.671(a)(1) states "All CPMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period." We do expect that most CPMS will cycle much more quickly. For example, we expect flow monitors used for flares would provide output by the minute to afford control of steam flows to maintain appropriate combustion zone concentrations. We specifically included this requirement in 40 CFR 63.670(j)(1) because the flare vent gas composition monitors (i.e., GC systems) were expected to have the longest cycle times of any of CPMS.

3.9.1 Continuous monitoring systems

Comment 1: Commenters suggested that the proposed GC calibration requirements at 40 CFR 63.671(e)(2) are infeasible, unnecessary and that they must be revised. Specifically, commenters raised issues with the requirements that all compounds in the flare gas stream be included in the calibration gas because there could be hundreds of compounds, suggested that the speciation requirements should focus on species that matter (i.e., hydrogen, olefins, hydrocarbons through C3 present above 1%, 1,3-Butadiene, n-butane, and n-pentane), and that 1,2-Butadiene is difficult to separate from 1,3-Butadiene and that there is negligible impact in ignoring it. Commenters suggested that 40 CFR 63671(e)(2)(ii) be revised to only require calibration using normal hydrocarbons through n-pentane.

A few commenters suggested that the EPA should limit the calibration gas requirements in 40 CFR 63.671(e)(2)(i) to compounds that are present in higher concentrations. One commenter suggested a concentration threshold of greater than or equal to 5 mole % on an annual average basis while another commenter suggested a concentration of 10 mole % or greater.

One commenter suggested that in order to limit the composition requirements to what may be accomplished with a single GC within the required 15 minute cycle time that the following component list be adopted in 40 CFR 63.670(j)(1): 1. Hydrogen 2. Oxygen 3. Nitrogen 4. Carbon

Dioxide 5. Carbon Monoxide 6. Methane 7. Ethane 8. Ethene (aka: Ethylene) 9. Acetylene 10. Propane 11. Propene (aka: Propylene) 12. 2-Methylpropane (aka: iso-Butane) 13. Butane (aka: n-Butane) 14. Butenes (including butene-1, isobutene, c & t-butene-2) 15. 1,3 butadiene 16. Pentane plus (aka: C5 plus) (i.e., all HCs with five Cs or more). The commenter also suggested that the EPA clarify that additional species such as hydrogen sulfide may be measured as long as the cycle time limit (15 minutes) is not exceeded, that the Items 2-4 be allowed to be grouped and reported as a single value, and that the EPA try and be consistent with the Texas HRVOC by allowing Propadiene and 1,2-Butadiene to be unresolved since they are difficult to resolve from methyl acetylene and 1,3-Butadiene and found only in very small quantities. Lastly, this commenter suggested that Table 12 be revised as appropriate to correspond with whatever changes are made.

Response 1: For most flares, flare gas composition will be variable, so it is difficult to know when high concentrations of some compounds may occur, but we find that it is generally necessary to include compounds at concentration of 1 percent or less to accurately characterize the flare vent gas stream. We are revising 40 CFR 63.671(e)(2)(i) to specify the target analytes as follows: hydrogen, methane, ethane, ethylene, propane, propylene, n-butane, iso-butane, butene (general), 1,3-butadiene, and pentane (as a surrogate for C5+ hydrocarbons). We note that speciation of specific butenes (cis-, iso- and trans-butene) is not necessary, but properties for trans-butene would be used for non-speciated butane. We also note that speciation of 1,2-butadiene is not required, but properties for 1,3-butadiene should be used for co-eluting butadienes. Additional compounds, such as acetylene, carbon monoxide, propadiene, and hydrogen sulfide can be included if the refinery owner or operator has sufficient quantities of these pollutants such they want to specifically include them in the calculation analysis. We are also revising the requirements in 40 CFR 63.671(e)(2)(ii) to limit the quantification of hydrogen and C1 through C5 normal alkanes. After incorporating these revisions, we consider the calibration requirements to be reasonable. We are not requiring calibration for oxygen, nitrogen, and carbon dioxide because these components do not need to be included in the calculations (NHV = 0). We are adding hydrogen sulfide properties to Table 12 in the event a refinery owner or operator elects to monitor H_2S (or has a separate monitoring system for H_2S for Refinery NSPS Ja).

Comment 2: One commenter suggested that the requirement in proposed Table 13 that Performance Specification (PS) 9 of part 60 Appendix B applies to GC used to measure flare gas net heating value needs modification. Specifically, the commenter suggested that the EPA waive the temperature specification for flare gas GC samples in PS 9 since they typically have temperatures much lower than 120 degrees C and that condensation of heavy hydrocarbons is not an issue. The commenters cited the requirements in the Shell Deer Park consent decree of maintenance of temperature of greater than or equal to 135 degrees F for the sample transport line and greater than or equal to 125 degrees F for the sample conditioning system as reliable and cost effective measures the EPA should require because electric heaters can be used.

Response 2: We agree that the sampling line for this source can be maintained at a lower temperature and we note this exception when referencing PS 9 in Table 13.

Comment 3: One commenter suggested that if the EPA does not delete the flare flow monitoring QA/QC requirements in favor of using a monitoring plan that the EPA should defer back to the flare flow monitoring requirements in 40 CFR 60 subpart Ja.

Response 3: We are revising Table 13 of Refinery MACT CC, Table 41 of Refinery MACT UUU and Refinery NSPS Ja to have consistent specifications for gaseous flow monitoring systems for flares.

Comment 4: A few commenters suggested that 40 CFR 63.671(a)(4) allow for at least a 5% downtime limit for continuous monitoring data outside of maintenance periods, instrument adjustments and calibration checks, similar to the requirements in Texas Sampling Rule protocol found at 30 TAC 115.725(d)(3).

Response 4: As proposed, 40 CFR 63.671(a)(4) requires operation of the CPMS at all times except during "maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero and span adjustments." We have more clearly written this requirement in the final rule to require operation of the CPMS at all times when regulated emissions are routed to the flare except for periods of "monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance and quality control activities." We believe that the original wording created some confusion, as a calibration check and checks to maintain precision and accuracy can be considered the same thing.

We note that the cited Texas rule states that the time required for normal calibration checks are not considered downtime; this exclusion does not apply to monitoring system malfunctions or repair periods. Therefore, 40 CFR 63.671(a)(4) allows more periods to be excluded from what is considered downtime than the Texas rule does, and as such the additional 5% downtime limit from the Texas rule is not warranted. We are not including any specific minimum data availability requirement in 40 CFR 63.671(a)(4). We do not believe that numerical missing data allowances provide incentive to conduct monitoring in a manner consistent with good air pollution control practices. We are excepting periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities from the provisions to collect data continuously. Because the data recorded during these periods are not generally considered valid data and are not generally allowed to be used in calculations used to report emissions or operating levels, it is not necessary for CPMS to provide data during these periods.

Also, we note that a monitoring system malfunction is a sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Owners and operators are expected to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

Comment 5: A few commenters showed general support for proper flare monitoring and operator training and suggested that a three year or longer delay before improving monitoring of flares is unacceptable and that facilities must be held accountable for proper operation of their flares now with existing equipment, regardless of whether it is automated or manual. Additionally, one of these commenters suggested that the EPA should consider amending its proposal to require refiners to install emissions sensors on flare stacks to alert refinery personnel in real time when flares malfunction and suggested these sensors could be used by refiners as a way to maintain a log of those malfunctions.

Response 5: While we appreciate the general support for the proposal to improve monitoring of flares, we disagree with the suggestion that these improved monitoring methods can be implemented immediately upon promulgation of the final rule. Without the proper instrumentation and control systems, refinery owner or operators cannot demonstrate compliance. For example, we assumed all flares would need to upgrade their steam control systems to provide both fine and coarse steam adjustment capabilities. Without such control systems, the refinery owner or operator cannot easily adjust steam addition rates to comply with the combustion zone gas operating limits. Based on the GHGRP data, three-quarters of all flares do not currently have a compositional or heat content monitors, and these monitoring systems are necessary in order for refinery owners or operators to be able to determine NHV_{cz} and assess compliance with the flare operating limits. While we understand and support the desire to implement these requirements as quickly as possible, we have determined, based on the flare system modifications needed to comply with the operating limits as well as the monitoring systems that must be installed to evaluate these operating limits, that 3 years will be needed.

3.9.2 Grab sampling systems

Comment 1: Several commenters supported the grab sampling option in the rule and suggested that the EPA change the sample frequency from once every 8 hours to once daily or once weekly; that the EPA should consider a provision to allow reduced grab sampling frequency for infrequently used flares, flares with a small total annual flaring volume, or flares that consistently exceed the minimum combustion zone requirements; and that the EPA should include Method ASTM D-1946 as another option for the compositional analysis.

A few commenters suggested that the grab sampling approach should ideally be used for refinery flares that only receive flare gas during emergencies, major refinery startups or shutdowns and/or unusual flare gas recovery outages and requested that the EPA clarify where the grab samples should be taken, whether grab samples are required for flares burning purge gas only (including those with FGR), and if an event occurs between routine samples whether the EPA would assume that the composition of gases flared during that event is the same as the composition of the routine samples.

Several commenters generally did not support the EPA’s proposed use of grab samples as a compliance option for monitoring the flare vent gas. One of the commenters suggested that the EPA must demonstrate that monitoring requirements are sufficient to assure compliance and that the option to allow grab sampling once every eight hours in lieu of continuous monitoring does not meet this standard.

Response 1: Although not specifically limited to “emergency only” flares or flares with well-designed flare gas recovery systems, these are the types of flares that we anticipated would use this monitoring option. We consider this to be the “reduced monitoring frequency” option for seldom used flares, and we are not changing the frequency of the grab sampling so that it can occur less frequently. We provided this option because installing and operating a CPMS can be costly and labor intensive and we determined this was not warranted for a flare that receives regulated material for only a few hours or a few days a year.

For flares that receive regulated material on a consistent basis, this compliance option is not practical. First, it is labor intensive to manually collect the 8 hour grab samples on a regular basis and thus the cost of this approach can exceed the costs of a CPMS for routinely operated flares. More importantly, there is significant risk of non-compliance under this option. This is because it takes time to get the grab samples analyzed and thus there may be a significant period where the flare operator will be adjusting steam rates based on experience and process knowledge without knowing the actual vent gas composition. As a result, if the results of the grab sample analysis indicates that the vent gas has lower heat content than expected, it is likely that the operating limits would not be met and that there could be a significant number of 15-minute block periods for which the operating limit was exceeded and the refiner could be subject to enforcement action.

In response to request for clarifications of when the grab samples must be taken, we note that the grab sampling is required whenever regulated material is sent to the flare. In general, a flare that does not have a water seal and uses sweep gas for the entire flare header system would be expected to monitor the flare vent gas continually because it would be extremely difficult if not impossible to ensure no regulated material is entering the flare gas header (from leaking relief valves or other issues), regardless of the sweep gas used (natural gas or refinery fuel gas). For flares that normally operate with a water seal (i.e., emergency only flares or flares with well-designed flare gas recovery systems), the purge gas is not subject to the grab sampling requirements or the operating limits provided the purge gas is not regulated material. For example, if natural gas is used as the purge gas, the flare is not subject to the requirement in 40 CFR 63.670 and 671 during time periods when only purge gas is provided to the flare (i.e., when the water seal is intact). Generally, we expect the first grab sample collected for a given event would be taken within the first 15-minutes of the start of the event.

3.10 Averaging time and calculation of flare operating limits

Comment 1: One commenter suggested that the claim that flares must meet a 98 percent Destruction Efficiency (DE) at all times (i.e., every 15 minutes) is invalid and is a significant change in the Refinery MACT 1 112(d)(2) and (d)(3) MACT Floor. The commenter claimed that the EPA has not supported the extension of the historical “typical operation” expectation to an every 15 minute minimum requirement. Further, the commenter asserted, the 98 percent DE assumed at the time the MACT was promulgated was for a daily average and not for 98 percent at all times. Finally, the commenter disagreed that these amendments should impose the MPV floor (98 percent DE) for emission types with a 95 percent DE floor. In addition, the commenter suggested that changing the averaging time established in 1995 for the MPV floor is a significant change in the stringency of the MPV limitation established pursuant to sections 112(d)(2)and (3) and cannot be done without demonstrating that it is achieved in practice and meets all of the CAA section 112(d)(6) criteria, including cost effectiveness.

Response 1: First, we disagree with the suggestion that the MACT floor control efficiency is based on a daily averaging time. The 98 percent or 20 ppmv control requirements in the original MACT were based on the results of performance tests, generally consisting of three 1-hour test runs. Additionally, the initial compliance demonstration in Refinery MACT 1 is based on a performance test consisting of three test runs of no less than 1 hour. Both of these facts indicate that the MACT floor performance requirement is based on a 3-hour average performance. While we require evaluation of the NHV_{cz} operating limit on a 15-minute block average, we are not requiring and do not expect that all flares would achieve 98 percent control efficiency for each 15-minute block period. In our revised analysis, we specifically evaluated how well various operating limit values and averaging times ensured that flares achieve 98 percent control efficiency over a 3-hour period. We found that the NHV_{cz} operating limit needed to be maintained at or above 270 Btu/scf for each 15-minute period in order to ensure flares achieve 98 percent control efficiency over a 3-hour average period due to the variability inherent in flare operations and the drastic drop in flare control efficiencies that can occur as a result of this variability (see memorandum entitled *Flare Control Option Impacts for Final Refinery Sector Rule* in Docket ID No. EPA-HQ-OAR-2010-0682).

We note that to demonstrate on-going compliance with the MACT for MPV controlled using process heaters, boilers, or thermal oxidizers, which generally have stable operations, we elected to provide a 24-hour average firebox temperature based on the expected stability of these systems in the original MACT standards. We considered whether it was necessary to revise the requirements in Table 10 to record the 3-hour rolling average temperatures and report all 3-hour rolling average periods when temperatures are outside the range established in the Notification of Compliance Status Report (NOCS) or operating permit. While these amendments would be consistent with the proposed amendments to revise the operating limit averaging times in Refinery MACT 2, we did not propose to revise these MPV operating limits. Therefore, we cannot finalize revisions to the averaging time of the MPV operating limits at this time. However, we appreciate the commenter for pointing out the discrepancy between the performance requirements and reporting requirements for MPV and we will consider revising the MPV operating limits to 3-hour averages (consistent with the performance test) in the future. However, this does not alter our determination of the MACT floor emissions limit is determined by a performance test (i.e., a 3-hour average basis) and it does not alter the need for a 15-minute averaging period for the NHV_{cz} operating limit for flares in order to ensure that flares achieve 98 percent control efficiency over a 3-hour average. Thus, we maintain that revisions to operating limits used to ensure continuous compliance with the emissions limits do not constitute a change in the underlying MACT standard, MACT floor or the performance demonstration requirements.

Comment 2: A few commenters suggested that the rule must clarify that it is not a deviation if flare gas flow is too short to allow the control system to obtain a measurement and respond.

Response 2: We consider that the flare standards apply for any 15-minute block that the flare receives regulated material. We recognize that there may be short periods of flaring that last only a few minutes (such as when cycling-up a new compressor in a staged compressor system). We are clarifying that grab samples of these short events are not required. While a flare is on standby, we expect that assist rates will be set at their minimum value, so that, when gases are vented to the flare, there will be minimum steam or air supplied to the flare, so the flare will not be over-assisted during these brief events. Due to the logistics of collecting a sample of the flare vent gas during very brief events, we are clarifying that, for events that last less than 15-minutes, calculation of certain operating limits (i.e., the flare tip velocity limit, NHV_{cz} and NHV_{dil}) is not required.

Comment 3: One commenter suggested that the rule needs to address how to handle time periods when there is no flare gas flow and periods when there is no regulated material flow in the calculations. The commenter recommended that no average be calculated when there is no flow to a flare for the entire averaging period and those averages be recorded and reported as “no flow” rather than zero and similarly, “no regulated material flow” be recorded where there is no regulated material flow to the flare within an averaging period. Where there is some flow or some regulated material flow to a flare during an averaging period, the commenter suggested that the average should be calculated based on the cumulative flow and the combustion zone properties associated with that flow (i.e., no flow periods should not be included in the average, since any assumed combustion properties would be incorrect and would invalidate the calculated average). For instance if flow to a particular flare only occurred for 30 minutes in an hour, the three hour average would be the average value for those 30 minutes. Otherwise the remaining 150 minutes of the three hours would have to be taken as zero and would yield a false indication of a failure to meet the minimum combustion zone properties.

Response 3: We agree with the commenter regarding the calculation procedures but not the suggested averaging period. The operating limits only apply when the flare receives regulated material. Within a 15-minute block, refinery owners or operators would only need to include the cumulative volume of flare vent gas and, if applicable, volume of assist air or steam during those periods when flow of regulated material is sent to the flare. It may be easier for some refinery owners or operators not to distinguish within a 15-minute block average, specific minutes when there is no flow of regulated material, so we are allowing the cumulative flow rates within a 15-minute block to be determined by excluding flows during periods which regulated materials are not sent to the flare. To clarify this, we are making several revisions to 63.670(k) and renaming this section “Calculation methods for cumulative flow rates and determining compliance with V_{tip} operating limits.” In this section, we specify that, if desired, the cumulative flow rates for a 15-minute block period only needs to include flow during those periods when regulated material is sent to the flare, but owners or operators may elect to calculate the cumulative flow rates across the entire 15-minute block period for any 15-minute block period there is regulated material flow to the flare.

Comment 4: One commenter suggested that a 15 minute frequency for taking flare samples is appropriate given the time required to collect, inject and analyze a sample, especially when using a GC. Additionally, the commenter suggested that there is no apparent significant benefit to more frequent grab sampling unless the system is fully automated to take advantage of the extra data.

Response 4: Thank you for the comment. We are finalizing this requirement as proposed.

3.11 QA/QC requirements for flare CPMS

Comment 1: One commenter suggested the EPA make the following revisions to 40 CFR 63.671: Paragraph (b)(3) References paragraph (c)(3)(vii) which does not exist, Paragraph (b)(3)(v) - There is a reference to (b)(10), which is not included in section (b), and Paragraph (b)(3)(vii) - There is no reference to a parametric signal analyzer.

Response 1: Thank you for the comment. Our responses to the specific comments are provided below.

40 CFR 63.671(b)(3): This paragraph should reference "…the information specified in (b)(3)(i) through (vii)" rather than referencing paragraphs (c)(3)(i) through (viii). We note that a similar error was made in 63.671(b)(5), where the reference should be "…procedures listed in paragraphs (b)(5)(i) through (vi)" rather than **(c)**(5)(i) through (vi).

40 CFR 63.671(b)(3)(v): The provisions anticipated in paragraph (b)(10) were not proposed, we are deleting the phrase "…and meet the requirements in paragraph (b)(10) of this section."

40 CFR 63.671(b)(3)(vii): The parametric signal analyzer is that part of the CPMS that converts the measured signal into the actual output of the CPMS when the parameter measured is different from the parameter monitored. This is common for flow monitoring systems that may measure pressure (from an orifice plate) or velocity and need to convert these to volumetric flow rates (sometimes corrected to standard conditions). Sometimes these calculations require additional inputs to perform the calculations (e.g., density or molecular weight of the gas; temperature and pressure of the system). This section requires identification of these parameters and the algorithms used to convert the parameters actually measured by the monitor to the final output used in the operating limit. We are finalizing this requirement as proposed.

Comment 2: A few commenters suggested the EPA consider the following for the revisions to the flare instrumentation portions of Refinery MACT 1 and 2: (1) Per NSPS Ja flare minimization requirements, excess flaring should not be required in order to perform marginal or unnecessary instrument testing, (2) The special situations associated with flare instruments must be addressed (e.g., inaccessible pilot monitors, sonic and optical flow meters, optical composition monitors), (3) Flare instrumentation requirements must be consistent with the requirements in NSPS Ja, State Rules (e.g., Texas HRVOC monitoring, SCAQMD and BAAQMD monitoring), and applicable refining consent decrees, so that wasteful duplication or replacement of existing instrumentation due to minor differences is avoided, (4) Flare instrument requirements must be technically feasible using, as much as reasonable, industry standard equipment, (5) Flare instrument requirements should impose no more instrumentation outage than is absolutely necessary and periods of instrument outage and maintenance must be excused from compliance demonstration requirements.

Response 2: We appreciate the comment, and we have revised several of the monitoring requirements to improve the consistency between Refinery MACT rules (subpart CC, UUU) and Refinery NSPS Ja. With respect to item 1, we are unaware of any requirements in the proposed of final rules that would require excess flaring.

With respect to item 2, we expect the inaccessible pilots to reference the inspection requirements. As noted in Section 3.2.2, we are not requiring flare pilot monitoring systems to be subject to the performance and quality control/quality assurance requirements in Table 13. For other monitoring systems, we recommend flare owners or operators employ redundant monitoring systems (thereby eliminating the need for visible inspections) for inaccessible monitors. We have revised the accuracy requirements for flare flow meters. We are unaware of any "optical composition monitoring" systems.

With respect to item 3, we have revised accuracy requirements for flare flow meters to improve the consistency between Refinery MACT rules (subpart CC, UUU) and Refinery NSPS Ja. We also revised the some of the requirements for Performance Specification 9 to address some requirements in State rules and consent decree requirements; however, we are not required to incorporate provisions in these rules that we do not consider adequate to ensure continual compliance with the MACT standards.

With respect to item 4, we are unclear as to what provisions the commenter is referring to. We have revised the calibration requirements (using n-pentane for C5+ rather that require calibrations up to C7 hydrocarbons). We maintain that the requirements included in the final rule are technically feasible using available industrial equipment.

With respect to item 5, we have minimized, to the extent practical, the calibration requirements for GC to minimize instrument outages. The proposed rule specifically allows for flare operation and compliance during these periods. We have added a specification consisted with the Texas HRVOC rule that these periods will not exceed 5 percent of operations.

Comment 3: One commenter suggested that a safety over-ride must be provided for 40 CFR 63.671 and Table 13 requirements where flare access is required because requiring instrument QA/QC for instruments that are not safe to access puts workers at risk. Also commenters suggested that temperature CPMS are unworkable and unnecessary for flare pilot monitors because the purpose of monitoring is to indicate the presence of a flame and an accurate reading of the flame temperature is not required to just show the presence of a pilot flame.

Response 3: As discussed elsewhere in this chapter, we are removing the proposed requirement of making flare pilot monitoring systems CPMS in the final rule. For other monitoring systems, flare owners or operators can use redundant monitoring systems if the monitors are unsafe to inspect.

Comment 4: One commenter suggested that all required CPMS outages be specifically allowed. The commenter specifically suggested that while 40 CFR 63.671(a)(4) lists activities during which a CPMS may be off-line, that not all activities required by 40 CFR 63.671 and Table 13 are covered. For instance, outages associated with the required Table 13 check of pressure CPMS taps for plugging and the 63.671(b)(5)(iii) daily response checks would not be allowed by proposed 63.671(a)(4). Therefore the commenter recommended this paragraph be generalized by adding a phrase to cover any outage required to comply with this rule or the procedures specified in the CPMS monitoring plan (e.g., manufacturer's recommendations or activities required by applicable Performance Standards).

Response 4: We reviewed these sections and conclude that 63.671(a)(4) specifically allows for all "required CPMS outages." As proposed, checks for plugged pressure taps would be considered "checks to maintain precision or accuracy." Obviously, a plugged pressure tap would not be accurate. As noted elsewhere in this document, we have revised the requirements for identifying plugged pressure taps to be daily review of pressure reading to ensure the CPMS is responding/fluctuating as normal and these checks would not require a CPMS outage. As discussed previously in this document, we also revised 63.671(a)(4) to place a maximum time the monitor can be offline due to "maintenance periods" and other instrument checks or adjustments.

Comment 5: One commenter suggested revisions be made to the proposed CPMS monitoring plan requirements at 40 CFR 63.671(b). Specifically, the commenter suggested that this section require the CPMS monitoring plan to list the manufacturer and model number for all monitoring equipment components and that the plan should be limited to the monitoring instrument itself by deleting the word "all", that the requirement of the monitoring plan to identify the parameter detected by the parametric signal analyzer and the algorithms used to convert these values into the operating parameter monitored to demonstrate compliance be deleted or only required where it is available and not confidential business information of a third party, and that the EPA remove the requirement to include a spare parts inventory as this requirement is ambiguous, wasteful, burdensome, and unnecessary.

Response 5: We note that in paragraph 40 CFR 63.671(a) we clearly delineate that the section applies specifically to CPMS installed to comply with §63.670. Additionally, we then reference the CPMS monitoring plan from 40 CFR 63.671(a)(5), which also supports that this plan only needs to cover CPMS installed to comply with §63.670. For additional clarity, in the final rule, we repeat this applicability phrase as follows:

- In 63.671(b): We are modifying the first sentence to clarify that "…a CPMS monitoring plan **that covers each flare subject to the provisions in §63.670 and each CPMS installed to comply with applicable provisions in §63.670**."
- In 63.671(b)(3)(i): We are revising to read: "Manufacturer and model number for all monitoring equipment components **installed to comply with applicable provisions in §63.670**."
- In 63.671(c): We are modifying the first sentence to clarify that "For each CPMS **installed to comply with applicable provisions in §63.670**, ..."
- In 63.671(d): We are modifying the first sentence to clarify that "The owner or operator shall reduce data from a CPMS **installed to comply with applicable provisions in §63.670** as specified in paragraphs (d)(1) through (3) of this section."

We believe that it is imperative that a facility understand how its monitoring equipment work. When an algorithm is needed to convert the signal measured by the equipment to the monitored output (e.g., in the case of a flowmeter measure pressure differential), we believe that it is reasonable to expect the facility to be aware of how this calculation is performed. We also do not believe that it is burdensome to provide a spare parts inventory. Our intent is not to require the facility to maintain a list of what spare parts are available at any given moment in the CPMS plan. The intent of this requirement is to provide a list of what spare parts are planned to be kept on site in order to quickly remedy any issues with the CPMS.

Comment 6: One commenter had specific comments and suggestions related to Table 13 in Refinery MACT 1 including: (1) Proposed Table 13 does not define how temperature performance evaluation is to be conducted, (2) Proposed Table 13 requires "visual inspections and checks of CPMS operation every 3 months, unless a CPMS has a redundant temperature sensor." How are such inspections to be conducted and recorded? (3) How is flow evaluation to be conducted under proposed Table 13? (4) Proposed Table 13 requires daily checks for obstructions, such as pressure tap pluggage. This requirement is excessive and unnecessary and should be removed, (5) Proposed Table 13 requires pressure performance evaluations, but does not specify how such evaluations are to be conducted.

Response 6: In general, we are not specifying how performance evaluations are to be performed, just the timeframes and types of inspections. Due to the many variations in monitoring equipment, we believe that the manufacturer of the equipment is the best source for determining the proper technique for performing most performance evaluations. The CPMS monitoring plan must include information on routine quality assurance and quality control procedures. The plan should include not only a schedule for performing the performance evaluations, but also a description on how the evaluations will be performed. Unless specifically specified, we are providing the facility with discretion to determine the best method to perform these evaluations for these site-specific monitoring systems.

As noted elsewhere in this document, we have revised the requirements for identifying plugged pressure taps to be daily review of pressure reading to ensure the CPMS is responding (fluctuating) as normal.

Comment 7: One commenter suggested that most CPMS do not measure concentrations, so the requirement for span of the analyzers at 40 CFR 63.671(b)(3)(v) must be limited to those analyzers that do or generalized to cover other parameters and that the reference at (b)(10) needs to be corrected. If it is generalized, the commenter suggested that it is made clear that the Table 13 accuracy requirements only need to be met for the normal range (as specified in Table 13) and not all expected values (as specified here). The commenter points out that generally, the Table 13 accuracy specifications cannot be met at the extremes of values that instruments can measure, which is particularly true for flare flow meters, which cannot meet + or - 5% accuracy below about 1 foot per second flow, but can measure with less accuracy down to about 0.1 ft./sec.

The commenter also suggested that 40 CFR 63.671(b)(3)(vi) should be clarified to specify just which analyzers it includes or it should be generalized by substituting "CPMS" for "analyzer."

Response 7: The "span of the analyzer" is applicable to other types of CPMS, not just those that measure concentration. We also note that a CPMS typically includes multiple components, such as the sensor (measuring device) and analyzer (that converts the sensor signal to a final output). For example, a thermocouple temperature sensor provides a voltage output. This voltage output is then converted to a temperature output reading by a meter (analyzer). We are revising 40 CFR 63. 671(b)(3)(v) to clarify that the span requirement applies to both the sensor and the analyzer as follows: “Span of the **CPMS**. The span of the **CPMS sensor and analyzer** must encompass **the full range of** expected **values**.” We are also revising 40 CFR 63. 671(b)(3)(vi) to refer to the “span of the CPMS” rather than the “analyzer’s span.”

Comment 8: One commenter suggested that the paragraph at 40 CFR 63.671(b)(5)(ii) be revised to allow having an alarm as an alternate to an operator check.

Response 8: We believe the commenter is referring to 40 CFR 63.671(b)(5)(iii) rather than (ii). We consider the commenter’s suggestion to be reasonable. We are revising the second sentence of 40 CFR 63.671(b)(5)(iii) to reads as follows: “If the CPMS system includes an internal system check, the owner or operator may use the results to verify the system is responding, as long as **the system provides an alarm to the owner or operator or** the owner or operator checks the internal system results daily for proper operation and the results are recorded.”

Comment 9: One commenter requested that the EPA include specific language in the rule providing that lack of compliance data for entire averaging periods is not a deviation from the combustion or velocity emission limitations. To support this suggestion, commenters pointed out that QA/QC and maintenance activities for the monitors take more than 15 minutes to perform and that this will result in several averaging periods every day for which no data is available, especially since daily calibrations of the GC, heat content and/or hydrocarbon analyzers are required and daily checks of pressure taps for pluggage are required.

Response 9: We consider that the current language is sufficiently clear on how to manage the availability of compositional data. For example, 63.670(l)(2)(ii) states that “For all other 15-minute block periods, use the results that are available from the most recent sample prior to the 15-minute block period for that 15-minute block period.” We clarify in this response that this language does not require that the “most recent sample prior to the 15-minute block period” must be the results for the 15-minute block immediately preceding the 15-minute block for which the calculations are being made. We recognize that a 15-minute block compositional analysis will typically be missed during the daily calibration check and we allow for this “miss.” If the most recent analysis available prior to the 12:45 a.m. to 1:00 a.m. became available at 12:20 am (because calibration check was performed after the 12:20 a.m. result analysis so no flare vent gas composition result is available prior to 12:45 a.m.), then the rule allows (and even requires) the use of the 12:20 a.m. result for both the 12:30 a.m. to 12:45 a.m. 15-minute block period and the 12:45 a.m. to 1:00 a.m. 15-minute block period. Given the cycle times of composition monitors, we consider this allowance necessary, particularly for GC compositional analyses. Calorimeters and hydrogen analyzers cycle times are much shorter, so it is less likely that data will be “missed” in any given 15-minute block period, but we have provided this allowance for each of these monitoring systems. We have not revised these requirements as a result of this comment. As noted previously in this document, we have revised the pressure pluggage check requirements, which eliminates the need for a CPMS outage for this check.

Comment 10: One commenter generally did not support parameter monitoring systems because they suggested that they do not tell you what air pollutants in what concentrations are emitted and suggested that they cannot tell you whether an actual air pollution violation has occurred.

Response 10: We appreciate the comment and understand the concern; however, continuous speciated emissions monitoring systems for flare gas exhaust emissions are not commercially available at this time. We consider the flare combustion efficiency requirements we are finalizing to be the best approach available to ensure refinery flares are operated with high destruction efficiencies.

3.12 Alternative means of emissions limitations (site-specific)

Comment 1: A few commenters supported the EPA's inclusion of the provisions for obtaining an Alternative Means of Emission Limitation (AMEL) in the rule and suggested that facilities seeking an AMEL should be able to rely on the results of a previously completed emissions tests if the flare and vent gas characteristics are similar to the flare seeking the AMEL request. The commenters also suggested that additional testing should not be required for every flare seeking an AMEL.

One commenter suggested that the rule should also allow for flare manufacturers to request approval for equipment specific operating limits.

Response 1: In general, we disagree that where a source performs tests for an AMEL for one flare that it can rely on that test for an AMEL for other flares. For the special case that identical flares are used in series (as in a cascaded flare system), then it seems reasonable that the AMEL developed for the primary flare in the cascaded system be relied on for an AMEL for identical secondary flares. But in most other situations, however, there is too much variation in the vent gas sources and compositions, flare diameters, flare tip design, etc., to be able to rely on the same test for an AMEL for different flares. In the final rule, we require in 40 CFR 63.670(r)(1) that an owner or operator must submit a flare test plan for approval prior to the source test. As such, we do not consider it appropriate to allow facilities to rely on an already conducted a flare performance evaluation in seeking an AMEL without a review and evaluation of the tests conducted. A flare owner or operator may submit the test plan for a previously conducted source test for approval, but if the test plan is deficient, a new performance evaluation would be required. If the test plan is approved, the owner or operator can continue the process specified in 40 CFR 63.670(r)(2) and (3) to request an AMEL. A complete test report must be submitted containing all of the pertinent data, including test methods used, calibrations, other quality control results, raw field data sheets, and laboratory data, if applicable. In any request for an AMEL, the EPA reserves the right to reject the request based on a determination that the test was insufficient to adequately characterize flare combustion efficiency; that the results have not been adequately documented (e.g., instrument not calibrated correctly, evaluation did not test for/quantify enough organic compounds likely to be in the flare plume, or no raw data); or that the reduction in emissions is not at least equivalent to the flare combustion efficiency performance requirements in the final rule.

Comment 2: One commenter suggested that the rule should be flexible enough to permit direct combustion efficiency measurement as a potential future compliance option since this technology is rapidly evolving and may one day prove to be a viable cost-effective alternative to the monitoring being proposed in this rulemaking.

Response 2: Although this technology may not be sufficiently advanced to be able to provide the requested provisions at this time, we can reconsider the need to revise these standards if a “flare CEMS” technology becomes available. If this technology becomes available prior to the next technology review, sources have the option to submit an alternative monitoring request for these systems.

Comment 3: One commenter recommended that the rule allow refineries the option of preparing alternative compliance approaches. The commenter states that flexibility could provide a viable method for resolving inconsistencies among flare combustion efficiency requirements in recent consent decrees, the NSPS Ja rule requirements, and the requirements of this proposed rule. It would also be an appropriate mechanism for refineries that have established their own combustion efficiency protocols separate and apart from any requirement to do so.

One commenter suggested that the majority of the flares that currently are subject to consent decrees with flare specific limits comply with a dynamic operating limit which requires a gas chromatograph to obtain speciated vent gas compositions. They go on to state that these flares also have the ability to dynamically control assist steam and supplemental gas flow rates. The commenter suggests that the EPA allow sources that want to establish and use a flare specific operating limit be allowed to do so and be able to comply with a dynamic operating limit without having to go through the proposed procedures at 40 CFR 63.670(r).

The commenters noted that the EPA’s existing flare combustion efficiency consent decrees state that as long as an entity subject to a consent decree is meeting its requirements, it is deemed to be meeting the required combustion efficiency. The commenter believes that refineries that invest in compliance with applicable consent decrees should not lose the benefit of these expenses by being required to comply with the EPA’s proposed rules.

Additionally, the commenter urged the EPA to allow an AMP that would allow monitoring and control similar to those included in an existing flare combustion efficiency consent decree, though the refinery may not itself be subject to a consent decree. Examples where such flexibility would be appropriate include a situation where a refinery purchases equipment to comply with a consent decree that is under negotiation, but the refinery is never subject to the consent decree (sold before the decree is finalized; or where a refinery invests in equipment based on consent decree negotiations before being subject to a consent decree itself). The commenter believes that refineries in these cases should have an opportunity to utilize the monitoring and emission control equipment purchased in good faith under these scenarios.

Response 3: We have provided mechanisms to develop site-specific operating limits through the AMEL provisions in 40 CFR 63.670(r). We do not consider it appropriate to bypass these provisions for flares with consent decrees. As noted in the previous response in this section, we will allow owners or operators to submit test plans for a previously conducted performance evaluation for approval, but we maintain the provisions in 40 CFR 63.670(r) are necessary to ensure that the alternative limits are at least equivalent to performance achieved via the operating limits included in the final rule.

3.12.1 Site-specific test plan

Comment 1: One commenter suggested that the EPA make clear in the final rule preamble that there is no initial or general flare performance testing requirements in the rule and that monitoring for and determining the combustion zone operational limits satisfies these requirements.

Response 1: There are several operating limits that apply to flares: a visible emissions limit, flare pilot requirements, flare tip velocity limits and combustion zone net heating value limits. We note that there is a requirement to conduct an initial 2-hour visual emissions observation, so there is an initial performance test for the visible emissions limit, but there are no other performance testing requirements for the other flare operating limits (unless the owner or operator elects to request an AMEL) to demonstrate that the flare is achieving 98 percent control efficiency. As suggested by the commenter, compliance with the MACT flare requirements (other than the visible emissions limits) is determined based solely on the operating and monitoring requirements in the final rule.

Comment 2: One commenter suggested that the EPA not refer to the testing required for development of an Alternative Emission Limitation as proposed in 40 CFR 63.670(r) as a “performance test” but rather call it a “flare specific test” because there are many requirements imposed for performance tests that are not for the test required for an AMEL, such as electronic reporting tool (ERT) reporting and testing at maximum representative conditions and that all of the requirements needed to assure a good flare performance test are already included in 40 CFR 63.670(r).

Response 2: Given that 40 CFR 63.670(r) specifies the conditions of the tests, which override GP requirements with respect to the maximum representative conditions and that ERT reporting is not applicable to these test methods, we see little substance in the commenter’s suggestion. However, we do note that the “performance test” is really a “performance evaluation test” in that it specifically looks to identify conditions at which performance of the flare begins to deteriorate. Therefore, we have revised 40 CFR 63.670(r) to describe the test as a “performance evaluation” rather than just a “performance test” and we note here that we consider the “performance evaluation” to be different and separate from a conventional “performance test.”

Comment 3: One commenter raised questions about the AMEL process proposed at 40 CFR 63.670(r). Specifically, the commenter wanted to know (1) the time-frame for the EPA approval when a deviation request and test procedure are submitted to prove that different operating parameters yield good destruction efficiency; (2) the time for the EPA to review the procedure submittals and re-submittals; (3) whether, if prior testing has been conducted which adequately shows good combustion, that data be re-submitted; and (4) what qualifies as a “sufficient number” of test runs to identify the point at which the flare efficiency deteriorates and what qualifies as deterioration?

Response 3: Generally, we try to review and respond to these types of AMEL requests within 60 days. However, if deficiencies are noted, the approval time can be significantly longer. Refinery owners or operators should begin their evaluation early in the process and determine if they wish to seek an AMEL 12 to 18 months before the applicability date of the new flare provisions in order to have time to get approval for and conduct their site-specific flare performance evaluations and then submit and get approval for site-specific operating limits. We are allowing refinery owners or operators to submit test plans for a previously conducted test and continue through the process to request an AMEL if that test plan is approved. The number of test runs will be outlined in the site-specific evaluation plan. The phrase “a sufficient number of test runs” is included in the event the performance of the flare is different from expected in order to require additional test runs to identify the point at which the flare efficiency deteriorates. We consider test runs with combustion efficiency less than 90 percent to satisfy this requirement. If the combustion efficiency for all test runs under given fuel type are less than 96.5 percent, we also interpret the testing provision to require additional runs to identify the point where 96.5 percent combustion efficiency is achieved. A “sufficient number” would be two or three runs in a given combustion efficiency range.

3.12.2 Request/approval of site-specific operating limits

Comment 1: One commenter suggested that the EPA include an alternative to site-specific limits with a five year time frame in which facilities be allowed to gather site specific data upon which compliance limits would be based. The commenter suggests that this will encourage proper flare operation and allow the regulated community to deal with any site or equipment specific issues prior to incurring any potential violations.

Response 1: We are providing 3 years to comply with the new flare provisions in the final rule consistent with the maximum time allowed to implement standards under CAA section 112(d)(2) and (d)(3). We encourage refinery owners and operators to act swiftly in the event they need to install new equipment or if they are considering submitting a request for an AMEL. We consider 5 years is more time than is needed and, moreover, it is more time than allowed under the CAA.

3.13 Definitions for flare control devices

Comment 1: One commenter suggested that the EPA clarify what constitutes a flare “event” for purposes of 40 CFR 63.670(1)(2)(i) and (3)(i) as the duration of an “event” could be so short that no vent gas sample can be collected.

Response 1: For the purposes of these requirements, an event is any time regulated material is sent to the flare. We have added provisions to the final rule such that certain operating limits are only applicable for an “event” that is at least 15 minutes in duration.

3.13.1 Air assist terms

Comment 1: A few commenters suggested that the EPA make revisions to the definition of “Assist air” or propose a definition for “air-assisted flare” to distinguish these flares from steam-assisted flares and make clear that the assist air addition is for the purpose of aiding combustion and that incidental air addition due to entrained air in the steam, from process sources, or leakage of instrument air does not qualify a flare necessarily as using “assist air.” One commenter suggested that the EPA make the following change to the second sentence in the definition of

<u>Assist Air:</u> Assist Air includes premix assist air, ***whether injected or induced***, and perimeter assist air.

Response 1: The definition of "assist air" already includes the notion that assist air is "…air that intentionally is introduced…" so we disagree that further clarification is needed. The second clarification appears to be more appropriate for the definition of premix air and we are clarifying the definition of premix assist air as follows: "*Premix assist air* means the portion of assist air that is introduced to the flare vent gas**, whether injected or induced,** prior to the flare tip. *Premix assist air* also includes any air intentionally entrained in center steam."

Comment 2: Several commenters suggested that the EPA make revisions or clarifications to the definition of "Perimeter assist air" because most air-assisted flares send air assist along the axis of the flare and not necessarily to the perimeter and, they believe, the definition was intended cover air conveyed through the upper or lower steam lines but not to cover the typical 3-10 pounds of unmeasurable ambient air entrainment per pound steam from upper and lower steam. Additionally, one commenter suggested the following definition change for "Perimeter Assist Air": means the portion of assist air introduced at the perimeter of the flare tip or above the flare tip. ~~Perimeter assist air includes air intentionally entrained in the lower and upper stream~~. Perimeter assist air includes all assist air except premix assist air. Perimeter assist air does not include the surrounding ambient air.

Response 2: We think it is important to consider all air that is intentionally introduced in or around the combustion zone. As we understand it, lower and upper steam is not mixed with the flare gas until the flare tip, so we consider this to be similar to "traditional" perimeter assist air and we are retaining that portion of the definition. Therefore we are finalizing the definition of perimeter assist air as proposed.

Comment 3: Several commenters suggested that the EPA make revisions or clarifications to the definition of "Premix assist air" as they stated that assist air is typically supplied at the flare tip and not prior to the flare tip to avoid creating a potentially explosive mixture inside of the flare, that it is not clear whether "prior to the flare tip" means prior to the flare tip inlet or flare tip exit, and that the definition needs to differentiate between air conveyed to the flare tip and ambient air entrainment.

A few commenters suggested specific regulatory definition language changes. One commenter suggested we delete the second sentence altogether and replace it with the following: "Premix assist air does not include the surrounding ambient air." Another commenter suggested we add the following to the definition of **<u>Premix assist air:</u>** means the portion of assist air that is introduced to the flare vent gas prior to the flare tip ***exit***. Premix assist air also includes any air ~~intentionally~~ entrained in ~~center~~ steam ***or assist gas injected into the flare vent gas prior to the flare tip exit***.

Response 3: We are revising the definition of premix assist air as noted in Response 1 of this section. We consider it important to emphasize that assist air is air intentionally added to the flare vent gas or tip. We see no need to clarify that premix assist air does not include surrounding ambient air since that does not seem pertinent to premix assist air (air added prior to that flare tip) and we have already made that clarification in the definition of assist air (the general term, which applies to both perimeter and premix assist air).

3.13.2 Steam assist terms

Comment 1: One commenter suggested the EPA revise the definition of "Assist Steam" to exclude "Center Steam" because no air is included with this steam, it is a diluent and used to reduce burn back, it increases exit velocity, and it creates confusion for users and is in error. The commenter provided the following regulatory definition language change to the second sentence of the definition of **Assist Steam:** Assist steam includes, but is not necessarily limited to~~, center steam~~, lower ***or tube*** steam and upper steam.

Response 1: We do not follow the logic that we should not include center steam in the definition of assist steam because no air is included in this stream. It is still steam added prior to the combustion zone and must be include in the assist steam flow determination. We understand that it is unusual to use "premix assist air" but flare vendors discussed this method of intentionally inducing air in with assist steam and the "premix assist air" definition was developed to address cases where are is introduced into the vent gas prior to the flare tip, whether directly or entrained in center steam. This is the same reason we clarified that air intentionally entrained in lower or upper steam must be included with perimeter assist air. We are not revising the definition of assist steam based on this comment.

Comment 2: Several commenters suggested the EPA revise the definition of "Center Steam" to clarify that this steam does not entrain ambient air and that it is injected in the flare tip to reduce burn back as well as into burning in the stack of a flare. One commenter suggested the following regulatory definition change for **Center Steam:** means the portion of ~~assist~~ ***intentionally added*** steam introduced into the stack of a flare to reduce burnback. ***There is no ambient air induced with this steam to assist the burning of the flare gas for smokeless operation.*** Another commenter suggested revision to the definition of **Center Steam** as follows: means the portion of assist steam introduced into the ~~stack of a flare~~ ***body of the flare tip*** to reduce ~~burnback~~. ***internal burning and provide dilution for small flows of flare gas that will generate visible emissions on a continuous basis and would be adversely effected by other assist steam injection. Center steam does not induce air into the flare tip.***

Response 2: As the definition of "assist steam" already includes the notion that assist steam is "…steam that intentionally is introduced…" so we deem no further clarification is needed on this issue because the term assist steam is used. As noted previously, we understand that it is unusual to use "premix assist air" but flare vendors discussed this method of intentionally inducing air in with assist steam. If no air is intentionally induced in the center steam, then the "premix air assist" flow will be zero, but we do not consider it necessary to outlaw or ignore this practice (if it does occur). We are not revising the definition of center steam based on these comments.

Comment 3: A few commenters suggested the EPA revise the definition of "Lower Steam" to include the fact that this steam induces ambient air before flowing through the tubes and minimizes smoke formation. One commenter suggested the following regulatory definition change for **Lower Steam**: means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, ***which induces ambient air, and then the mixture*** flows through the tubes to the flare tip ***outlet, and ultimately mixes with the flare gas exiting the flare tip.*** Another commenter suggested revision to the definition of **Lower Steam** as follows: means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, which then ***induces air and*** flows ***in*** ~~through~~ tubes ***passing through*** ~~to~~ the flare tip ***body***, and ultimately exits the tubes at the flare tip ***exit with no premixing with the flare vent gas stream*****.**

Response 3: We are unaware that all lower steam would "intentionally" induce air and we are not necessarily concerned about this in the definition of lower steam, nor are we concerned whether mixing of the steam occurs in/at the flare tip or as exiting the flare tip. The key point is that any steam, whether mixed with the flare vent gas before the flare tip (center steam), through tubes at the flare tip (lower steam), or through nozzles at the perimeter of the flare tip (upper steam), must be considered in the assist steam flow term when calculating combustion zone gas properties. Assist air intentionally entrained in the lower steam is included in the definition of perimeter assist air and must be considered when determining the dilution parameters, but it is not really relevant to the lower steam definition. We are not revising the definition of lower steam based on these comments.

3.13.3 Flare gas terms

Comment 1: One commenter suggested that for clarity, the EPA revise the term "vent gas" in 40 CFR 63.670(k)(2) to "flare vent gas" since that is defined.

Response 1: We agree with the commenter and have revised 40 CFR 63.670(k)(1), (k)(2), and (l) [lower case L] to use this term.

Comment 2: One commenter suggested that phrase "minimum amount of gas necessary" in the definition of flare sweep gas is ambiguous and not enforceable without clarification and that the EPA should either delete this phrase or add clarifying language to the definition to provide the regulated community with the concise criteria that the agency will use to determine if the flare sweep gas rates are "minimized."

Response 2: There is no requirement to minimize the quantity of sweep gas. The intent here is to recognize that some quantity of sweep gas is necessary for the safe operation of the flare header system and that even the minimum flow of sweep gas needed for flare operation is to be included as part of the flare vent gas. However, for the purpose of the flare requirements, there is no specific need to refer to this as the "minimum amount of gas." We are replacing the phrase "the minimum amount of gas necessary" with the phrase "the gas intentionally introduced into the flare header system" in two places within the definition of "flare sweep gas."

Comment 3: One commenter suggested that the EPA should include pilot gas as part of the flare vent gas because, for some flares, the heat release of the pilots can be a significant portion of the total heat release from the flare. Alternatively, one commenter supported EPA's assessment and agreed with the EPA that it is unnecessary to consider pilot gas in calculating the combustion zone parameters.

Response 3: We appreciate the comments. The data available to us suggests that heat release from the flare pilots are generally negligible when regulated materials are sent to the flare and exclusion of the flare pilot gas simplifies the NHV_{cz} calculation. Even when only purge gas is used, the flare pilots typically only provided about 10 percent of the total heat input to the flare and typically well less than 1 percent in the recent PFTIR flare tests when potential regulated material is routed to the flare (this is dependent on the size of the flare, number of pilots, and flare tip design, which impacts minimum purge flows). We are finalizing the definition of flare vent gas as proposed, which excludes pilot gas.

3.14 Cost and emission impacts for flares

Comment 1: Several commenters suggested that the EPA underestimated the cost burden that would be imposed on industry by the proposed new flaring requirements. To support their claims, the commenters suggested that, among other things, the EPA failed to account for the 500+ new flares and needed to comply with the flare tip velocity and visible emissions requirements during emergencies (and 200+ new flares needed to control atmospheric relief valves in organic HAP service), costs for new automatic pilot ignition systems, costs for personnel needed to perform daily Method 22 observations, and that the EPA should have evaluated the cost burden considering at a minimum a 10% compliance margin. Additionally, commenters went through their own cost analysis, making assumptions that a much larger percentage of flares will need continuous controls (and in most cases it will need to be redundant controls of both a GC and Btu analyzer) as well as larger excesses of natural gas because of the proposed 15-minute compliance time, proposed dual combustion zone limits, and additional operational 10% compliance margin and suggested that the new flare requirements would lead to a capital investment of at least $343 million and annualized costs of $118 million versus the EPA’s estimates of $147 million capital and $36.3 million annualized. One of these commenters also noted that the GC specifications in the proposal cannot be met by the GCs typically in place to meet State, consent decree, and permit requirements, as the EPA assumed. This commenter stated that their existing GC installations may have to be supplemented, adding an additional $500,000-$600,000 cost. Lastly, several commenters suggested that a combustion zone net heating value of 200 Btu/scf as a 3-hr average (and equivalent lower flammability limit and total combustibles combustion zone metrics) is all that is justified under a cost-effective basis to provide reasonable assurance of 98% destruction efficiency for steam-assisted refinery flares.

Response 1: First, it was not our intent or expectation that refineries would have to install hundreds of new flares in attempts to meet the velocity and visible emissions limitations at all times. We understand that, under high “hydraulic” load events, that the flare tip velocity and visible emissions limits possibly cannot be met, but we also understand that these events are infrequent and typically caused be power outages or other activities out of the refinery owners or operators control and that discharging these gases to the flare is better for both plant safety and environmental control, even when these emission limitations are not met. Having reviewed all of the comments, we have implemented a work practice standard to manage these large but infrequent events. This work practice standard is expected to reduce the frequency of these instances while obviating the need for hundreds of new flares. As such, we deem the extreme costs estimates for the installation of new flares to be unnecessary and inapplicable to the requirements in the final rule.

Next, and as discussed previously in Section 3.5 of this document, we have included an allowance to use 1,212 Btu/scf for the net heating value of hydrogen and eliminated the proposed dual combustion zone NHV_{cz} operating limits. The provision for hydrogen allows the NHV_{cz} limit to be an excellent indicator of good flare performance without "Type 2" errors previously expected from this compliance option so that refinery owners or operators may be less compelled to install full GC systems. With the elimination of the LFL and combustibles concentration operating parameters, we consider it unnecessary for flare owners or operators to install monitoring systems of both a GC and BTU analyzer as suggested by the commenters. We did revise our cost estimates for refinery flares to include costs to install hydrogen analyzers needed to determine hydrogen concentration in the flare vent gas (to allow use of the adjusted heat content of 1,212 Btu/scf for hydrogen). We also made minor changes to the supplemental natural gas and steam savings that results in complying with the "hydrogen adjusted" NHV_{cz} operating limit. Thus, as a result of these actions, we project the costs for refinery flare combustion efficiency requirements to increase slightly from $147 MM capital cost and $36.3 MM annualized cost at proposal to $156 MM capital cost and $45.6 MM annualized cost in this final action (see Table 8 in memorandum entitled *Flare Control Option Impacts for Final Refinery Sector Rule* in Docket ID No. EPA-HQ-OAR-2010-0682).

Lastly, the data available clearly refute the unsubstantiated assertion that a 200 Btu/scf 3-hour average NHV_{cz} provides "a reasonable assurance of 98 percent destruction efficiency for steam assisted flares." Our Monte Carlo analysis suggests that 90 percent of flares would not be achieving a 98 percent destruction efficiency if the NHV_{cz} operating limit was established at 200 Btu/scf on a 3-hour average basis.

Comment 2: A few commenters suggested that the EPA overestimated the emissions reductions that the newly proposed flaring requirements would achieve while another commenter suggested that the EPA underestimated these benefits.

One of the commenters that suggested that the EPA overestimated the emissions reductions points out that recent refinery flare consent decrees and the September 2012 finalized NSPS Ja amendments have driven flaring baseline emissions down and that they would project a 2015 baseline of 22,300 tons per year (tpy) VOC and 2,560 tpy HAP compared to the EPA's estimate of 33,100 tpy VOC and 3,810 tpy HAP. This commenter also did another analysis with differing assumptions from those of the EPA's (e.g., a different CE v. DE relationship, a higher baseline destruction efficiency, a 10% compliance margin for complying with the combustion zone limits and operating at 300/400 BTU/scf (proposed limits of 270/380 BTU/scf)), and this analysis determined that the proposed new flare requirements would result in smaller reductions of 11,150 tpy VOC, 1,280 tpy HAP, and actually cause a net increase of 111,700 metric tpy CO_2e (compared to the EPA's estimated 327,000 metric tpy carbon dioxide equivalents (CO_2e) reduction).

Alternatively, one commenter suggested that the EPA underestimated the benefits of the proposed new flaring requirements (0568) supported this assertion by stating that the average of the PFTIR test data shows that flares only reduce emissions by 92% (and not 93.9% as was assumed in the EPA's analysis) and that evidence from specific refineries shows that flare DE could be 12-25 times higher than the presumed 98% destruction efficiency and that it is arbitrary and capricious for the EPA to rely on the industry's data when evidence suggests that it is inaccurate. This commenter also suggested that the EPA has determined that the AP-42 emission factors for VOC emissions from flares operating at 98% destruction efficiency are approximately four times more on a heat input basis and that if this same ratio holds at lower destruction efficiencies that emissions reductions should be significantly higher.

Response 2: We appreciate these comments. Given that much of the information used to support this rulemaking came from an industry-wide 2011 ICR (with 2010 data), we still continue to feel that use of data from 2010 and 2011 from the EPA's GHGRP in concert with flare specific industry submitted data used to assess additional potential emissions reduction impacts from the same time period is consistent with our overall approach of using best available data as well as a consistent timeframe in estimating the impacts of this rulemaking. We reviewed the more recent GHGRP data for refinery flares and see no evidence of reduced use of flares, so our baseline emissions estimates appear to accurately portray current industry flaring practices. Therefore, we consider the approach we used to be a reasonable projection of the current emissions and projected emission reductions. We have revised our analysis slightly, considering the allowance to use 1,212 Btu/scf as the net heating value for hydrogen and the use of a single NHV_{cz} operating limit. Based on these revisions, we estimate 3,670 tpy emissions reduction of HAP, 31,900 tpy emissions reduction of VOC, and 396,000 metric tonnes per year emissions reduction of CO_2e as a result of implementing the refinery flare NHV_{cz} operational requirements as provided in the final rule.

Comment 3: Two commenters stated that cost-effectiveness of the NESHAP proposal must be adjusted to reflect any current local programs that address the same pollutant but perhaps in different ways. For example, consider the Flare Efficiency Requirements. Most refineries in California, including those in Wilmington and the Bay Area, already are under regulations that minimize or monitor flare utilization. As a result in California, flare use has already been minimized by regulation since the early 2000's and the reduction in flare use and flare emissions have already been documented.

These commenters recommended that the EPA's cost-effectiveness analysis be adjusted to reflect the capital and operating costs of emissions control technology. Rather than looking at overall costs for the nation, the EPA should document cost-effectiveness of the NESHAP controls by region because it seems likely that the cost-effectiveness calculations are likely too low. One of these commenters added that this is probably also true for toxics emissions as well as for VOC emissions and even for GHG emissions such as CO_2.

One of the commenters also stated that the EPA should be aware that the AB2588 process in California, for example, reduced toxic emissions and risk, such that most refineries posted risks that are already less than 10, certainly less than 25-in-1 million, which appears to be meeting EPA's target for residual risk, after implementation of all these controls. The commenter asked how refineries should address the EPA proposal if they have already achieved target levels.

Response 3: Our emission reduction estimates considered consent decrees as well as state and local requirements where these were known. Therefore, we disagree with the commenters that we overstated the emissions reductions. With respect to California provisions for flares, we acknowledge that these requirements helped to reduce flare emissions by reducing the amount of gas flared, but these requirements do not necessarily ensure that the flare is achieving the desired control efficiency. The flare impact estimates relied on nationwide data reported under the GHGRP (40 CFR part 98) based on 2010 and 2011 data, which would have accounted for reduced flare use from early 2000s regulations.

As this is a federal standard, we generally present the costs and environmental impacts on a nationwide basis. We also develop facility-specific cost estimates for use in the economic impact analysis. We acknowledge that the impacts and cost-effectiveness of the new standards varies for different facilities, but unless there are specific adverse impacts on a class of refineries (such as small businesses), we generally use the nationwide impact estimates to support our decisions.

With respect to AB2588, we note that the new flaring provisions are being promulgated under CAA section 112(d)(2) and (d)(3) and are not being promulgated under section 112(f). All major source refineries will be required to comply with all of the flaring requirements in the final rule, regardless of what their contribution to risk is projected to be. We also expect that the risks projected by the commenter assumed that all flares were achieving 98 percent destruction efficiency. The final Refinery MACT requirements for flares will ensure that these flares achieve that control efficiency.

3.15 Other/Ancillary Flare Comments

Comment 1: One commenter suggested that the implementation of low sulfur gasoline standards and clean fuels projects created dirty neighborhoods because the EPA failed to simultaneously require upgraded pollution control technology at the refineries and that fence line communities near refineries may be more impacted even though emissions from vehicles will go down. Because of this, they argue that fence line monitoring is crucial for these communities and wanted the EPA to clarify how many and which refineries are using flares as a pollution control device as well as to clarify how these proposed requirements will prevent more pollution in the event that more clean fuels projects are implemented.

Response 1: The commenters do not explain how they EPA should address their concerns through the residual risk and technology review rule at issue here. We assume their concerns are with the SRU, which many refineries had to install (or increase the use of existing units) to manage and recover the additional sulfur removed from the fuels as a result of the clean fuel standards. However, the commenters do not explain why they believe our risk and technology review for SRU was insufficient.

Second, we note that we have included requirements for fenceline monitoring. The fenceline monitoring program is for the purpose of addressing fugitive emissions and thus would not address emissions from the SRU.

With respect to the request that the EPA clarify how many and which refineries are using flares as a pollution control device, we note that the 2011 Refinery ICR included information regarding the number of flares and the general use of the flares (routine use classified by hours of operation as well as emergency only) and this information was included in the docket for the proposed rule (see Docket Item Nos. EPA-HQ-OAR-2010-0682-0061 through 0069). Any flares for which the General Provisions of 40 CFR part 60 or subpart 63 apply are assumed to be used as control devices. With respect to the request that the EPA clarify how the proposed requirements will prevent more pollution in the event that more clean fuels projects are implemented, we maintain that the final rule will ensure any new SRU or any flare receiving gases from clean fuels related project will be controlled to the MACT performance level.

Comment 2: One commenter suggested that stronger regulations for flaring at night are needed and that stronger community monitoring systems are needed to track and chart events and alert nearby residents when the events occur, through both web-based and phone-based systems.

Response 2: The final rule will ensure high flare combustion efficiencies, whether they occur during the day or night. As noted previously, we consider the existing emergency notification to be reasonable and appropriate and that the community will be notified in the event of a release or flaring event that creates a risk that would require evacuation of nearby residents. It is unreasonable to notify the public of every instance in which regulated materials are sent to a flare, therefore, we did not revise the rule requirements in response to this comment.

Comment 3: One commenter suggested that the flare monitoring requirements for presence of a pilot flame and no visible emissions as well as continuous monitoring of flare tip velocity accounting for the assist media to determine the combustion zone gas properties will give refiners a more accurate picture of the actual combustion efficiency of flares and that owners now have options and flexibility on how to demonstrate compliance.

Response 3: We agree that the monitoring requirements will provide refinery owners or operators with significantly more information than most refinery owners or operators currently have and that this information, along with fine air or steam assist controls that we included in or cost estimates, will enable them to operate their flares in a more efficient manner.

Comment 4: One commenter suggested that the requirement to replace flare tips is being implemented on an impractical timeline and that doing so is minimally beneficial at best.

Response 4: We did not propose, nor are we finalizing, requirements to replace flare tips.

Comment 5: One commenter suggested that the EPA consider providing exceptions or reduced requirements for refineries already complying with more stringent local rules pertaining to flaring and fugitive emissions.

Response 5: We do not agree that such exceptions are warranted because we have found no local requirements that are equivalent in performance to those in the final rule.

Comment 6: One commenter suggested that Refinery MACT 1 and 2 must specifically authorize the additional flaring required for compliance. Other commenters suggested this is needed because NSPS Ja requires minimizing flare emissions and Refinery MACT 1 and 2 will require new flare instrumentation and some of the QA/QC requirements for this instrumentation could cause an increase in the base emissions for the purpose of establishing the basis for the NSPS Ja 500,000 scf/d flare excess flow trigger. Additionally, commenters suggested these flare flows should not be counted in determining whether a flare meets the “emergency flare” criterion in NSPS Ja of 4 releases per year or less.

Response 6: We disagree. Generally, flare refinery owners will comply with the flare requirements by reducing steam flow, so we consider it unlikely that the final Refinery Sector Rule will significantly impact baseline flow characteristics. We also do not agree that the monitoring systems or QA/QC requirements will ever have an appreciable impact on baseline flare flows. For those few flares where supplemental fuel is needed to meet the operating limits in the final rule, refinery owners or operators may always request a revision to their NSPS baseline flow rates. Finally, we see no reason the requirements in this final rule would ever cause additional emergency flare releases. In fact, we are implementing work practice standards as part of this final rule that are expected to reduce the frequency of emergency release events.

4.0 Miscellaneous Process Vent Provisions

Comment 1: Many commenters stated that where a CPMS flow meter will now be required, three years is needed to engineer, procure, and install that system and thus the effective date should be three years after promulgation. The commenters added that eighteen months is required to bring all other instruments up to the new requirements, change procedures, train personnel, and revise permits, obtain and/or revise AMPs, and revise Consent Decrees and/or comply with an alternate work practice if adopted.

Response 1: The primary requirement for a CPMS flow meter in the MPV provisions is for bypass lines. Previously these bypass lines only required a “flow indicator that determines whether a vent stream flow is present at least once per hour.” We agree that, for bypass lines, the new CPMS flow requirements are significantly more stringent than previously required. As described in more detail in subsection 4.4 of this section, we are not finalizing this requirement for bypass lines, so no additional time is needed to comply with the bypass line monitoring. It is possible that flow meters may be used for alternate monitoring provisions in 40 CFR 63.644(b), but it is expected that such flow meters would be used for the purpose of quantifying flow rates, not simply as an indicator of flow. The 5 percent accuracy requirement for flow rate monitoring systems is a reasonable accuracy requirement for industrial flow meters and we do not expect 18 months is needed to meet these requirements.

The other primary CPMS for MPV are temperature monitoring devices used for thermal destruction devices. We do not consider the requirements in Table 13 to be onerous for these systems. As the normal operating range is likely 1,300 to 1,700 degrees F, the ± 1 percent accuracy requirement requires measurement to ± 13 or 17 degrees F. For refineries using alternate monitoring systems as provided in 40 CFR 63.644(b), we do not expect that any reasonable monitoring system to have difficulty meeting the accuracy requirements in Table 13. Therefore, we disagree with commenters that additional time is needed to upgrade monitoring systems used for MPV.

Comment 2: One commenter explained that in proposing revisions to the Refinery MACT 1 MPV provisions under the authority of section 112(d)(2) and (3), the EPA may be subject to claims that it reopened the entirety of its original MACT standard for comment and challenge, because the data used to support the EPA’s proposal calls into question the foundation of that standard. When the EPA originally set the MPV standard, it based the standard on a finding that “combustion control” qualified as the MACT floor. Lacking specific data on the control efficiency that could be achieved by “combustion control,” the EPA relied on information from its experience under the NSPS and HON source category regulations to assume an achieved level of control at 98% VOC emissions reduction. The commenter argued that now, the EPA offers information suggesting flares are not achieving this level of emissions control.

The EPA’s flares impacts analysis claims that combustion control under the current MACT standard achieves a nationwide average control efficiency of only 93.9%. In this regard, the EPA’s rationale for the proposed rule could appear diametrically opposed to its original standard. For example arguably, the EPA should not simultaneously claim that a 98% combustion control efficiency is not assured without the proposed rule enhancements, and yet continue to claim that the MACT floor was 98% emissions reduction when the best performing 12% of sources were not implementing these enhancements when the EPA established the MACT floor.

The commenter asserted that they do not believe that the EPA is necessarily compelled to re-examine the basis for its MACT floor decision to make improvements to the monitoring, recordkeeping and reporting requirements of a standard, in all cases. Here, however, because the EPA arguably presents data to support its proposed rule that calls into question the EPA's original basis for the control level, and also relies on section 112(d)(2) and (3) as the legal authority for the proposed changes, the EPA may be vulnerable to claims that the EPA must address the impact that this new information has upon its original decision-making. "Rulemakings that significantly change the context for a regulatory provision can re-open it for comment, even if an agency does not change the provision itself." *Sierra Club v. EPA*, 551 F.3d 1019, 1024 (D.C. Cir. 2008).

The commenter stated that they believe that the EPA established 98% as the appropriate control efficiency for the original section 112(d)(2) and (3) standard. Even if the EPA should have properly established the MACT floor at a lower control efficiency, such as 93.9%, the commenter remains confident that the EPA could have justified a 98% control efficiency as a control measure beyond the MACT floor that was cost effective and reasonable considering the non-air quality health and environmental benefits, and energy requirements. Nonetheless, to avoid reopening the original standard, and then defending the original basis for the standard, or re-affirming the original standard as cost-effective, the commenter urged the EPA to consider relying on section 112(d)(6) rather than section 112(d)(2) and (3) as the source of authority for its final regulations, because this will not have the effect of potentially reopening the original basis for the standard.

Response 2: We disagree that our proposal regarding flares calls into question our MACT floor analysis for MPV. We determined in the 1995 Refinery MACT 1 (subpart CC) that the MACT floor level of control for MPV is 98 percent VOC control (or reduction to 20 ppmv on a dry basis, corrected to 3 percent oxygen) based on the number of MPV controlled and the types of controls used on those MPV. At the time we set the MACT standard for MPV, we found that well over 12 percent of MPV used "combustion controls" that achieved 98 percent control efficiency. We note that not all "combustion controls" used for MPVs were flares (some facilities used thermal oxidizer/incinerators and some facilities used boilers or process heaters to control MPV). Additionally, we believe that flares prior to the MACT standard generally achieved 98 percent control efficiency and that it was only after the implementation of the Refinery MACT 1 standards, which imposed visible emissions limits through the General Provisions requirements for flares, and the increased use of flare gas recovery systems that refineries began to over-steam their flares had have reduced combustion efficiency. Even if some flares in 1995 were not meeting the 98 percent control efficiency at the time that MACT standard was set, we still expect that most flares were meeting this control efficiency. Even today, with average performance of all flares estimated to be 93.9 percent based our analysis of the recent API flare data, that same data set indicates that 20 of the 38 flares achieved 98 percent destruction efficiency in all operating modes. Thus, we are confident that the best performing flares (along with thermal oxidizers, boilers and process heaters) were achieving 98 percent destruction efficiency, so there is no question that the original MACT requirements for MPV were correctly established at 98 percent control efficiency.

While the best performing MPV sources were (and still are) meeting 98 percent control efficiency, the API data together with recent flare performance studies indicate that the on-going monitoring requirements established in the MACT rule (i.e., reliance only on the General Provision requirements) were not adequate to ensure that all flares were performing at the level equivalent to the top 12 percent of sources. As such, we are finalizing the monitoring standards for flares to ensure these control systems achieve the MACT performance level established in 1995 under CAA section 112(d)(2) and (d)(3).

Comment 3: One commenter stated that carbon adsorption controls are widely used to control remotely located, small and/or dilute or low pressure emission sources, such as waste management unit vents and certain tankage. The commenter explained that carbon adsorption generally cannot be used during shutdown of this equipment if steam is present (e.g., during hydrocarbon-freeing equipment) because the water will damage the carbon and/or prevent adsorption of hydrocarbons and/or cause desorption of already adsorbed hydrocarbons. In such cases, good air pollution practice is to bypass the carbon beds to prevent damage to the carbon and desorption of previously adsorbed hydrocarbons. The commenter recommended language be added to Refinery MACT 1 clarifying that carbon adsorption controls may be bypassed when the equipment they control is being steamed for hydrocarbon freeing purposes.

Response 3: This request to bypass the control device appears to be a request to allow unregulated emissions from MPV for a period of time. We do not believe that this is consistent with the requirement that emission standards must apply at all times. Best practices would be to have a knock-out drum and/or cooler to prevent steam or very hot gases from entering the carbon adsorber (and stripping VOC/HAP from the carbon in the adsorber). In addition, water spray cooler with a knock-out drum is a reasonably efficient and inexpensive means to lower the vent stream temperature prior to the carbon adsorber. Other MPV control systems, such as combustion devices, would allow sources to meet the applicable emission standard during these steaming events.

4.1 Revisions to the definition of miscellaneous process vents

Comment 1: One commenter stated that the proposed rule would preserve the exemption for emissions associated with “vents from storage vessels”, however this fails to comport with the definitional provision of EPA’s broader statements regarding SSM provisions. The commenter specifically stated that it is unclear whether emissions associated with vessel degassing would be subject to MACT requirements under the Refinery MACT as SSM related, or governed by the exemption from the definition of MPVs, and therefore not subject to any standards under Refinery MACT. The commenter suggested that the proposed rule be revised to clarify the inapplicability of MACT standards during these operating scenarios.

Response 1: Vents from storage vessels are not MPV as provided in item 12 of the MPV definition. We address requirements applicable to storage vessels separate from the requirements for MPV. We understand some storage vessels will have PRD which may release as a result of a process upset or malfunction. Storage vessel PRD in organic HAP service are subject to the equipment leak monitoring provisions and, if the set pressure is greater than 2.5 psig, the pressure release management provisions in 40 CFR 63.648(j).

Comment 2: One commenter interprets EPA's proposal to remove high point bleeds, open-ended valves or lines, and pressure relief valves from the list of exceptions to the requirements of 40 CFR 63.644(c), to mean that these types of equipment are subject to the 40 CFR 63.644(c) monitoring requirements unless they meet the exception of being subject to 40 CFR 63.648. Many commenters objected to the inclusion of high points bleeds as MPVs and suggested this change not be finalized. Additionally, one commenter explained that the examples of MPVs included in the proposed definition create confusion, and that it is the material vented, not the piping component through which the venting occurs that is considered in deciding whether a stream sent to a control device or to the atmosphere is a MPV. Many commenters argued that these changes are unclear and should be clarified or the existing language left unchanged.

Response 2: The provisions in 40 CFR 63.644(c) are specific to Group 1 MPV bypasses. High point bleeds are expected to be used primarily on liquid transport lines to collect and remove gases that might enter the system. In this application, we agree that the high point bleed would not be a bypass of a Group 1 MPV, rather the high point bleed would be an MPV itself, thus engineering calculations would be used to determine if this vent is a Group 1 MPV requiring control or a Group 2 MPV. In rare instances, the owner or operator may classify a release point on a gaseous vent system associated with a Group 1 MPV as a "high point bleed." In this case, the high point bleed when open acts as a bypass line (allowing direct atmospheric release) of a Group 1 MPV stream). These examples demonstrate that depending on the circumstance, a high point bleed could be construed as an MPV or a bypass line. Thus, we see no reason to categorically allow use of high point bleeds to bypass controls required for a Group 1 MPV streams. Additionally, in the case of liquid transport lines, we expect that this exemption has been used to neglect these releases from evaluation as a Group 1 or 2 MPV. We therefore retain the revisions to not include high point bleeds in the list of equipment that are not considered to be a bypass line.

We consider open-ended valves or lines and pressure relief devices to be equipment subject to 40 CFR 63.648 so it is redundant to list these items separately in 40 CFR 63.644(c). The first sentence remains the primary definition of MPV, i.e., "*Miscellaneous process vent* means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged from a petroleum refining process unit meeting the criteria specified in section 63.640(a)." Consistent with the definition, we agree that the first criterion to consider in determining whether a stream is an MPV is whether the gas stream contains greater than 20 ppmv organic HAP discharged from the petroleum refining process at a major source of HAP emissions. We are retaining the list of potential release points that could be an MPV because we consider them to be useful and add clarity to the definition.

4.1.1 Revision of fuel gas system exclusion

Comment 1: Two commenters raised a concern that the MPV provisions would apply to flares that are connected to a fuel gas system and that typically operate only during SSM because of

EPA's proposal to remove the fuel gas exemption for MPV, which according to one commenter directly conflicts with the EPA's Refinery MACT 1 finding, "that it is not necessary to revise Refinery MACT 1 requirements for miscellaneous process vents…" One of these commenters added that refinery fuel gas systems are processes that generate fuel gas for internal and sometimes external use, and thus fuel gas is a refinery product just as gasoline is a refinery product. This commenter further noted that the proposed rule could trigger immediate applicability of Refinery MACT 1 or 2 evaluation and control requirements including permitting, closed vent system and control device requirements for gas streams routed to that fuel gas system. The commenter stated that the requirement is unlawful because it would arbitrarily and without justification convert countless internal process streams into MPVs and estimated that hundreds or thousands of streams could be impacted.

Another commenter recommended two changes to the proposed regulatory text if the EPA eliminates the current exemption for vent streams routed to fuel gas systems from the requirements for miscellaneous process vents. First, the commenter stated the definition of "*miscellaneous process vent*," should include an exemption for vent gas streams routed to another refinery processing unit for further processing, internal use or sale. Second, the commenter requested that the regulations include an exemption for vent gas streams routed to the fuel gas system provided that any fuel gas going to flare is normally recovered by a flare gas recovery system which is designed with excess capacity under normal operations and operates at least 95 percent of the time.

Response 1: First, we note that the full quotation from Section IV.B.1.a of the proposal preamble is "that it is not necessary to revise Refinery MACT I requirements for miscellaneous process vents pursuant to CAA section 112(d)(6)." This conclusion follows our discussion of the inadequacy of the General Provisions at 40 CFR 63.11 to ensure flares used as control devices achieve a 98 percent destruction efficiency (in Section IV.A.3 of the proposal preamble) and need to ensure flares used with fuel gas systems currently exempted from the definition of MPV achieve the desired control efficiency (in Section IV.A.4.d. of the proposal preamble), revisions that were taken pursuant to CAA sections 112(d)(2) and (d)(3). Therefore, the technology review conclusion pursuant to CAA sections 112(d)(6), which focused on the primary control requirements for MPV (i.e., 98 percent reduction or 20 ppmv), does not conflict with conclusions made pursuant to CAA sections 112(d)(2) and (d)(3) to ensure that flares achieve the 98 percent destruction efficiency that was the determined to be the MACT floor.

Second, we did not remove the exemption for fuel gas systems, rather the exemption has been revised to specify that flares used with the fuel gas systems are operated with appropriately high combustion efficiencies. In our impact analysis, we assumed that all refiners would elect to comply with the new flare monitoring and operating requirements rather than consider all fuel gas streams to be a Group 1 MPV. While it is possible that a refinery could elect to treat their fuel gas as an MPV (if, for example, all of the fuel gas is used in process heaters or boilers with heat input capacity of 44 megawatts or greater, so no other monitoring is required), such an action would not exclude the flares that might receive that fuel gas from meeting the new flare monitoring and operating requirements. We expect that facilities will elect to upgrade their flare monitoring and operations and retain the fuel gas exemption provided in Item 1 of the definition of miscellaneous process vent. Since we are not eliminating the exemption for vent gas streams routed to the fuel gas system, we do not see a need to add additional exclusions suggested by the commenter. However, we do note that gases recycled internally to a process or that are purified and sold as a product and that are not vented would not meet the definition of MPV so these streams would be excluded in any case.

Finally, with respect to the suggestion that we allow an exemption for fuel gas systems with flares with flare gas recovery, we find it extremely difficult to develop requirements for a flare gas recovery system that could be considered equivalent to the 98 percent MPV control requirements. It is important to note that the recovered flare gas is generally being used in a process heater or boiler. While we agree these units achieve 98 percent combustion efficiency or higher without additional monitoring or operating requirements (and thus we are retaining the primary exemption for gases routed to the fuel gas system), they do not necessarily achieve 100 percent HAP emission reduction. Thus, a flare gas recovery system recovering 98 percent of the gas that would otherwise be sent to a flare is not necessarily equivalent to 98 percent emissions reduction of all HAP in the Group 1 MPV unless the 2 percent that is not recovered is also efficiently controlled. While we would like to encourage the use of flare gas recovery systems, we find that the exemption requested by the commenter is not equivalent with the MACT control requirements for MPV, and we have not provided such an exemption from the flare monitoring and operating requirements or MPV provisions for flares utilizing flare gas recovery systems. We do note that facilities have the right to request alternative monitoring options to demonstrate that their overall system achieves 98 percent HAP reduction at all times, regardless of the flare's level of performance.

Comment 2: One commenter stated the proposal to eliminate the route-to-fuel gas exemption imposes costs and burdens for no benefit and should not be finalized. The commenter noted that the EPA has failed to provide any explanation of the legal authority on which it is relying for this new requirement. In the preamble, the discussion of this new requirement is located in a section entitled "What actions are we taking pursuant to CAA sections 112(d)(2) and 112(d)(3)?", but according to the commenter, the EPA has not provided the explanation and analysis needed to understand how this new provision satisfies the requirements of sections 112(d)(2)/(3). The commenter stated the EPA did not identify the best performing source or sources, did not calculate a MACT floor, and did not set a standard based on consideration of the mandatory statutory factors (such as consideration of the cost of any "above the floor" alternatives). In short, one commenter argued that the EPA has effectively proposed a flare performance standard for flares in which fuel gas is combusted, but has not asserted any factual or legal justification for this new standard and, therefore, has violated EPA's obligation under section 307(d)(3) to provide an explanation in the proposed rule of the basis and purpose for this requirement.

Response 2: First, we note that we are not eliminating the route-to-fuel gas exemption; rather, we are simply conditioning it to those systems that may discharge to a flare that does not meet the Group 1 MPV control efficiency requirements. As explained in Section IV.A.3, the EPA determined that the current requirements for flares are not adequate to ensure compliance with the MACT. The previous exemption for fuel gas systems was predicated on an assumption that all fuel in a fuel gas system would be introduced in the flame zone of a combustion device, effectively ensuring efficient combustion with no on-going monitoring requirements, or sent to a flare. As noted elsewhere, the MACT floor level of control has not changed; however, we are implementing requirements, consistent with our determination that improperly operated flares do not meet the required control efficiency, to ensure Group 1 MPV streams that are discharged to the flare from the fuel gas system are properly operated and achieving the MACT floor control level.

We note that the limitation of the fuel gas exemption does not become effective for 3 years, providing time for refinery owners or operators to upgrade their flare systems. In our impact estimates, we assumed all refinery flares would install the enhanced monitoring system, including those serving a refinery fuel gas system.

Comment 3: One commenter stated that the section 63.640(d)(5) affected facility exception applies to emission points that are routed to fuel gas and that the current rule repeats the “route to fuel gas exception” in several places indicating its importance and the potentially large impact of these proposed revisions. The commenter suggested that only refinery flares should be subject to Refinery MACT 1 or 2 flare requirements and specific exclusions should be given for flares not owned or operated by the refinery (e.g., it is a flare in an associated chemical facility). For flares which are not refinery flares, a commenter suggested an hours per year criterion (based on various flare APCDs) be used to avoid imposing the costly refinery flare requirements and the burdens associated with this change on flares that only receive refinery fuel gas occasionally or due to unusual circumstances. The commenter asserted that there is no legal, logical, or environmental basis for imposing large costs and operating burdens on non-refinery flares because of the potential for a small amount of regulated HAP to reach that flare via a fuel gas system. Thus, the commenter asserted the proposed revision should not be finalized and the routing of fuel gas to flares should be addressed directly by defining fuel gas vented from a fuel gas system that might contain what would otherwise be Group 1 vents, as a Group 1 MPV. The commenter provided specific suggested changes to the regulatory text to address their concerns.

Response 3: Contrary to the concerns of the commenter, Refinery MACT, including the revisions being promulgated in this final action, do not apply to flares that do not receive refinery fuel gas or that are not located at the refinery affected facility (e.g., associated with an off-site chemical facility). In most applications, it is readily apparent which flares could receive gas from a fuel gas stream that receives gases that would otherwise be a Group 1 MPV gas stream. However, if a facility is uncertain regarding the applicability of the rule in a specific instance, then that facility can request an applicability determination. In our impact analysis, we assumed all flares at the refinery would be subject to the new flare monitoring requirements primarily as a result of the consideration of flares used as back-up control systems to a refinery’s fuel gas systems. We recognize that some flares may only occasionally act as a Refinery MACT 1 (or 2) control device. We explicitly included language in the flare monitoring and operating limit requirements to specify that these flares only need to meet the Refinery MACT requirements when the flare is acting as a Refinery MACT control device, but we see no reason to disregard the Refinery MACT requirements simply because the flare is not always acting as a Refinery MACT control device. We would hope that, given the improved information on flare gas flow and composition afforded by the required monitoring systems, refinery owners or operators would elect to operate the flare efficiently at all times whenever the flare is receiving waste gas. However, we recognize that these standards are specific to flares used as Refinery MACT control devices, so the operating limits apply only during times the flare is acting as a Refinery

MACT control device. Nonetheless, when being operated as a Refinery MACT control device the control requirements must apply at all times, so flares that are receiving “regulated material”, i.e., a Group 1 MPV stream, must comply with the flare monitoring and operating limits at all times. For these same reasons, we are not changing the proposed regulatory text as the commenter suggested.

Comment 4: Two commenters stated that if the proposed approach is finalized, it is critical that the wording of proposed 40 CFR 63.640(d)(5), 63.1562(f)(5) and exception 1 to the MPV definition be revised to remove the language requiring “compliance” with 40 CFR 63.670. One commenter explained this language would result in the affected facility and MPV exceptions being lost for any 15 minute period where compliance is not being achieved while fuel gas is routed to that flare. Loss of those exceptions for even 15 minutes would trigger the massive burdens of creating new MPVs and revising the affected facility. The commenter argued that failure to meet a flare requirement should only result in a deviation for that flare. Thus, the commenters stated that the fuel gas exemption should use the phrase “subject to 40 CFR 63.670” rather than “in compliance with 40 CFR 63.670.”

Response 4: We did not intend that a deviation of the flare requirements would cause all other combustion devices associated with the fuel gas system to become Group 1 MPV and subject to any applicable MPV monitoring requirements (either ongoing or only during the deviation). While we do not consider it likely that the current language would be interpreted in this manner, we agree that the phrase “subject to” rather than “in compliance with” would more accurately express our intent in this case, so the final regulatory text uses the phrase “subject to.”

Comment 5: One commenter suggested that fuel gas used as sweep gas, purge gas, assist gas, and pilot gas for flares be excluded from the Group 1 requirements, as the their amount of uses is minimized per NSPS Ja requirements.

Response 5: We disagree that an exemption should be given for sweep, purge, assist and pilot gases because if the fuel gas comes from a fuel gas system that receives a Group 1 MPV stream, then the combustion of the fuel gas must meet the minimum efficiency requirements for a Group 1 MPV stream because the standard applies at all times. We also disagree that the subpart Ja requirements minimize the use of sweep, purge, assist and pilot gases as the requirements were primarily focused on reducing waste gas that is flared. As we understand, a minimum quantity of gas is needed as purge/sweep gas to ensure air (oxygen) does not enter the flare tip and facilities already have an economic incentive not to use more gas than needed for this purpose. Similarly, pilot gas is used to maintain a constant pilot flame and is not varied with flare use or reduced as a result of the NSPS Ja flare provisions.

4.1.2 Removal of in situ sampling exclusion

Comment 1: One commenter stated that the definition of MPV should not be revised with respect to the “in situ sampling (on-stream analyzer)” exclusion. If the definition is revised in the final rule, the commenter contended that the proposed revisions are a confusing approach to address analyzer vents and that a clearer regulatory approach would be to define “in situ sampling systems” and maintain an exclusion for these systems in the definition of MPV. The commenter also recommended separately defining on-stream analyzer vents which would be covered as a MPV.

Response 1: The definition of MPV historically contained an exclusion for “in situ sampling system (on-stream analyzers).” We did not change the terminology; we merely proposed to phase out this exclusion. The term “in situ sampling system” is not defined and given the previous wording, it appears that in situ sampling systems and on-stream analyzers are considered to be interchangeable terms. Given the historic phrasing, we have concluded that the most clear and direct approach to resolve concerns with large sampling system or analyzer vent releases is to eliminate this exclusion in its entirety. As the rule amendments were only to phase out this exclusion (eliminating it within 3 years of publication of the final rule), we do not consider it necessary to define this term at this time, which will be irrelevant after the removal of the exemption. We did specifically request comment on issues as to why Group 1 sized analyzer vents would not be amendable to control and we received no comments suggesting such control was not feasible. Therefore, we are finalizing the elimination of this exclusion as proposed.

4.2 Revision of the definition of periodically discharged

Comment 1: Several commenters stated EPA’s proposed definition of “periodically discharged” is broad and would result in all gas stream containing greater than 20 ppmv organic HAP that are continuously or periodically discharged from a petroleum refining process unit to be considered MPV. These commenters argued that this is a significant expansion of the universe of MPVs. The commenters stated that in order to ensure this change does not apply retroactively or immediately on promulgation of the final rule, the EPA must expressly provide the specific effective date. The commenters specifically identified MPV exceptions 1, 2, 4, and 11 as proposed for modification without an applicability date. The commenters recommended adding applicability dates for each addition to the exception language and maintaining the old language and adding a deactivation date for that language in each entry.

Response 1: Owners or operators of affected facilities must meet the requirement that exist at the time the venting event occurs. Exception 1 of the MPV definition was proposed with an effective date 3 years after the date of publication to allow refineries to upgrade their flare systems, as needed. Exception 2 of the MPV definition is in the existing regulation; EPA’s proposed revision was not intended to change the substance but rather to provide additional clarity regarding why these discharges are not MPV (i.e., because they are regulated under 40 CFR 63.648). Since we did not substantively change Exception 2, we intended (and are finalizing) that it will be effective as of the effective date. Exception 4 of the MPV definition (episodic or non-routine releases) was proposed to be removed as of the effective date. The rationale for this was that these periodic events could be planned and, if the planned event would trigger the Group 1 MPV thresholds, then the plans could include the control of these larger vent streams. Based on other comments received, we have included special provisions for vents associated with process unit startup or shutdown to reflect best industry practices for these vents. Those provisions provide that the requirements apply as of the effective date for the reasons provided in the preamble to the final rule. Exception 11 of the MPV definition was proposed to fully exclude vents associated with decoking operations and is broader than the previous exception, although equivalent in practice. This provision will be effective upon the effective date of the final rule.

4.3 Bypass line provisions

Comment 1: One commenter stated that most flows through vent system bypass lines are not violations and there is no basis for arbitrarily declaring that they are by prohibiting all bypass flows as proposed 40 CFR 63.644(c) and 63.660(i)(2). The commenter stated that this would make refineries inoperable.

The commenter explained that in most cases such bypasses are done purposely (e.g., as part of a startup or shutdown, control device maintenance, or for some other process purpose) and the bypassed material is routed to a process, a fuel gas system or an alternative control device. The commenter claimed that while these flows will be detected by the current flow indicators and the proposed flow monitoring, removal of a car seal or opening of a lock, no atmospheric release occurs in such cases and flow through these connections is not an indicator of an uncontrolled release to the atmosphere and certainly is not a violation. Thus, the commenter concluded that the proposal to declare any flow through a bypass a violation is arbitrary and unsupportable and that proposed language must not be finalized.

The commenter also stated even when there is flow to the atmosphere through a bypass, there is not necessarily a violation. The commenter provided an example of when a stream containing mostly nitrogen would be bypassed around a combustion control device to avoid upsetting its operation. Alternative controls in these circumstances may not be feasible or justifiable for the minimal HAP release potential. The commenter provided another example when Group 1 vents may not be going to the vent system at the time other gases in the vent header are bypassed or the flow through the bypass is a start-up or shutdown stream that does not occur during normal operation and is not a Group 1 stream. This situation can readily occur for intermittent Group 1 vents and during maintenance, startup, and shutdown situations.

Further, the commenter added that operators retain records as required in 63.655(g)(6)(iii) of potential bypasses to the atmosphere, and these must be included in the Periodic Report. The commenter argued that the EPA has the necessary information to determine if a violation has occurred rather than making them a violation by rule.

The commenter suggested the wording of 40 CFR 63.644(c) and 63.660(i)(2) be revised to apply to bypasses that route Group 1 streams to the atmosphere or to a control that does not meet the applicable control requirements of Refinery MACT 1 and are not exempted under equipment leak work practice to clarify applicability. The commenter also stated that bypasses to another process or to fuel gas should be specifically excluded from the requirements in 40 CFR 63.644(c) and 63.660(i)(2).

Response 1: We did not intend to include lines that divert gases from one control system to another (such as diverting flow from an incinerator to a flare) to be a bypass line. Thus, we are revising 40 CFR 63.644(c) to clarify that a bypass line is one that diverts a vent stream away from the control device used to comply with paragraph (a) of this section and vents the stream either to the atmosphere or to a control device that does not comply with 40 CFR 63.643(a).

In several of their comments, it appears that the commenters are suggesting that there may be times that there is flow in the bypass line that is "associated with a Group 1 MPV," but that a specific flow event may in that line may not be flow of a Group 1 MPV stream. We note that the proposed language at 40 CFR 63.644(c) that the "[u]se of the bypass line at any time to *divert a Group 1 miscellaneous process stream* is an emissions standards violation" [emphasis added]. The proposed language did not say that the use of the bypass line is always an emissions standards violation, but only when that use specifically diverts a Group 1 MPV stream from the required control. We have clarified the recordkeeping requirements to include records to demonstrate whether flow detected in the bypass line includes flow from the Group 1 MPV. We have also clarified the reporting and recordkeeping requirements regarding the quantity of HAP released is specific only to those periods when the bypass line is used to divert a Group 1 MPV stream to the atmosphere or to a control device that does not comply with the requirements in §63.643(a). If the commenters are suggesting that Group 1 MPV streams may be directed to the atmosphere without a violation of the standard, we disagree. We maintain that any diversion of a vent stream meeting the definition of a Group 1 MPV stream (i.e., the thresholds for HAP concentration and mass emissions) either to the atmosphere or to a control device that does not comply with 63.643(a) is a violation of the MPV emissions standards.

We also note that we have established special provisions for maintenance MPV associated with startup and shutdown events, which are expected to address many of the issues raised by the commenter. Please see the preamble to the final rule for further details of the maintenance MPV provisions.

Comment 2: One commenter asserted that prohibiting bypasses and, thereby, declaring all bypasses to be violations complicates the management of any unavoidable bypass and required bypasses associated with maintenance, startup, and shutdown. The commenter argued that control is not always feasible, because of the properties of the stream or the control device and if the EPA believes there are feasible controls available for bypass streams, a CAA justification for imposing them must be provided and cost estimates and emission impact estimates to install such control must be provided for comment.

Response 2: As described in more detail in the preamble, we are finalizing requirements for maintenance vents (vents only used as a result of startup, shutdown, maintenance, or inspection), which we expect will typically address the concerns expressed by the commenter. We note that maintenance MPV may appear to be a bypass line if opened during normal operations; however, as long as the vent line is opened only for startup, shutdown, maintenance, or inspection, these vents can be classified as a maintenance MPV. This does not eliminate the need to monitor the vent line for flow if the vent line "could" act as a bypass line for a Group 1 MPV stream; however, special provisions apply to these vents when they are only used for startup, shutdown or maintenance. If the bypass line may be used for other purposes, including routine venting or emergency venting due to equipment or control device malfunctions, then the maintenance provisions are not applicable, and the bypass provisions as described in the previous comment response applies and it is a violation of the emissions standards to divert a Group 1 MPV stream to the atmosphere or a control system that does not comply with the requirements in §63.643(a). Based on the final rule requirement, we consider the MPV and bypass provisions can be achieved at all times.

Comment 3: One commenter stated that there are significant legal, technical, and cost issues associated with installing flow CPMS in bypass lines. The commenter added that flow monitoring was available in the initial Refinery MACT 1 rulemaking and does not represent new technology and thus is not authorized under section 112(d)(6). There is no evidence presented in the record to demonstrate this change reduces emissions or increases compliance assurance nor is there any indication that the costs and burdens of replacing the current compliance monitoring has been tabulated, published for comment, and justified. The commenter also argued that flow monitors offer no advantage to a flow indicator in alerting the operator of a release. The commenter concluded by stating no such change is proposed for other potential bypasses and there is no legal basis for this proposed change.

The commenter asserted that bypasses to the atmosphere are not a significant problem and reporting under federal and state rules and facility permits is already required. Any bypass to the atmosphere of a Group 1 stream, as indicated by the flow indicator required under the existing Refinery MACT 1 for any potential closed-vent system (CVS) bypass, already has to be recorded and reported (including an emissions estimate) under Refinery MACT 1 requirements, under permit reporting requirements, and under a variety of federal and state release reporting requirements. The commenter argued that the proposed requirement adds no new information while significantly increasing the instrumentation costs and burdens. The commenter added that the EPA provided no data that indicate unplanned bypasses to the atmosphere are frequent or common.

The commenter stated that there are feasibility and cost issues with requiring flow monitors instead of flow indicators. The commenter specifically stated that one criterion is to meet the specified accuracy requirement at normal flow which they argued is zero, but the bypass flow may be high. If the meter is set for no or low flow, it may serve as a flow indicator, and if it is set for the bypass flow, it will miss low flows.

The commenter also discussed the QA/QC requirements in Table 13 and stated that monthly and quarterly frequency is nonsensical if there is no flow. Additionally, the commenter stated that an annual performance check is required, but could not be completed without having to bypass material which would result in a violation. The commenter also noted that meeting the swirling flow or abnormal velocity distribution requirements will require revisions of bypass lines to install long straight meter runs. Such piping revisions come at significant cost in the typically congested areas where these bypasses are typically located.

Conversely, another commenter supported the requirement for flow monitoring through bypass lines, noting that such monitoring will discourage facilities from manually bypassing flares to disguise potential activation of pressure relieving devices and give the appearance of having less HAP released than is actually leaving the process.

Response 3: The issue of whether the use of bypass is frequent or common is not pertinent to a determination that when such an event occurs it is a violation of the emissions standards. Our proposal was for the purpose of ensuring, through monitoring, that the applicable emissions standards are continuous and are not circumvented by a bypass of the control device.

We considered all of the comments that we received on this issue and we re-evaluated the need to use a quantitative CPMS for flow in bypass lines. Based on that re-analysis, we have determined that the use of a flow indicator along with engineering estimates and process knowledge are sufficient for the purpose of estimating the magnitude of the release without having to install new quantitative flow monitoring systems. Therefore, we are not finalizing the proposed requirements to install flow CPMS, and are, instead, retaining the existing requirements to have flow indicator monitoring systems. We are finalizing, similar to the proposal, recordkeeping and reporting requirements for bypass lines to require an estimate of emissions (previously only the duration of the flow was required to be reported, not an estimate of the mass emissions as suggested by the commenter). We are also finalizing clarifications that these estimates can be made using instrument readings, engineering calculations, and/or process knowledge.

Comment 4: One commenter stated that defining a bypass in 40 CFR 63.644(c) as including occurrences of air intrusion into a control device is new, unjustified, technically flawed, ambiguous, and should be deleted. The commenter explained that this has never been considered a bypass in the past and does not involve emissions to the atmosphere. The commenter added that air is added to many combustion control devices to allow combustion to occur (i.e., air-assisted flares) and some regulated vent streams include air (i.e., some tank vapor spaces and waste treatment unit vapors), and these would presumably now be a disallowed with this proposed prohibition.

The commenter also stated that the term “bypass” is ambiguous since it would mean that a stream with any amount of air intrusion would be considered a bypass. The commenter provided an example of minute, unpreventable leakage into a vacuum system through fittings as a stream which could be construed as a bypass under the proposed definition. The commenter concluded by asserting that a bypass under Refinery MACT 1 should be limited to releases of Group 1 streams to the atmosphere without their passing through a compliant control device, being routed to a process (including fuel gas process), or being allowed under special circumstances, such as during identified maintenance, startup, and shutdown scenarios, and all proposed language associated with air intrusion in this proposal must be deleted.

Response 4: We did not intend to define a bypass as including occurrences of air intrusion and the language in 40 CFR 63.644(c) does not include any language that suggests that a bypass would include occurrences of air intrusion. However, we did inadvertently include a recordkeeping requirement for bypass lines regarding air intrusion and we are not including that reference to air intrusion in 40 CFR 63.655(i)(4) in the final rule.

Comment 5: One commenter stated that the prohibition on routing MPV and storage vessel bypasses to the atmosphere will require installation of controls, where they are feasible. The commenter explained that the installation of monitoring equipment will require new flow meter installations as well as piping revisions wherever flow indicators are currently used for MPV bypass monitoring to meet the Table 13 requirements for these new monitors. The commenter stated that at least 3 years will be required to implement controls and monitoring equipment required by the proposal. The commenter also suggested that applicability dates should be provided in 40 CFR 63.644(c) to indicate when the flow monitor requirements take effect and when the flow indicator requirements are no longer applicable.

Response 5: We have included specific startup and shutdown provisions for maintenance MPV that we anticipate will eliminate the need to install new control devices. Also, we are not finalizing the requirements to install flow CPMS for bypass lines, so no additional time is needed. Based on the provision included in the final rule as described in the preamble and in the responses to the other comments in this section, we have determined that no changes in compliance dates are necessary.

Comment 6: With regard to the proposal to remove the exception from 40 CFR 63.644(c) monitoring requirements for PRD on MPV vapor collection systems, two commenters expressed concerns over closing or blocking (even by a flow meter) relief paths which they stated could cause potentially catastrophic events. One of these commenters added that the EPA has proposed 40 CFR 63.648(j) to address PRD and thus the exception for equipment subject to 40 CFR 63.648 might be adequate for excluding PRD from 40 CFR 63.644(c). However, 3 years is provided for the PRD monitoring requirements in 40 CFR 63.648(j) to be met and there may be a question as to whether the 40 CFR 63.648 exception applies prior to that PRD compliance date. Furthermore, controlled PRD (e.g., PRD routed to a flare) are excepted from 40 CFR 63.648(j)(1)-(3) and thus there may be a question as to whether the 40 CFR 63.648 exception applies to controlled PRD. Since the impact of misunderstanding the applicability of 40 CFR 63.644(c) to this critical safety equipment is dire and the current rule calls them out separately from 40 CFR 63.648 regulated equipment, the commenter strongly suggested that the separate 40 CFR 63.644(c) exception for PRD be maintained.

Response 6: We agree with the commenter that the phrase “regulated under §63.648” provides some ambiguity regarding whether certain PRD are MPV or exempt because they are regulated as equipment components in 40 CFR 63.648. In our proposal, we intended that PRD would be subject to the requirements in 40 CFR 63.648 and we consider PRD vented to a flare or other control device to be subject to the requirements in 40 CFR 63.648(j). In the final rule, we are proposing additional work practice requirements for PRD under 40 CFR 63.648 which will likely further confuse the issue (with respect to timing of certain requirements). Therefore, we are maintaining the general exclusion for PRD; we are simply rephrasing item 2 in the definition of MPV to exclude “Pressure relief device discharges” rather than “Relief valve discharges” to more clearly note that this exclusion applies to PRD (including rupture discs) and is not limited to “valves”; this revision also provides more consistency with the terms used in final rule at 40 CFR 63.648(j).

Comment 7: One commenter requested that the EPA add an option for a manual block valve equipped with a valve position indicator, to be used in lieu of a flow indicator, under 40 CFR 63.644(c). Associated with the use of a manual block valve, the EPA could require continuous monitoring of the indicator and reporting of any diversions to the atmosphere. The arrangement would be similar to a lock and key or car-sealed valve (i .e. manually operated block valve).

Response 7: We agree that a manual bock valve with a valve position indicator is a type of flow indicator and have provided language in §63.644(c)(1) to allow this as an option.

Comment 8: One commenter stated the proposed 40 CFR 63.644(c)(1)(i) and Table 10 revision requires that the flow monitor "record the volume of the gas stream that bypassed the control device". However, flow monitors measure flow rates, not volumes, and, thus, this wording is imprecise. The commenter suggested that the wording should be that the monitor "record the flow rate of the gas stream" and that the estimated volume be calculated from the flow rate data.

Response 8: We are not finalizing the flow CPMS provisions, and, thus, we are not revising the provisions in Table 10 concerning bypass lines. However, we are requiring refinery owners or operators to estimate the volume of gas and mass of HAP diverted to the atmosphere via the bypass lines.

4.4 Monitoring requirements

Comment 1: One commenter stated that the EPA failed to explain or justify the proposed amendment to the second sentence in section 63.644(a). The commenter noted there is no change in instrumentation proposed for monitoring combustion controls other than flares (in sections 63.670 and 63.671) and no demonstration that there are compliance assurance problems that justify the large additional burdens imposed by Table 13 or that justify the change of the existing monitoring instrumentation to meet the new Table 13 accuracy requirements. The commenter continued by stating there has been no change in monitoring instrumentation that might authorize these revisions under section 112(d)(6), and this change is not reflected in the cost and burden analyses for this rulemaking.

Response 1: We disagree with the commenter's assertion that the Table 13 requirements are arbitrary. The existing rule requires monitoring equipment be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures to ensure that the equipment will monitor accurately. In order to make this requirement clearer, ensure the accuracy of monitoring equipment, and provide framework for enforceability, we have proposed and are finalizing reasonable and achievable calibration and quality control requirements in Table 13.

Comment 2: One commenter stated that flare tips cannot be safely accessed when the flare is in service. The commenter argued that the proposed revisions to 40 CFR 63.644(a)(2) put people at great risk, because they require accessing the flare tip frequently, and the commenter urged EPA to retain the current language.

Response 2: We revised 40 CFR 63.644(a)(2) to transition the requirements for flares used for MPV to meet the new flare monitoring and operating requirements in 40 CFR 63.670. We consider these revisions necessary because we found that the current monitoring requirements (which only includes pilot flame monitoring) is insufficient to ensure that flares are achieving 98 percent control efficiency. For these reasons, we disagree that revisions to 40 CFR 63.644(a)(2) are not necessary.

We expect that the commenter is concerned with the application of Table 13 to monitoring systems to detect the presence of a flare or to pilot flame monitoring requirements in 40 CFR 63.670, similar to the comments summarized in Section 3.2.2 of this document. As noted in the responses in that section, we do not consider monitors used to detect the presence of a flame to be a temperature CPMS or any other type of CPMS listed in Table 13, and we have revised 40 CFR 63.671(a)(1) to specifically exclude pilot flame monitoring systems from the QA/QC requirements in Table 13. The existing language used in 40 CFR 63.644(a)(2) for flare pilot monitoring is to "monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present." While we allow the use of a thermocouple, we do not refer to it as a temperature monitor, and we clearly do not limit the devices to thermocouples or other direct temperature monitoring systems. As noted in previous responses in Section 3.2.2, we do not consider it necessary that monitors used to detect the presence of a flame require the same accuracy as a monitor used to determine a temperature used to determine compliance with a specific temperature operating limit. While we maintain that there are no direct CPMS monitoring requirements in Table 13 for CPMS used to "detect the presence of a pilot flame," we are revising 40 CFR 63.644(a) to include the phrase "except for CPMS installed for pilot flame monitoring" with regards to requiring monitors to meet the requirements in Table 13, similar to the revisions we included in revised 40 CFR 63.671(a)(1).

4.5 Recordkeeping and reporting requirements

Comment 1: One commenter stated that the proposed 40 CFR 63.655(g)(6)(iii), 63.655(i)(4)(ii), and Table 10 should all be revised to remove references to air intrusion events. Also, the commenter added that most flows through bypasses do not involve regulated materials or releases to the atmosphere and there is no reason to require records or reports unless regulated materials are present and are not routed to a process, fuel gas system or compliant control device. The commenter noted that the proposed 40 CFR 63.655(i)(4) contains the recordkeeping provisions associated with the proposed bypass monitoring requirements. The introductory paragraph appears to apply the recordkeeping requirements to all closed vent system bypasses, not just those regulated by 40 CFR 63.644(c) and to include drains and vents, which are specifically excluded from monitoring by those paragraphs. Thus, the commenter recommended section 63.655(i)(4) be revised as follows.

(4) For each closed vent system that contains bypass lines that **are required to be monitored by section 63.644(c)**~~could divert a vent stream away from the control device and to the atmosphere, or cause air intrusion into the control device,~~ the owner or operator shall keep a record of the information specified in either paragraph (i)(4)(i) or (ii) of this section **when Group1 streams are present,** as applicable.

Response 1: We agree that the references to air intrusion in these sections and Table 10 should be removed. The emission limitations in Refinery MACT 1 are not susceptible to air dilution so these provisions are not needed. We have revised the Group 1 MPV requirements, and there may be flow in a line that may serve as a bypass line during normal operations, but may have permissible flow during certain periods, such as prior to equipment openings. Therefore, we are revising the reporting requirements to limit the reporting for bypass lines to instances when flow of "regulated material" (i.e., Group 1 MPV stream requiring control) is discharged to the atmosphere. Records must still be kept of instances of flow in the bypass line as well as records needed to document that the flow was not "regulated material."

5.0 Storage Vessel Provisions

5.1 Technology review results

Comment 1: One commenter asserted that the EPA's proposed enhanced tank requirements should be based only on the EPA's section 112(d)(6) authority, not on section 112(f). The commenter explained that in the proposal, the EPA conducted a technology review under CAA section 112(d)(6) to "identify the latest developments in practices, processes, and control technologies for storage vessels." 79 Fed. Reg. at 36914. The EPA evaluated three options for requiring additional tank controls. Based on its cost-effectiveness analysis, the EPA proposed adopting option two, which included the controls in option one. Id. at 36915. The EPA also evaluated these three options in its section 112(f) risk assessment. The EPA determined that the controls in option two also "are necessary to provide an ample margin of safety to protect public health." 79 Fed. Reg. at 36940

The commenter argued that the EPA's approach in this roposal is contrary to the statute in that sections 112(d)(6) and 112(f)(2) address fundamentally different issues using fundamentally different factors. The commenter asserted that the agency's obligation under section 112(d)(6) is separate from the EPA's duty to evaluate the health risks of hazardous air pollutant ("HAP") emissions from a source category on a one-time basis through section 112(f)(2). The commenter suggests that if Congress had intended the two review processes (which address wholly different concerns) to be dependent, it could have required the EPA to conduct them concurrently or otherwise relate them. In recent years, the EPA has chosen to conduct the two reviews simultaneously as a matter of convenience, but that approach is not required by the statute. The EPA could conduct them in separate proceedings at separate times. The commenter argued that the EPA's analysis has improperly conflated these separate provisions and argues that addressing 112(d)(6) and 112(f)(2) in the same rulemaking would deprive section 112(d)(6) of any meaning. Another commenter argued that EPA's approach in this rulemaking is inconsistent with and contravenes Congressional intent.

Response 1: These amendments were appropriately implemented under the authorities of both sections 112(d) and 112(f) of the CAA. There is nothing in the CAA that precludes us from performing the duties under section 112(d) and under section 112(f) within the same rulemaking. We performed a technology review and risk review, separately, and found that additional controls were appropriate for storage vessels under the authority of 112 (f) (2) because the additional tank controls were found to be cost effective and would reduce cancer incidence and the number of people exposed to risks of greater than 1-in-1 million, and therefore we are finalizing our decision that these controls are necessary to provide an ample margin of safety. Because we also found these controls to be cost effective, we proposed and are finalizing our decision to require tank controls under 112 (d)(6) as well. We note that for other emission sources, we proposed and are finalizing additional controls under the authority of 112 (d)(6) only as they were not found to reduce risk but were found to be cost effective. Therefore we disagree that section 112 (d)(6) has no meaning independently of section 112 (f)(2).

Comment 2: One commenter generally supported the EPA's proposal to require better controls for external and internal floating roof tanks and expand the applicability of the standards to smaller storage vessels and/or those with lower vapor pressure due to pollution control developments that have occurred and to assure an ample margin of safety to protect public health. However, the commenter asserted that the EPA also has no lawful basis to not require the following improvements based on costs: degassing controls; retrofit external floating roof tanks; additional monitoring of tanks using the EPA Method 21 or optical gas imaging; and warning monitors for liquid overfill and roof landings. The commenter asserted that the statute contains no authorization to place cost above the statutory objectives of section 112(d) or 112(f). The commenter further supported its assertions by citing examples of existing SCAQMD requirements for external floating roof any storage vessel at a refinery having a capacity larger than 75 cubic meters for materials having a vapor pressure greater than 3.0 pounds per square inch (psi) and existing Texas and the SCAQMD requirements for refineries to control emissions from tanks when they are emptied and degassed for any reason.

The commenter contended that the EPA should revise its cost analysis of the rejected control options on the most recent data from the petroleum ICR. The commenter asserted that the EPA failed to provide any reasoned analysis for how it estimated the resulting VOC and HAP reductions from augmented monitoring and warning control. The commenter requested clarification on how EPA derived potential emission reduction in the conclusory estimate of VOC and HAP possible reductions for implementing these controls in the memorandum to the docket "Impacts for Control Options for Storage Vessels at Petroleum Refineries" (EPA-HQ-OAR-2010-0682-0199). The commenter also contended that there is significant evidence that leaking storage vessels are significant sources of fugitive HAP emissions and that emissions from tanks are significantly underestimated, citing the report to the docket "Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City, Texas" (EPA-HQ-OAR-2010-0682-0070). The commenter requested that the EPA include these potential emissions reduction in its analysis of requiring augmented monitoring requirements.

The commenter also requested that the EPA reevaluate the benefits of requiring degassing controls and the conversion of external floating roof tanks into internal floating roof tanks based on the actual vapor pressures of the stored material as reported in the ICR, citing that earlier analysis of control options assumed that that the vapor pressure of the material stored by external floating roof tanks is significantly lower than what was actually reported to the ICR.

Response 2: The EPA appreciates the general support to require better controls for storage vessels at refineries. Regarding the commenters assertion that the EPA has no lawful basis to consider costs of controls, section 112(d)(2) of the CAA states that we shall take cost into consideration in establishing emission standards under that section of the Act. If the application of cost effective controls under section 112(d) results in unacceptable residual risk, then any standards promulgated to mitigate such unacceptable risk under section 112(f) would not take costs into consideration. Because the proposed standards for storage tanks based on technology review left no unacceptable risk, we had no rationale for requiring controls are that not cost effective for storage vessels at refineries. Regarding the emission reduction estimates used, "Impacts for Control Options for Storage Vessels at Petroleum Refineries" states that it was assumed that the additional monitoring requirements would reduce emissions by 10 percent. We have not received any comments providing evidence of an alternative estimate. Any estimate would involve gross assumptions about the number of avoided floating roof landings and the occurrences of tank control equipment failures or improper operations that would be detected by Method 21 or optical sensors.

Regarding fugitive emissions from leaking storage vessels, to the extent that benzene emissions are present in such, these types of emissions are expected to be detected in the fenceline monitoring requirements promulgated herein. Facilities will have an incentive to find the cause of higher than normal concentrations (including leaking storage vessels) and fix the cause of the higher than normal readings before an action level is triggered.

Regarding degassing controls and retrofitting fixed roofs on tanks that are currently equipped with external floating roofs, we considered these controls in developing the proposal, but were not included in the proposal because we considered them not to be cost effective. Because there was no unacceptable residual risk after application of cost effective controls, these controls were not needed to mitigate unacceptable risk. The rationale for this consideration is expressed in the document "Impacts for Control Options for Storage Vessels at Petroleum Refineries." Regarding the assertion that the ICR reported vapor pressures are higher than the vapor pressures that we used to assess the cost effectiveness of degassing and retrofitting fixed roofs onto existing external floating roofs, we note that we used annual average vapor pressure values, which we consider appropriate when developing nationwide annual emissions estimates. The vapor pressures reported in the ICR are maximum true vapor pressures and not annual averages (footnote: Table 4-1 of https://refineryicr.rti.org/Portals/0/Petroleum_Refinery_ICR_Component_1.pdf), so the ICR values are expected to be higher than those used in emissions impact analysis for various stored liquids.

Comment 3: One commenter stated that the existing Refinery MACT 1 storage vessel provisions in section 63.119 through 63.121, where the requirements for use of a closed vent system and control device are specified in 40 CFR 63.119(e). Paragraph 40 CFR 63.119(e) includes 1) a provision to grandfather control devices that were installed on or before December 31, 1992 and achieve at least 90% effectiveness, and 2) a provision that addresses planned routine maintenance. The commenter explained that the proposed change in 40 CFR 63.660 to invoke the requirements of subpart SS does not include these provisions from 40 CFR 63.119(e)[88], and no rationale or analysis is presented to justify removal of these provisions and no compliance time is provided if a grandfathered control device must be upgraded. If the grandfathering provision specified in 40 CFR 63.119(e)(2) is not preserved in the revisions to the

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[88] Subpart SS contains the recordkeeping and reporting requirements associated with the planned routine maintenance provisions, but relies on the referencing subpart to contain the planned routine maintenance provision itself.

rule, then a control device that has been in compliance with this provision will need to be either upgraded or replaced. Consistent with CAA section 112(i), 3 years should be allowed for upgrade or replacement of an existing control device. The provisions for planned routine maintenance in 40 CFR 63.119(e)(3) and (e)(4) are needed to allow for the routine maintenance necessary in order to maintain control devices (and in some cases closed vent systems) in good working order. These paragraphs from 40 CFR 63.119(e) should be carried over into the new requirements of 40 CFR 63.660(i).

The commenter suggested specific revisions to proposed 63.660(c) to maintain grandfather and the planned routine maintenance provision provisions in their comment on pages 204-205.

Response 3: EPA disagrees that a grandfathering provision for closed vent control devices that were installed on a storage vessel on or before December 31, 1992 should be added to §63.660. By the promulgation date of this RTR rulemaking, storage vessels with controls installed prior to December 31, 1992 will have had 23 years to upgrade controls, and thus we maintain that ample time has been provided. EPA did not, however, intend to eliminate the provisions for planned routine maintenance. The routine maintenance provision was originally established in the HON (see 40 CFR 63.119(e)(3)–(4); 57 FR 62710, December 31, 1992 (proposed); 59 FR 19402, April 22, 1994 (final)) for facilities that elected to use a closed vent system and control device to comply with the emission limitation requirements for tanks. Consistent with other recent rulemaking packages, including the NESHAP for Off-site Waste and Recovery Operations (OSWRO) codified in subpart DD of part 63, we intended to include the routine maintenance provision in the HON for tanks routing emissions to control devices. We are including these provisions in the final rule because the estimated HAP emissions to degas the tank would be greater than the emissions that would result if the tank emitted directly to the atmosphere for a short period of time during routine maintenance of the control device.

5.1.1 Other controls (degassing, geodesic domes, roof landings)

Comment 1: Many commenters generally supported the rule provisions for storage tanks. The commenters did provide additional suggestions or clarifications for the proposed rule regarding emissions detection technology, stormwater run-off, primary seals, regulating more categories of tanks, and the grandfathering exemption.

One of these commenters added that the EPA should consider the use of newer emissions detection technology including Fourier Transform Infrared Spectroscopy (FTIR), Solar Occultation Flux (SOF) Time Correlation Tracer, Vertical Radial Plume Mapping, and DIAL. Another commenter added that the EPA should also require monitoring at the bottom of the tank to capture all evaporate leakage.

One commenter also asked how evaporative emissions from rain accumulation and run-off from the roofs of the storage tanks would be addressed in this rulemaking.

This commenter also asked the EPA to clarify which primary seal (liquid mounted foam or mechanical shoe) is more protective of human health.

Another commenter added that the EPA should upgrade roof deck fitting controls by adding requirements to cover roof openings, sleeves, and wipers for guide poles as well as expand the regulation to tanks that are in excess of 20,000 gallon capacity and exceed 1.9 psi or are in excess of 40,000 gallon capacity and exceed 0.75 psi. Two commenters recommended that all tanks be required to be covered by domes to prevent leakage.

One commenter added that the BAAQMD and SCAQMD regulations in California governing organic liquid storage tanks are at least as stringent as those proposed in this rulemaking and, in some cases, require emission controls at even lower product vapor pressures. The commenter supported the requirements in California and stated that the EPA should adopt the SCAQMD requirement for all refinery tanks to have internal floating roofs.

Two commenters stated that the grandfathering exemption for tanks in subpart WW of part 63 should be removed from the proposed rule.

Response 1: The EPA appreciates the support for enhanced control requirements for storage vessels and the additional suggestions.

Regarding the suggested detection methodologies, the EPA did consider these before proposing these amendments. The fenceline monitoring provisions in this final rule specify a technology that is highly effective at detecting emissions of benzene from storage vessels at concentrations expected to be present at refinery property boundaries. In the fenceline monitoring section of this response to comment document, please see responses to comments about the possible use of alternative detection technologies in the fenceline monitoring provisions of this rule.

Regarding emissions from rain accumulation and run-off from the roofs, any product that becomes entrained in rain water drains is required to be addressed in the wastewater provisions of this rule.

Regarding what type of primary seal is most effective, theoretically, according to equations and rim-seal loss factors in AP-42, all else being equal, a storage tank with a liquid mounted primary seal would have less rim seal loss emissions than one with a mechanical shoe primary seal. This is the case for either a primary only seal or if a rim mounted secondary seal is also present. However, another important factor in the emissions is how well the primary seal is maintained. Proper maintenance of rim seals are at least as important as the type of primary seal on a storage vessel. There is anecdotal evidence that the service history of mechanical shoe seals are better than liquid mounted seals.

Regarding the recommendations to upgrade desk fitting controls on certain tanks and to require internal floating roofs on all storage vessels at refineries, the EPA did examine enhanced controls when it developed the proposal. Based on the technology review the EPA performed, additional storage tank controls beyond what are provided in the final review would not be cost effective.

5.1.2 Revision of definition of Group 1 storage vessels

Comment 1: One commenter stated that small storage vessels should be included in the storage vessel definition if a pressure exception is not added to the proposed atmospheric PRD requirements. The commenter explained that the definition of a storage vessel in Refinery MACT 1 contains an exclusion for "[v]essels with capacities smaller than 40 cubic meters." This exclusion has not been an issue in the past. Under this proposal, however, the commenter argued that the pressure/vacuum (P/V) vent on these small tanks would be miscellaneous process vents or, if the tank is controlled with a closed system, relief valves and would be subject to evaluation under those sections and potentially control. Thus, these smaller vessels, which are permitted as tanks and were considered tanks in the development of Refinery MACT 1, should be clearly identified as storage vessels in Refinery MACT 1.

Response 1: The final rule now provides exemptions for PRDs in §63.648(j)(5), including relief devices with a designed set relief pressure of less than 2.5 psig, from complying with the pressure release management requirements in §63.648(j)(3). We expect most P/V vents on storage vessels will meet this criteria and, therefore, will not be subject to the additional monitoring, prevention measures, and RC/CA requirements finalized for atmospheric PRDs.

Comment 2: One commenter stated that the bypass monitoring requirement in 63.660(i)(2) need to be clarified to match those applicable to potential miscellaneous process vent bypasses. Proposed 63.660(i)(2) includes language that makes any flow through a Group 1 storage vessel vent system potential bypass a violation. The commenter referred the EPA to the comments made on the MPV bypass provisions as they are similar in nature.

Response 2: We maintain that bypassing the emissions controls of a CVS for a storage vessel to the atmosphere is a violation of the standards of this final rule. The final rule requires the installation, maintenance and operation of a flow indicator for any bypass line that could divert the Group 1 storage vessel vent stream to the atmosphere or to a control device that does not comply with the requirements in subpart SS. We made minor revisions to the proposed language to clarify that a bypass line that diverts the vent gas to an alternate control system meeting the requirements in subpart SS is an allowable bypass and would not be a violation of the final standards. Please see our responses to comments of the MPV bypasses in this document which are consistent with this response.

Comment 3: One commenter stated that emissions associated with vessel degassing could not be practically controlled to any specific MACT-level standard under numerous operating scenarios, including the degassing of storage tanks with significant solids in the bottom; continuous control, which would otherwise be required to satisfy such standard, could not be applied during solids removal from the tank. Further, the commenter argued extending the nitrogen purging would adversely affect flare gas recovery operation, likely resulting in flare gas recovery bypass. The commenter asserted that the rule should expressly exclude from all MACT standards emissions associated with tank venting and degassing, regardless of any contention that any such emissions would be related to SSM activity.

Response 3: For storage vessels, the requirements that apply during normal operations also apply during startup and shutdown. We evaluated degassing controls as a control alternative for Group 1 storage vessels that use floating roofs (i.e., that do not already route emissions to a control device) and do not consider the installation and use of controls during the degassing of such storage vessels to be cost effective (see memorandum *Survey of Control Technology for Storage Vessels and Analysis of Impacts for Storage Vessel Control Options*, Docket Item Number EPA-HQ-OAR-2010-0871-0027). Based on this review, neither did we propose, nor are we finalizing any additional standards for floating roof storage vessels during startup or shutdown. However, if a control device is used to comply with this final rule during normal operations, then such a control device must be used at all times, including during degassing of the storage vessel. Any bypassing of emissions from being routed to a control device to being routed to the atmosphere would be considered a violation of the standard.

Comment 4: One commenter is concerned that the vapor pressure of 0.75 psia or greater in the proposed revision of the definition of Group 1 storage vessels at an existing source for storage tanks greater than 40,000 gallons may not be low enough to achieve the gains sought. The commenter based their discussion off of results from the DIAL study conducted by the Houston Department of Health and Human Services through its Bureau of Pollution Control and Prevention funded by an EPA grant. The commenter stated that the DIAL report noted that measured emissions from process areas and storage tanks exceeded the emission factor estimates for benzene and VOC. Some of the surveyed tanks had true vapor pressures ranging from 0.00 to 0.56 psia, and thus would not be subject to the Group 1 control requirements under the proposed regulation because their true vapor pressure is less than 0.75 psia.

Response 4: In the study cited by the commenter, direct measurement of the composition or vapor pressure of the materials stored in these tanks was not performed. As noted in "EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems," cutting fluids are often used for heavy liquid materials that generally have low vapor pressures and the effect of these cutting fluids are not always considered when determining the true vapor pressure of the tank contents when doing emission inventory calculations. However, the rule requires that the true vapor pressure be determined based on all materials in the storage vessel. There are also potentially significant differences in short-term emissions that may occur during, for example, tank filling in the heat of summer, than the annual average emission rate. Therefore, the short-term DIAL measurements are often not representative of the long-term annual average emissions rate. Based on our technology review, the 0.75 psia vapor pressure threshold was determined to be the appropriate threshold for cost-effective additional storage vessel control requirements.

5.1.3 Revision of definition of reference control technology for storage vessels

Comment 1: One commenter suggested revisions to 63.660(b) to clarify requirements for floating roof deck fittings by adding requirements for ladders that have at least one slotted leg that are identical to the proposed requirements for slotted guidepoles. The commenter added that these provisions were specified in the proposed Uniform Standards, but were left out of the proposed revisions. The proposed options included a ladder sleeve, the effectiveness of which was demonstrated to the EPA prior to proposal of the Uniform Standards, and no rationale is given for the omission of this control option in this proposal. Thus, the commenter has requested that the control options from the proposed Uniform Standards be included here.

Response 1: EPA agrees with and has amended this final rule in response to this comment. These revisions would require the same controls for slotted ladder poles as those proposed for slotted guidepoles. These two types of slotted poles are similar deck fitting structures having similar emissions characteristics, even though they provide different structural functions. These amendments prevent an unintended loophole that would have allowed more emissions of HAPs to the atmosphere.

Comment 2: One commenter stated that the requirements for floating roof deck fittings are in need of editing for clarity and completeness, as well as for correcting minor typographical errors. The flexible enclosure control option is allowed under the STERPP for internal floating-roof tanks as well as for external floating-roof tanks. The proposed language to revise Refinery MACT 1 limits this option to external floating-roof tanks, but there is no rationale given for this limitation. The commenter assumed this to simply be an oversight, and requested that the flexible enclosure control option be allowed for both internal floating-roof tanks and external floating-roof tanks. The commenter also stated that if this is a purposeful change, the cost impact for internal floating roof tanks using this control to make this change and the justification should be provided and published for comment. This issue pertains to 63.640(n)(8)(vii) and (n)(10)(vii), with respect to the overlap provisions, and to 63.660(b), with respect to citations to subpart WW.

Response 2: EPA agrees the flexible enclosure control option is applicable to both internal and external floating-roof tanks and has amended the final rule requirements to extend the use of this control option for both types of tanks.

5.2 Compliance schedule provisions

Comment 1: One commenter stated that the format for introducing the new storage vessel requirements must be improved. The commenter added that applicability dates are needed for the new requirements. While the commenter endorsed the approach of adding a new section (i.e., 63.660) for the new standards and adding a statement at the beginning of the prior standards (i.e., 63.646) explaining that this section will no longer apply after demonstration of compliance with the new section, they recommended further clarification in the applicability section of the rule.

The commenter explained it would be very helpful if the compliance schedule provisions in 63.640(h) alerted the reader to the separation of the prior and new standards for storage vessels in sections 63.646 and 63.660, respectively.

Response 1: EPA maintains that the applicability dates for storage vessels are adequately described in the introductory paragraphs to §§63.646 and 63.660, as well as in Table 11. The provision in §63.640(h) specifically direct the reader to Table 11 where the compliance dates are listed separately for §§63.646 and 63.660. It should be noted that compliance with §63.646 for new and existing sources will only be permitted for up to 90 days after publication of the final rule. Therefore, we consider it unnecessary to revise the referenced provisions, and they will be finalized as proposed.

Comment 2: One commenter stated that editorial corrections are needed in 63.660(d) to clarify the compliance timing for storage vessels that become Group 1 as a result of these amendments. The commenter explained that 63.660(d) pertains to equipping a fixed-roof storage vessel with controls, if it has not been subject to control prior to these amendments. The specified control could be achieved by routing the vapors to a control device or by installing a floating roof. However, the citation to “the requirements of section 63.1062” could be construed as being applicable only to the installation of a floating roof. It would be apparent that the control requirements in question could be either routing to a control device or installing a floating roof if this phrase were changed to read “the requirements of this section,” in that the introductory text of this section (63.660) addresses complying with either subpart WW (for installing a floating roof) or subpart SS (for routing vapors to a control device). In addition, the term “storage vessel fixed roof” in 63.660(d) should read “fixed roof storage vessel.”

Response 2: EPA agrees that corrections are needed to the provision contained in §63.660(d), as it was not our intent to limit compliance options to the installation of a floating roof. The provision has been amended in the final rule to allow compliance for an uncontrolled fixed roof storage vessel that commenced construction on or before June 30, 2014 and that meets the definition of Group 1 storage vessel in item 2 in §63.641 but not the definition of Group 1 storage vessel in item 1 in §63.641, to comply by installing a floating roof or by routing vapors to a control device.

Comment 3: One commenter stated that the compliance date is unclear for storage tanks complying with the Kb option under 40 CFR 63.640(n)(8). The commenter explained that Table 11 (4)(iii) references section 63.660, but that section should not be applicable since section 63.660 references tanks complying with 40 CFR part 63 subparts WW or SS. The commenter inquired if the citation of section 63.640 was intended to provide the compliance date for the subpart Kb option found in Table 11 (4)(ii). The commenter added if so, the EPA should provide a 10-year upgrade option as found in subpart WW (63.1063(a)(2)(ix)). Finally, the commenter stated that the table contains two references to subsection “(iii)” with respect to requirements applicable to units with a date of construction on or before July 14, 1994. The latter reference should be changed to “(iv)” to avoid confusion.

Response 3: EPA expects storage vessels which are in compliance with subpart Kb of part 60 to already be using guidepole controls as outlined in the notice of the STERPP (described at 65 FR 19891 on April 13, 2000)). The STERPP notice specifically stated, “that uncontrolled slotted guidepoles do not comply with the ‘‘no visible gap’’ requirement in NSPS subparts Ka and Kb. See 65 FR 2336 (January 14, 2000).” Appendix I in the STERPP notice went on to identify acceptable controls for slotted guidepoles. Facilities have now had over 15 years to implement these controls. Therefore, the EPA maintains that sufficient time has passed to implement controls for storage vessels complying with subpart CC of part 63 through the overlap provisions, and no 10-year upgrade option will be given. We are clarifying in this response that the citation of 63.660 is intended to provide compliance for the Kb option found in Table 11. We note that the overlap provisions provide facilities with a way to comply with the applicable requirements of subpart CC for storage vessels (i.e., §63.660), and thus the applicable compliance dates in subpart CC apply to tanks utilized the overlap provisions. In the final rule, we are correcting the typographical error in Table 11 (4) in which two rows in the proposed table were given the same "(iii)" label.

5.3 Impact estimates for storage vessel requirements

Comment 1: One commenter asserted that the EPA's cost effectiveness determinations in the RTR proposal may not apply to them. Because of the distance of St. Croix from the continental U.S., costs for a given project are 1.3 to 2.3 times higher at the commenter's refinery than a continental refinery. Also, the commenter is almost entirely dependent on marine movement of products and raw materials and has many more storage tanks (due to limit supply interruptions) than continental refineries. These storage tanks will be subject in many cases to added control costs by the RTR Rule. The commenter recommended that the EPA consider these added impacts to non-mainland facilities in finalizing the RTR Proposal provisions at section 63.600 and the potential for enhanced tank repair requirements under the fenceline monitoring provisions.

Response 1: The EPA develops impacts as an average of data collected nationwide, and thus we expect some facilities to be above and below the cost effectiveness determinations, and thus the cost to comply will vary. Furthermore, we believe the refinery identified in this comment is no longer in operation, and thus the requirements no longer apply.

5.4 Monitoring and inspection requirements

Comment 1: In response to the EPA request for comment in the preamble, one commenter stated that consistent with the allowance in subpart WW, the EPA should allow in-service inspections of internal floating roof tanks. The commenter asserted that performing inspections in this way avoids significant hazardous waste generation, shutdown emissions, the operating risk associated with having tanks out of service, and is much less costly than performing an out-of-service inspection. The commenter argued that to require a facility to incur the otherwise unnecessary emissions associated with tank cleaning, when the inspection can be performed adequately with the storage vessel in service, is unjustifiable and less favorable for the environment. Thus, the commenter recommended the EPA not take any action that would interfere with this proven subpart WW provision.

Response 1: After reviewing the solicited comments regarding the internal inspection provisions for in-service tanks in subpart WW, we agree with the commenter and have finalized these referenced provisions as proposed.

Comment 2: One commenter contended that the requirement for tank inspections is too infrequent, and 10 years is too long to go without an inspection.

Response 2: Although there are types of inspections with a frequency of every 10 years, storage vessels are subject to different types of inspection with varying frequency. An internal floating roof's floating roof deck, deck fittings, and rim seal are required to be visually inspected through openings in the fixed roof annually. The inspection with a frequency of 10 years requires owners and operators to inspect these same items from within the tank unless all deck components are visually accessible from the top side. Therefore, the allowance to perform this 10-year inspection without taking the tank out of service does not reduce the number or frequency of all required tank inspections, but rather provides facilities with a less costly and labor intensive way to perform the inspection (i.e., not requiring it to be taken out of service).

Comment 3: One commenter stated that the bypass monitoring requirement in 63.660(i)(2) needs to be clarified to match those applicable to potential MPV bypasses**.** The commenter explained that 63.644(c), which addresses MPV bypass monitoring, contains exceptions to the bypass monitoring requirements including: Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, PRVs needed for safety reasons, and equipment subject to 63.648 are not subject to this paragraph.

The commenter asserted that while revisions to these exceptions have been proposed and the commenter provided comments on those revisions, it is important that 63.660(i)(2) contain the same exceptions as are finalized for 63.644(c). The commenter argued that there is no logical reason for treating these two situations differently and equipment that is subject to other Refinery MACT 1 requirements or is required for safety should not also be considered potential bypasses and subject to these sometimes conflicting requirements as well.

Response 3: We agree with the commenter and have finalized a consistent list of exceptions for bypass for MPV and storage vessels.

Comment 4: One commenter stated that the citation in 63.660(i)(2) to 63.985(a)(3)(i) or (ii) should be to 63.983(a)(3)(i) or (ii).

Response 4: We have corrected these references and will finalize these changes.

5.5 Recordkeeping and reporting requirements

Comment 1: Commenters requested several editorial changes and clarifications to the reporting requirements for storage vessels including:

- Clarifying the scenarios under which information related to gaskets and slotted membranes are required to be reported, specifically with respect to provisions in §§63.655(g)(2)(i)(B)(1) and 63.655(g)(3)(i)(C)(1).
- Adding a reporting requirement to report whether compliance is being demonstrated for §§63.646 or 63.660.
- Adding a note from §63.119 to §63.655(g)(2)(i)(A)(1) which allows the floating roof to rest on the leg supports.
- Modifying the term “slotted membrane” to read “slotted membrane fabric cover” specific to roof drains in external floating roofs which empty into the stored liquid consistent with §63.119.
- Modifying the term “slotted membrane” specific to the sample wells in internal floating roofs to be referred to as “slit fabric cover” consistent with §63.119.
- Adding a reference to the reporting requirements for facilities utilizing the subpart Kb of part 60 overlap provisions as outlined in §63.648(n)(8) to §63.655(g).

Response 1: We disagree with the commenter that these changes are necessary. We did not materially change the provisions identified above in the proposed rule. Further, these provisions are for storage vessels complying with the requirements in §63.646, and they will only be available as a method for demonstrating compliance for up to 90 days after publication of the final rule. Therefore, the suggestions will not be incorporated into the final rule.

Comment 2: One commenter requested that the EPA clarify how the requirements in section 63.655(g)(3)(i)(C) is invoked. The commenter explained that section 63.655(g)(3)(i) only references (g)(3)(i)(A) and (g)(3)(i)(B).

Response 2: To correct the referential error identified by the commenter, we have amended paragraph 63.655(g)(3)(i) in the final rule to reference subparagraphs (A) through (C) and not just (A) and (B).

Comment 3: Commenters recommended that external floating roof tanks converted to internal floating roof tanks should be subject to the same requirements as internal floating roof tanks. One commenter added that the reference in 63.655(g)(2)(i)(A)(2) to (g)(2)(i)(C) should refer to (g)(2)(i)(A)(3). The commenter also stated that the reference to (g)(2) through (5) in 63.655(g)(1) should be to (g)(2) and (3). The commenter also added that paragraph 63.655(g)(4) is unnecessary if paragraphs 63.655(g)(2) & (3) are complete and self-contained. The commenter provided draft regulatory text in their comment package for the recommended revisions.

Response 3: Section 63.655(g)(2)(ii) references 40 CFR part 63 subpart WW, which makes no differentiation between an internal floating roof tank. In fact, the definition of internal floating roof in §63.1061 states, "[f]or the purposes of this subpart, an external floating roof located in a storage vessel to which a fixed roof has been added is considered to be an internal floating roof." We would like to clarify in this response that we did not intend to differentiate between internal floating roofs and external floating roofs which have been converted to internal floating roofs in §63.660. We have updated (i) and removed (iii) from the definition of *Reference control technology for storage vessels* consistent with this clarification. We agree with the commenter that the reference in 63.655(g)(2)(i)(A)(2) should be to (g)(2)(i)(A)(3) and have finalized this change. We disagree that the reference in 63.655(g)(1) should be changed, as it appropriately references citations with recordkeeping and reporting requirements for storage vessels and are finalizing this provision as proposed. We also agree with the commenter that the paragraph in 63.655(g)(4) is redundant and unnecessary and will not be finalized.

5.6 Other

Comment 1: Two commenters identified a typographical error at 63.640(n)(1), specifically that the citation in the phrase " ... is required to comply only with the requirements of 40 CFR part 60, subpart Y, ..." should be "40 CFR part 61, subpart Y".

Response 1: EPA agrees with this comment and has corrected the citation in the final rule.

Comment 2: Two commenters noted typographical errors at 63.640(n)(8), specifically that the citation in the phrase " ... in paragraphs (n)(8)(i) through (n)(8)(vi) of this section ..." should be “(n)(8)(i) through (n)(8)(viii)” and that the citation in the phrase “ ... in paragraphs (n)(8)(i) through (n)(8)(vii) of this section.” should be “(n)(8)(i) through (n)(8)(viii)”

Response 2: EPA disagrees with the commenters regarding the need to amend §63.640(n)(8) from “ ... in paragraphs (n)(8)(i) through (n)(8)(vi) of this section ...” to “(n)(8)(i) through (n)(8)(viii)”. This part of the provision applies to Group 2 storage vessels in §63.640(n)(1) which do not require add-on controls and thus the requirements in §63.640(n)(8)(vii) and (viii) are not expected to apply. EPA agrees with the commenters regarding the need to amend the citation in the phrase “ ... in paragraphs (n)(8)(i) through (n)(8)(vii) of this section.” to “(n)(8)(i) through (n)(8)(viii)”, as this provision applies to Group 1 storage tanks which are expected to have add-on controls and has finalized this change.

Comment 3: Several commenters discovered a typographical error at 63.640(n)(10). The citations to paragraphs in the phrase “...paragraphs (n)(10)(i) through (n)(8)(vi) of this section” should be “(n)(10)(i) through (n)(10)(viii) of this section”

Response 3: Similar to the response above, EPA disagrees with the commenters regarding the need to amend the citations to paragraphs in the phrase “...paragraphs (n)(10)(i) through (n)(8)(vi) of this section” to “(n)(10)(i) through (n)(10)(viii) of this section”. This part of the provision applies to Group 2 storage vessels in §63.640(n)(1) which do not require add-on controls and thus the requirements in §63.640(n)(10)(vii) and (viii) are not expected to apply.

Comment 4: One commenter stated that the requirements for floating roof deck fittings are in need of editing for clarity and completeness by correcting typographical errors. Specifically, at §63.660(b), the citations to subpart WW should be to 63.1063(a)(2)(viii) for slotted guidepoles, rather than to §63.1063(a)(2)(vii).

Response 4: EPA agrees with the commenter and has corrected the typographical errors at §63.660(b) in the final rule.

6.0 Equipment Leak Standards

6.1 Technology review results

Comment 1: One commenter stated as a legal matter, a leak is a type of malfunction. The commenter argued that authorizing facilities to leak below a given threshold, and to do so without repairing or ending the leak, means that the EPA's standards do not apply continuously, as the CAA requires. The commenter asserted that the EPA must finalize a rule that sets a leak prohibition and establishes up-to-date, stronger leak detection and repair requirements.

The commenter also identified the provisions in the current rules that allow sources to delay and defer leak repair indefinitely as unlawful malfunction exemptions. The commenter argued in particular that the EPA proposes to continue to rely on 40 CFR part 60, subpart VV, and 40 CFR part 63, subpart HH, which according to the commenter contain a number of deferred monitoring and repair provisions that are unlawful exemptions that the EPA must remove. The commenter asserted that the EPA must set a firm, enforceable deadline for the repair of all leaks found and must not exempt any valves, connectors, or other equipment from the leak detection and repair standards and requirements.

Response 1: We disagree with the commenter's claim that the types of equipment leaks addressed in Refinery MACT 1 are "malfunctions." Equipment leaks typically occur from equipment such as pumps, compressors, agitators, sampling collection systems, open-ended valves or lines, valves, and connectors.[89] At the time we developed the MACT standards for this source category, we recognized that these emission points even at the best performing facilities regularly emit small quantities of HAP, and we promulgated standards regulating equipment leaks from these components based on what the performance of the best performing sources at 40 CFR 63.648. These provisions require petroleum refiners to monitor for leaks and to repair any detected leaks. While any specific equipment leak is not predictable, the types of equipment leaks addressed by the regulations at 40 CFR 63.648 are fairly routine emissions from sources are not the type of unpredictable or infrequent event for which we cannot anticipate when, where or how they may occur, but that we generally consider to be malfunctions.

The delay of repair provisions were included to prevent the undesirable impact of creating more emissions from shutting down and evacuating major process equipment than are emitted from the leaking equipment component. In such cases, the environment is better served by allowing a small leak to persist until the next scheduled shutdown than to shut the unit down to replace the leaking component, and the owner or operator must make this demonstration to avail themselves of these provisions[90]. Contrary to the suggestion of the commenter, the delay of repair

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[89] 40 CFR 63.648; see also 60 FR 43260 (August 18, 1995)

[90] *40 CFR 60.482-9 (c) (1) Delay of repair for valves will be allowed if:(1) 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,…*

requirements do establish firm timelines by which a leak must be repaired. Further, difficult to monitor equipment are still subject to audible, olfactory and visible emissions inspections (although from a distance), so these equipment components are not exempt from the LDAR provisions.

Comment 2: One commenter noted that the EPA concluded in the proposal that updating the standards for equipment leaks was not "necessary" based in part on the annualized cost and "cost effectiveness" (dollars per ton of HAP reduced) estimated for available methods to reduce emissions. However, the commenter argued that section 112(d)(6) does not authorize the EPA to refuse to update standards based on cost. Where "developments" have occurred, the EPA must "account" for those. The D.C. Circuit has held that, when setting revised air toxics standards, the EPA may consider cost, but it has not held that the EPA may not update a standard, at all, as it proposes to do for leaks and wastewater, based on cost. That Court has recognized that "developments" are the core requirement of this provision.[91] Thus, the commenter asserted that if they are present, the EPA must set revised standards. The commenter further opined that the D.C. Circuit's holding on cost in *Association of Battery Recyclers v. EPA* was wrongly decided.[92] Notwithstanding that decision, the EPA should decide to follow the plain text of section 112(d)(2)-(3) and applicable precedent requiring explicit authorization to consider cost. The commenter argued that the EPA's decision to make cost-per-ton the standard-setting criterion and to choose a number it deems unreasonable, without a rational explanation, is arbitrary and capricious.

Commenters added that certain facilities have complied with stronger LDAR provisions in the state of California or under consent decree demonstrating that such requirements are technologically and economically feasible and the commenters asserted that because the EPA's cost analysis does not consider this, it is thus arbitrary and incomplete. The commenters also stated that the EPA has ignored positive economic impacts that the rule improvements can have, such as job creation.

The commenter also stated that the cost-per-ton does not consider the benefits associated with reducing health risk by reducing the amount of HAP emitted by these sources. The commenter stated that the EPA's cost-focused analysis ignored the statutory objective of assuring the "maximum" achievable degree of emission reduction provided in section 112(d)(2) and implemented through the review required by section 112(d)(6). The commenter added that it also ignored the statutory goal of protecting public health, which is the core purpose behind this provision and the stated purpose of section 112(f)(2). Thus, the commenter asserted that the EPA's proposed inaction is unlawful, arbitrary, and capricious because it ignored key statutory purposes that are required factors to consider.

Moreover, the commenter detailed that the cost the EPA found here is lower than that in other rules or for other source categories within this proposed rule, for which the EPA has determined the cost-per-ton to be appropriate. For example, the EPA recognized that an annualized cost of

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[91] *NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008).

[92] *ABR v. EPA*, 716 F.3d 673 (D.C. Cir. 20132003); *NASF v. EPA* Opening and Reply Briefs of Environmental Petitioners.

$36.3 million/year is appropriate for the flare provisions. That is orders of magnitude higher than the annualized costs of the leak reduction provisions the EPA proposed to reject.

The commenter added that the EPA has recognized as appropriate or cost-effective much higher cost-per-ton ratios. For example, in the NESHAP from Secondary Lead Smelting (77 FR 556, 576; Jan. 5, 2012), the EPA determined that the following cost-per-ton measures were appropriate: $0.33 million/ton ($170/lb) (for stack lead emission limit); $1 million/ton ($500/lb) (for enclosure requirements); $1.5 million/ton ($550/lb) (for fugitive control work practices).

Response 2: We do not agree that in reviewing a standard under CAA section 112(d)(6), the CAA mandates that the EPA must promulgate revised standards if "developments" have been identified. CAA section 112(d)(6) requires that EPA review and revise standards "as necessary." Under CAA section 112(d)(6), the EPA retains very significant discretion in balancing relevant factors in determining whether it is "necessary" to revise the existing technology-based MACT standards. See, e.g., *Sierra Club v. EPA*, 325 F. 3d 374, 378 (D.C. Cir. 2003) (under CAA section 202(l)(2), EPA is to consider factors beyond pure technological capability, and the statute does not direct how EPA should weigh such factors). In reviewing section 112(d)(2) standards, and determining whether to revise them is "necessary" under section 112(d)(6), the EPA may take into consideration cost and feasibility when evaluating developments in practices, processes and control technologies.

With regard to the comment referring to more stringent state requirements and consent decree requirements, we did consider these, and in fact, as noted in the proposal preamble at 79 FR 36916, we acknowledged that some owners and operators are required to repair leaking valves as low as 100 ppm and pumps as low as 500 ppm. However, these lower leak definitions would have been more costly than the leak definitions of 500 ppm for valves and 2,000 ppm for pumps that we already rejected as not cost effective.

We also reject the commenter's argument that in rejecting more stringent LDAR requirements, we ignored the statutory goal of protecting public health, which is the core purpose of section 112(f)(2) and that rejecting more stringent LDAR requirements based on cost-per-ton failed to consider the ensuing health benefits associated with reducing the amount of HAP emitted by these sources. In the proposed rule, as part of the CAA section (f)(2) risk assessment, we evaluated the impacts on risks of all the equipment leak advancements in technologies and practices that we identified. We concluded that the available control options for equipment leaks for petroleum refineries do not provide quantifiable risk reduction and therefore, we proposed that further controls were not necessary to provide an ample margin of safety, regardless of costs or cost effectiveness (see 79 FR 36941, June 30, 2014).

The commenter's comparison of dollar per ton cost values against other rules and other requirements within this final rule are also misplaced. First, the commenter draws a comparison to an analysis for metal HAP in the Secondary Lead NESHAP RTR, where those costs per ton were determined to be within the range of metal HAP values for other section 112 rules (see 77 FR 576, January 5, 2012). However, organic HAP are the issue of concern for equipment leaks, and the EPA has historically used a different cost effectiveness scale for organic HAP versus metal HAP (i.e., tons versus pounds) due to their relative toxicity. As for the flare operating requirements in this final rule, the annualized cost of $36 million is not related to the RTR, but rather, is an estimate of the cost of proposed revisions to the flare monitoring requirements to ensure that flares used as APCD meet the MACT standards at all times when controlling HAP emissions under the authority of CAA section 112(d)(2) and (d)(3). A more appropriate comparison would be how LDAR controls were considered under technology reviews in recent rulemakings. For example, we conducted technology reviews for LDAR requirements in the final RTR rules for the Polymers and Resins IV, Pesticide Active Ingredient and Polyether Polyols Production MACT standards (see 79 FR 17340, March 27, 2014), the Acrylic and Modacrylic Fibers Production, Amino/Phenolic Resins Production and Polycarbonate Production MACT standards (see 79 FR 60898, October 8, 2014) and the Offsite Waste and Recovery Operations MACT standards (see 80 FR 14248, March 18, 2015), and our decisions for LDAR under the technology review for this rule are consistent with these recent rulemakings. Further, the commenter fails to acknowledge that we proposed and are finalizing a fenceline standard in this rule as part of our technology review to ensure that petroleum refinery owners and operators properly monitor and manage fugitive HAP emissions, which includes equipment leaks. As stated in the proposal preamble (see 79 FR 36919, June 30, 2014), it is impractical to directly measure emissions from fugitive sources at refineries, thus requiring the use of emission estimation models, which in turn introduces uncertainty into the inventory for emission sources, such as equipment leaks. We evaluated the developments in processes, practices and control technologies for measuring and controlling fugitive emissions from the petroleum refinery as a whole and identified fenceline monitoring as a development. We evaluated several fenceline monitoring techniques and proposed to require a system of passive monitors. Fenceline monitoring will identify increases in HAP emissions in a timely manner, which will allow corrective action measures to occur more rapidly than would happen if a source relied solely on the traditional infrequent monitoring and inspection methods, such as those associated with periodic Method 21 LDAR requirements.

It should also be noted that positive impacts to the economy as a result of the rulemaking were considered as documented in 4.3.2.2 Environmental Protection Sector and 4.3.2.3 Labor Supply Impacts of the Economic Impact Assessment (EIA) which can be found in the docket for this rulemaking (EPA–HQ–OAR–2010–0682).

Comment 3: One commenter argued that the EPA must strengthen the leak detection and repair standards so they are consistent with evidence showing leaks can be prevented and minimized. The commenter stated that the EPA must set standards to limit leak emissions based on currently available “zero emissions technologies” and practices, at a minimum, as demonstrated by the best performing sources in order to follow the CAA’s requirements, under section 112(d)(2)-(3).

For example, the commenter stated that the EPA proposed to retain the leak definition of 10,000 parts per million (ppm) for valves and pumps at existing sources and 1,000 ppm for valves at new sources, which is inconsistent with lower leak definitions in other EPA rulemakings (77 FR 49490, August 16, 2012) and the leak definitions in the BAAQMD and SCAQMD rules. The commenter asserted that it would be arbitrary and capricious for EPA not to finalize LDAR requirements that are at least as stringent as these rules.

The commenter also noted that the EPA identified additional developments in its memo on the uniform standards and certain chemical plant sources that have occurred that the EPA has not acknowledged in this rulemaking, including the use of low-leak technologies; lowering the leak definitions to even tighter levels, and requiring tighter timelines for minimization of leaks to within 24 hours of identification and repairs within seven days.[93] In addition, the commenter explained that leak-free pumps, leakless valves, and improvements in practices that reduce the number of leaks by using a greater percentage of other kinds of leakless devices reflect developments within the meaning of section 112(d)(6) that the EPA is required to consider.[94] These types of provisions are included in the consent decrees for Hovensa, BP Whiting, Murphy Oil, Shell Chemical, and Dow Chemical, as well as numerous chemical plants. The commenter stated that an increase in enforcement actions surrounding equipment leaks demonstrates the need for stricter standards.

Response 3: As the commenter stated, we did identify developments in practices, processes, and control technologies, documented in *Analysis of Emissions Reduction Techniques for Equipment Leaks* (Docket Item No. EPA-HQ-OAR-2010-0869-0029); this memorandum was referenced from *Impacts for Equipment Leaks at Petroleum Refineries* (Docket Item No. EPA-HQ-OAR-2010-0682-0207), which documents the costs and environmental impacts for the regulatory options considered as part of the technology review for equipment leaks at petroleum refineries. While the memorandum *Analysis of Emissions Reduction Techniques for Equipment Leaks* mentions some of the developments identified by the commenter, such as sealless pumps and "low leak" packings for valves, the memorandum does not include an evaluation of the cost and emission reduction impacts of these developments, as the necessary data are not available. However, these requirements are more stringent and more labor and equipment intensive than other approaches and thus almost certainly more costly. Since we rejected those other approaches as cost effective, we also would have rejected other more costly approaches as not necessary under section 112(d)(6).

In addition, we note that the requirements in consent decrees are negotiated settlements and are not based on an analysis of the nationwide impacts, including costs, conducted as part of a technology review. The analysis conducted for this final rule package supports the requirements in this national rulemaking and is based on the nationwide costs and emissions reductions achieved.

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[93] Analysis of Emissions Reduction Techniques for Equipment Leaks, EPA-HQ-OAR-2010-0869-0029 (uniform standards docket); Supplemental Technology Review for Equipment Leaks in Group IV Polymers and Resins, Pesticide Active Ingredient Production, and Polyether Polyols Production Source Categories (Jan. 31, 2014), EPA-HQ-OAR-2011-0435-0082.

[94] In addition to the documents cited herein, we have also attached and incorporate by reference the discussion of developments and leak detection and repair methods discussed by the Bruce Buckheit Report on oil and gas, as all or many of the same problems are issues that EPA must address in this rule for Refineries. See Buckheit Report (Nov. 2011).

6.2 Optical gas imaging provisions

Comment 1: Two commenters supported the use of optical gas imaging as an alternative means for leak detection on Refinery MACT 1 equipment leaks as proposed (*i.e.*, in place of Method 21 instrument monitoring). Two commenters requested that the EPA finalize the protocol for optical gas imaging as Appendix K to 40 CFR part 60. Another commenter stated that optical gas imaging should also be provided as an alternative for equipment in VOC service, regulated in 40 CFR part 60, to provide consistent approaches for the facility's overall LDAR program. Another commenter also requested that the EPA establish effective dates for using the optical gas imaging techniques after the rules and protocol are finalized to ensure facilities have time to develop the systems necessary to comply with the requirements and are able to properly detect leaks.

One commenter added that ultrasound or optical scanning or imaging programs should be a part of an overall LDAR program. The commenter noted that they can be used to conduct daily or weekly scans to identify areas to target during LDAR inspections. The commenter also added that remote scanning devices should be used to monitor equipment that is not currently required to be monitored using Method 21, and EPA should require facilities to report the results of any optical gas imaging scans conducted.

To the contrary, two commenters opposed the use of optical gas imaging because the instrument cannot provide instantaneous measurement of actual VOC concentrations in ppm.

Response 1: We do not plan to propose the optical gas imaging protocol in Appendix K to 40 CFR part 60 until we develop procedures and specifications that we determine will result in effective detection of leaks. As we noted in the preamble to the proposed rule, we plan to propose Appendix K and request comments on that appendix and how those requirements would apply to equipment subject to Refinery MACT 1. We will not take final action adopting use of Appendix K to 40 CFR part 60 for optical gas imaging for refineries subject to Refinery MACT 1 until such a time as we have considered any comments on that protocol as it would apply to refineries.

In response to the comment that optical gas imaging should be provided as an alternative for equipment in VOC service, we note that Refinery MACT 1 regulates HAP emissions, and any change in requirements for equipment in VOC service is beyond the scope of this rulemaking. However, while we are first considering how Appendix K to 40 CFR part 60 would apply to equipment in HAP service at petroleum refineries, we anticipate that it may be an alternative to Method 21 for other monitored process units for which the owner or operator can verify that the instrument selected can image prevalent chemicals. Therefore, owners and operators of those process units with equipment in VOC service would be able to request to use Appendix K to 40 CFR part 60 as an alternative to Method 21, just as they would request to use any other alternative test method.

As the use of optical gas imaging would be a voluntary alternative to the standards in Refinery MACT 1, we do not at this time anticipate needing to establish effective dates for compliance. Depending on the content and format of the final Appendix K, we may decide to establish dates within Refinery MACT 1 before which optical gas imaging using Appendix K cannot be used, although we do not anticipate this will be necessary at this point. We think most owners and operators will take the time they need to ensure they can comply with Appendix K and that it will not be necessary to prescribe a beginning date.

As part of the development of Appendix K to 40 CFR part 60 and how it will apply to equipment subject to Refinery MACT 1, we will consider the appropriate monitoring and repair requirements along with the recordkeeping and reporting requirements. At that time, we will evaluate the suggestions raised by the commenter for integrating optical gas imaging programs into existing LDAR programs, as well as similar requirements in existing standards such as the Alternative Work Practice To Detect Leaks From Equipment (40 CFR 63.11(c), (d) and (e)).

While current optical gas imaging technology does not provide instantaneous readings of VOC concentration, we do not believe that this is a deterrent to the use of this technology once an appropriate protocol for its use has been developed. Because anything that is imaged by a camera is considered to be a leak, there is no real need for the instrument to provide a numerical reading, such as is necessary when complying with a numerical leak definition. We also note that this technology is quickly evolving and believe that these cameras may be able to quantify leaks in the near future, should quantification be necessary. Sources may also choose to quantify leaks in other ways (e.g., use of a Method 21 instrument, bag sampling) if this information is needed for other purposes.

Comment 2: One commenter stated that the requirement in 40 CFR 63.661(a)(2) requiring that the owner or operator be in compliance with the fenceline monitoring provisions of 40 CFR 63.658 in order to make use of the optical gas imaging (OGI) alternative (if the other conditions specified in 40 CFR 63.661(a) are met) should not be finalized because the fenceline and leak detection requirements are work practice based standards and compliance for these requirements are not tied to an emissions limit.

The commenter added that compliance with the fenceline requirements is based on a two week sampling period for which the refinery may not know the status for up to 30 days, while OGI is performed periodically at various locations within the refinery and thus the compliance status may be unknown. The commenter also requested guidance for a scenario in which non-compliance with the fenceline program occurred in between OGI runs for a particular portion of the refinery, but the fenceline monitoring program was in compliance for the two week period during which the OGI for that portion of the refinery was performed. The commenter also stated that using Method 21 when the OGI alternative is not being utilized presents further challenges because of the amount of time it can take to perform Method 21 for a particular unit or the entire refinery.

Finally, the commenter added that from a practical standpoint, is it unclear how one could move in and out of the OGI program every 2 weeks. Presumably, when OGI is not being used one must do Method 21 monitoring, but the whole point of OGI is to save the effort associated with Method 21 monitoring. Furthermore, Method 21 monitoring typically takes more than a 2-week period to complete for any particular unit and takes at least a quarter to complete for the entire refinery. Therefore, the commenter stated, it would be impossible to switch back and forth for unplanned 2-week periods, making the use of OGI impractical and forcing sources to simply remain with Method 21 monitoring rather than using the OGI alternative.

Response 2: As noted in the response to Comment 1 of this section, we do not plan to propose Appendix K to 40 CFR part 60 until we have developed procedures and specifications that we determine will result in detection of leaks at least as effectively as Method 21. We had anticipated that Appendix K would have been proposed prior to finalizing the Refinery MACT 1 requirements. Given the current status of Appendix K, we are not finalizing the proposed amendments at 40 CFR 63.661.

Comment 3: One commenter stated that it is unclear just which provisions in 40 CFR part 60, subpart GGGa (and through it, subpart VVVa) may be replaced by OGI and which still apply. The commenter requested that the individual sections of 40 CFR part 60, subparts GGGa be identified in the second sentence of 40 CFR 63.640(p)(2). Additionally, the commenter stated that the last part of the second sentence in 40 CFR 63.640(p)(2) should be revised to match the wording in 40 CFR 63.661(a)(1) and indicate that facilities still have to comply with the other provisions of subpart GGGa, but not that a facility must be “in compliance” with those other provisions. If this language is not changed, the commenter noted that, for example, a failure to perform a single weekly pump check somewhere in the refinery would mean the facility would not be permitted to comply with OGI.

The commenter also requested that the reference to paragraph (a)(2) be changed to paragraph (a)(3) in proposed 40 CFR 63.661(b)(3).

Response 3: We had anticipated that Appendix K would have been proposed prior to finalizing the Refinery MACT 1 requirements. Given the current status of Appendix K, we are not finalizing the proposed amendments at 40 CFR 63.661.

6.3 Clarification of seal for open-ended lines

Comment 1: Several commenters objected to finalizing the proposed clarification of “seal” as proposed because it would cause owners and operators to incur a violation if the open-ended line (OEL) is equipped with a proper plug, cap, or second valve but the “seal” is found leaking above the leak threshold of 500 ppm. Two commenters added if OELs are subject to a leak standard, they should not also be required to have a cap or plug; the requirement should be either install a cap/plug or comply with a 500 ppm leak definition. Two commenters also stated that it is arbitrary and capricious to establish an emission limitation in the case of OELs when other similar fugitive emission components (e.g., connectors) are regulated through an LDAR work practice standard

Another commenter requested the proposed rule language be revised to specify that if a missing cap or plug is found, sources will have 24 hours to monitor the opening and determine if the leakage exceeds 500 ppm. The commenter suggested that if the instrument reading is above 500 ppm, a deviation from the cap or plug requirement would be identified, and if not, no deviation would be identified and the source would have to install a cap or plug.

Response 1: For reasons provided in the preamble to the final rule, we are not finalizing any changes to the rule language related to the requirements for OELs subject to Refinery MACT 1. Therefore, the clarification requested by the commenters is not necessary.

Comment 2: One commenter stated that the proposed 500 ppm leak detection limit for OELs is not necessary for components in heavy-liquid service but noted the provisions did not clarify this. The commenter requested clarification that the requirement does not apply to heavy-liquid components.

Response 2: The OEL standards apply to all open-ended valves and lines subject to Refinery MACT 1 except those specifically described in 40 CFR 60.482-6(d) and (e). We did not propose to change those provisions, and we are not finalizing any changes to those provisions.

Comment 3: Several commenters stated that the proposed approach established a 500 ppm emissions limitation for controlled OELs in addition to the existing cap and plug standard, rather than establishing it as a LDAR program action level. These commenters suggested that if the EPA determines that OELs should become subject to a 500 ppm leak definition, the EPA should treat these OELs like other pieces of equipment and provide a period of time to repair the leak, rather than considering the leak to be an immediate non-compliance. Several commenters agreed and stated that to the extent that the EPA should propose a monitoring schedule and a traditional LDAR work practice standard of 5 days for a first attempt and 15 days for a final repair.

Response 3: We did not propose periodic instrument monitoring of OELs at petroleum refineries, and we are not finalizing such a requirement in this rulemaking. If we determine that periodic instrument monitoring of OELs at petroleum refineries is appropriate to add to Refinery MACT 1 at a later date (e.g., as part of a future technology review), we will propose those requirements and document our analyses to ensure that there is an opportunity for public comment.

Comment 4: Two commenters stated that the proposed requirement to “seal” OEL is a significant change and would result in an estimated 20 percent increase in LDAR costs associated with the proposal. The commenters suggested adopting the Texas regulations, which require OELs to be equipped with a second valve, cap, plug, or blind flange. This would make Refinery MACT 1 consistent with requirements already in place, avoiding additional unnecessary compliance costs.

Response 4: The provisions of Refinery MACT 1 currently require that OELs be equipped with a cap, blind flange, plug, or a second valve. Therefore, no change was made to the requirements in Refinery MACT 1 as a result of this comment.

Comment 5: Several commenters stated that if the clarification of “seal” is finalized as proposed, at least two years should be provided for compliance, allowing time to identify and properly tag all OELs and to equally distribute the monitoring throughout the year. One commenter agreed with the need for additional compliance time, but requested 3 years be provided.

Response 5: We are not finalizing any changes to the rule language related to the requirements for OELs subject to Refinery MACT 1. Therefore, the additional compliance time requested by the commenters is not necessary.

6.4 Requirements for pressure relief devices

Comment 1: Commenters stated that the definition of relief device includes a wide universe of relief devices, not all of which should be subject to standards, particularly those with little potential for loss to the atmosphere (e.g., chemicals with very low vapor pressures). Commenters provided specific recommendations for exemptions from the work practice standard for PRDs including:

- Relief devices for ethylene glycol, polymerizing materials, heavy liquids, and those with less than 5% HAP.
- Relief devices in liquid service, as commenters argued providing this exemption would be consistent with previous rulemakings relative to handling under the LDAR provisions, noting that existing LDAR monitoring requirements and reporting requirements under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and EPCRA regulations are sufficient to identify, notify, calculate, and report unauthorized releases from these relief valves. Commenters also noted that the EPA has a long history of considering the physical properties of HAPs when making control requirement decisions, and provided storage tank and wastewater rules as examples (e.g., HON, MON). The commenters suggested that the EPA compare Table 1 of subpart CC to Table 9 of subpart G volatile organic hazardous air pollutant (VOHAPs) and exclude those non-VOHAPs from the pressure release management requirements. Alternatively, the commenters suggested that the EPA could just refer to Table 9, as well as exclude equipment in heavy liquid service from the requirements.
- Thermal PRDs which are liquid-only relief valves used to manage thermal expansion of liquid and are often located in difficult to access and/or remote areas of the refinery and are typically associated with equipment that is not continuously monitored. The commenters also asserted that the expected emissions from such devices are small.
- High/low point bleeds which, the commenter stated, are used to clear lines for important maintenance purposes and result in no material HAP emissions.

Another commenter requested that if the proposed 40 CFR 63.648(j)(3) applies to liquid RVs, those routed to process drains be excluded just as gaseous RVs routed to control are excluded consistent with the BAAQMD rule.

Several commenters added that the EPA must demonstrate that the change to apply these requirements to liquid PRD is justified and demonstrated in practice under the provisions of CAA section 112(d)(6) and no such demonstrations have been made. One commenter stated that liquid RVs are regulated by 112(d)(2) and no basis is provided for overriding these section 112(d)(2) sensory leak check requirements and converting the current liquid RV work practice requirement into a prohibition and violation. The commenter argued that if the EPA proceeds with imposing atmospheric RV monitoring requirements such monitoring must be limited to RVs in gas-vapor service. The commenter added that that the EPA must, at a minimum limit the pressure relief management to those devices with a reasonable expectation that a possibility exists for significant organic HAP emissions.

One commenter stated that liquid RVs present much less environmental risk relative to the increased safety risk resulting from requiring control of those not already controlled, and several commenters stated that they are much more difficult and costly to safely monitor, if such monitoring is feasible at all. One commenter concluded that their inclusion is not warranted and certainly has not been justified. The work practice requirements associated with the Process Safety Management (PSM) and Risk Management Plan (RMP) programs and the audio, visual and odor monitoring already required by the applicable equipment leak rules are more than adequate to assure these RVs are properly handled.

Response 1: As a practical matter, we note that the PRD standards only apply to PRD in organic HAP service (as defined in §63.641), so the provision is already limited to PRD associated with process streams with a HAP content of 5 percent or more. The majority of the other comments summarized here relate to the applicability of the PRD provisions to PRD in light liquid or heavy liquid service. First, we are not revising the applicability of the operating and release requirements contained in §63.648(j)(1) and (2) to ensure the PRD is properly sealed. For reasons provided in the preamble of the final rule, we are promulgating a work practice standard for PRD releases in place of the proposed prohibition on atmospheric releases and are providing exemptions for PRD in heavy liquid service and for liquid thermal expansion valves (see Section IV.C.4 for the preamble to the final rule for additional details). We generally do not consider low point or high point bleeds to be PRD. If a PRD is used to release material (i.e., used as a low point bleed), then the PRD release would be subject to the work practice standard unless the liquid release is specifically exempted (e.g., heavy liquid release or the “light liquid” hard-piped to a controlled drain system). As discussed in Section 4.1 of this document, we consider most high point bleeds to be an MPV. If a PRD is used as the release point of a high point bleed, the high point bleed would be subject to the work practice standards (and would not be MPV, based on the “exclusion 2” in the definition of MPV.

Comment 2: One commenter stated that the requirements for PRDs should include *de minimis* thresholds to exclude systems with little potential for loss to the atmosphere. The commenter suggested that EPA set a *de minimis* reporting value equal to the reportable quantity (RQ) values in EPCRA and/or CERCLA. The RQ values vary from chemical to chemical, and the RQ value is typically lower for more hazardous and/or volatile chemicals. The commenter stated that the EPA should re-propose a work practice standard that applies only to devices with the potential for significant gas/vapor emissions of the Table 1 HAP. Significant would mean a release of a Table 1 HAP above an established RQ value.

Response 2: We considered the commenter’s suggestion to provide a *de minimis* release quantity for the PRV requirements. We disagree that RQ values from EPCRA and/or CERCLA should be used as there is some dispute on how these apply to petroleum derivatives in the refinery. We also are concerned with a post-event exclusion evaluation that generally requires engineering calculations and assumptions. However, we understand there may be very small PRD on certain lines, such as a PRD on a sample analyzer line to protect the analyzer that could not, considering the size of the valve opening and design release pressure, release more than 72 pounds per day

VOC. We are using the size threshold for MPVs since these PRD releases, would be considered Group 2 MPV and would not require additional control. Consequently, we consider it reasonable to exclude these very small PRD from the pressure release management requirements, consistent with the control requirements for miscellaneous process vents.

Comment 3: Three commenters recommended that small mobile tanks should not be subject to the PRV limits on HAP emissions, as the openings on these tanks are too small to meet the technical specifications (regarding calculation of inlet losses) adopted by API for routing to a flare. One of the commenters requested that atmospheric relief valves on portable and mobile tankage including trucks, railcars, and marine vessels should be excluded from the relief valve control and/or monitoring requirements. The commenter stated that RVs on this mobile equipment are regulated by the Department of Transportation (DOT) or the Coast Guard (for marine vessels) and prohibiting their release to the atmosphere and modifying them to allow monitoring requires at least consultation with those Agencies and, likely, revision of their regulations, which the commenter asserted has not been performed. Furthermore, the commenter added, the openings on these tanks would typically not be sized large enough to route to a flare under the industry inlet loss standard calculation for a RV.

The commenter stated that loading and unloading of this equipment is regulated under the various air regulations that deal with transfer operations and/or receiving tankage and that the risk of a release at other times is very low since these tanks are not an active part of a process. Furthermore, the commenter state, these RVs are sized for release to the atmosphere since that is the only option during transport and thus routing to another disposition would reduce their ability to relieve in the case of a fire or other emergency. The commenter asserted that the increased safety risk, their temporary nature, their need to be easily moved, and their construction make it difficult to route these RVs to control or to continuously monitor them.

Response 3: Except for equipment needed to control loading and unloading activities, we consider that the construction and safety design for mobile equipment regulated by the DOT or the Coast Guard to be adequate to ensure the safety and minimize releases. We also note that, due to their size and typical pressures, this equipment typically has a limited potential to emit (PTE).

Comment 4: One commenter suggested that atmospheric relief valves on temporary equipment be excluded from the relief valve control and/or monitoring requirements. Various pieces of equipment are used by refineries for short periods of time to allow for equipment maintenance (e.g., temporary storage or temporary pump), as temporary controls (e.g., portable thermal oxidizer or diesel engine for degassing a tank), or to temporarily offset equipment issues, such as fouling or internal damage (e.g., temporary exchanger to provide additional cooling). All of this equipment will have RVs, designed for atmospheric release. This equipment, by its nature, will not be in a location that is already equipped with CVS connections or monitoring instrument connections. In some cases, the need for this temporary equipment will not have been anticipated. Even where small distances are involved such connections likely could not be designed and installed in the time the equipment is in use, nor could the RVs be resized for relief to a closed system quickly, and the expense for these changes certainly cannot be justified for the low risk of a release in that short time. The commenter requested that RVs on temporary equipment (i.e., equipment that is in use for less than 12 months) be excluded from the new atmospheric RV pressure relief requirements.

Response 4: As described in greater detail in the preamble to the final rule, we are establishing work practice standards based on the implementation of prevention measures to limit the occurrence of releases and the magnitude of releases when they occur. Consequently, we are less concerned with the ability to pipe this equipment into a CVS (although for longer “temporary” service periods, this can still be accomplished), and more concerned with how to limit the likelihood that a release will occur. Unlike mobile equipment that are separately regulated by DOT and the Coast Guard and that are not directly tied to the process units, this temporary equipment is not otherwise subject to regulations and often becomes an integral part of the refinery process unit. The work practice standards we are finalizing in this rule requires prevention measures be implemented for this equipment to reduce the chance of a release and to minimize the size of the release if it occurs similar to “permanent” process equipment.

Comment 5: One commenter requested that low pressure RVs and RVs handling oxygen-containing vapors be excluded from the RV control and/or monitoring requirements. The commenter stated that P/V vents on storage vessels that are controlled with CVSs routed to control (whether for compliance with regulation of not) often serve as RVs for those vessels, should the CVS system be blocked. Typically these type vents are excluded from RV requirements by excluding RVs with a design relief pressure of greater than (we assume the commenter meant “less than”) 2.5 psig from the definition. While the definition of relief valve in Refinery MACT 1 would exclude storage tank P/V vents in their normal service (diurnal pressure relief), it would not exclude them on tanks controlled with a CVS and control device. The commenter requested a specific exclusion for RVs with a design release pressure below 2.5 psig needs to be added to the RV definition.

The commenter added that there are technical challenges in applying the 500 ppm LDAR standard definition to the P/V vent on a fixed-roof tank. These weighted-pallet type P/Vs do not close to that standard of leak tightness, while higher set point RVs do not provide adequate protection against tank failure. Similarly, some RVs protect equipment in services where oxygen is present, such as in most wastewater management units. These RVs cannot be routed to combustion controls without potentially explosive results and generally have such low levels of condensables present that routing to other types of controls is ineffective. The commenter requested that the RV definition be modified to exclude RVs where unsafe levels of oxygen are present.

Response 5: We are not finalizing the prohibition on atmospheric releases, which is the provision in the proposal that spurred these comments but are instead finalizing work practice standards for these PRD releases. For the reasons discussed in the preamble, we determined it practical to exclude PRD with design release pressure of less than 2.5 psig from the pressure release management requirements as requested by the commenter.

Comment 6: Two commenters recommended that 40 CFR 63.648(j)(4) exclude RVs that are routed to a process or to fuel gas. The commenters stated that most leakage from RVs is routed to process dispositions including to fuel gas systems. As done throughout Refinery MACT 1 and in the referenced equipment leak rules (part 60 subpart VV and part 63 subpart H), these alternatives need to be included in 40 CFR 63.648(j)(4). In these situations, as with RVs routed to control devices, leakage and releases will not reach the atmosphere and, thus, leakage and release requirements are not appropriate. Furthermore, recovery of this leakage is environmentally beneficial relative to destruction in a control device and should be, and has historically been, encouraged.

The commenters added that eliminating the route to process and route to fuel gas alternatives will create substantial problem, because it will essentially eliminate the exception for most currently controlled RVs, since most controlled RVs are routed to fuel gas. The piping and, maybe, the disposition would have to be modified for most existing installations to allow the monitoring required by this proposal if these RVs were no longer excluded. Compliance time, costs, and burdens for such changes are not addressed in this rulemaking and are not justified, in any case, and thus, there is no legal basis for not allowing the same control options as allowed by the current Refinery MACT 1.

Response 6: We agree with the commenter, and we did not intend to treat PRD that are routed to the fuel gas system any different from those routed to a CVS. We generally expected that PRD would not typically vent to the fuel gas system as the fuel gas system operates at much higher pressures than the flare gas system or other closed vent system. However, we agree with commenters that, if the PRD can be routed to the fuel gas system, then the exclusions 40 CFR 63.648(j)(4) should apply and we are revising this paragraph to specifically indicate this.

Comment 7: One commenter stated that there are many small atmospheric PRDs in refineries that pose little release risk and would be costly, difficult or infeasible to monitor or to outfit with equipment based preventative measures. The commenter suggested excluding PRDs which have a diameter of less than or equal to 2 inches from the equipment related portions work practice, but not the RC/CA portion. The commenter asserted that this exclusion will focus the costs for additional hardware on those PRDs that would have higher emissions in the event of a release while still addressing the smaller valves in the event of a release to the atmosphere from one of them.

The commenter explained a large number of these size PRDs are thermal relief valves (discussed in a comment above) and that another large population of PRDs with a diameter less than 2 inches are on instruments such as process analyzers. These are typically very small (e.g., 0.25 inches) and protect against blockage within the instrument. The commenter asserted that monitoring and equipment based preventive measures are infeasible or inordinately expensive relative to the potential release risk.

Response 7: A 2-inch valve can release a significant amount of material in a relatively short period of time, so we disagree with the commenters that suggest these types of releases are "small." As discussed previously, we understand there may be very small PRD on certain lines, such as a PRD on a sample analyzer line to protect the analyzer, that could not, based on valve size and maximum pressure, release more than 72 pounds per day VOC, and we have excluded these PRD from the pressure release management requirements, consistent with the control requirements for miscellaneous process vents.

6.4.1 Pressure release (remonitor) requirement

Comment 1: One commenter asserted that there is no valid reason to add a Method 21 monitoring requirement to proposed 40 CF 63.648(j)(2)(ii) or to remove the current delay-of-repair provision. The commenter stated that proposed 40 CFR 63.648(j)(2)(ii) reflects the requirements currently imposed by Refinery MACT 1 for rupture disk PRDs and PEDs that have a rupture disk associated with a valve to assure no leakage when the relief valve is not relieving. The proposed language, however, imposed a new monitoring requirement not in the existing rule and does not include language referencing the delay of repair provisions. The commenter stated that neither of these changes is explained in the preamble and neither is justified; therefore the commenter requested these changes not be finalized.

One commenter also added in general, rupture disks are not used in refineries as PRDs, but are used upstream of a valve to assure that there is no leakage when the PRD is not relieving. Therefore, monitoring serves no purpose and the current equipment leak rules, including Refinery MACT 1, do not require such monitoring. This proposal would impose a 5 day Method 21 monitoring requirement in addition to the 5 day rupture disk replacement requirement. The commenter argued that there is no emission or compliance basis for this change, since leakage is not possible.

The commenter also stated under Refinery MACT 1, delay-of-repair of a PRD system that includes a rupture disk is allowed if the conditions in 40 CFR 60.482-9 or 40 CFR 63.171, as applicable, are met. This provision is critical for rupture disk PRD systems, because it may take a process shutdown to change the rupture disk. In such cases, there is little environmental reason not to allow delay because the rupture disk is a voluntary option and the facility could have just the PRD, as long as the less than 500 ppm limit was met. The commenter requested that 40 CFR 63.648(j)(2)(ii) include the delay-of-repair language from NSPS VV and HON, or provide that after a pressure release the owner/operator must within 5 days either replace the rupture disk or demonstrate a leak rate of less than 500 ppm. This would be equivalent to including the current delay-of-repair requirements for this particular situation.

Response 1: We proposed monitoring of PRD after a release to ensure the PRD is properly seated following the relief event. We agree that, if a rupture disk is used in conjunction with a direct atmospheric PRD and the atmospheric PRD is properly sealed, then it is unnecessary to replace the rupture disk immediately. In the final rule, we are revising 40 CFR 63.648(j)(2)(ii) to allow the owner/operator to either replace the rupture disk or demonstrate a leak rate of less than 500 ppm must no later than 5 calendar days after the PRD returns to organic HAP service.

6.4.2 No atmospheric discharges

Comment 1: A number of commenters objected to the prohibition of emissions from PRDs to the atmosphere and further stated that EPA has no authority under section 112 to set a zero emissions standard for these devices. Several commenters stated that the EPA has improperly misconstrued the holding of *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) by prohibiting emissions to the atmosphere from PRDs. Commenters asserted that the Sierra Club ruling does not prohibit SSM emissions and does not require that a single standard apply at all times.

According to commenters, the ruling stated that the emission limits under section 112 of the CAA must be continuous, which can be numerical, or where the statutory criteria are met, a work practice can be established when the source is in operation. Commenters concluded that although EPA claimed in the proposal that it cannot set an emissions standard for these malfunction emissions, the proposed prohibition on emissions from atmospherically vented PRDs is in fact an emissions standard. Therefore, the commenters argued stated that the EPA's legal justification is inherently contradictory and, therefore, fatally arbitrary.

Commenters stated that PRDs are currently regulated through the equipment leak provisions which apply during normal operations as well as to leaks which may occur if a valve does not reseat after discharge. Commenters added that the EPA may revise the existing MACT standards only under section 112(d)(6) authority and only "as necessary (taking into account developments in practices, processes, and control technologies)." This commenter argued that the EPA has not made a showing in the proposed rule that a revision of the existing standards is "necessary" upon consideration of the specified factors. It is well established, according to commenters, that a section 112(d)(6) standard must be cost effective and technically feasible. These commenters argued that a zero-emission standard is plainly not cost effective or always technically feasible. Therefore, the commenters concluded that no change to the existing standards is warranted.

Other commenters noted that the EPA's assertion that a zero-emission standard is grounded in section 112(d)(2)/(d)(3) fails because the "MACT floor" for atmospherically vented PRDs is not zero, and a prohibition on emissions cannot be justified as an "above the floor" standard.

Several Commenters suggested that a work practice standard would be a more legally supportable and reasonable approach. One commenter explained that because the timing, nature, and extent of PRD emissions are inherently unpredictable, there is ample justification for the EPA to conclude that it is not technically or economically practicable to measure PRD emissions. The commenter asserted that because these releases are not malfunctions developing a work practice standard rather than a numerical emission limitation, as provided in section 112(h), is more appropriate.

On the other hand, another commenter expressed support for the proposed elimination of venting refinery gas to atmosphere during a malfunction, stating that as the EPA recognized, the limits established under 112(d) of the CAA apply at all times. The commenter stated the EPA must set limits on all HAP sources as a result of *National Lime Association v. the EPA* (233 F.3d at 642). The commenter asserted that the proposal will close a regulatory gap that currently allows certain PRDs to vent emissions directly to the atmosphere during a malfunction.

Response 1: As proposed, the requirement was to control atmospheric PRD. In other words, PRD releases could not be vented directly to the atmosphere, but must either be eliminated or vented to a control device, such as a flare. Thus, the proposed requirement did not purport to limit PRD to zero emissions, but rather that such emissions must be routed to a control device, and any control device used, such as flares, would not achieve 100 percent control efficiency.

Direct atmospheric PRD releases were previously covered in the facility's SSM plan, which we consider to have been considered illegal under the *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir.

2008) ruling. We are not revising the MACT provisions for PRD as a result of our technology review, we merely contended that, in the absence of a legal SSM plan, direct PRD releases needed to be specifically addressed in the rule because they are sources of HAP emissions at petroleum refineries. As such, we maintain that the pressure relief management requirements are appropriately being developed under CAA 112(d)(2) and (d)(3), rather than (d)(6).

We agree with commenters that suggested that the CAA 112(d)(2) and (d)(3) standards must be based on a MACT analysis. Therefore, we conducted a complete MACT analysis for PRDs. As described in further detail in the preamble to the final rule, we concluded that a work practice standard for regulating PRD emissions is justified under CAA section 112(h) and we are finalizing a work practice standard based on the best performing PRD sources. See the preamble to the final rule for more information regarding the requirements and our rationale for the PRD work practice standards we are finalizing.

Comment 2: Several Commenters asserted that the venting of a PRD is not a malfunction as defined in section 63.2 of the CAA and therefore the EPA does not have legal authority to prohibit emissions to the atmosphere from PRDs. Commenter argued that the EPA cannot justify its rule by stating that PRDs are malfunctions without any explanation as to how PRDs meet all elements of the malfunction definition.

First, commenters asserted that PRDs are not malfunctions because emissions from these devices are not “excess emissions” but “normal” operation of these devices because PRDs are designed precisely to allow for the immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage. Commenters noted that while the release may be due to a process upset, the regulatory definition of malfunction requires excess emissions.

Second, commenters argued it is unclear how the “not reasonably preventable” criteria is met since the entire design premise of PRDs is to assure that unpreventable pressure buildups, particularly those associated with highly unlikely occurrences, are relieved and do not cause injury, death or property damage. The commenter concluded that if an emission were reasonably preventable it would not be released through a PRD.

Third, commenters stated that the EPA has provided no evidence that emissions from PRDs generally will be the result of sudden and infrequent failures.

One commenter stated that if EPA treats atmospheric PRD emissions as malfunction emissions and proceeds with setting standards under section 112(d), then arguably, atmospheric PRDs are not part of the regulated stationary source until a specific valve actually experiences a release and the EPA would lack authority to regulate PRDs under section 112(d). This is because a stationary source only includes pollutant-emitting activities that emit or have the “potential to emit” a HAP. “Potential to emit” (PTE) does not include malfunction emissions, and is generally computed based on normal source operations. As such, if the PRDs release only malfunction emissions, these relief valves have no potential to emit HAP.

On the other hand, commenters asserted that PRD releases occur during upset conditions, but that the actual release of emissions during the event is “normal operation” for a PRD. By the

EPA's definition, a PRD is designed as a valve used only to release an unplanned, nonroutine discharge. 40 CFR 63.641. Although relieving during an unplanned event is "normal operation" for the PRD, it is not "normal operation" for the process equipment that the PRD protects and, therefore, is not included in the PTE determination of that process equipment. According to the commenter, establishing PRD releases as "normal operations" might provide the EPA with authority to regulate these emissions under section 112(d). Nonetheless, under this interpretation, the commenter asserted that the EPA must conduct a MACT floor analysis and provide this analysis to the public for review and comment before finalizing a section 112(d) regulation.

Commenters suggested that PRD releases continue to be treated as equipment leaks and an alternative work practice standard be established in conjunction with the general duty requirements in the existing MACTs. According to commenters, this would be legally justified and would avoid interfering with PRD operations during emergencies, large investments and incurring increased emissions to address emissions that occur infrequently.

Response 2: We believe that the arguments about whether or not emissions from PRD are malfunctions is somewhat of a red herring as it pre-supposes that EPA can only regulate PRD releases if they are malfunctions. And, we disagree with such an assumption. EPA certainly has authority under section 112 to regulate emissions of HAP, and, while we do not believe that we are required to regulate malfunctions emissions under section 112, we do not believe that we are prohibited from regulating such emissions. We also disagree with the commenter's assertion that PRDs have no PTE and therefore are not an affected source subject to the MACT emissions limitations. Atmospheric PRD at petroleum refineries can release HAP both when they do not seat properly (equipment leak) and when they open "intentionally," and we considered that, for this source category, it is necessary to regulate these HAP emissions sources. As we have explained in more detail in the preamble to the final rule, we are not finalizing the prohibition on atmospheric releases from PRD, which appears to be the fundamental concern of the commenters, but are instead establishing work practice standards. See the preamble to the final rule for more information regarding the requirements and our rationale for the PRD pressure relief management standards we are finalizing.

Comment 3: One commenter stated that if the EPA proceeds to regulate PRD emissions under section 112(d), and sets a no discharge standard for atmospheric PRDs, then the EPA should explain how it considered these adverse impacts in setting such a proposed standard. The EPA's proposal does not provide a rationale for distinguishing between classes, types and sizes of PRDs in setting the standard, but according to the commenter, there are two different standards: PRDs to flares, and atmospheric PRDs. PRDs routed to a flare must meet only 98% control efficiency or contain less than 20 ppmv HAP, while those venting to atmosphere must meet 100% control efficiency. The commenter stated that it is appropriate for the Administrator to distinguish between classes, types and sizes of PRDs for purposes of setting a section 112(d) standard, but not in the manner in which the EPA proposed. The commenter suggested that instead, the EPA should look at the technical feasibility and ability to control the PRDs in distinguishing appropriate classes, types or sizes for determining the MACT floors. The commenter noted that this has been the EPA's standard practice on all MACT standards including the original Refinery MACT under 40 CFR subpart CC.

Rather than relying on section 112(d) for its legal authority, which would entail an extensive analysis of MACT floor and other considerations, the commenter recommended that EPA rely on either section 112(h) or section 112(r)(7) to establish work practice standards

Response 3: As provided in more detail in the preamble to the final rule, we are not finalizing the prohibition on atmospheric releases from PRD but instead are establishing work practice standards. We disagree with the commenter that we can rely on section 112(h) to set a work practice standard in place of relying on section 112(d). We may establish work practice standards as allowed under section 112(h), but these work practice standards must meet the definition of MACT as provided in section 112(d)(2) and (3). As noted previously, we identified the BAAQMD and SCAQMD rules to represent the "best performers" within the meaning of section 112(d)(3). We also disagree that we established two different standards, one for controlled PRD and one for atmospheric PRD. In the proposal, we established a single standard that required that PRD releases be vented to a control device and we clarified that, if the emissions were not vented to a control device, it was a violation of the standard.

Comment 4: Several commenters expressed safety, feasibility, and cost concerns if all PRDs in organic HAP service are routed to existing and new flares.

Commenters detailed a list of concerns for routing PRDs to existing flares including:

a. The existing flare system would have to have sufficient additional hydraulic capacity for both the individual relief loads and common mode relief loads, without raising the backpressure on other relieving PRDs. This could require additional flares to increase pressure relief capacity, which will increase net annual emissions because of the continuous pilot, purge and sweep gas combustion required.

b. The flare sterile area would need to be adequate for an increase in individual or common mode flare loads.[95]

c. The flare would need to be able to meet the other applicable regulatory requirements (e.g., smokeless operation, velocity, combustion zone heating value) at the increased load, which is of particular concern if the underlying circumstance giving rise to flaring is an emergency event.

d. Compatibility of fluids (freezing issues from fluids that can auto-refrigerate with water containing streams for example, hot and cold stream).

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[95] Due to the thermal radiation reaching the ground during a major flaring event, which can happen at any time and without warning, an area around the base of an elevated flare is treated as a no entry zone. This area is often referred to as the sterile area. Providing this sterile area is the reason flares require significant plot space, which often is unavailable near the equipment the flare serves and which will be a major concern if new flares are required as a result of this rulemaking.

e. Relief valves may have to be elevated so that they are free draining and are sloped into the flare header. Increasing the height will increase the inlet pressure loss which may violate the 3% rule and also lead to RV instability (e.g., chatter with the potential for loss of containment).

f. Over-pressure scenario could occur in which the refinery vacuum tower could experience loss of cooling water at the vacuum ejector discharge condensers as a result of routing all RVs in organic HAP service to existing and/or new flares. The commenter stated that this scenario would result in very significant amounts of steam being discharged to the flare and have negative effects on the flare system.

g. “Stepped” RVs will be banned by this proposal. “Stepped” RVs are when a primary RV is routed to control and additional RVs with somewhat higher set pressures routed to the atmosphere.

h. These controls require very large investments (millions of dollars per RV) in new flares and flare header systems.

i. Space may not be available for siting new flares.

j. The surrounding community objects to the addition of flares.

Two commenters also explained that for non-thermal relief, liquid RVs, the flare system would also need to meet the following requirements:

k. The column foundation and structure would need to be strong enough to support a liquid full column;

l. The flare knockout drums would have to have sufficient capacity for the identified liquid overfill relief rate;

m. The flare piping would need to be strong enough to handle the liquid weight and flow regimes associated with the liquid relief and any coincident vapor flows to the flare;

n. The flare system would have to have adequate capacity to vaporize and/or recover the liquid and is designed to handle any associated cold safety issues.

The commenter suggested that when the EPA considers these types of technical and safety concerns, the EPA should appropriately identify classes, types or sizes of PRDs and would likely determine that certain PRDs, which currently release to the atmosphere, are distinguishable from other PRDs for the purpose of setting standards.

Response 4: We recognize many of the concerns raised by the commenters about routing all PRDs to flares. For example, low pressure PRD on storage vessels cannot relieve to a flare because the flare header may often be at a higher pressure than the storage vessel PRD. To address these concerns (as well as concerns expressed by other comments in this section), we are not finalizing the prohibition on the atmospheric releases of HAP from PRD, which is the basis for these concerns. Rather, we considered what the best-performing facilities do with respect to atmospheric PRD and developed a work practice standard for PRD releases (as described in more detail in the preamble). This work practice requires the use of 3 prevention measures as well as root cause analysis and corrective action for releases. In the development of the MACT standard, we did consider PRD type, size, design pressure, and type of service (vapor versus liquid service). We expect that the final requirements for PRD resolve many of the potential issues identified by these commenters. See the preamble of the final rule for more details regarding the final pressure release management requirements.

Comment 5: A few commenters stated that the prohibition of any pressure release from a relief device to the atmosphere directly violates the general duty provision in proposed 63.642(n) of Refinery MACT 1. A few commenters added that while this general duty applies to owners and operators, the EPA must allow for safe operation of refineries by not prohibiting such operations to ensure compliance with the general duty provisions.

Some commenters noted that because of the safety implications of this change, this proposal requires coordination with the Occupational Safety and Health Administration (OSHA) and the RMP Group at EPA to assure there are no inconsistencies between this proposal and the OSHA PSM Requirements and CAA section 112(r) RMP requirements and current update effort in the context of Executive Order 16350 that the impacts of this proposal are appropriately coordinated with safety related requirements. Other commenters stated that EPA should use its authority under section 112(r) to ensure that the rule is requiring inherently safer technologies (IST).

Other commenters stated that prohibiting atmospheric safety valve releases will increase the chance of a catastrophic equipment failure, particularly during the period between promulgation of these amendments and installation of the new flare systems and additional/larger safety valves that would be required to control existing atmospheric safety valves. Several commenters expressed similar concern that the prohibition of PRDs releasing directly to atmosphere will increase safety risks at refineries from what many of the commenters deemed to be infrequent and low impact emission sources. A few commenters stated that this prohibition requires operators to deal with conflicting safety and environmental regulations. One commenter stated that the need to control a PRD is normally addressed during the complex process of process hazards analysis (PHA). PHAs take into account the specifics of the situations in order to properly apply solutions in order of importance for the explicit purpose of protecting life and property. The commenter asserted that the EPA should not mandate the imposition of a control system that safety experts may deem to be unnecessary.

Response 5: As noted previously, we are not finalizing the prohibition on the atmospheric release of HAP from PRD. The work practice standards that we are finalizing address the concerns expressed by the commenters. See the preamble of the final rule for more details regarding the final pressure release management requirements.

With respect to coordination with section 112(r) requirements and the need for this rule to require IST, we note that the EPA's regulations on catastrophic releases appear in 40 CFR part 68. We currently have a petition for rulemaking to address IST under section 112(r) and part 68. Also, pursuant to Executive Order 13650, EPA has issued a "Request for Information" soliciting public views on the appropriateness of IST regulations and is considering pursuing rulemaking as part of the regulation, standard and guidance modernization effort called for by the Executive Order. Historically, EPA's authority to address catastrophic releases under the NESHAP program was viewed as limited under the pre 1990 CAA. Congress added section 112(r) to address this gap. In light of the extensive history and efforts of the agency on IST specifically and catastrophic accidents generally under the section 112(r) program, and in light of the statutory structure of section 112, we view the request to enact IST provisions in this rule to be outside the scope of section 1112(d)(2), section 112(f)(2) and section 112(d)(6). Therefore, the comment suggesting that this rule require IST is outside the scope of the current rulemaking

6.4.3 Monitoring system requirements

Comment 1: One commenter stated that, to ensure compliance with the proposed requirements, they will need to purchase and install monitoring equipment on each affected atmospheric PRD, hardwire the monitoring equipment to the distributed control system (DCS), and program appropriate alerts and/or alarms. The commenter stated that the cost to implement this program is not justified given that atmospheric PRDs rarely open. The commenter argued that the EPA's expectation that atmospheric PRDs be alarmed so that operators may minimize the venting to atmosphere as quickly as practicable is not sensible because atmospheric PRDs are most likely to open during an emergency when dozens of alarms may simultaneously be going off, and an operator's primary concern will be to safely regain control or shut down operations. Under such circumstances, atmospheric PRDs vent to atmosphere precisely so that refineries can safely contain the emergency and mitigate risks to personnel and the public, and to prevent equipment and catastrophic loss of containment. The commenter added that to expect refineries to minimize venting to atmosphere during extreme emergencies is counter to an atmospheric PRD's intended purpose and could increase the danger to personnel, and the public. The commenter stated that the EPA's desire to regulate a critical safety device as an air pollution control device will increase the health and safety risk from refineries.

Other commenters similarly noted that the parametric monitoring requirements could prove to be both challenging and expensive, particularly for liquid PRDs in piping associated with tank farms or other areas that are not co-located with a process unit. One commenter explained that it is unclear that flow monitoring is even feasible for all liquid PRDs. The commenters concluded that, given the high cost of continuously monitoring liquid/thermal PRDs, their low likelihood of ever relieving and their minimal release potential, the existing work practice emission limitation provisions of 60.482-8 and 63.169 of part 63 subpart H are more than adequate and appropriate for this class of PRDs. One commenter asserted that the record for this rulemaking does not show that continuous instrumental monitoring is required, authorized or justified for liquid PRDs and that portion of the proposal, therefore, cannot be finalized.

Response 1: After reviewing these comments in light of the requirements in the BAAQMD and SCAQMD rules, we are not requiring PRD monitoring requirements for: liquid PRD routed to drain or process piping; PRD with set pressure less than 2.5 psig; PRD in heavy liquid service; PRD that have a maximum release rate less than 72 lbs/d VOC; thermal expansion relief valves;

PRD on mobile equipment. These sources have small emissions potentials, so we consider it reasonable to reduce the monitoring burden for these PRD.

6.5 Compliance time for equipment leak/PRD requirements

Comment 1: One commenter stated that if the PRD prohibition is finalized, a compliance time of 10 years should be granted to install and configure the hundreds of additional flares anticipated for compliance. This time is needed for permitting, greenhouse gas reviews, and construction. Further the commenter stated that in order to modify existing flares to meet the new requirements in this rulemaking as well as install new flares to address the RV prohibition, the additional compliance time is needed to minimize significant outages and disruption of fuel production to ensure flare capacity is maintained for safety purposes.

Another commenter suggested that a minimum of 5 years for compliance be given depending on the refinery's turnaround schedule as well as an expedited process for obtaining permit and construction authorizations for the new flare under parts 60, 61, and 63, and providing provisions to request additional time, if needed.

Finally, one commenter stated that if their proposed work practice approach is adopted, a compliance period of three years should be granted for installing the requirement monitoring and instrumentation and the preventative measures. Some commenters requested that 18 months be provided to develop procedures and systems, train personnel, and institute the suggested root cause corrective action (RC/CA) approach in the proposed work practice.

Response 1: We are not finalizing the prohibition for atmospheric PRD releases. Instead, we are establishing work practice standards requiring the use of prevention measures with the goal of reducing the frequency of PRD releases and reducing the magnitude of releases if a release does occur. We are providing a 3 year compliance time to implement the prevention measures required in the PRD work practice standards based on the time needed to perform the hazard analysis and purchase and install any equipment necessary for the prevention measures.

6.6 Impact estimates for equipment leak/PRD requirements

6.6.1 Emissions Changes

Comment 1: One commenter argued that while claiming there is significant HAP release potential, the EPA makes no claims that there are, in fact, significant amounts of HAP released from PRDs or that there is any risk impact from these typically short, very infrequent occurrences that would justify the billions of dollars in investments and operating costs this proposed prohibition imposes.

Response 1: We are promulgating the standards for PRD pursuant to CAA sections 112(d)(2) & (3) and these standards are technology based, not risk based. Neither the amount of HAP released or the risk potential of the emissions is considered in developing these standards. However, we note that we do have specific information regarding emissions from PRD from Component 1 of the 2011 Refinery ICR survey and we evaluated the potential health risks associated with these PRD emissions as detailed in Appendix 13 of the Final Residual Risk Assessment for the Petroleum Refining Source Sector in Docket No. EPA-HQ-OAR-2010-0682).

Comment 2: One commenter stated that the proposed regulation would result in more emissions because of the need to add additional flares. In addition to the natural gas purge, the new flares would require pilot gas to ensure flared gas is combusted; supplemental fuel gas to meet the Btu content requirements for efficient combustion; and, steam injection to meet tip cooling requirements and smokeless combustion requirements. Combusting additional purge gas, pilot gas, supplemental gas, and fuel to provide the steam for steam injection would result in additional emissions of regulated air pollutants and GHGs on a continuous basis, e.g. 8760 hours a year in order to avoid an accidental release that may only occur 5 minutes every 10 years, if ever. The commenter argued that this results in unnecessary adverse environmental and health impacts related to increased natural gas production.

Response 2: We agree that the installation of flares to address infrequent emissions from PRDs could well result in greater harm to the environment than would be provided by controlling the PRD releases. We are not finalizing the atmospheric PRD prohibition but are instead establishing a work practice standard that should not result in negative secondary impacts.

Comment 3: One commenter stated that there is no justification to change the equipment leak control device emissions limitation from 95% to 98%. The commenter explained that the proposed 63.648(j)(4) requires that the CVS and control device systems used for RVs that are exempted from the section 63.648(j)(1) through (3) requirements meet the requirements in 63.644. 63.644, which is titled “Monitoring Provisions for Miscellaneous Process Vents” and contains requirements that reflect those determined to be appropriate for Refinery MACT 1 Group 1 MPVs (i.e., 98% control). However, the commenter argued that those requirements are more stringent than those determined to be applicable to equipment leaks in the Refinery MACT 1 rulemaking (i.e., 95% control) and those are the requirements that 63.648(j)(4) must reference unless the change has been justified under the provisions of section 112(d)(6). RVs are clearly identified as being an equipment leak source in Refinery MACT 1 and they are specifically excluded from the MPV definition. Even in the proposal, RVs complying with 63.648(j)(4) are excluded from the MPV definition. The commenter stated that no analysis or justification is presented for changing the equipment leak control device emission limitation from 95% to 98% and thus concluded 63.648(j)(4) cannot reference 63.644, but must reference the same control provisions as are referenced today (i.e., 60.482-10 and 63.172).

Response 3: Historically, PRD have been included under equipment leaks to ensure the valves are properly seated, and there are no emissions during normal operations. In this mode, the PRD is an equipment component that may leak and is subject to the equipment leak requirements. However, when the PRD opens, we consider this mode of operation to be analogous to an MPV. Consistent with this interpretation, we are finalizing the control device requirement as proposed.

6.6.2 Control costs

Comment 1: Two commenters stated that the EPA has provided incomplete costs associated with complying with the proposed ban on atmospheric PRDs. One commenter stated that as many as 300 new flares and new header systems may be required to control the EPA estimated 12,000 atmospheric RVs as a result of the proposal.

The commenter stated that in 2005, the BAAQMD evaluated requiring control of the 324 atmospheric safety valves at the 5 refineries in the District and concluded that approach would require addition of seven flares and have an investment cost of $192 Million ($17.9 Million annualized over 20 years), with a cost effectiveness of $890,000-1,500,000 per ton of VOC reduced.[96] The commenter asserted that scaling the BAAQMD data to the 12,000 atmospheric RVs the EPA estimated, would result in a national investment cost of $7.1 Billion 2005 dollars ($663 Million annualized over 20 years) and require construction of 209 new flares. According to commenters, these costs and the number of new flares would be increased significantly due to the imposition of the 400 ft./sec velocity limit as proposed in this rulemaking, and the increase in refinery construction costs which were not applied to the BAAQMD flares. The commenter stated a current investment estimate would approach $12 Billion as a result of this prohibition.

Another commenter provided a company-specific estimate of greater than $25 million dollars capitol cost for the addition of at least two flares to control 266 atmospheric relief valves and 1.1 million dollars in annualized operating costs. The commenter also stated that considering the estimated emissions reductions, the cost effectiveness would be greater than $200,000/ton VOC. Another commenter provided a company specific estimate of $200 million dollars to connect all of its atmospheric relief valves to flare systems. The commenter estimated that it would need to install 25 new flares for a $1.5 billion investment.

Another commenter also stated that additional large costs will accrue from the production losses associated with process shutdowns to install the new flares and header systems and to add nozzles and RVs to equipment because of the requirement for additional relief area to compensate for the added backpressure of relieving into a flare system rather than the atmosphere.

The commenter also expressed concern about whether land will be available for these additional flares or if they can be permitted, in light of community concerns over flares. Another commenter also highlighted concerns associated with obtaining and complying with preconstruction NSPS requirements and the feasibility for obtaining offsets for facilities located in nonattainment areas. The CAA requires that the Agency consider these costs and the increased emissions associated with adding flares, among other issues, in establishing an emission limitation. The rulemaking record needs to clearly identify that this proposal requires installation

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[96] Douglas, Victor and Crockett, Alexander, BAAQMD, Proposed Amendments to Regulation 8, Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries, Staff Report, November 2005, Pages 35-38. This cost effectiveness assumes no existing spare flare system capacity, a situation that is generally true and will be totally true under the proposed extension of the 400 fps velocity limit to emergencies. Even if 100% spare flare capacity was assumed the BAAQMD estimated costs of $10-80 million for new piping.

of additional flares and it must inform the public of that impact. No such analyses have been performed in support of this proposal to prohibit atmospheric pressure releases.

Response 1: We are not finalizing the atmospheric PRD prohibition but are instead establishing a work practice standard. Some facilities will need to implement additional prevention measures on atmospheric PRD and we provide an estimate of the costs associated with the work practice in the memorandum titled "Pressure Relief Device Control Option Impacts for Final Refinery Sector Rule" in Docket ID No. EPA-HQ-OAR-2010-0682.

Comment 2: Regarding the EPA estimate of $9.54M (roughly $7,500 per installation), with an annualized cost of $1.36M per year for the monitoring requirements, several commenters provided the results of an industry trade group (API and AFPM) survey. The survey indicated that the cost per wireless PRD monitoring system would range from $12,000 to $16,700 with an average cost of $14,350 which is approximately double what was included in the rulemaking. The commenters indicated that wireless systems are not usable at some locations including areas associated with liquid valves and would require hard-wired systems. One commenter reported costs of $75,000 - $100,000 for hard-wired systems.

Response 2: First, we are not finalizing a prohibition on atmospheric PRD. Secondly, we are providing exemptions from the pressure release management procedures (which includes the PRD monitoring system requirements in §63.648) for devices in heavy liquid service as defined in §63.641, and those that only release material that is liquid at standard conditions (1 atmosphere and 68 degrees Fahrenheit) that are hard-piped to a controlled drain system or piped back to the process or pipeline, among others. As a result, we do not expect nearly as many new monitoring systems to have to be installed as suggested by the commenter and maintain the rule requirements are cost effective.

6.7 Recordkeeping and reporting requirements

Comment 1: One commenter stated that the EPA cannot demonstrate that new and additional reporting requirements for releases from relief devices are justified. The commenter argued that the regulated community is well aware of relief device events that result in emission releases, and that industry takes action both to report and correct such events. Some commenters cited specific regulatory programs requiring the reporting of unpermitted releases of HAP including polyvinyl chloride (PVC) NESHAP, the HON, Group IV Polymers and Resins NESHAP, Polyether Polyol NESHAP, MON, Polymers and Resins I NESHAP, 40 CFR 63, subpart UU, Title V Reporting, EPCRA, and CERCLA and asserted that the EPA neither collected nor analyzed any of this information as part of this rulemaking.

Response 1: We disagree with the claim that regulated communities are aware of these releases and comments from community groups support the fact that they are not aware. Regarding other rules that require reporting of unpermitted releases, we note that most of these regulations do not apply to emissions from sources regulated pursuant to Refinery MACT 1 and Refinery MACT 2. Thus, it is unclear why the commenter is suggesting that EPA should have collected and considered that information. We note that the reporting requirements we are establishing in the final rule are consistent with the reporting requirements in the BAAQMD and SCAQMD rules, which represent what is required of the best performing sources.

Comment 2: One commenter stated that proposed 40 CFR 63.655(g)(10)(iii) requires reporting information on any pressure release to the atmosphere that occurred during the reporting period. It calls for reporting "estimate of quantity of substances released." The commenter stated that "substances" is an ambiguous word and would include materials that are not pollutants and are not HAPs. The commenter suggested that since section 112 deals with HAPs, this reporting requirement should be limited to estimates of releases of organic HAPs regulated by Refinery MACT 1. Other CAA rules and rules authorized under other statutes are already in place to obtain information on releases of other substances.

Response 2: We agree with the commenter that the reporting requirements 40 CFR 63.655(g)(10)(iii) should be specific to quantities of organic HAP released, and we have made this change in the finalized rule requirements. Note that this is consistent with the proposed requirement 40 CFR 63.648(j)(3)(iii) to calculate the quantity of organic HAP released during the event.

Comment 3: One commenter stated that EPA proposed to add a new paragraph (vii) to 40 CFR 63.655(f)(1) to address NOCS reporting requirements relative to PRD monitoring. However, this paragraph appears to require information for PRDs that are not required to be monitored (i.e., PRDs excluded from monitoring by 40 CFR 63.648(j)(4)). The commenter suggested that the proposed 40 CFR 63.655(f)(1)(vii) needs to be revised to only address PRDs in organic HAP service that are subject to the 40 CFR 63.648(j)(3) monitoring requirements. There is no justification or need for listing those PRDs that are routed to a process, a fuel gas system, or control.

The commenter also stated that proposed paragraph (10) to 40 CFR 63.655(g) to address periodic reporting requirements for PRDs appears to apply to all PRDs and not just those subject to monitoring. The commenter suggested that 40 CFR 63.655(g)(10) introductory paragraph needs to be revised to only apply the requirements in this section to PRDs that are not excluded from the requirements of 40 CFR 63.648(j)(1) - (3) by 63.648(j)(4).

The commenter also suggested that 40 CFR 63.655(g)(10)(ii) be modified to read as italicized below, because, the commenter claimed, the current wording suggests that monitoring of all PRDs to show compliance is required in each semiannual reporting period. No such monitoring frequency is specified in 40 CFR 63.648(j).

(ii) For relief valves in organic HAP gas or vapor service subject to 63.648(j)(2), report confirmation that any monitoring required to be done during the reporting period to show compliance was conducted.

Response 3: We agree with the clarifications suggested by the commenter. We did not intend to require reporting of controlled PRD or reporting of monitoring information from PRD not subject to the monitoring system requirements. Specifically, the following revisions are included in the final rule, 63.655(f)(1)(vii): “For **pressure** relief **devices** in organic HAP service **subject to the requirements in §63.648(j)(3)(i) and (ii), this report shall include the information specified in paragraphs (f)(1)(vii)(A) and (f)(1)(vii)(B) of this section:** ….”

63.655(g)(10)(i): “For **pressure** relief **devices** in organic HAP gas or vapor service, pursuant to §63.648(j)**(1)**, report any instrument reading of 500 ppm or greater, more than 5 days after the **pressure** relief **device** returns to service after a pressure release.”

63.655(g)(10)(ii): “For **pressure** relief **devices** in organic HAP gas or vapor service subject to §63.648(j)(2), report confirmation that **any** monitoring **required to be done during the reporting period** to show compliance was conducted.”

63.655(g)(10)(iii): “For **pressure** relief **devices** in organic HAP service **subject to §63.648(j)(3)**, report each pressure release to the atmosphere, including duration of the pressure release and estimate of **the mass** quantity of **each organic HAP** released, **and the results of any root cause analysis and corrective action analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.**”

7.0 Delayed Coking Units

Comment 1: One commenter asked how the refinery rule affects coker units still included in permits, but shut down due to business decisions. The commenter also asked about coker units not in the petroleum refinery sector. According to the commenter, there are three Rain CII calcining plants in Louisiana with their own terminals and coker units. One of these plants is adjacent to the ExxonMobil Chalmette refinery, yet it will not be subject to the EPA proposed refinery rules, because it is not in the petroleum refinery sector. According to the commenter, this plant emits the "lion's share" (over 7,000 tons per year) of the sulfur dioxide emissions said to designate St Bernard Parish non-attainment for the 2010 NAAQS one-hour health standard for SO_2. Two commenters recommended that the EPA should consider improving pollution controls on all coker units, including those at coke calcining facilities.

Response 1: Delayed coking units at facilities that are currently not operating for business reasons will need to meet the emission limitations of the final rule based on the compliance schedule for an existing source. While delayed coking units may be used to supply coke calciners, we are not aware of any independent (non-refinery) coke calcining facility that operates a DCU. That is, we expect that the facility the commenter is referring to likely receives coke from the adjacent refinery and the coker at that refinery will be subject to the final requirements for DCU. Coke calciners are very different emission sources than DCU and the emission controls applicable to coke calciners would be very different as well. Coke calciners are not a source category regulated under section 111 or 112 of the CAA and the development of NSPS or other regulations for the coke calcining industry is beyond the scope of this rulemaking effort.

7.1 Technology review/need for MACT standard

Comment 1: Three commenters supported the EPA's determination that the DCU atmospheric vent was previously unregulated and it is appropriate to establish a MACT standard for this source. One commenter suggested that decoking units are archaic and obsolete and that the EPA should encourage the refinery industry to conduct research to develop a continuous decoking operation where emissions can be more easily reduced or captured. Other commenters argued that delayed coking unit vents are already regulated as a MPV. Two commenters claimed that DCU are clearly sources regulated under Refinery MACT 1 as they are "process units for thermal cracking." These commenters suggested that the exclusion stating that "coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge [psig], deheading, draining, or decoking (coke cutting) or pressure testing after decoking" is simply an exclusion for when emissions were considered de minimis. According to these two commenters, this exclusion is analogous to the 20 ppmv concentration threshold for Group 1 MPV. If these vents are discharged to the atmosphere at a pressure above 15 psig, they would need to be evaluated as MPVs and controlled if the Group 1 criterion were met. One commenter noted that the background document for the 1995 Refinery MACT rule suggests that EPA understood its 15 psig threshold not to constitute a determination to leave delayed coker vents unregulated, but to set the threshold "to encourage vapor recovery" at facilities using DCUs.

Response 1: We disagree that the DCU is an obsolete technology and should be replaced with continuous coking operations. The refining industry has already developed continuous coking processes, but these processes generally have significantly higher emissions than DCU and most refineries have elected to use DCU rather than these continuous coking processes.

We agree with commenters that the DCU are sources that are part of the affected source under Refinery MACT 1. However, as explained in the preamble to the proposed rule, we believe that there are two distinct types of vents associated with DCU and these two types of vents are treated very differently within the existing Refinery MACT rule. The “delayed coker vent” (i.e., the vent for the DCU blowdown system) is specifically defined and cited as an MPV, which requires the blowdown system to be controlled rather than open to the atmosphere. The atmospheric vents associated with decoking operations (the coker “steam vent” as well as releases from deheading, draining and coke cutting) are completely different venting locations and these vents are specifically excluded from the definition of an MPV (at pressures less than 15 psig), which effectively excluded these vents from any regulatory requirements. The EPA did not attempt to determine the emissions limitation achieved by the top performing decoking operation vents in establishing the exclusion regardless of whether it might be “to encourage vapor recovery.” We also note that there are no monitoring requirements in the existing Refinery MACT requirements to ensure compliance with this 15 psig threshold, which further undermines the assertion that this limit was intended as a MACT standard. It is evident that refineries considered this a full exclusion for decoking operation vents. See, e.g., ICR responses. In Appendix C of commenter EPA-HQ-OAR-2010-0682-0583, the commenter indicated that one facility reported that they typically vent to the atmosphere at 17 psig and did not control this vent as an MPV.

We agree that at the time the MACT standard was developed in the mid-1990s, the EPA did not make a determination that the emissions from the decoking operation vents were de minimis. More recently, the EPA has obtained data to truly characterize these emissions. Available data indicate that the HAP concentration in the atmospheric steam vent is often greater than 20 ppmv on a wet basis and much greater than 20 ppmv when determined on a dry basis. Available data also suggests that these vents release greater than 33 kg/day VOC (especially when venting at higher coke drum pressures). Therefore, we disagree that the 15 psig is analogous to the de minimis emissions levels used for MPV (i.e., the 20 ppmv threshold).

Because the EPA has concluded that decoking operation vents were excluded from MACT requirements at the time the standards were initially promulgated, EPA has authority at this time to determine the appropriate MACT limit for these operations under Refinery MACT 1.

7.2 MACT floor determination

Comment 1: One commenter agreed with the EPA that the DCU standard must be a work practice standard under section 112(d)(6) because “it is not feasible to prescribe or enforce an emission standard for the DCU steam vent because the application of a measurement methodology for this source is not practicable due to technological and economic limitations.” The commenter contended that the EPA is arbitrarily and unlawfully using the MACT standard (MACT floor) setting approach for a standard where the Agency determined that the MACT standard setting approach cannot be used, i.e., in establishing a work practice standard. The commenter stated that the EPA is obligated to provide an explanation of how section 112(d)(6) can or should be construed to require or allow the use of the section 112(d)(2)/(3) MACT standard setting approach in setting a work practice under section 112(d)(6). According to the commenter, the failure to provide an explanation of the legal authority for this standard setting approach violates the Agency's obligation under section 307(d)(3) to provide an explanation of the basis and purpose for the proposed rule.

Response 1: The premises of the commenter's arguments are incorrect. As an initial matter, the EPA is developing standards for the DCU decoking operation vents under section 112(d)(2)/(d)(3) not 112(d)(6) because we determined that these vents were inappropriately excluded from the MACT requirements in subpart CC. Under section 112(d)(6), we concluded that the current MPV requirements for the "delayed coker vent" were appropriate and that there were no developments in practices, processes, or control technologies for MPV. Section (112)(d)(2) clearly allows that the MACT standards can be a work practice standards and section 112(d)(3) states that the minimum (MACT floor) requirements "shall not be less stringent...than the average emission limitation achieved by the best performing 12 percent of the existing sources..." While strict application of the MACT floor analysis might create issues in terms of practical application in the context of setting certain work practice standards, that is not the case in this instance and use of the MACT floor was appropriate.

Comment 2: One commenter suggested that the EPA must supplement the 2 psig limit with an additional long-term standard on the annual average maximum pressure of the coking unit prior to release to the atmosphere. While the commenter noted that the EPA's short-term, never-to-be exceeded limit is important, the commenter argued that the available data show that the top performing 12% of coking units actually achieve much higher levels of control on average. For new units, the law requires EPA to set a standard that is "not less stringent than the emission control that is achieved in practice by the best controlled similar source." At existing units, EPA must set a standard based on "the average emissions limitation achieved by the best performing 12 percent of the existing sources." According to the commenter, the ICR data shows that the typical pressure of the coke drum prior to release to the atmosphere for the best performing facility and the best performing 12 percent of facilities is 1 psig.

Response 2: We disagree with the commenter that a long-term, annual average standard is required. Based on our analysis of permit requirements, no DCU is required to meet a short- or long-term standard. The only existing requirements for DCU are based on pressure limits for a single cycle. While we agree that a facility achieving a 2 psig emission limitation for each cycle will likely have an average venting pressure well below 2 psig, that fact alone does not mandate that we create for existing units a long term limit where one does not currently apply to any of the top performing sources.

Regarding the comment that we must establish a 1 psig limit for new sources because it represents the best performing facility, we disagree. The reported "typical venting pressure" reported by ICR respondents is insufficient evidence to conclude that any facility meets an annual average of 1 psig. For example, assume a facility operates a DCU vent at about 1 psig 60 percent of the time, 2 psig 35 percent of the time, and 3 psig 5 percent of the time. Such a facility would likely report that they “typically” vent at 1 psig, but this facility would not be able to meet a 1 psig annual average emission limit.

7.2.1 Existing source alternatives

Comment 1: Two commenters requested that an alternate work practice standard should be provided for “water overflow” DCUs. Water overflow DCUs are a type of DCU design that employs a unique process operation in which the coke drum is filled with water and the overflow from the coke drum is passed through the overhead vapor line. According to the commenters, this capability must be designed into the DCU and the pressure in the overhead line is not necessarily a reliable indicator of the extent of bed cooling in this type of operation. For these DCUs, the temperature of the water in the overhead line would be representative of the temperature in the top of the coke drum. The commenters requested that water overflow DCUs should be allowed to comply with the 2 psig depressurization work practice standard if equipped to make that demonstration or, as an alternate, demonstrate compliance with work practice standard precluding atmospheric venting prior to water overflow and an overhead temperature of 220 °F (based on the EPA’s analysis of bed temperature at 2 psig). One commenter also requested that, it should be clearly identified that water overflow drums, where water is routed to an atmospheric tank, while vapors are recovered to the closed blowdown system, are permissible.

Response 1: We agree with the commenter that a 220 °F overhead temperature is at least equivalent to the 2 psig limit since this is the saturated steam temperature of a system at equilibrium (i.e., a closed system) at 2 psig. Since the coke drum is actively venting, it is easier for a traditional DCU to meet the 2 psig pressure limit than 220 °F and that a traditional DCU achieving an overhead temperature of 220 °F would have emissions equivalent to or less than a traditional DCU achieving 2 psig pressure limit. Similarly, we find that an overhead temperature of 218 °F is at least equivalent to a 2.0 psig limit. During our site visits, we asked about water overflow as a means to help cool the coke bed by allowing more cooling water flow through the bed; however, the sites visited did not have a system that was designed to do this and it was unclear if such a system was possible. We are supportive of DCU with water overflow design, but we are concerned with superheated overflow water being exposed directly to the atmosphere. We expect that the overflow line would be hard piped to the overflow water storage tank. Given the height of the DCU overhead pipe, no pump would be needed to allow flow to the storage tank through a submerged fill pipe. Submerged fill will prevent atmospheric exposure of superheated water and allow cooling of the overflow water as it mixes with the tank contents. Therefore, we have revised the provisions of the rule to expressly allow water overflow DCU to discharge water to an atmospheric tank provided that submerged fill pipe (pipe outlet below the existing water level in the tank) is used.

Comment 2: Two commenters requested that an average atmospheric vent time of less than 20 minutes should be established as an alternative standard and considered to have satisfied the depressurization work practice. Short depressurization time is indicative of a well-cooled bed and low vent emissions, even if the initial release pressure is somewhat above a specified do-not-exceed limit. Such an alternate would allow for reduced investment in those cases where excess emission risk is minimal, but back pressure fluctuations are sometimes encountered. The 2010 ICR acknowledged the de minimis emissions emitted by DCUs with such short vent times and provided that these units need not perform stack tests. Short duration vented cokes (defined as those with average vent duration times of less than 20 minutes on a monthly basis) should be considered to be compliant. One commenter requested that the EPA should allow a facility, at its choice, to test and demonstrate that its VOC emissions (as a surrogate for the organic HAPs) are not appreciably different at venting pressures between 5 psig and 2 psig. According to the commenter, if the VOC emissions measured from a DCU at 5 psig (or other pressure) does not result in more than one (1) ton per year of increased VOC emissions compared to emissions at 2 psig, then that facility should be allowed to depressure to 5 psig (or other pressure limit tested).

Response 2: Through site visits, review of source tests, and conversations with delayed coker operators, we have greatly increased our understanding of DCU coke drum cooling and the emissions from decoking operations. For the ICR, facilities that initiated draining within 20 minutes of opening the atmospheric steam vent were considered to have venting times of less than 20 minutes and were not required to test. We now know that venting can occur for some time after the initiation of draining, so many of these DCU that were not required to test were likely to have steam vent emissions for more than 20 minutes. Moreover, had we fully understood the emission sources, including the potential for emissions from the draining area when draining the very hot and often super-heated water, we would have placed requirements that the DCU could not be drained until the vent velocity was no longer measurable or 90-minutes, whichever is shorter. Had we implemented this testing constraint at the time of the ICR, we do not believe any DCU would have vent times of less than 20 minutes.

CAA section 112(h)(3) provides that "If after notice and opportunity for comment, the owner or operator of any source establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such pollutant achieved under the requirements of paragraph (1), the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant." We have codified regulations to implement this provision at 40 CFR 63.6(g). Any facility may use that regulatory provision to demonstrate to the Administrator that an alternative limit is equivalent to the final work practice standard. The key point is that the alternative emissions limitation must be at least equivalent to the emissions limitation in the final rule (not "appreciably similar to" or that "result in more than one (1) ton per year of increased VOC emissions compared to emissions at 2 psig"). Given that our DCU testing requirements would prohibit or restrict draining during the source test, at this time, we consider it unlikely that a facility will be able to demonstrate that a higher venting pressure or that a set venting time is equivalent to the 2 psig limit. However, owners or operators can submit a demonstration pursuant to 40 CFR 63.6(g), if they believe they can make an acceptable equivalency demonstration.

Comment 3: One commenter requested that compliance with the SCAQMD Rule 1114 should be deemed as compliance with proposed requirements in 40 CFR 63.657. According to the commenter, the SCAQMD Rule 1114 is at least equivalent to this proposed rule; therefore, compliance with that regulation be established as a compliance alternative to the requirements in 40 CFR 63.657.

Response 3: We disagree that the compliance requirements are equivalent because South Coast refineries with multiple DCU can comply with a 5 psig limit for some time period prior to compliance with the 2 psig limit. Additionally, the monitoring requirements to ensure compliance with the 2 psig limit are not identical. For these reasons, we are not providing the equivalency requested by the commenter.

Comment 4: Two commenters opposed the requirement prohibiting draining of a coke drum until the 2 psig vent pressure limit is reached. According to the commenters, the reverse flow of water through a coke bed that occurs by draining the bed allows the water to contact additional hot coke, reducing cracked vapor emissions and reducing depressurization time. According to the commenters, limiting pre-vent draining would therefore increase cycle time and reduce coke and gasoline production. Three commenters stated that the proposed ban also imposes a safety risk by prohibiting "double quenching of hot drums." In some cases, a coke drum does not cool properly during the initial quench and overhead temperature cannot be reduced to the allowable release limit. In such a case, a significant quantity of quench water must be drained to allow fresh, cold quench water to be added to provide a second "double" quench. According to the commenters, without the ability to double-quench, the drum would sit idle for indefinite periods of time, while waiting for it to eventually cool down and once it reached the pressure limit it would be opened and the coke bed could still contain hot spots that could cause safety concerns as the coke is removed from the drum. Therefore, the commenters urged EPA to develop a work practice standard that allows draining prior to achieving the overhead pressure requirement in order to reduce emissions and allow "double quenching" of hot drums.

Response 4: While we agree that early draining of the coke drum does limit emissions from the steam vent, as noted in the preamble to the proposal, early draining of the superheated water increases emissions to the atmosphere in the drainage area. We do understand that there are times when the normal cooling cycle is not effective and additional water may be needed to adequately cool the bed. With improved evacuation/blowdown systems, steam loss from the bed will reduce water levels over time and allow additional water to be added. However, we understand that if there is significant channeling in the coke bed, adequate cooling of the coke bed may not be possible using normal cooling algorithms without significant delays in the overall cycle time. Therefore, we are allowing draining of the coke drum for the purpose of double-quenching a coke drum that did not cool adequately using the normal cooling process. DCU owners or operators may drain under certain circumstances, for safety-purposes, provided that they maintain and operate a temperature CPMS at the bottom of the drum or drain line that can measure the temperature of the drain water and they maintain the temperature of the water being drained below 210 °F. This would allow draining and adding of some water (double-quenching) to improve coke bed cooling without draining super-heated water. Owners and operators would be required to record the date, time and duration of each pre-vent draining event, the pressure of the drum for the 15-minute period prior to the pre-vent draining, and the drain water temperature at 1-minute intervals from the start of pre-vent draining to the complete closure of the drain valve. Owners and operators must include in their semi-annual report the number of pre-vent draining events that occurred and, for each instance that the drain water temperature reached 210 °F or higher, the maximum drain water temperature during the draining event. We considered setting a limit on the number of pre-vent draining occurrences that could be performed per year, but we do not consider that appropriate because, as long as high drain water temperatures are avoided, we consider double-quenching to be an effective means to improve coke bed cooling thereby reducing the average coke bed temperature and thereby reducing the overall emissions from decoking operations.

7.2.2 New source & NSPS Ja

Comment 1: One commenter stated that the EPA should incorporate the new Refinery MACT 1 DCU standards into NSPS subpart Ja. The commenter stated that it would be unlawful and arbitrary to delete the Refinery subpart Ja standards because they regulate different pollutants. Four commenters stated that, if the EPA does regulate DCU decoking operations in Refinery MACT 1, the EPA should define the standard at a depressurization level of 5 psig, consistent with requirements identified in 40 CFR part 60, subpart Ja. Three commenters noted that the EPA previously determined that 2 psig was not cost-effective for new sources and it would be less cost-effective for existing sources to meet a 2 psig standard. One commenter stated that the 5 psig limit would more accurately reflect a degree of reduction justifiably characterized as “achieved in practice” and more closely reflect cost-effective, additional HAP emission reductions for these sources. One commenter noted that lowering the MACT limit undermines a company’s investment made to comply with the 5 psig NSPS subpart Ja limit.

Response 1: As mentioned previously, our understanding of DCU operations has changed during the process of developing these MACT standards and the methodology used to estimate these emissions has changed significantly. We have also revised our emissions and cost estimates based on the comments received. Even after these revisions, we still expect greater VOC and HAP emissions compared to our earlier NSPS Ja estimates and thus a lower cost-effectiveness than assumed at the time NSPS Ja was promulgated in 2008. More significantly, however, as described previously, we have determined that we must establish a MACT floor performance level for DCU decoking operations. The MACT standard can be no less stringent that the average emissions limitation achieved by the top performing 12 percent of sources. The EPA does not consider costs in determining the MACT floor, but does consider cost in evaluating whether to promulgate more stringent, “beyond the floor” standards. As described in more detail in the memorandum entitled “Reanalysis of MACT for Delayed Coking Unit Decoking Operations” included in Docket ID No. EPA-HQ-OAR-2010-0682, we agree that it is not cost-effective to further lower the DCU decoking operations venting pressure beyond the 2 psig limit, which we have determined is the MACT floor for existing sources, and thus we are promulgating a limit of 2 psig averaged over 60 events as the MACT standard for existing sources. We also note that, based on the comments and information received during the public comment period, DCU designed to meet a 5 psig limit on a per venting event basis will generally vent at an average pressure of approximately 2 psig and will be able to comply with the 2 psig limit averaged over 60 events we are establishing in the final rule.

7.3 Feasibility of 2 psig requirement

Comment 1: One commenter noted that California refineries have already implemented several emission control measures consistent with U.S. EPA’s proposed 2 psig requirements through compliance with local air district rules and another commenter noted that several refineries in the Houston area already depressure down to 2 to 5 psig, so the 2 psig limit is achievable. Two commenters supported the 2 psig limit for decoking operations, but recommended that EPA establish a 0.2 psig limit. Two commenters supported the 2 psig limit and the inclusion of all decoking operations (venting, draining, deheading, and coke cutting). One commenter stated that the 2 psig limit may not be achievable for facilities with flare gas recovery systems due to variability in the pressure of the flare header system. This commenter suggested that a 5 psig limit would be more appropriate.

Response 1: We appreciate the support for the 2 psig limit for decoking operation vents. We disagree with commenters that recommended a 0.2 psig limit should be established. As noted in the preamble to the proposed rule, the low pressure point in the blowdown system is generally operated at approximately 0.5 psig to prevent air infiltration into the vapor lines. Therefore, it is not technically feasible to achieve a 0.2 psig pressure in the coke drum while venting to the blowdown system. With respect to the comment that the 2 psig limit is not achievable for facilities with flare gas recovery systems, we disagree. We recognize that different vapor recovery or flare gas recovery systems operate at different inlet pressures and, for remote flare gas recovery systems, there may be significant back pressure at the DCU. However, there are flare gas recovery systems in-place that allow compliance with the 2 psig limit. Therefore, we conclude that it is technically feasible to design and operate a flare gas recovery system to control emissions from the DCU blowdown system that allows depressurization of the DCU coke drums to 2 psig prior to atmospheric venting.

7.4 New/revised definitions related to delayed coking units

7.4.1 Delayed coker vent

Comment 1: One commenter noted that the coke drum overhead is not typically “routed to the atmosphere through the delayed coking unit’s blowdown system.” Instead, the coke drum overhead is routed to the closed blowdown system for recovery to the fractionator, fuel gas, or for routing to a control device (i.e., a flare) until such time as a particular drum overhead pressure is achieved, at which time the coke drum overhead vapor is routed directly to atmosphere. The proposed definition seems to imply that sometimes the stream goes to atmosphere via the blowdown system. One commenter noted that it is unclear from the definitions, whether a delayed coker vent to the atmosphere is considered a bypass under the MPV provisions of proposed 40 CFR 63.644(c). The commenter requested that the EPA either confirm that section 63.644(c) applies to delayed coker vents vented to the atmosphere or amend and clarify the proposed regulation such that these vents are subject to section 63.644(c). A third commenter suggested that the definition of delayed coker vent should clarify that the vent associated with the blowdown system is the miscellaneous process vent and the final steam release vent is not a miscellaneous process vent.

Response 1: There are several potential release points or vents from delayed coking units and we are clarifying in the regulation the difference between a “delayed coker vent”, which is a miscellaneous process vent, and decoking operation vents, which were excluded from the definition of MPV. Prior to Refinery MACT 1, it was our understanding that some units used open blowdown systems for their delayed cokers and the MPV provisions of Refinery MACT 1 has effectively required all blowdown systems to be controlled. Therefore, we consider any direct atmospheric releases from the DCU blow down system would be considered a MPV. However, if a control system is in-place on the delayed coker vent and these controls are by-passed, the atmospheric releases would be considered a bypass of the MPV provisions in 40 CFR 63.644(c). Under the amendments promulgated in the final rule, direct discharges to the atmosphere prior to or that by-pass the DCU's blowdown system would be subject to the decoking operation requirements in 40 CFR 63.657. We are clarifying the definition of delayed coker vent to specifically refer to the vent as a miscellaneous process vent. We are also clarifying that the delayed coker vent contains the uncondensed vapors from the DCU blow down system rather than referring to the blowdown system as open or closed. The revised definition reads:

Delayed coker vent means a miscellaneous process vent that contains uncondensed vapors from the delayed coking unit's blowdown system. Venting from the delayed coker vent is typically intermittent in nature, and occurs primarily during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery. The emissions from the decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be delayed coker vents.

7.4.2 Decoking operations

Comment 1: One commenter stated that the second sentence of the proposed definition of decoking operations refers to "steam released from the coke drum is no longer discharged via the delayed coker vent to the unit's blowdown system," but the definition of delayed coker vent is limited to vapors that go to the blowdown system, so there is an internal inconsistency in the statement. The commenter recommended that the term delayed coker vent be deleted from the definition of decoking operations.

Response 1: In response to comments on the revised definition of "delayed coker vent" we have clarified that the delayed coker vent is the vent containing uncondensed vapors from the delayed coking unit's blowdown system. Given this revision in the definition of delayed coker vent, we agree that there is an inconsistency with the inclusion of the phrase "...via the delayed coker vent..." Therefore, we have removed this phrase from the definition of decoking operations, as recommended by the commenter. The final definition of decoking operations reads:

Decoking operations means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. Decoking operations begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged via the unit's blowdown system but instead is vented directly to the atmosphere. Decoking operations include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

7.5 Impact estimates for DCU requirements

7.5.1 Emission reductions

Comment 1: One commenter noted that although reducing the venting pressure by 12 psig does not sound like much, these are very large vessels that release twice a day, so the rule would result in appreciable emission reductions. Two commenters noted that the available test data are highly variable and insufficient to assess the impacts of the proposed requirements and recommended additional test data be collected in order to determine a clear measurable effect of the proposed control requirements on DCU emissions. One of these commenters stated that the proposed limit for DCU is premature because the initial steam vent testing was not coupled with any emission testing of the draining, deheading, or coke cutting, which will include cutting through hot spots, and because the testing did not lend itself to emission rate differentiation with respect to the size of the drum or the release pressure. The other commenter stated that the EPA relied excessively on the results of one source test (Hovensa), which is not representative of industry emissions, and therefore significantly overestimated HAP emissions.

Response 1: We recognize that there are difficulties in comparing the available emissions data due to differences in draining times relative to initiation of venting so that the "steam vent" tested does not necessarily include all of the emissions from the unit. However, the data are of sufficient quality and scope to indicate that the DCU is a significant source of HAP emissions and that some of the HAP emitted from the DCU decoking operations (particularly naphthalene and 2-methylnaphthalene) can contribute significantly to the total cancer incidence from petroleum refineries. Additionally, the available emissions data indicate that DCU decoking operations emissions are proportional to the quantity of steam released, which is, based on heat balance considerations, related to the initial venting temperature or pressure. Therefore, we maintain that there is sufficient evidence to support the conclusion that lowering the venting pressure will reduce HAP emissions from these sources.

Comment 2: One commenter evaluated the SCAQMD model and provided detailed comments on some of the model assumptions. Key issues noted by the commenter include:

1. There is a uniform temperature throughout the entire coke bed and the quench water at the time the vent is started and that 100% of the water in the coke drum at the time of venting is at its bubble point (i.e. all the heat evolved goes toward affecting evaporation and none of it is used in heating the water to the boiling point).
2. There is a 10 percent convective loss term; commenters suggested a convective loss value of 80 percent be used to account for heat needed to raise water to bubble point (see item 1).
3. The model uses a void fraction of 0.5 for the coke bed, resulting in overestimating the amount of quench water that could be in the bed and underestimating the mass of coke. In addition, the model assumption that all the void space is filled with water is not supported by available information. If the model void fraction is decreased from 0.5 to 0.35, the average bulk density of the coke bed would be more in line with available data for green coke (55 lb/cubic foot (ft^3)).

4. The model overestimates the base case emissions because it assumed the coke and quench water for the average coke drum in the base case was at a much higher temperature than indicated by correlation to the overhead pressure.

The commenter also expressed concerns about the typical coke drum dimensions, moisture content of the vent gas, and dry vapor pollutant concentrations used in the SCAQMD model. According to the commenter, the assumptions used in the model estimates result in a significant overestimation of DCU baseline emissions and an overestimate of the emission reductions achieved by the proposed 2 psig emissions limitation.

Response 2: When developing the emission impacts for the DCU emission control options, we used a heat balance model, which we shared with SCAQMD. Several of the comments specific to the assumptions used in this model are pertinent to our impact analysis and we have considered these comments and have revised our emission impacts to address some of the key concerns raised by the commenter.

1. We recognize that there is a temperature gradient in the coke drum with the hottest temperature at the top of the bed and cooler temperatures at the bottom of the bed. Therefore, we recognize that using the overhead temperature for the average bed temperature over-estimated the baseline emissions (and thereby the emission reductions). In recently proposed updates of the Emissions Protocol, we recommended using the average of 212 °F and the overhead temperature as the average bed temperature. While there may be a small portion of the bottom of the bed that may be lower than 212 °F, we also recognize that there may remain hot spots in the coke bed that are much higher than the wall temperature (where measurements are generally taken), so we consider this approach to provide a good estimate of average bed temperature.
2. Even accounting for the heat needed to raise some of the water temperature to the bubble point, we do not believe that this effect can be used to estimate such a high convective heat loss since the enthalpy of the phase change is 960 Btu/lb compared to the heat capacity of water, which is 1 Btu/lb/deg F. Thus, if every pound of water that turned to steam had to increase in temperature by 20 °F, the heat used to increase the temperature of the water would only be 2 percent of the heat loss from vaporization. If the entire amount of water in the drum increased 20 °F and 10 percent of that water volatilized, only 20 percent of the total heat loss would be due to raising the water temperature. Therefore, the 80 percent convective loss term is considered unreasonable. Furthermore, using an average bed temperature (rather than an overhead temperature) minimizes, to some extent, the amount of heat that may be used to raise the water temperature. While we consider 10 percent convective heat loss to be a reasonable assumption, we also evaluated the emission impacts using a 20 percent convective heat loss assumption.
3. We have seen very limited data on the bulk density of coke as it exists in a coke drum. Data for green coke (that has been removed from the coke drum) is expected to have less void space than exists within the coke bed. Based on reported coke production capacity, drum dimensions and drum outages, a coke drum porosity of 0.5 appears to be much more appropriate than the suggested value of 0.35. Therefore, we have not revised this value.

4. The pressure-temperature correlation is only more accurate if one has a closed system (and that closed system is allowed to come to equilibrium). As vapors are continuously being vented from the drum, the overhead drum pressure is lower than the equilibrium pressure of the system, which is commonly seen with pressure increases as the system is sealed to close the vapor line valves to the blowdown system prior to venting to the atmosphere. As noted in our response to item 1, we do agree that the overhead temperature alone would overestimate emissions, but we consider using the average bed temperature, as described in item 1, to provide at least as accurate an estimate of the average coke bed temperature as the overhead venting pressure during active venting of the vessel to the blowdown system.

We have revised our analysis to use average pollutant emission factors from the source tests so comments on the moisture content of the emissions and dry pollutant concentrations are not directly pertinent to the revised emission impact method. Comments concerning drum dimensions are also not pertinent. Unlike the SCAQMD impacts, we used facility-specific drum dimensions, outages, and water heights when calculating the emissions rather default average values. Based on these model revisions, we have lowered our estimated HAP emissions but we still estimate our final rule will achieve approximately 400 tons per HAP and 2000 tpy VOC. See the memorandum entitled “Reanalysis of MACT for Delayed Coking Unit Decoking Operations” in Docket ID No. EPA-HQ-OAR-2010-0682 for additional detail.

7.5.2 Control costs

Comment 1: Six commenters stated that the EPA underestimated the costs associated with complying with the 2 psig DCU emissions limitation. According to the commenters, the EPA relied on a single cost estimate for a steam ejector system of $1-mllion and many DCU would need to do significantly more expensive upgrades of their system in order to meet the 2 psig emissions limitation. According to the commenters, unit-specific upgrade costs range for $1- to $20-million (with most in the $1- to $10-million range). According to the commenters, jet ejector systems may not work if the blowdown system cannot handle the additional steam. Thus, some facilities would also need blowdown system upgrades. Alternatively, some facilities would elect to install a new compressor for the DCU blowdown system. Two commenters noted that the EPA assumed a compressor would be needed to achieve 2 psig emission limitation in its impacts for Refinery NSPS Ja and a cost of $12- to $18-million per unit. According to the commenters, the total capital costs projected for the subpart CC impact analysis are about a factor of 10 too low.

Response 1: We based our cost on a steam ejector system that was actually installed to achieve a 2 psig pressure limit. While a significant range of costs were provided by the commenters, a majority of DCU were projected to have costs under $5-million and many had no costs at all, so we disagree with commenters suggesting the capital costs are a factor of 10 too low. The costs provided by the commenters were early stage engineering estimates, while the costs we used were based on a system that had already been installed and used to comply with the venting pressure limit. While we do expect some variability in the final project costs, many of the costs suggested by commenters are caused more by capacity creep (trying to process more gas oil and/or use shorter cycle times than the equipment was originally designed). In order to account for additional costs associated with additional emissions reduction measures, we assumed that the steam ejectors would be sufficient to achieve a two-thirds (67 percent) emission reduction (i.e., if the current venting pressure is about 6 psig or less). If a DCU would need more than 67 percent emissions reduction, then the capital costs were projected to be twice our estimate for a single steam ejector system, or $2-million (again assuming the use of steam ejector systems along with additional modifications to improve the blow down system capacity). The annual operating costs for the $2-million system is expected to be the same as the simple steam ejector system with the addition of 4 percent of capital costs (for taxes and insurance). On a nationwide basis, the final capital cost estimates increased by 60 percent from proposal to $81-million and the total annualized costs (considering VOC recovery credits) increased by a factor of 3 to $11.7-million, primarily due to lower VOC recovery credits due to changes in the emission modelling assumptions described previously in Section 7.5.2 of this document. See the memorandum entitled "Reanalysis of MACT for Delayed Coking Unit Decoking Operations" in Docket ID No. EPA-HQ-OAR-2010-0682 for additional detail.

7.5.3 Cost effectiveness and risk

Comment 1: Several commenters stated that the cost-effectiveness of the 2 psig standard is very high (commenter estimates ranged from $76,000 to $636,000/ton HAP); therefore, the commenters concluded that a 2 psig work practice standard is not cost-effective and cannot be justified under CAA section 112(d)(6). One commenter noted that this conclusion is consistent with the conclusion the EPA reached in promulgating a 5 psig depressurization work practice standard under NSPS subpart Ja. Three commenters noted that, based on their cost estimates, a 5 psig pressure limit would also not be cost-effective.

Response 1: While our revised cost analysis is generally in line with the lower cost-effectiveness values of the range provided by the commenters, we conclude that a MACT floor limit was never established for this emissions source and that we must now establish proper MACT requirements for this source under CAA section 112(d)(2) and (d)(3). Based on our cost estimates, we agree that additional reductions beyond the MACT floor are not cost-effective, therefore MACT is being established as the MACT floor level of control.

Comment 2: Several commenters stated that the EPA has overstated the risk associated with DCU emissions. Two commenters suggested that the Protocol overstated PAH concentrations, a risk driver for cokers, by approximately an order of magnitude because the Protocol predated the required stack tests from the ICR, which, according to the commenters, demonstrated that the data set used to develop the Protocol was an outlier. These commenters also alleged that there is significant conservatism in the employed toxicological values for naphthalene and benzene because, for example, the cancer URE which the EPA used for naphthalene did not take into account the most recent scientific information. According to the commenters, results of the research funded by the Naphthalene Research Council suggest that the URE used by the EPA in this document is overly conservative and that development of cancer in humans due to naphthalene exposure may not even be a relevant endpoint. The commenters stated that, even if one accepts the conservative selection of toxicological values and the base case emissions as described by the EPA, the proposed revision to the DCU standard of 2 psig is not cost effective and proposes to address a very small risk of 0.05 incidences per year nationwide according to the

EPA estimates. The commenters also asserted that, even considering the EPA's modeling conservatism, the cancer incidences reductions are still overstated by approximately 65% because approximately 64% of the cancer incidences reductions were attributed to units located in the SCAQMD, units that already are or will be subject to a federally enforceable not-to-exceed limit of 2 psig. On the other hand, one commenter urged the EPA to set section 112(f)(2) standards for these emission points because the health risks from refineries are unacceptable. The commenter asserted that the fact that many sources have achieved much lower levels of toxic air emissions from DCUs shows that the EPA must set standards for DCUs under section 112(f)(2) in order to assure the requisite "ample margin of safety to protect public health."

Response 2: We are not finalizing the DCU requirements under CAA section 112(f)(2) because we maintain that these emission points were not previously regulated and that these standards are being finalized under CAA section 112(d)(2) and (d)(3). After the application of the final MACT standards for decoking operations, we have not identified any other technically feasible methods to further reduce the emissions from decoking operations. We also conclude that the risks are acceptable. Together, these findings lead us to conclude that the final MACT standards achieve an ample margin of safety.

7.6 Monitoring requirements

Comment 1: With respect to proposed section 63.657(a), one commenter requested that the EPA clarify that the coke drum vessel pressure referenced in this section is the pressure as measured at the top of the drum.

Response 1: We agree that the requested clarification is reasonable and necessary, particularly as we understand that most refineries generally measure the pressure in the overhead line from the coke drum rather than the direct drum pressure at some point within the coke drum. Therefore, we have clarified 63.657(a) as follows:

"Each owner or operator of a delayed coking unit shall depressure each coke drum to a closed blowdown system until the coke drum vessel pressure, ***measured at the top of the coke drum or in the overhead line of the coke drum as near as practical to the coke drum***, is 2 pounds per square inch gauge (psig) or less prior to venting to the atmosphere, draining or deheading the coke drum at the end of the cooling cycle."

Comment 2: One commenter stated that reasonable pressure instrument specifications and QA/QC requirements must be included in the rule and consistency with the instrumentation requirements specified in the Greenhouse Gas Protocol achieved. To avoid costly addition of all new instrumentation, pressure instrument spans should cover the entire typical range of pressures encountered at coke drum overheads (typically up to 100 psig and 1000 °F) and specified accuracy must coincide with standard instrumentation and the Greenhouse Gas Protocol. Inadequate span requirements cause unnecessary outages, since, under EPA's proposed QA/QC requirements, pressure instruments have to be replaced or at least recalibrated, if over ranged. Furthermore, unreasonable accuracy specifications, as have occurred in the NSPS Ja rulemaking, can make it infeasible to comply or require installation of all new instruments in addition to the existing process instruments.

Response 2: The rule requires an instrument that is capable of reading a 2 psig pressure to within 0.5 psig accuracy. We recognize that system operating pressures are much higher than the final depressurization, but allowing a pressure monitor that is accurate to 5 percent of full-scale for a monitor with a full-scale of 100 psig would suggest that the monitor would only have to be accurate to 5 psig. Obviously, enforcing a 2 psig limit using an instrument that is only accurate to +/-5 psig is unworkable. Therefore, regardless of what the full-scale operation pressures are, the instrument must be able to distinguish between a compliant 2 psig pressure and a non-compliant 3 psig pressure. Thus, if the pressure monitor has a full-range of 100 psig, then the instrument must have an accuracy of 0.5% of full scale. We are unsure of any specific accuracy or calibration requirements for DCU venting pressures in the Greenhouse Gas Protocol and the "standards" provided appear to be general guidance. With respect to the requirements to recalibrate instruments that have been over-ranged, we maintain that it is reasonable to expect that pressure system excursions can negatively impact the accuracy of the pressure monitors, particularly when the occur for extended periods (more than 24 continuous hours). Therefore, we have retained the requirement to re-evaluate the accuracy of the monitors when these events occur.

Comment 3: One commenter explained that the term CPMS is used in discussing the coker vent pressure monitor in 63.657(b) of Refinery MACT 1, but Table 13 requirements are not applied to that monitor by that paragraph. Since Table 13 is clearly referenced for flares and Group 1 MPV combustion controls and in the one place a bypass continuous flow monitor is proposed, the commenter has taken the lack of a reference to Table 13 in 63.657(b) as meaning that the Table 13 requirements do not apply to coker vent pressure monitors. The commenter added that if Table 13 is intended to be applicable to the coker vent pressure monitor, there are serious safety and operability issues with applying Table 13 requirements to that vent that need to be addressed. The commenter's concerns relative to coker vent pressure taps include the following:

- Coke drum overhead pressure taps are kept free of coke using blowback steam. Turning that steam on and off to perform the required daily check for plugging would ultimately lead to plugging of the pressure tap, steam leaks, and increased risk of burns.
- Coke drum overhead pressure taps are not active when the coke drum is open for coke cutting and there is no reason to check the pressure tap when the drum is open. Thus, daily checks are not always possible and that requirement should only apply when the coke is being deposited in the drum through the time the drum vent has been opened to the atmosphere.

Response 3: As the commenter noted, 40 CFR 63.657(b) does refer to the pressure monitor as a CPMS but it does not specifically reference that Table 13 requirements must be met. Instead, we specify the accuracy requirements of the monitoring system in 40 CFR 63.657(b) because we determined that the accuracy requirements in Table 13 were inadequate for the 2 psig monitoring requirement as DCU operate at much higher pressures (80 to 100 psig) while in the operating cycle. After considering the issues identified by the commenter, we agree that the use of the term CPMS makes it unclear whether Table 13 applies and have altered the phrasing of the requirements in 40 CFR 63.657(b) to avoid this terminology. While we agree that the daily check of the pressure taps is unnecessary as the monitor's expected fluctuation between operating and cooling cycles provides sufficient evidence that the pressure taps are not plugged, we do want to clarify that some review and maintenance of the pressure monitor is performed. Therefore, instead of the daily pressure tap inspection requirements, we are requiring a daily inspection of the pressure trends across the coking and cooling cycles to ensure the pressure taps are not clogged. We are also specifying the calibration and placement criteria in 40 CFR 63.657(b) so that all DCU pressure monitoring requirements are clearly outlined in this section. Specifically, 40 CFR 63.657(b) is being finalized to read as follows:

(b) Each owner or operator of a delayed coking unit shall install, operate, calibrate, and maintain a monitoring system, as specified in paragraphs (b)(1) through (5) of this section, to determine the coke drum vessel pressure.

(1) The pressure monitoring system must be in a representative location (at the top of the coke drum or in the overhead line as near as practical to the coke drum) that minimizes or eliminates pulsating pressure, vibration, and, to the extent practical, internal and external corrosion.

(2) The pressure monitoring system must be capable of measuring a pressure of 2 psig within ±0.5 psig.

(3) The pressure monitoring system must be verified annually or at the frequency recommended by the instrument manufacturer. The pressure monitoring system must be verified following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale.

(4) All components of the pressure monitoring system must be visually inspected for integrity, oxidation and galvanic corrosion every 3 months, unless the system has a redundant pressure sensor.

(5) The output of the pressure monitoring system must be reviewed daily to ensure that the pressure readings fluctuate as expected between operating and cooling/decoking cycles to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired prior to the next operating cycle.

8.0 Fenceline Monitoring Provisions

Comment 1: Commenters claimed that the proposed fenceline monitoring standard represents a section 112(d)(6) review of the proposed outcome of the EPA's concurrent section 112(d)(6) review of existing tank, LDAR, and wastewater operation emission standards. Commenters argued such a concurrent review is unlawful because the EPA is not reviewing "an emission standard promulgated under this section."

Response 1: Section 112(d)(6) states that "The Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years." Thus, section 112(d)(6), while allowing review of each standard individually, does not prohibit review of standards collectively. The fenceline monitoring standard is innovative and applies to the collection of fugitive emissions sources within a petroleum refinery, which were individually regulated in the original Refinery MACT 1 rule. In the preamble to the proposed rule, we evaluated specific emission standards individually, but explained that fenceline monitoring is a development in processes, practices and control technologies for measuring and controlling collective fugitive emissions from petroleum refineries. This development provided distinct advantages by addressing the infrequency of the monitoring and inspection requirements and providing necessary assurance that the emission control levels projected for these sources are achieved. Therefore, we deemed it necessary, under section 112(d)(6), to include a single overarching requirement to fenceline monitoring.

Comment 2: One commenter noted that the EPA did not impose the fenceline monitoring standard on other source categories, with essentially the same fugitive emission requirements. In fact, in the Generic and Amino/Phenolic Resins NESHAP amendments finalized on October 8, 2014, where very similar requirements to those proposed here are imposed, the EPA confirmed that existing fugitive emission compliance requirements are adequate to demonstrate compliance.

Response 2: We relied on source-category specific information to propose and finalize amendments to the Refinery MACT. Similarly, decisions made for other source categories are based on information specific to those source categories and should not be construed as setting a precedent for other source categories. As we have discussed earlier in this document, the record is replete with evidence that emissions from refinery MACT sources may be understated, particularly from fugitive sources (storage tanks, wastewater treatment, and equipment leaks), which are difficult to characterize and are significant. The work practice standard is tailored to detect and correct fugitive emissions using benzene as a surrogate for organic HAP in refinery process streams. Additionally, the development and evaluation of Methods 325A and 325B were ongoing until the finalization of the Refinery MACT amendments.

Comment 3: One commenter disagreed that the primary goal for a fenceline monitoring system, should be to ensure that owners and operators properly monitor and manage fugitive HAP emissions. Instead, the commenter stated, the primary goal should be to determine the residual risk to the downwind community as required by law.

Response 3: Although we believe that the information collected by refineries as part of this fenceline monitoring work practice standard will be valuable to downwind communities in understanding the location of areas that are impacted by refinery fugitive emissions, it will not and cannot provide affected communities all the information necessary to understand the risk they face as downwind communities.

As we stated in the preamble to the proposed rule, we are concerned about the potential for high emissions from fugitive sources and due to the difficulty of measuring these emissions, there is significant uncertainty associated with emission inventories. Because the requirements and decisions that were proposed are based on the results of our risk modeling of emission inventories (i.e., the expected control effectiveness of the existing MACT requirements), our goal was to ensure that fugitive emissions were not, in fact, significantly higher than what was reported in the inventories and that fugitive emissions would be managed to the levels expected to be achieved by the best performing sources upon which the MACT standards were originally based.

Comment 4: Commenters stated that there is no correlation between the fenceline maximum benzene value and equipment leak or fugitives emissions and thus this requirement is not a compliance assurance method for those emission types. The commenters added that this measurement is a duplication of the source specific monitoring already specified for equipment leaks in Refinery MACT 1, state and local rules and permits. Additionally, the commenters contended that the fenceline benzene concentration is a function of the location of sources of all types within the facility, not just fugitive sources, contributions from mobile and non-refinery sources, release heights and velocities, and wind direction and speed.

Response 4: We disagree with the commenters. The EPA performed pilot studies and actual and allowable emissions/dispersion modeling to support the development of the fenceline monitoring program and ensure that the monitoring would represent emissions from refinery fugitive emission points. We further note that an API study, in which a fenceline monitoring program was implemented at 12 facilities, was submitted during the comment period, and also supports that the fenceline monitoring program will achieve the stated goals of measuring benzene emissions from refinery emission points (EPA-HQ-OAR-2010-0682-0583). Appendix D of the API report presents plots showing facility fenceline concentrations at the sampler locations prescribed in the proposal’s siting requirements as well as extra samplers where a known emission source is located within 50 meters (162 feet) of the fenceline. These plots also show predominant wind direction and speed over each 14-day sampling period. A review of these plots indicates that qualitatively there is a correlation between potential sources of fugitive emissions and higher benzene concentrations. Generally, higher concentrations were detected either at the extra sampler location or sampling location next to the extra sampler.

Further, while low level miscellaneous process vents may contribute to the fenceline benzene concentration, most large stack emissions, including flares, have buoyancy effects (due to elevated temperatures) and velocities that result in minimal contribution to the fenceline concentrations. Even so, we used the entire emissions inventory (both fugitive and “stack” emissions) in our determination of the action level. Thus, while the fenceline monitoring standard is targeted specifically to ensure proper control of fugitive sources, we did not establish the action level based only on fugitive source emissions. As such, we consider the action level to include contributions from stack emissions and is achievable for refineries regardless of the height and location of their stack emissions.

While we agree that mobile sources and non-refinery sources would also contribute to fenceline concentrations, in theory, they would generally not likely be the most contributing factor for elevated concentrations of benzene. Our ICR data indicates that most benzene at refineries is emitted from fugitive sources (80%); and refinery sources (93%); further, the final rule provides a means to identify non-refinery MACT sources (on-site interfering sources) and subtract out the contribution from these sources. To understand the contribution of mobile sources to benzene fenceline contributions, we looked at background levels readings of benzene in urban and rural settings from the API study and noted that there was no appreciable difference, and readings remained relatively constant (from 0.1 to 0.3 parts per billion (ppb)). Meanwhile, the highest fenceline concentrations of benzene at these same locations varied from 0.4 to 6.4 ppb, indicating significant contributions from refinery sources. It is likely that most mobile emissions sources will be external to the refinery and their emissions will increase the background concentration and correction concentration (that may overstate the true background and cause an underestimation of the refinery's impact on the net concentration). However, we do recognize that there are cases where a significantly travelled roadway may bisect the refinery and contribute to the highest concentration point but not the lowest concentration point. While we do not consider that these situations will significantly impact the highest concentration measured, the final rule provides a means to identify these sources, conduct additional monitoring, and use a uniform background and near-field source correction for determining the refinery contribution to the fenceline concentration.

Finally, we disagree with the commenter's suggestion that the fenceline monitoring standard is "simply … a duplication of the source specific monitoring already specified." Fugitive monitoring and inspection requirements are required on a relatively infrequent basis. We determined that improvements to individual fugitive emissions source requirements were not cost effective and not necessary pursuant to section 112(d)(6). However, we concluded that the fenceline monitoring standard was a cost-effective development that would augment the source-specific requirements.

Comment 5: Commenters suggested that rather than being prescribed as an on-going MACT requirement, the EPA should collect fenceline data using these methods for a period of two years through CAA section 114 authority. This would allow the EPA to determine the value of the program and identify and correct deficiencies in the methods should a longer period of monitoring be demonstrated as necessary.

Response 5: We disagree that we should establish the program as a temporary requirement pursuant to CAA section 114. We identified the fenceline monitoring program as a cost-effective development within the meaning of CAA section 112(d)(6) and thus that it is necessary under that provision.

Comment 6: One commenter stated that the proposed fenceline monitoring program is not an appropriate substitute for an EPA-funded national ambient air toxic monitoring network.

Another commenter stated that because benzene concentrations vary depending on the geographical area and the emission source potential, the EPA should defer to the States to implement fenceline monitoring. The commenter noted that TCEQ, for example, has identified areas of elevated benzene concentrations not related to refinery emissions and in 2004, established Air Pollution Watch List Area 1203 for benzene in an area of Texas City, Texas. The commenter contended that according to TCEQ's analysis, benzene emissions were due to pipeline operations in the area and subsequent actions to reduce emissions resulted in the area being removed from the Watch List in 2007.

Response 6: We agree that the fenceline monitoring work practice standard is not a substitute for ambient air toxic monitoring networks and never intended for it to be. The commenter noted some examples of where ambient monitoring was used to identify previously unknown or under reported emissions and to correct the excess emissions source. This is precisely the idea behind the fenceline monitoring standard. However, this standard was developed specifically to address refinery sources. If a local area has other significant HAP emission sources that are not petroleum refineries, those sources are beyond the scope of this rulemaking. Nothing in this rulemaking prevents local agencies from developing additional strategies to address these non-refinery emissions sources. If these other emission sources are subject to other MACT standards, the EPA is required to conduct a technology review of the MACT standards every 8 years to determine if it is necessary to revise source category-specific standards, considering developments in processes, practices and control technologies.

8.1 Proposed siting procedures (including comments on Method 325A)

Comment 1: Some commenters stressed the importance of monitor placement and maximum coverage to ensure as much emissions data is being collected as possible to achieve the goal of protecting human health. One commenter specifically disagreed with allowing 2,000 feet between monitoring sites stating that this could allow large fugitive sources and clouds of VOC or HAP to remain unmonitored and added that while the EPA proposal requires additional samplers be deployed when an emissions source is within 50 feet of the fenceline, it is insufficient to plug a gap that is nearly seven football fields long. One commenter added that open-path systems address placement concerns because the energy source and detector pair can be placed 100-500 meters apart ensuring 100% coverage between those distances.

Response 1: We agree that monitor placement and coverage is important, which is why we require monitoring around the entire plant. However, we disagree with the comment suggesting that the monitoring siting procedures will allow large clouds or VOC or HAP to remain unmonitored. First, the 2,000 feet (610 meters) distance between monitors can only be used by relatively large facilities (perimeter of 24,000 feet or greater, which is about 800 acres or greater); smaller facilities are still required to have 12 monitoring locations, which would be evenly spaced and less than 2,000 feet apart. Moreover, fugitive emissions are expected to expand and disperse along the wind vector and are highly unlikely to pass between monitoring stations undetected, particularly as shifts in wind direction are likely to cause the plume to pass across the monitoring location for at least some portion of the 2 week monitoring interval. That, combined with the low detection limit capabilities of the passive diffusive tube monitoring method allows the proposed monitoring placement method to detect unusual, large fugitive releases.

We disagree with the comment that open-path systems provide better coverage than the passive diffusive tube monitoring. This is because there are significant detection limit issues with current open-path systems. While longer path lengths for open-path systems theoretically improve the detection limit, the detection limit for an open path system is an average concentration over the entire path length, so it is still possible for small, reasonably concentrated plumes to remain undetected while the passive monitoring system could detect an increase in fenceline concentrations even though the plume only occasionally passes across the fixed diffusive tube monitoring location. Additionally, increasing the path length of an open-path monitoring system also increases interferences with other ambient compounds and pollutants. To date, there are no commercially-available, real-time open-path monitors capable of detecting benzene at the levels necessary to demonstrate compliance with the fenceline benzene action level in this final rule. For these reasons, we find that the proposed diffusive tube monitoring systems actually provides better coverage and better capabilities for detecting fugitive emission plumes from a refinery than current open-path systems.

Finally, we note that the proposed additional monitoring requirement is for sources within 50 meters (which is 162 feet) from the monitoring perimeter, rather than just 50 feet. This may have been an editorial error, but we find that the additional monitor requirement for sources within 50 meters of the monitoring perimeter is more likely to require additional monitor placement and/or it will provide a greater distance between the source and the monitoring location, which will allow the plume more time to disperse prior to monitoring perimeter, than had the additional placement requirement been set at 50 feet.

Comment 2: One commenter explained that passive diffusive tube monitoring method is subject to four potential common errors affecting the Fick’s law relationship, all of which can result in low benzene measurements in the test results: 1. High face velocity; 2. Low face velocity; 3. Desorption of analyte due to excessive sampler heating; and 4. Sample overloading. High wind speeds (generally greater than 10 mph or 15 m/s) may reduce the effective benzene collection rate because it moves past the sampler before it can be trapped. No wind or very low wind (0 to greater than l mph) may also reduce the collection rate because the media scavenges the local benzene faster than the air can replenish it to maintain the ambient benzene concentration. The commenter argued that all of these are issues when using passive dosimeters for OSHA compliance monitoring that should be considered when using similar monitors for the EPA compliance monitoring. The commenter continued that overexposure to heat may cause the sampling trap to re-emit some previously collected benzene; therefore, the protective covers referenced in the sampling method should be improved. The use of a reflective coating to reflect sunlight and placing an insulator between the housing and the sampler to prevent heat transfer and potential desorption of analyte should be required. And lastly, sampler adsorbent capacity is important because each sampling tube has a finite capacity to adsorb analytes and as that capacity is approached, the collection rate for any collectable analyte will drop. Once the adsorption capacity is exceeded, analyte collection will either stop or preferential replacement may occur (analytes which are weakly bound are replaced by those more strongly attracted to the adsorbent). The commenter asserted that it is critical when using passive methods to know this limit before overloading occurs. Active samplers use multiple sections to identify overloading conditions during analysis by looking for analyte breakthrough, but that is not often an option with a passive sampler. Measuring total hydrocarbons collected, in addition to benzene, allows the user to identify such cases of overloading and flag the data, provided that the manufacturer has provided an estimate of sampler capacity. Data collected from an overloaded sampler should not be used without flagging because the true value may be much higher.

The commenter suggested that the proposal include more detail on areas that should and should not be used for monitor placement to ensure that the plants have some consistency and limit the potential for abuse of the system to reduce apparent emissions solely through the selection of monitoring points (see earlier references to factors affection the benzene collection rate).

Response 2: The commenter's concerns regarding wind speed effects are unfounded. High wind speeds will actually increase sampling rates. According to the ISO method at Section A.4.4.2 "Tube-type samplers are typically unaffected by low air velocities but those without a draught shield may be affected by high speeds." High temperatures can affect sorbent capacity and may reduce uptake rates, but a temperature as high as 140 ºF only lowers the uptake rate by about 8% (ISO method A.4.1). Issues regarding sorbent capacity are also unfounded. Given the typical fenceline concentrations at the refinery, it would be extremely unlikely that the tubes would become saturated even if the sampling time was extended to a month or longer. Furthermore, the sorbent capacity of a sampling tube is known, so one could tell if a tube is saturated based on the monitors reported concentration. While this highly elevated concentration may be understated, ΔC will clearly exceed the 9 $\mu g/m^3$ action level for that sampling period, if not the entire year due to that single sample.

Comment 3: One commenter stated that the EPA included details in the rule regarding areas that can and cannot be used to site monitors in order to ensure consistency among facilities and reduce the possibility of abuse of the system though poor monitor placement. The commenter added that EPA could rely on the same monitoring siting criteria used for the National Ambient Air Quality Standards monitoring, in order to establish valid data collection.

Another commenter explained that section 63.658(c) refers owners and operators to the general guidance for siting passive monitors in EPA-454/R-98-004, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II: Part 1: Ambient Air Quality Monitoring Program Quality System Development, August 1998 (incorporated by reference, see section 63.14). The commenter also added that Section 4.1 of Method 325A includes reference to the general guidance for siting in EPA-454/B-13-003, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II: Ambient Air Quality Monitoring Program, May 2013 (incorporated by reference, see 63.14). The commenter argued that since Section 8.2 of Draft Method 325A specifies that the samplers be placed at specific radial points along the property boundary or, alternately, at specific distances along the boundary, it is unclear how EPA-454/R-98-004 or Section 4.1 of Method 325A can apply and citing them only adds confusion. Thus, the commenter recommended the second sentence of section 63.658(c) be deleted or, if the EPA's intent is to allow a siting approach other than the two in Draft Method 325A, it should specifically identify that alternative in this paragraph as being allowed in addition to the two alternatives in Draft Method 325A. If there are other items in the cited manual that sources are expected to follow those should be incorporated into Method 325A. A general citation, such as this, to a large online manual, particularly one meant to apply to ambient monitors rather than fenceline monitors, results in confusion and compliance uncertainty.

Response 3: We agree with the commenter and amended Section 4.1 of Method 325A to remove the reference to the Handbook.

Comment 4: Proposed 8.2.2.1.5 and 8.2.3.5 of Draft Method 325A call for extra samplers to be placed near known sources of VOCs that are within 50 meters of the property boundary.

One commenter stated that the proposed test method language is vague and flawed in the proposed requirement to install additional monitoring stations where there are emissions sources within 50 meters of the fenceline. The commenter argued that this is because fugitive emissions will expand and disperse along the wind vector and are highly unlikely to pass between stations undetected. The commenter recommended an approach in which the EPA would require additional monitors when there are emission sources of benzene exceeding 10 tpy within 50 meters of the fenceline.

Another commenter added that specific clarifications are needed for these provisions including changing “known emission source” in 63.658(c)(1) to “known sources of VOCs” and “potential emission source” consistent with the terminology used in the method to avoid misunderstandings and claims of violations.

The commenter added that there are wastewater treatment units and Group 1 storage vessels that do not contain benzene (except perhaps at very low impurity levels). Two commenters recommended that 63.658(c)(1) be limited to areas near sources of benzene such as wastewater treatment units that contain at least 10 ppm benzene and Group 1 storage vessels that contain at least 500 ppm benzene in the stored liquid. The commenter continued explaining that because some Group 1 tanks are quite small and individual portions of wastewater treatment systems may be relatively small, it is also possible that after adding an extra sampler to comply with this requirement, there may be a source between the new sampler and one of the existing samplers. The Method seems to call for the additional sampler to be placed halfway between the otherwise required samplers, even if the “known emission source” is not exactly halfway between the other samplers, but is closer to one than another. This seems appropriate to avoid samplers being too close together and because the nearest point at the property boundary may not be in the predominant downwind position. Several commenters stated that it would be helpful, however, if it could be clarified that siting the additional sampler halfway between the existing samplers is the EPA’s intent.

Response 4: We agree that fugitive emissions will generally expand and disperse, which is why the monitors do not all have to be closer together. However, if the source is near the fenceline, it is much more likely that an emissions plume from this source could remain undetected by the perimeter monitors if the 50 meter (162 feet) extra monitor provisions are not included. We therefore finalized these requirements as proposed. Since this placement consideration applies to all monitoring placement options, we moved the extra monitor placement requirements to Section 8.2.1.

We agree that the terminology in the rule text regarding “known emission source” should use the correct terminology consistent with the terms in Method 325A. We disagree with the commenters’ suggestion that we should limit the placement only to sources with benzene concentrations above a certain threshold. We are using benzene as a surrogate for organic HAP and even sources with low levels of benzene must be included as these sources can contribute to the fenceline benzene concentration. Therefore, because we are using benzene as a surrogate for organic HAP, we are not placing restriction on the benzene concentrations of the “known emission sources.”

Comment 5: Commenters recommended that language be added to the proposed rule requiring and detailing the placement of fenceline monitors at petrochemical complexes that include refineries. Commenters also recommended including provisions in the proposed rule that address the placement of monitors within or around these large petrochemical complexes to reduce the likelihood that refinery emissions will be attributed to associated chemical plants.

Response 5: We provided guidance in this response to comment document and clarified in Method 325A that monitors should be placed at or inside the facility boundary so as to encompass all sources at the facility. The term “facility” is not defined in the general provisions, but we have consistently considered a facility to mean the collection of equipment, activities, or both within a single contiguous area and under common control. If an owner or operator is unsure of what is considered to be the “facility” in their specific case, he/she should submit an applicability determination request to the EPA (or designated authority). We are aware that some petroleum refineries will also have petrochemical processes within the boundaries of the facility and the fenceline monitors should encompass all sources at the facility, including these petrochemical processes. As a practical matter, a facility can comply with the 9 $\mu g/m^3$ concentration difference for the entire facility or perform additional monitoring to correct for the contribution of these sources that are specifically excluded from Refinery MACT 1. Specifically, the final rule allows under 63.658(i) a site-specific monitoring plan where the owner/operator can determine the impact of these “near-field” sources for each monitoring location and subtract this contribution from the measured concentrations for those sources exempt from Refinery MACT 1 under 63.640(g).

Comment 6: One commenter stated that based on the definition for property line, the marine vessel docks would be included for fenceline monitoring. The commenter explained that it would require placement of monitors over 1/2 a mile from shore on a dock and in several locations placing a significant burden on the refinery. Placing monitors on the dock does not fit with the EPA’s purpose as the facility is not required to have vapor emissions collection and control and will not accomplish the goal of evaluating the controls on tanks, wastewater, and process fugitives. The commenter recommended that the EPA exclude docks from the fenceline definition. Another commenter agreed and added that many times tank farms or marine terminals are separate facilities only connected to the refinery by a pipeline. These locations are typically low emitters of HAP, but under the proposed rule, provisions would require additional monitors and additional costs to the refinery. Many of these monitors will also be along the waterfront.

Response 6: Marine vessel loading and tank farms are considered part of the refinery source category and were modeled as part of the assessment, so the maximum modeled off-site concentrations should include these emissions. Therefore, we see no reason to provide an exemption for these operations. In fact, we are revising “known sources of VOCs” (formerly referred to as “known emissions sources”) to include other refinery fugitive emissions sources, such as marine vessel loading operations. In the final rule, we provided guidance on monitor placement for segregated/remote sources. With that said, we do not consider it necessary to place monitors along or at the end of a dock. When we modeled facilities we generally considered the shoreline as the facility boundary. Therefore, we are providing special provisions for monitoring at the shoreline for marine vessel loading operations.

Comment 7: One commenter explained that complicating matters and compounding costs is the determination of monitoring locations for small refineries with non-contiguous dock facilities, remote tank farms or multiple ownership structures. Small business refiners in this situation face disproportionate cost burdens because they will essentially have to install the same minimum amount of monitors around the perimeter of non-contiguous portions of their refineries as well as around the main part of the refinery or possibly even around facilities owned and operated by others that are located within the boundaries of a refinery. This can multiply the compliance costs necessary to comply with this mandate. Another commenter argued that this could result in small refineries incurring greater monitoring cost than some relatively larger facilities that could have far greater potential emissions and potential impact on the community. Another commenter stated that for facilities with highly irregular property boundary, contain public roadways, or have third parties co-located within their boundaries, the number of samples will be much higher than the EPA estimated.

In addition, refineries with numerous sub-areas and/or multiple nearby sites that are each treated separately for monitoring purposes will incur benzene monitoring costs much higher than a regularly shaped refinery of similar size. The increase in monitoring costs will be further exacerbated at those irregularly shaped refineries having many sources within 50 meters of the facility property boundary, as this will necessitate the placement of more monitors.

Response 7: For reasons discussed in the preamble to the final rule, we clarified a number of monitor placement provisions that address many of the issues noted by the commenter and minimized the number of extra sample locations that may be needed due to irregularly shaped (including segregated) facilities. As seen by the monitoring results presented in the API study, the additional monitoring locations due to near-boundary sources frequently exhibited higher concentrations. Therefore, we find that it is critical that additional samplers be used and finalized the requirements as proposed. We do agree with the commenter that the cost impacts were estimated considering only regularly shaped, contiguous facilities. Therefore, we revised our cost impacts based on the number of monitoring locations used in the API study for different-sized facilities. Small refineries had, on average, 6 additional monitoring locations and medium and large refineries had, on average, 8 additional monitoring locations. Based on this analysis of available data, we disagree with commenters that the fenceline monitoring program will have a disproportionate impact on small refineries.

Comment 8: One commenter stated that Sections 8.2.2.1.4 and 8.2.3.4 call for the samplers to be placed “securely on a pole or supporting structure at 1.5 to 3 meters above ground level.” The commenter added that while this is an improvement over early, more prescriptive statement, the wording should be slightly more specific by specifying that it is the bottom of the diffusive sample cap that is to be 1.5 to 3 meters above ground level.

Response 8: We agree with this clarification. It does apply to all monitors regardless of the placement options. This language was also in Section 8.5.5. In the final Method, this requirement was removed from Section 8.2, but remains in Section 8.5.5 and states, “Secure passive samplers so the bottom of the diffusive sample cap is 1.5 to 3 meters (4.9 to 9.8 feet) above ground using a pole or other secure structure at each sampling location.”

Comment 9: One commenter is concerned about the amount of human error that is introduced by using a passive monitoring system including placing, handling, removing, packaging, and transporting of the samples. The commenter provided an example in which a field operator would be instructed not to refuel their vehicles while handling the samples so as not to introduce gasoline vapor during the deployment of uncapped samples.

Response 9: We find little merit to the commenter’s concern. The sampling tubes are often made of metal and are very durable. Sampling tubes are to be capped at all times except when installing or removing the diffusive cap. For example, Method 325A at 8.6.1 specifies that sampling tubes should be “immediately” resealed after removing the diffusive cap, so there should be no contamination during transport. The only potential source of contamination is during the few seconds while the caps are removed or replaced. For this reason, it is good practice to have clean hands when deploying/collecting the diffusive samplers. Thus, we find that the instruction to field operators not to refuel their vehicle (or to wash their hands thoroughly if they do refuel their vehicle) to prevent sample contamination during sample deployment or collection is reasonable.

Comment 10: One commenter discussed the specifics of wind direction and surrounding contributions to air emissions with respect to a nearby facility. The commenter argued that it will be important for the EPA to require monitoring that is up wind and down-wind of the refinery sources, as well as requiring monitoring that is ground-level and stack-level.

Response 10: The finalized approach requires sampling of the entire perimeter, which allows for approximate upwind and downwind concentrations. Further, both theory and actual gradient data have shown that concentrations due to the refinery fugitive emissions drop exponentially as you move away from the source, practically regardless of topography and weather.

Comment 11: One commenter stated that the proposal does not appear to consider the effect on relatively uniform wind directions on the trigger level and its measurement. The commenter stated that at their refinery the wind blows regularly and steadily in a relatively small vector range. The effect is that (1) the background concentration will almost always be zero and (2) the fenceline monitors will be monitoring the effect of only certain sources that happen to be near the fenceline and downwind of the prevailing wind direction. The commenter recommended that the EPA exclude facilities in trade wind areas from fenceline monitoring at least until a better study can be conducted to identify an effective means of monitoring.

Response 11: We do not understand the commenter's concern that the monitoring is not effective where uniform meteorology conditions persist. On the contrary, we note that this situation, where the wind blows regularly and steadily in the same general direction is the simplest scenario where a subtraction of upwind and downwind concentrations would be the clearest indication of the refinery's contribution. In the case described by the commenter, if the upwind concentrations (or background) are always near zero, then the concentration at the downwind point is entirely attributable to the refinery. We do understand that there may be facilities where there are no prevailing winds such that all monitoring locations surrounding the refinery are impacted by the facility's emissions and the ΔC approach may understate the refinery's impact on the concentration, but this does not provide a reasonable rationale to preclude the ΔC approach where it is more accurate. Finally, in our modeling efforts we considered the local meteorological data when estimating fenceline concentrations. That is, when we developed the action level, we accounted for cases where there are consistent prevailing winds. Therefore, we specifically considered site-specific conditions in establishing the action level and concluded that all refineries could comply with the action level of 9 μg/m^3.

Comment 12: Several commenters are concerned about the effectiveness of the proposed passive diffusion tube sampling method during cold weather conditions. Stationary sources located on Alaska's North Slope and in the Interior routinely experience winter temperatures as low as -40 °C. Strong atmospheric temperature inversions can result in such extreme conditions lasting for extended periods of days or even weeks. One commenter added that collecting samples in extreme weather to meet an arbitrary 14-day period can put employees at risk or make strict adherence to sampling protocols impossible. Several commenters expressed similar concerns for parts of the northern continental U.S. such as Wyoming and added that the rule must allow for refineries to use proper media for the operating climate and encourage refineries to work with their laboratories to ensure media and sampling rates are designed for their operating climate.

One commenter requested that as part of finalizing the rule, the EPA provide data and analysis that show the proposed monitoring requirements can be met across the range of temperature conditions that will be experienced by stationary sources across the country including Alaska and other cold region states. The commenter further requested that the EPA explain whether any comparative testing data performed at low temperatures demonstrated the effectiveness in terms of accuracy and precision for this sampling protocol before finalizing the rule as proposed. The commenter questioned if after evaluating such data, did the EPA find that there are limitations to the sampling method due to low temperatures? Does the EPA have data on alternative, similarly low cost, sampling methods which would be available for use in cold weather regions?

Response 12: Ambient temperatures will generally have little impact on the diffusive tube samplers. At colder temperatures, the sorbent should work effectively. Molecular diffusion is dependent on absolute temperature. The mass of a pollutant collected is expected to be proportional to the square root of the absolute temperature (ISO Method, Section A), with lower diffusion rates (lower sampling rates) with lower temperatures. However, typical shifts in ambient temperatures do not significantly alter the absolute temperature or the sampling rate. A temperature shift of 100 ºF is needed in order to change the sampling rate by 10%. Consequently, we do not see a significant issue with sampling in cold climates. Lab data demonstrated the passive tube recovery of benzene challenged at a known concentration was acceptable across a range of temperatures (6 ^{o}F - 120 ^{o}F). The primary issue with the cold weather would be if ice forms on the sampler and covers the diffusion cap holes. The weather protector is designed to limit this, but in a high swirling snow storm, some issues may exist, but these issues will generally lead to lower than expected sampling rates and would not cause facilities to exceed the action level. Since volatile HAP emissions are temperature dependent as well, emissions during these extreme cold conditions are generally low and we do not expect significant issues with the samplers or the methods for facilities in cold climates.

Comment 13: Several commenters stated that the fenceline monitoring rule requires every refinery to install an on-site meteorological station without any requirement for how data from that station is to be used. One commenter stated that if the station is used to collect wind speed and direction over a two week period, it will likely result in data indicating wind from all directors and add little to no value in identifying sources of benzene. Several commenters understand that weather data may be useful in determining source locations, but argued it should not be a requirement to have a met station. The commenters requested that EPA drop this requirement or allow the use of United States Weather Service (USWS) data if a station is within 25 miles of the refinery.

A number of commenters also added that the EPA should broaden site-specific monitoring plans for the met station to allow for any off-site sources (not just “upwind”) and other on-site sources, and allow these plans to be used from the date of submission.

Several commenters argued that specifying that any weather station used for complying with 63.658(d) be “dedicated” could cause refineries to have to have multiple weather stations, since some refineries have weather stations for compliance with other requirements or for their own use. These commenters concluded by stating that the requirement for a met station should be changed to an optional requirement but if retained, the word “dedicated” should be removed from proposed section 63.658(d) language. One commenter provided sample rule text for revising the requirement to be optional in Section 1.4.3.2 of their comment package.

Response 13: Meteorological data are important in understanding the fenceline concentration data and to identify the source of emissions if high concentrations are measured. However, we agree that these data are only critical if a site-specific monitoring plan is needed and near-field source corrections are to be made. Therefore, in the final rule we are allowing facilities that have met data available from USWS data within 25 miles of the facility to use it in place of an on-site meteorological station. However, we are retaining the requirement for an on-site weather station if near-field source correction method is used. We also agree that the requirement that the met station be “dedicated” is unnecessary and we are deleting this provision in the final rule.

Comment 14: One commenter explained that proposed 63.658(e) and Sections 1.4, 3.8 and 8.5.9 of Method 325A specify that the length of the sampling episode must be fourteen days. However, the commenter argued that all samplers cannot be changed out simultaneously and there is some delay in shutting down a sampler and starting up a replacement, particularly in bad weather, or when sample support, sample holder or security lighting or fencing maintenance is required. The commenter added that by the nature of the methodology (two week samples used to develop an annual average) exactly fourteen day samples are unnecessary. Annual average values will not be sensitive to relatively small variations in the sampling time. Nor, are the types of emissions the EPA claims they are addressing with this program subject to short-term aberrations that might be missed by short sampling outages. Thus, the commenter recommended that rather than 14 days these paragraphs specify a sample duration of “approximately” fourteen days. One commenter proposed that the requirement be modified to allow the sampling episode length to be 12 -16 days, at the discretion of the refinery, if needed.

Response 14: The commenter is correct that the samplers will work well whether the sampling duration is a few days longer or a few days shorter. The method requires recording the time/date of deployment and the time/date of collection and the sampling time is used in the calculation of the concentration for the sampling period. Therefore, the sampling duration is used specifically in calculating the concentration for the sampling period. However, we currently do not require the use of the sampling duration when calculating the annual average. By requiring consistent sampling intervals, there is no need to weight each sample by the number of days or hours represented by that sample. If the sampling durations are not consistent, then a direct average of the 26 samples collected over the year may not represent the true average. Therefore, the guidance remains that the sampling period should be 14 days. We are softening the language in Section 8.4.2 from “sampling tubes must be changed at approximately the same time of day at each of the monitoring sites” to “to the extent practical, sampling tubes should be changed at approximately the same time of day at each of the monitoring sites.” We find that best practice would be to maintain a consistent day and time for sampler deployment and collection. However, if there is a significant thunder storm, tornado warning or similar event, there is no issue with altering the sampling time to avoid dangerous conditions. If the sampler deployment and collection were delayed a day, that would not invalidate the sample. Therefore, we are clarifying in 40 CFR 63.658(e) that “For the purpose of this subpart, a 14-day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days.” This provision provides some of the flexibility requested by the commenter while minimizing potential issues associated with directly averaging the sampling period values. Nonetheless, we believe every effort should be made to deploy and collect the samples using a consistent 14-day sampling interval.

Comment 15: One commenter stated that proposed 63.658(c)(3) and Section 9.3.1 and 9.3.2 of proposed Draft Method 325A call for one co-located duplicate sample for every 10 field samples per sampling episode and at least two field blanks per sampling episode. However, the note in Section 8.5.5 only calls for one duplicate sample for each monitoring episode and Section 8.5.10 requires one field blank for every 10 samplers, rather than two per sampling episode. The commenter requested that these conflicts need to be resolved and made consistent.

Response 15: The co-located duplicate sample requirement is 1 for every 10 field samples per sampling period and the field blank requirement is at least 2 field blanks per sampling period. The note for Section 8.5.5 was revised to say “Duplicate sampling assemblies must be deployed in at least one monitoring location for every 10 monitoring locations during each field monitoring period.” Section 8.5.10 actually says 1 field blank for every 10 samplers in one sentence and then says that no less than 2 blanks are required per monitoring study in the next sentence. In the final rule, we deleted the first sentence regarding the 1 field blank for every 10 samplers and retained the second sentence, consistent with the requirements in 9.3.2.

Comment 16: One commenter recommended a number of editorial corrections/suggestions to the EPA Method 325A including:

1.) Section 1.2 to the start of Section 1.3: The first sentence should read "..to determine the average concentration of the select VOCs using the corresponding uptake rates listed..."

2.) Section 1.2 to the start of Section 1.3: Incorporate all relevant validated uptake rates from cited standards into a new table numbered 12.2 and all qualified uptake rates from relevant peer-reviewed literature into a new table numbered 12.3 and revise the regulatory text to reference these tables, "listed in Method 325B, Tables, 12.1, 12.2 and 12.3. Additional compounds or alternative sorbents must be evaluated as described in Addendum A of Method 325B, unless already validated in later editions of one of the following national/international standard methods: ISO 16017-2, ASTM D6196-03 or EN 14662-4, or reported in the peer-reviewed open literature. 1.3 Methods 325A and 325B" It should also be noted that Section 1.3 states three different sorbents Carbograph 1TD, Carbopack B, and Carbopack X or equivalent can be used. Inclusion of the new tables would support this.

3.) Section 1.4, line 6: for consistency with Sections 2.2.2, 8.4 and 12.3.4, amend to: "The duration of each sampling period is normally 14 days - See Sections 2.2.2, 8.4 and 12.3.4."

4.) Section 3.7: This definition of Retention Volume is very unusual and the commenter is not sure its correct. The term is also defined differently, and more conventionally, in Method 325B. To avoid confusion and minimize debate the commenter suggested deleting this definition and refer readers to Method 325B.

5.) Section 3.9: Suggested correcting the typo in the definition of Sorbent tube, "Sorbent tube (also referred to as "adsorbent tube")." Also, recommended omitting the words 'stainless steel tubes' from the second sentence as it is redundant to the first sentence.

6.) Section 4.3, line 6: Suggested amending "excludes" to "exclude"

7.) Section 4.4, line 4: Suggested amending "samplers" to "sampler"

8.) Section 6.1, line 4: Suggested amending to: "and preparation requirements described in"

9.) Section 6.1, Note, lines 5/6: Suggested amending to: "Other sorbents may be used"

10.) Section 6.3, lines 4/5: Suggested amending to: "(see Section 4.4) For example this could comprise an inverted cone/funnel constructed"

11.) Section 6.4 and elsewhere: Recommended the header font be changed to italic

12.) Section 8.2.1, last line: Suggested amending to "to assess the accuracy of PS results."

13.) Section 8.2.3.5, line 10: The commenter stated they think it's only two additional monitors in Figure 8.4

14.) Section 8.4.1: The commenter questioned if some of the cited uptake rates are for 24 hours (e.g. Table 12.1) hand stated that it would make sense to extend the range to 24 hrs to 14 days.

15.) Section 8.5.5 note, given even the smallest refineries require a minimum of 12 sampling locations the commenter suggested amending this note to say: "Duplicate sampling assemblies must be deployed at least two monitoring locations during each field monitoring exercise" - for consistency with Section 9.3.1 of Method 325A and Section 8.3.2 of Method 325B.

16.) Section 8.5.9: for consistency with Sections 2.2.2, 8.4 and 12.3.4, the commenter suggested amending to: "Expose the sampling tubes for the required sampling period - normally 14 days - See Sections 2.2.2, 8.4 and 12.3.4."

17.) Section 12.3.4; For clarity regarding "shorter periods" the commenter suggested referencing Section 8.4 - "Additional monitoring for shorter periods (See Section 8.4) may be necessary ..."

Another commenter noted additional editorial corrections/suggestions to the EPA Method 325A including:

1.) It appears 63.658 references are based on earlier versions of Draft Methods 325A and 325B and that as a result references are incorrect. We have pointed out the specific reference errors we have noticed, but recommend a careful review of all references to those methods prior to publication of the final rule and methods, particularly if further changes to the methods are made in response to comments.

2.) The reference in the last sentence of paragraph 63.658(c) to placing monitors at 2 kilometers intervals, should be corrected. Section 8.2.3 of Draft Method 325A specifies spacing intervals that depend on the overall length of the refinery fenceline, but in no case would that spacing be 2 km.

3.) The reference in the last sentence of paragraph 63.658(c) to Section 8.2.2.5 in Method 325A should be to Section 8.2.3.5. Also, the same provision would apply to the radial method in the first sentence and for consistency it should be included and reference Section 8.2.2.1.5 of Method 325A.

4.) Section 8.4.1 of Method 325A still states that "sample collection may be performed for periods from 48 hours up to 14 days." It is assumed that EPA intended to revise Section 8.4.1 to be consistent with the other Sections that were revised to specify 14 days.

5.) 63.658(i)(1)(3) 'Diffusion tub monitoring' should be 'tube.' 8.) 63.658(c)(2) 'Site-specific monitoring plant' should be 'plan.'

Response 16: We reviewed the list of edits and made changes as appropriate.

8.2 Proposed analysis procedures (including comments on Method 325B)

Comment 1: One commenter stated that the proposed passive monitoring does not have any EPA test method associated with it, unlike ultraviolet differential optical absorption spectroscopy (UV-DOAS), which is specifically listed in EPA’s Other Test Method 10 (OTM-10). The commenter does not believe it is possible to develop a scientifically sound method for two week average of passive samplers for benzene.

Response 1: As part of this proposal, we proposed both a siting method (Method 325A - Sampler Deployment and Collection) and an analytical method (Method 325B - Sampler Preparation and Analysis) and are finalizing these methods based on comments for Methods 325A and 325B. Methods 325A and 325B were written based on extensive research and validation performed by EPA’s Office of Research and Development and Office of Air Quality Planning and Standards. Implementation studies using Methods 325A and 325B were subsequently performed to demonstrate and validate these methods for measuring refinery fenceline benzene concentrations. These methods are proposed in their own right as reference methods fit for the purpose of this rule.

EPA’s OTM-10 is a method for identification of “hot spots” and measurement of emission fluxes through a vertical plane using path-integrated optical remote sensing techniques such as UV-DOAS and other open-path optical spectroscopic approaches. OTM-10 does not describe the specifics of long-term facility fenceline monitoring with open-path equipment including but not limited to: definition of and determination of method detection and quantitation limits, calibration and quality assurance procedures, limitations of operations, handling of data and spectral interferences, etc. To our knowledge, standardized and validated reference methods for use of open path UV-DOAS for long term facility fenceline monitoring have yet to be developed. Even if OTM-10 included specific information on UV-DOAS for continuous fenceline monitoring applications, methods posted on the EPA’s Emission measurement center website as OTMs have not undergone the Federal rulemaking procedure as have Methods 325A and 325B. The posting of OTMs with their technical support documentation is done to provide the information to the measurement community and support their continued development and evaluation.

Comment 2: One commenter suggested that Draft Method 325B should provide complete Quality Assurance/Quality Control Procedures to verify results prior to electronic data submittals. Specifically, the commenter requested that the Draft Method 325B provide a more robust procedure for identifying and excluding outliers, provide data substitution rules to address lost, damaged, and delayed samples, and specify a minimum number of data points to calculate a representative facility wide average. Some commenters also asked that in addition to procedures for identifying invalid data, provisions for such exclusions should be added to 63.658(f)(1). A record of excluded data and the reason for the exclusion should be required. Such an allowance is alluded to in the reporting requirements in proposed 63.655(h)(8)(iii), where reports of such exclusions are required, but the fact that such exclusions are allowed needs to also be included in 63.658(f).

One commenter also stated that it is suspected that there is wide variability between different laboratories conducting the analysis prescribed by the proposed test method and asked what the results from the EPA's round robin study of three laboratories and the Agency's laboratory were as they have not been publicly provided.

Response 2: We acknowledge that quality review of data is important to reporting data suitable for the purpose of this rule. However, we have not included additional outlier procedures or minimum data availability requirements for fenceline monitoring data nor do we provide a specific tool for data substitution beyond what is currently in the method(s). We note that Method 325A as proposed provides qualitative procedures for identifying and reporting outliers in Section 9.2 of Method 325A. Procedures to identify outliers are typically case-by-case specific. We determined that proposed procedures are adequate and performance based. Further, we have clarified requirements for sampler placement and minimum number of samples in Section 8.2 of Method 325A and 63.658. On the issue of applying a data substitution procedure, we understand that issues may arise during review of data that are not easily understood without further examination of test metadata. We would consider it very unusual that all data for a given monitoring period would be lost. Furthermore, we do not want to lose important data through the use of a prescriptive approach that may not be responsive to all situations. Generally, the ΔC should be calculated based on the measurements completed during a sampling period. We would find it suspicious if the monitors with the highest concentrations are "missing" more than once per year and should the refinery or the enforcement authority be concerned about the representativeness of data during periods of missing data, either may consider collecting information through other means (e.g., supplemental sampling) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status. We further believe that the final rule provides sufficient means to ensure ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We consider that failure to collect required or otherwise excepted data is a deviation from the rule and that this will provide the necessary incentive to collect data sufficient to demonstrate compliance with the final rule.

The "Evaluation of VOC Passive Sorbent Tube Technology Performance" report is in the Docket. The report states, "…variability among multiple laboratory analysis was equivalent to the variability when one laboratory was performing the analysis. This also indicates that within the error associated with different laboratories performing analysis, passive sorbent tube results are comparable across the laboratories and EPA Draft Method 325 A/B provides reproducible procedures."

Comment 3: One commenter stated that the 30 day time period from completion of each sampling episode to determine if the action level has been met provided in section 63.658(f) should be extended to 60 days because outside laboratory analysis may require more time to receive and process samples, especially if there is delay in data transmission or if QA/QC follow up is needed to evaluate the problem.

Response 3: We generally find that most situations can be resolved in 30 days, but we realize that some events may cause additional delays. However, we find that an additional two weeks should be sufficient to complete processing of the data even if there are QA/QC follow-up issues.

Therefore, in the final rule, we provided a 45 day time period for completing all analysis needed to assess ΔC for a given sampling period.

Comment 4: One commenter recommended use of half the detection limit for samples below the detection limit where benzene is suspected to be present, rather than the proposed requirements in 63.658 (f)(1) to use zero as the value for below detection limit values for the lowest sample result (and for background and near-field source samples) and use method detection limit as the highest value if all samples are below the detection limit. The commenter also requested that we provide a definition for method detection limit.

Response 4: The passive diffusive tube monitoring method using 14-day monitoring periods was specifically selected because of its ability to accurately assess benzene concentrations at very low concentrations (detection limits as low as 0.05 ppb or 0.2 $\mu g/m^3$). As seen from our pilot study and API's pilot study, the question posed is largely a theoretical concern as no samples were below detection limits. Further, while the proposed handling of non-detects provides a "conservative" estimate of ΔC, it is not expected to cause issues related to compliance. A ΔC based on a monitoring period of all non-detects (however improbable that is) should be on the order of 2% of the 9 $\mu g/m^3$ action level, so the facility would easily demonstrate compliance with the ΔC action level. If only the upwind samples are below detection limits (more likely than all non-detects, but still rare), using one half the detection limit versus zero would only cause about a 1% difference in the ΔC for facilities near the ΔC action level so it is extremely improbable that this assumption will make the difference between compliant ΔC and noncompliant ΔC values. As such, we find the proposed treatment of non-detect values to be reasonable and we are finalizing these requirements as proposed.

Comment 5: One commenter requested that the EPA study uptake rates for alternative sorbents, such as Carbograph 5 TD, which they believe is a viable sorbent for benzene monitoring. The commenter also asked if Carbograph 1 TD and Carbopak B would be suitable, even though the known breakthrough volume is 2.3 L not 20 L. Two other commenters also requested that Carbograph 5 TD be identified as equivalent to Carbopack X sorbent. Additionally, one of the commenters stated that it is inappropriate to mention a vendor name in the sorbent descriptions. This commenter indicated that Carbopack X is the only sorbent that meets the qualified breakthrough volume requirements and uptake rates and is solely manufactured by Sigma-Aldrich and is not readily available to all consumers. With only one company supplying sorbent by default, per the current Methods 325A and 325B, the commenter indicated that there could be concerns about supply shortages, monopoly, or price gouging. Further, this commenter was concerned about not being able to enter the market for sorbent tubes.

Response 5: We recognize the need to allow equivalent sorbents in passive sampling tubes. Method 325 is based on EPA research using Carbopack X. We could not determine viability and equivalency of Carbograph 5 TD to Carbopack X during extensive internet search. Therefore, it is not specifically included in the Method. We revised Method 325B to be consistent with Method 325A which included more than Carbopack X and listed other options that are commercially viable and not sole-source. In addition, the Method allows for alternative sorbents if the uptake rate is published by a consensus body or the sorbent is evaluated using Addendum A should a facility, tester, or vendor deem it needed and necessary to use an alternative sorbent.

Comment 6: One commenter asked whether PVC is considered a "non-outgassing material" and whether PE is considered a "non-emitting polymer" referring to the requirements of Method 325B. The commenter also asked what sorbent material should be used inside of the focusing trap/secondary trap for Method 325B. The commenter also asked what material should be used for sampling tubes, inert coated stainless steel or non-coated stainless steel. Another commenter recommended in Section 6.1 line 5, for consistency with Section 3.9 of Method 325A amending to state 'The tubes are made of stainless steel or inert-coated stainless steel with...' The commenter also asked if there are certain requirements certifications or qualifications a lab or refinery must obtain in order to perform the laboratory analysis for Methods 325A and 325B.

Response 6: PVC is an acceptable waterproof hood material based on research and subsequent field tests conducted by EPA. High density linear polyethylene may be acceptable for shipping samples as described in Method 325B. However, it is incumbent for sample management during analysis to evaluate blank samples to confirm handling procedures do not contaminate samples.

The selection of absorbent material is a performance-based variable that allows manufacturers and laboratories to optimize equipment performance now and in the future to meet quality control method requirements. Therefore, we will not specify absorbent materials.

We removed stainless steel as the tube construction and clarified throughout Method 325 inert coated stainless steel tubes must be used.

We do not require laboratory certification for parts 60 and 63 testing. The laboratory is free to pursue their own certification. The performance criteria in Method 325 are adequate to generate confidence on a sample-by-sample basis.

Comment 7: Two commenters noted that the analytical blank procedure in Section 9.1 states that the system blank requires desorption of an empty tube or desorption of the focusing trap alone. However the criteria for the internal standard response should be removed as it is not possible to add an internal standard to an empty tube. One commenter recommended changing "System blank analysis" to "Laboratory Blank" in Table 17-1. Further, commenters stated that requiring an analytical system blank and application of data flags based on its failure is unnecessary. If the system blank shows unacceptable artifacts, then the lab blank or Method blank will also show unacceptable artifacts. One commenter also stated that the Method blank will also allow more effective evaluation of the level of contamination given the fact that internal standards can be used to calculate concentrations. The commenter further suggested that if unacceptable background is observed, that it be remedied prior to sample analysis. Most data processing software is unable to utilize an internal standard area count from a different data file to calculate a concentration. Table 17.1, the commenter stated System blank Analysis should be replaced with laboratory blank analysis. The system blank is an empty thermal desorption tube, so cannot have Internal Standard (IS) parameters associated with it. One commenter also indicated that the process to calculate the system blank concentrations using the factors of the continuing calibration verification (CCV) is impractical as it requires a manual off-line calculation for each target compound.

Response 7: We agree that the quality checks are adequate and revised Method 325B to remove system blank analysis and separated the information on laboratory blanks and field blanks into two sections within Section 9.0. The EPA disagrees with the commenter that the CCV is impractical, particularly as there is only one required target compound. The EPA determined that laboratories have two viable alternatives to perform quantitative calculations using CCV. Laboratories may modify their Laboratory Information Management System to generate quantitative data based on CCV or convert data based on initial calibration to CCV concentration using a stand-alone spreadsheet. Furthermore, based on data provided in public comments, EPA determined that using this modification provides better consistency between facilities for compliance purposes. The EPA provided further clarification on CCV in Sections 9.13.2 and 11.3.2.4.

Comment 8: Several commenters recommended a number of editorial changes to the language of Method 325B to revise, expand, clarify, or modify requirements as follows. [For clarity, we are providing responses to each bulleted item (or group of bulleted items) within this comment.]

- Table 12-1, the commenter stated that based on the literature reference, these rates are based on a 24-hour duration; however, there is no footnote stating this limitation. Since the rule covers 14-day collection period, the commenter suggested that uptake tables should list the appropriate duration as well as sorbent.

  Response: We added note on duration to Table 12.1. However, there is not a significant difference in uptake rates between 24-hour and 14-day duration periods.

- Section 12.2.4 and Equation 12.6, the commenter recommended clarifying that U_{NTP} is the published rate in table 12-1, and U is the sampling site uptake rate. It is U that is plugged into equation 12.5 to report the corrected target concentrations. (See reference ASTM D6196-03(2009) 14.2.2.1 Note 7. Additionally, the commenter suggested that this “adjustment” is unnecessary as the small variations in the uptake rate as a function of temperature and pressure is insignificant relative to the cited uncertainty of the published rate and uncertainty of the analytical measurement. Another commenter suggested removing Section 12.2.4, along with equation 12.6 because they felt it was confusing to add this in. The commenter also stated U_{NTP} should be the published uptake rate and if this is the case then this equation is incorrectly labelled. The commenter continued, given the normal uncertainty of uptake rates, making minor adjustments to correct for ambient temperature and pressure variation is not justified.

  Response: We disagree that U_{NTP} is the published rate in Table 12.1. The term U_{NTP} is the site-specific corrected value for the average temperature and pressure. In addition, we determined it is necessary to adjust for temperature and pressure as outlined in ISO 16017-2, EN 14662-4, and ASTM D6196-03. We agree that the proposal was not clear in specifying the correction procedure and added clarifying information on temperature, pressure, and uptake rates corrected for local conditions. We also clarified the intent of correcting U for local conditions and reversed the order of Equation 12.5 and 12.6.

- Section 1.3, the commenter suggested amending the text of this section from the 3rd sentence to read: “Compounds with known uptake rates and associated sorbents are listed in Tables 12.1, 12.2 and 12.3. This method provides performance criteria to demonstrate acceptable performance of the method (or modifications of the method) for monitoring one or more of the compounds listed in Tables 12.1 to 12.3. If standard passive sampling tubes are packed with other sorbents or used for other analytes than those listed in Tables 12.1, 12.2 and 12.3, then method performance and relevant uptake rates should be verified according to Addendum A to this method unless already validated in later editions of one of the following national/international standard methods: ISO 16017-2, ASTM D6196-03 or EN 14662-4, or reported in the peer-reviewed open literature.”
- Section 7.1.2 line 6, the commenter recommended amending to “...listed in Tables 12.1 to 12.3 and used...”
- Section 7.1.3, from line 5 to 15, the commenter recommended amending to “...according to Addendum A to this method unless already validated in later editions of one of the following national/international standard methods: ISO 16017-2, ASTM D6196-03 or EN 14662-4, or reported in the peer-reviewed open literature. A summary table...”
- Section 12.1.8, the commenter suggested amending the text to say “Diffusive uptake rates for common VOCs using sorbent tubes of the dimensions specified in Section 6.1 are presented in Tables 12.1, 12.2 and 12.3. Adjust analytical conditions.” The commenter also proposed for clarity and consistency including uptake rates from other validated standards and peer reviewed publications as Tables 12.2 and 12.3.
- Section A.1.1 line 4, the commenter recommended amending to “…in Tables 12.1 to 12.3 must be evaluated”
- Section A.1.1 lines 8 to the end, the commended suggested amending the current text to “...this Addendum unless the compound or sorbent has already been validated in later editions of one of the following national/international standard methods: ISO 16017-2, ASTM D6196-03 or EN 14662-4, or reported in the peer-reviewed open literature.”

  Response: We clarified and expanded information about acceptable absorbents for use in Method 325 in response to these comments. We did not add additional Tables or “later editions” to national/international standard methods, but added additional absorbent uptake rates for Carbograph 1TD and Carbopack B to Table 12.1.

- Section 2.3 lines 6 and 7, the commenter recommended replacing “desorping” with “desorbing”.

  Response: We agree and revised by replacing “desorping” with “desorbing”.

- Section 4.1.1 line 7, for clarity, the commenter suggested amending “polymer” to “polymeric sorbent”.

  Response: We agree and revised by replacing “polymer” with “polymeric sorbent”.

- Section 6.2.1 line 7, the commenter recommended deleting repeat of ‘only’.

  Response: We agree and revised to read: “Note that the analytical TD system should be used for tube conditioning only if it supports a dedicated tube conditioning mode...”.

- Section 9.3.4 lines 5 - 8, for consistency with Section 9.3.2 of Method 325A the commenter requested amending the lines to read “...throughout the monitoring exercise. The field blanks must be installed under a protective hood/cover at the sampling location, but the long-term storage caps must remain in place throughout the monitoring period (see Method 325A).”

  Response: We agree and revised to read: “throughout the monitoring exercise. The field blanks must be installed under a protective hood/cover at the sampling location, but the long-term storage caps must remain in place throughout the monitoring period (see Method 325A).”

- Section 9.4 line 2, the commenter recommended correcting the term to be ‘co-located’

  Response: We agree and corrected the grammar by replacing “collocated” with “co-located”.

- Section 9.6 line 13, the commenter recommended amending ‘measure’ to ‘detect’ because this refers to LOD.

  Response: We agree and corrected the grammar by replacing “measure” with “detect”.

- Section 9.10.1, for clarity the commenter requested the sentence be amended to “must be demonstrated by quantitative re-collection and repeat analysis of a tube standard (See Section 13.4.2 of ASTM D6196-03(2009).”

  Response: This section was intentionally left general since different analysis equipment provide different options for this quality check. We disagree with specific language recommended by the commenter as what was proposed provides the minimum requirements to demonstrate compound recovery in system and tubes used for analysis. Requiring what the commenter requested may not be possible on all equipment. Therefore, quantitative recollection and analysis is not necessary to generate data sufficient to meet requirements.

- Section 9.10.2 line 2, the commenter requested the line be edited to read “...system can also be demonstrated by...”

  Response: We agree and revised to read: “...system can also be demonstrated by...”.

- Section 12.1, the commenter recommended the typo in sub-section title be corrected.

  Response: It is unclear what typo is, so we did not make any revisions.

- Section A.2.1 first sentence, the commenter suggested reducing the first sentence so it just says: “Known concentrations of VOC are metered into an exposure chamber (see Figure A.1 for an example exposure chamber).”

  Response: We agree and revised to read: “(see Figure A.1 and A.2 for an example of the exposure chamber and sorbent tube retaining rack)” instead of reducing sentence as suggested by commenter.

- Section A.4.3, the commenter recommended for extra clarity amending the text to say: “As passive sampling devices are placed into the exposure chamber, they should only be handled by personnel wearing clean, white...”

  Response: We disagree and did not amend text as recommended. Performance based requirements of the Methods will identify contamination issues and care should be taken at all times when handling passive sampling devices.

- Section A.6.1, the commenter stated for consistency with A.8.4 the text be amended to say: “sufficient size to simultaneously expose a minimum of eight sorbent tubes.”

  Response: We agree and revised to read: “…expose a minimum of eight sorbent tubes”.

- Section A.7.1, the commenter stated the percent relative humidity requirements of A.7.1 must be consistent with the requirements of A.8.5.

  Response: We agree and revised to read: “…between 35 percent and 75 percent relative humidity…”.

- Section A.7.1, the commenter stated the VOC concentration requirements of A.7.1 must be consistent with the requirements of A.8.4.1 and A.8.4.2.

  Response: We agree and revised to read: “…evaluation at two to five times…” to make consistent with Section A.7.1.

- Section A.7.3, last bullet the commenter suggested correcting the typo amend to “Purified dilution air containing less than”

  Response: We agree and revised by adding “containing” between “air” and “less”.

- Section A.8.1 from line 9, the commenter stated given the note which follows this text and allows users to control humidity by controlling the fraction of humidified and dry pure air entering the chamber, should the text be amended to say: “You must control the relative humidity in the test gas throughout the period of passive sampler exposure." NB RH monitoring frequency is covered in A.8.7.4.

Response: We agree and revised to read: "You must control the relative humidity in the test gas throughout the period of passive sampler exposure."

- Section A.8.7.4, the commenter stated they feel the EPA does not think you need to record the time on an hourly basis. Plus, given this test must continue for at least 24 hours (A.8.7), the last bit of the sentence is not needed.

  Response: We agree and revised by removing "at hourly intervals or" and "whichever is greater".

- Section A.9.2, the commenter suggested amending "house air" to "humidified air"

  Response: We agree and revised by replacing "house" with "humidified".

- Section A.12, the commenter suggested correcting the typo in title.

  Response: It is unclear what typo the commenter is referring to, so we did not make any revisions.

Comment 9: Two commenters stated that demonstrating tube performance each year following Addendum A is not practical for most laboratories as it requires an environmental chamber. One commenter suggested applying the criterion of replacing or demonstrating performance every 50 uses or every 2 years. Given that the tubes will be deployed in the field for 2 weeks, it is unlikely that a tube will be used for sample collections more than 13 times in a year which is more conservative than the alternative of 50 uses.

Response 9: We agree and revised Section 7.1.6 to read: "at least every 2 years or every 50 uses…".

Comment 10: One commenter suggested that the requirement to use lab blank tubes from the same conditioning batch as the field tubes should be removed. It is not practical to manage this requirement if the tubes from multiple projects are being conditioned in a given batch. Furthermore, allocating a minimum of 2 laboratory blanks per monitoring episode becomes unwieldy when conditioning batches are typically 20 tubes, and tubes for multiple projects may be conditioned as a batch.

Response 10: We agree and revised information in Section 9.0 to eliminate the requirement that the laboratory blank must be from same conditioning batch as field samples. In addition, we removed the requirement for two laboratory blanks per monitoring episode and replaced it with one laboratory blank per analytical sequence.

Comment 11: One commenter believes it is unclear how the lab is to flag data in Sections 9.3.2 and 9.3.5 if only one of two blanks fails to meet the criterion (in Section 9.3.2) or if one of two field blanks fails to meet the criterion (in Section 9.3.5). Finally, the commenter recommended the application of flags to a data set as a result of field precision non-compliance be applied by the data user rather than the laboratory. Field duplicates may be submitted to the laboratory without this designation on the chain of custody form, and it may not be clear to the laboratory from the submitted documentation as to which samples are field duplicates. The commenter stated that guidance is needed in the rule as to how to handle these biased results when calculating averages. Since a root cause analysis of an average exceedance that uses such data is likely to find the exceedance is due to this biased data, the commenter recommended avoiding that unnecessary burden and excluding biased data from the average calculation.

Response 11: We eliminated the need for data to be flagged based on unacceptable laboratory blank by revising laboratory blank requirements in Section 9.0 to require corrective action and successful testing of laboratory blank before analyzing samples. We clarified and added the following phrase, "If either field blank fails, flag all data…". Per Method 325A, field blanks and duplicates are required to be documented on chain of custody form.

Comment 12: One commenter recommended expanding the range of volume aliquots of the standard to the sampling end of conditioned tubes allowed from 0.5 to 500 ml to provide a wider calibration range.

Response 12: We agree and revised to expand the range of volume for standards preparation.

Comment 13: One commenter suggested including EPA T0-17 as an alternative confirmation technique to active SUMMA canister sampling. The commenter stated that, as highlighted in A.4.4, canister sampling is not appropriate for all vapor-phase organics in air for example the main components of middle-distillate fuels which are likely to be present in ambient air near refineries (references available if required). Given Method 325 relates to sorbent tubes that are passively sampled, a more appropriate independent method for checking chamber concentrations, that would have a very similar analytical scope (analyte volatility and polarity range), would be pumped sorbent tubes, i.e., US EPA Method TO-17. The commenter suggested a number of amendments to allow the use of US EPA Method TO-17 to confirm chamber concentrations.

Response 13: We disagree that EPA TO-17 should be included as an alternative to measure chamber exposure concentration(s). We want an independent method to verify sorbent exposure concentration(s) and do not want a sorbent method to verify another sorbent method. However, we recognize that other methods besides TO-15 and Method 18 may be used to verify chamber concentrations. We revised Addendum A to provide more flexibility by including whole gas sample collection and analysis or direct interface volatile organic compound measurement methods.

Comment 14: One commenter stated that one chamber air change per minute is not critical if the face velocity and the depletion requirement (A.8.4) are both met. While the prescribed exchange rate may be necessary to meet the face velocity and depletion requirement in cases where very small volume chambers are utilized (such as the one shown in Figure A-1), chambers described in ASTM D5116 are on the order of 119 L and can easily meet the face velocity and depletion requirements under conditions of less than one chamber air change per minute. The commenter recommended removing the air exchange requirement.

Response 14: We agree and determined that other quality control procedures were adequate to ensure constant target compound in test chambers. We removed the air exchange requirement from the method.

Comment 15: One commenter noted that several chemicals in Table 12-1 and in the reference method ISO 16017-2 Table 2 have a published uptake rate of less than 0.5 milliliters (ml)/minute (min.) Method 325B states that sorbent tube performance is acceptable if the relative accuracy of the passive sorbent sampler agrees with the active measurements by ± 10 percent at the 95 percent confidence limit and the uptake rate is greater than 0.5 ml/min. It is unclear how to apply acceptance criteria for these chemicals. According to the commenter, given the range of analytes of interest, 0.3 ml/min would be a more useful minimum. The commenter suggested amending the text to “95 percent confidence limit and the uptake rate is greater than 0.3 ml/min (or >1.0 nanogram (ng)/ppm/min.)”

Response 15: We disagree with the suggestion to lower the limit because the lower uptake rates are subject to greater uncertainty due to temperature and humidity variations (based on EPA’s experience with 1,3-butadiene). We revised to include “equal to” or greater than 0.5 mL/min. To clarify this point, the upper 95% confidence limit of uptake rates in Table 12.1 are all equal to or greater than 0.5 mL/min.

8.3 Need for alternative monitoring technologies for fenceline monitoring

Comment 1: Several commenters recommended that the EPA provide sufficient flexibility in its regulations to allow state and local jurisdictions to develop alternative monitoring programs that can be demonstrated to provide equal or greater access to monitoring information or the amount of information. Other commenters stated refineries with open-path monitors along the fenceline or ambient downwind monitoring stations should not be required to install fenceline monitors. The commenters indicated that some petroleum refineries have, or may have in the future, federally-enforceable obligations to install, maintain, and operate population oriented ambient air monitoring systems. The commenters claimed that these programs focus on the prevalent wind situation and, because of cost or other obstacles, such as adjoining water bodies, do not require monitoring around an entire refinery perimeter but require monitoring in the prevalent downwind direction.

Response 1: We currently find that available real-time, open-path monitoring systems are not capable of measuring benzene concentrations within the range we expect to see at refinery fencelines (on average). For that reason, we are not providing a direct allowance to use of an open-path monitoring system in lieu of the required passive diffusive tube monitoring locations. However, we believe that the state of technology is advancing and that the capabilities of these systems will continue to improve. Under the provisions of 40 CFR 63.7(f), owners and operators can request the use of an alternative test method and we have provided specific provisions at 40 CFR 63.658(k) of the final rule to outline the requirements related to the fenceline monitoring program. In order to obtain approval for an alternative test method, the owner or operator must demonstrate that the system proposed meets certain minimum requirements. Because alternative approaches must ensure the same level of protection as the standard that they replace, a request for an alternative method must demonstrate how the alternative approach achieves that goal. At a minimum, an alternative approach to fenceline monitoring using Methods 325A and 325B must have the same level of spatial coverage as the work practice standard. Additionally, the alternative approach must be able to achieve a nominal method detection limit that is appropriate for the monitoring objective outlined in the work practice standard. In order to quantify the emissions detected using an alternative method, we believe any alternative method must be able to achieve method detection limits that are an order of magnitude below the action level, or 0.28 parts per million by volume (ppbv) benzene. For time-resolved measurement approaches, detection limits can vary over time based on the specific operational principals of the measurement instruments/sensors employed, operational conditions and on the maintenance state of the systems. As an example, for open-path devices, detection limits can depend on optical signal levels (alignment), atmospheric conditions, etc.; therefore, the alternative method must include operational procedures to track detection limits over time to ensure data quality objectives can be met on a continuous basis. Additionally, an alternative monitoring approach could encompass several different types of instruments and measurement techniques (e.g. sorbent tubes, open-path monitoring), as long as the entire system provides the same spatial coverage that is provided by the work practice standard and each monitoring technique achieves the appropriate method detection limit.

When submitting a request for an alternative monitoring approach, the following should be included in the request at a minimum: a description of the monitoring instrument and measurement technique (measurement principle) employed by the instrument; the method detection limit of the instrument; a map showing the spatial coverage of the monitoring approach (e.g., locations of paths, locations of point monitors, etc.); initial installation certification procedures, including criteria for linearity, drift, and accuracy; ongoing quality assurance/quality control checks and timeframes for such checks, including tracking the detection limit over time through field verification, if appropriate; means for in-field verification of calibration and other performance metrics using National Institute of Standards and Technology (NIST) traceable gas standard challenges; definition for when the system is out-of-control and corrective action for such periods; and frequency of measurement (e.g., once every 15 minutes). The detection limit must be based on field verification. For measurements made on a path length (as opposed to a point), the detection limit should be expressed as a path average concentration.

Comment 2: One commenter does not believe that fenceline monitoring should be required or is necessary. The commenter stated that the TCEQ has an extensive air monitoring network that is already in place and functioning to identify and address emissions issues. The commenter noted that this network gives TCEQ the ability to monitor and manage benzene concentrations in the communities located near refineries and other industrial sources and to seek and obtain reductions in emissions, when necessary, from multiple facilities. The commenter went on to describe the ambient air monitoring data for benzene and other toxics available to the public through TCEQ’s website.

The commenter noted that TCEQ has a program to address persistent high levels of pollutants and that some areas near petroleum refineries have never had benzene emissions that warranted being placed in that program. Further, the commenter stated, areas near petroleum refineries that have been placed in the program have successfully lowered emissions to a point that TCEQ has removed the area from the program for benzene.

Another commenter suggested that the rule should also make provisions for fenceline monitoring data to be used to improve ambient air standards, in addition to bringing about emissions reductions. For fenceline monitoring to contribute most effectively to the EPA's goals of improving health in communities next to refineries, the EPA should develop a plan for using information generated by fenceline monitoring at refineries across the country to evaluate the adequacy of action levels set in the rule so as to ensure that those levels are protective enough.

Response 2: We applaud TCEQ's proactive approach for protecting communities near industrial complexes. As an initial matter, the TCEQ program applies only in Texas and thus does not address emissions from the refineries located in 35 other states. Second, and significantly, the purpose and goal of the TCEQ monitoring program is different than the purpose of the fenceline monitoring program we are establishing in this final rule. Monitors placed in communities some distance from the refinery, as with the TCEQ program, are not capable of providing information regarding the emissions from any specific facility. These types of ambient monitors provide valuable information in that they identify the level of pollutants within a community attributed to a variety of sources; but they do not provide the type of information that would allow a specific facility to identify whether it is managing its fugitive emissions consistent with the federal requirements or to take any corrective action.

Comment 3: One commenter supported incorporating alternative approaches to fenceline monitoring and is concerned that the proposed monitoring will not be sufficient in most cases to meet the goals the EPA has set forth. The commenter stated that in light of EPA's justification that fenceline monitoring is necessary because of uncertainties in the fugitive emissions estimates and the potential for higher emissions, EPA should allow facilities the use of tools which identify potential issues as close to their source as possible. Specifically, the commenter recommended that sources should be allowed an alternative to fenceline monitoring that increases the Method 21 and/or optical gas imaging obligations to those in subpart H of part 63. The commenter also recommended that EPA allow Method 21 and/or optical gas imaging for wastewater drains and floating roof tanks if cost-effective. Another commenter urged the EPA to speed up development of the OGI camera protocol in 40 CFR part 60 Appendix K and allow it to be used as an alternate to fenceline monitoring. One commenter suggested that more frequent tank inspection would be a far less onerous solution than the proposed fenceline monitoring.

Response 3: Although we did propose to allow OGI as an alternative to Method 21, we cannot finalize this requirement at this time because Appendix K has not been proposed. We continue to work on Appendix K and we intend to propose that method as soon as it is fully developed. As a practical matter, the refinery owner or operator may elect to use OGI to help identify a specific source of emissions when a high fenceline monitoring concentration is measured, and we specifically noted that OGI could be used as part of a required root cause and corrective action analysis in 40 CFR 63.658(g)(2). Based on the comment to use a more frequent, direct source monitoring alternative, we expect the refinery owner or operator would need to submit a request for an alternative means of emission limitation pursuant to the General Provisions requirements at 40 CFR 63.6(g). We consider it will be very difficult to determine the alternative monitoring requirements (frequency, detection limits, etc.) that would achieve an equivalent emissions limitation as the fenceline monitoring program short of performing inspections of tanks, monitoring of all equipment components, and monitoring for detectable emissions around all wastewater drains and tanks and other sources of emissions (e.g., gasoline loading racks, marine vessel loading operations) every two weeks. As noted previously, we included provisions at 40 CFR 63.658(k) of the final rule to allow refinery owners or operators to request an alternative test method because we found that use of an alternative method would be relatively feasible and common. Based on the anticipated costs of more frequent monitoring of all potential fugitive emission sources, we do not consider it likely that facilities will seek an alternative emissions limitation for the fenceline monitoring work practice standards and, therefore, we did not include specific procedures in Refinery MACT 1 for requesting an alternative emissions limitation for the fenceline monitoring work practice standards. However, refinery owners/operators may still submit such a request to the Administrator pursuant to 40 CFR 63.6(g).

Comment 4: One commenter suggested that the EPA require use of active monitors at large refineries and those located in close proximity to population centers and claimed active monitors are preferable for carcinogens, such as benzene, and other substances of high toxicity. The commenter stated that the EPA has a number of complex responsibilities in relation to U.S refineries, including but not limited to reducing overall emissions as proposed in this rule, preventing catastrophic accidental releases under section 112(r), and facilitating a community’s emergency response capabilities in the event of a significant release. The commenter noted that while the EPA is in the process of finalizing this rule, it is also soliciting comments on *possible revisions to its current Risk Management Plan, 40 CFR part 68 (RMP).* The commenter contended that the EPA may in the near future require active monitoring systems in order to achieve objectives under the RMP. The commenter suggested that the EPA instead consider requiring the use of active fenceline monitoring systems under this rule and that such a system could be expanded, if needed, to fulfill the purposes of the RMP.

Response 4: Based on the current state of technology, we are skeptical that one type of monitoring system can serve both fugitive management purposes and emergency management purposes. This is because the fenceline work practice standard appropriate for managing fugitives is aimed at detecting benzene at low concentration on average over time. Also, as discussed in the preamble to this final rule, passive sampling is capable of these low concentration measurements but active real-time open path systems are not. In comparison, monitoring for the purpose of emergency management requires real-time quality assured measurement capability and may not need to detect low concentrations since emergency events will presumably occur at elevated concentrations and for shorter periods of time.

Comment 5: A commenter supported the proposed passive sampling sorbent tubes fenceline monitoring requirement, stating that it is reliable, economical, and scientifically sound. Additionally, the commenter pointed out that it uses no electricity during sampling and is easy to handle and ship. The commenters noted that these merits have been recognized and utilized by other countries, especially countries in European Union and in Asia.

Response 5: We appreciate the support.

Comment 6: One commenter suggested that robust community participation in planning, implementing, and overseeing fenceline monitoring is necessary to ensure that monitoring systems remain state-of-the art and are trusted by the public. The commenter asserted that monitoring and information technology are constantly advancing, and residents of refinery communities can be a source of ideas about how new social networking platforms, for example, could make monitoring information more accessible and ensure that it is used more fully.

The commenter further claimed that active community involvement is important because, without it, information generated by monitoring is unlikely to be credible to the public. The commenter pointed out that community members often dismiss as biased information generated by refinery-funded programs even when overseen by regulatory agencies. The commenter stated that community involvement is necessary to counteract the perception that monitoring programs are designed to show only what companies are willing to divulge by ensuring that companies do not overlook issues of concern to the community. The commenter concluded that the rule should require companies to arrive at plans for fenceline monitoring in consultation with neighboring communities and to provide on-going opportunities for community involvement.

Response 6: The final rule requires facilities to monitor concentrations around the fenceline and to make the fenceline monitoring data available to the public. The final rule also contains substantive QA/QC requirements for the monitoring methods that ensure the data collected are of high quality. While we agree that it is important that neighboring communities understand and believe the data collected, we disagree that the rule should require that the facility owners or operators engage each neighboring community in planning, implementing and overseeing monitoring at a given facility. Thus, while we encourage refineries to keep open lines of communication with local communities to let them know about the monitoring programs they put in place, respond to concerns raised by communities and answer questions about the monitoring program and its results, we find that the monitoring and reporting requirements provided in the final rule are sufficient to ensure quality data are collected and that the monitoring results are readily available to local communities in a timely and transparent manner.

Comment 7: One commenter asked why the EPA did not take the approach recommended by a panel of national air monitoring experts who recently published a report on current air monitoring capabilities near Bay Area refineries and potential air monitoring technologies, methodologies and tools to provide air quality information for communities near refineries and gather data to evaluate health impacts associated with air quality near refineries and track air quality changes and trends over time near refineries. The Expert Panel generally agreed that an approach that utilized a combination of fenceline, community, and mobile monitoring would be required to adequately define exposures during normal operations and when upsets and incidents occur. The fenceline monitoring would be leveraged primarily to identify non-routine emissions during normal operation, while the community monitoring would be utilized to develop spatial gradients of chronic exposures. Mobile monitoring would be used to supplement on-going monitoring during major upsets and incidents and to help develop information on spatial variability.

Response 7: As an initial matter, under both sections 112(f)(2) and (d)(6), the EPA was evaluating if it was necessary to require further reductions from the refineries source category.

We do not agree that community monitors can isolate emissions from specific sources and thus they are not an effective tool, at least at this time, in regulating emissions as required under either of these CAA provisions. Thus, we did not consider community monitors in this rulemaking. We note, however, as indicated by a number of other commenters, that many communities near refineries already have community monitors that provide data on pollutant levels in the community that are attributable to a broad spectrum of sources.

Regarding mobile monitors to address upsets, we do not agree that CAA sections 112(d)(6) and (f)(2) are the correct tools for determining how to identify or address violations of standards. Rather, these provisions are focused at determining whether the existing standards should be tightened either because of developments in processes, practices and control technologies or because the existing standards do not protect public health with an ample margin of safety. We note that separate from this rulemaking, EPA is involved in a leading research group in the mobile measurement area and including the use of mobile measurements for fugitive emission detection (Refer to OTM 33A and other). As part of EPA's research it has facilitated development of and demonstrated the use of the first commercially available prototype mobile benzene measurement system (based on cell-based UV optical spectroscopy) for detection of benzene emissions near refineries and other facilities.

In identifying the available technologies, the EPA talked with experts, including vendors of monitoring systems and facilities that operate them. We then evaluated a variety of monitoring methods, as discussed elsewhere in the preambles to the proposed and final rules and this response to comment document, considering technical capabilities, such as monitor detection limits and coverage, and costs. We concluded that, for the purposes of improving fugitive emissions management, fenceline passive diffusive tube monitoring was the best monitoring alternative.

Comment 8: One commenter indicated that he does not think that the present proposal requires monitoring stations to be elevated to a level that would reliably monitor fugitive emissions from towers and other elevated equipment. The commenter noted that there are "continuous emissions" that are found every time downwind measurements are taken, and they are not detected by ground-level monitors. The commenter stated that SOF and DIAL have the advantage of being able to measure concentrations from the ground to the sky and that they also use wind speeds to quantify their pollutant leak rates.

Response 8: We identified fenceline monitoring as a development in practices, processes and control technologies for improved management of fugitive emissions at refineries. "Elevated equipment" typically means equipment that is vented to a stack or a control device and does not fall within the ambit of fugitive emissions. While some equipment, like distillation columns are tall and can have elevated equipment components that may leak, these tall sources are generally located near the center of the refinery so that the emissions released are dispersed and measureable at ground levels by the time they reach the property boundary. For the purposes of improving fugitive emissions management, a system that can measure levels at ground level is the most effective tool.

8.4 Applicability of fenceline monitoring requirements

Comment 1: One commenter objected to the requirement that operators must be in compliance with the fenceline monitoring provisions of section 63.658 in order to use optical gas imaging (provided in 40 CFR part 60, Appendix K) as an alternative to using EPA Method 21. The commenter claimed EPA provides no rationale for this requirement. The commenter asserted that since Appendix K is equivalent to, and arguably better than Method 21 monitoring, there is no reason for EPA to impose any additional conditions for the use of optical gas imaging technology.

Response 1: Use of Appendix K would not alleviate the need to comply with the fenceline monitoring requirements. Petroleum refinery owners and operators would be required to meet both the equipment leak survey requirements and the fenceline monitoring requirements. We were seeking to develop Appendix K as an alternative equivalent method to EPA Method 21, so that refinery owners or operators could elect to use Appendix K as an alternative to Method 21. However, Appendix K has not been proposed, and will not be available as an alternative to Method 21 until it is finalized. Therefore, the final rule does not reference the use of the optical imaging camera as an alternative to Method 21.

Comment 2: One commenter stated that his refinery idled its process units in 2012 and is presently operating as a terminal. However, because the refinery is idled rather than permanently shut down, the refinery continues to apply the provisions of Refinery MACT 1 and 2 rules to the facility. The commenter stated that it would be helpful for the EPA to exclude idled refinery locations from the fenceline monitoring requirements because such facilities have an emissions profile much more similar to a terminal operation.

Response 2: If the facility is subject to Refinery MACT 1, then implementation of the fenceline monitoring standard would be required. If the facility no longer intends to operate as a petroleum refinery, the facility owner or operator may elect to have their permits revised to indicate that the refinery operations are permanently being discontinued and seek permitting solely as a terminal. The idled refinery remains subject to Refinery MACT 1 and any revisions to the MACT until it is no longer identified as being subject to Refinery MACT 1.

Comment 3: One commenter stated that the proposed rule would require every refinery to install fenceline monitors at significant ongoing costs despite very low levels of risk. The commenter stated that this one-size-fits-all approach will not improve public health, particularly when EPA's analysis shows that a number of these refineries pose no health risk to the surrounding communities. The commenter noted that one quarter of the refineries had maximum individual risk levels below 1-in-1 million, and two-thirds had risk levels below 10-in-1 million. Another commenter also claimed that risk does not support the fenceline monitoring requirement, noting that 115 of the 142 facilities analyzed that have a cancer risk less than 10-in-1 million. This commenter asserted that fenceline monitoring should not apply to these 115 facilities.

Another commenter stated that the one-size fits all approach to fenceline monitoring fails to comply with EO 13563, which mandates that agencies take a regulatory approach that reduces burdens and maintains flexibility and freedom of choice. The commenter stated that the fenceline monitoring proposal fails to account for the specific conditions at the regional and local levels or risk to surrounding communities. The commenter concluded that EPA should tailor the requirement to those refineries in higher risk areas.

A commenter claimed that EPA should exempt Small Business Refineries which have inherently lower emissions and disproportionately represent facilities located in remote locations. The commenter stated that small refiners are concerned that this proposal would impose unnecessary costs on small entities and would serve no useful purpose where there are no nearby downwind off-site residential receptors. The commenter concludes that the "uncertainty" EPA relies on for the requirement by narrowly tailoring monitoring to sources of uncertainty or gathering data on a limited basis to better understand those sources of uncertainty.

Response 3: As an initial matter, the commenters erroneously assume that EPA is promulgating the fenceline monitoring requirement to address risk. As EPA has noted in the preambles to both the proposed and final rules, EPA is promulgating the fenceline monitoring requirement as a cost-effective development in processes, practices or control technologies. We disagree that the fenceline monitoring program cannot be implemented cost-effectively, even at smaller refineries. As proposed, we are establishing requirements for the number of monitoring locations based on the size of the refinery. We are providing facilities an option, after two years of data collection, to submit site-specific monitoring plans to reduce the monitoring frequency as described in more detail in the preamble and elsewhere in this document.

8.4.1 Require tiered levels of monitoring

Comment 1: One commenter was glad to see the fenceline monitoring proposal. The commenter recognized that refineries might dispute the need for this monitoring based on a claim that they are operating their refinery well. The commenter noted that those that are well managed will not have violations of the 2 week average. The commenter supported adoption of the full fenceline systems designed and built in the San Francisco Bay Area, which the commenter claimed has upgraded community based technologies of auto-sampling hardware and particulate monitors added to the fenceline lasers and chemical detection systems.

The commenter suggested that EPA could exempt from the full San Francisco Bay Area system those refineries that do not exceed the EPA's minimalist detection system's limit for a year unless a significant off-site impact occurs. Also, the commenter suggested, if a leak, explosion or fire has off-site impacts, the requirement for the full system would be triggered. The commenter realized that this is an after-the-fact monitoring system, but also that requiring all refineries to build the full system may not be politically possible. The commenter further recommended that if the EPA adopts this tiered approach to monitoring, the EPA should provide requirements for the more complete system and the commenter detailed requirements that EPA should include.

The commenter noted that a full real-time system can warn the local public of an ongoing release. The commenter further stated that the proposed systems would be a setback locally if they replaced the current Bay Area systems or the systems about to be required by the local Air District.

Finally, the commenter suggested that the EPA consider adopting the BAAQMD's fenceline system siting guidance which they claim is more robust than the limited fenceline systems proposed.

Response 1: We appreciate the commenter's concerns, but for the reasons provided in the preamble and elsewhere in the response to comments document, we disagree that the type of system they recommend is as effective for improved management of fugitive emissions at the refinery. We further note that state or local agencies may elect to require additional monitoring techniques at some refineries and we do not anticipate that those areas with monitoring requirements already in place will consider the fenceline monitoring approach in the final rule to be an adequate substitute for the myriad purposes for which they are requiring monitoring.

8.4.2 Limit time or number of locations that need ongoing monitoring if concentrations are low

Comment 1: A number of commenters indicated that the fenceline monitoring program should provide relief for facilities that always achieve low monitored levels. For example, the commenters stated, a refinery that consistently reports fenceline concentrations below the corrective action level should be allowed to discontinue the program, if the facility is located within a region that contains a rigorous monitoring network.

Several commenters suggested that if a facility reports less than half the action level for a period of two years, then the frequency of monitoring be reduced to once every three years. One commenter suggested that the EPA should consider waiving the fenceline monitoring program for sites with modeled concentrations at or below the concentration action level or a threshold used by a state to demonstrate protectiveness for a permit action.

Several commenters stated that, after an initial period is completed establishing that the normal baseline of a particular refinery is below the action level, less frequent monitoring should be allowed. These commenters recommended that, after two years of demonstrating a background corrected maximum fenceline annual average concentration below the action level, monitoring frequency be reduced to one 2-week period every quarter. Another commenter suggested two consecutive 2-week periods per quarter. The commenters stated that if the background corrected annual average benzene concentration based on the quarterly monitoring exceeds the action level, a return to every two week monitoring would be required along with meeting the RCA/CA requirement. The commenter further provided that reduced frequency should be available again after one year of meeting the action level. Further, one commenter requested that a permanent off-ramp be provided after five years of data below the background-corrected action level. Commenters stated this is consistent with many U.S. EPA regulations that offer facilities the opportunity to reduce the sampling frequency when measured values are consistently low or below action levels. In this instance, it would further demonstrate to refineries that through good housekeeping and generally good environmental management they are able to aggressively identify and repair sources of fugitive emissions. Reducing their fugitive emissions will reduce their contribution to fenceline monitoring levels and hopefully it will allow them to reduce their benzene monitoring costs by keeping fenceline levels consistently below the action level.

One commenter stated that while they continue to support use of Perimeter Boundary Monitoring (PBM) systems for information gathering only, a more robust system could, nonetheless, provide for future coordination of the dual monitoring systems (referring to other conventional fugitive monitoring programs). EPA could structure the PBM requirements to allow facilities to periodically review the effectiveness of the monitoring systems. For example, for an initial period of two years, all refineries could use both conventional fugitive emissions monitoring and a PBM program. After this initial period, the EPA should eliminate unnecessary monitoring by allowing refineries the option of using the more effective compliance approach, if a single monitoring approach would not leave unacceptable gaps in the monitoring protocol. If there is not a more effective program at a given refinery, then the refinery would continue using both methods, and re-evaluate the systems at two year intervals to determine whether either system proves more effective in subsequent years.

Other commenters strongly supported that the fenceline monitoring remain in place at facilities and that EPA not create an “off-ramp” for consistent compliance. These commenters were concerned that a facility could have an unexpected event that would be undetected without the monitors in operation. The commenter also contended that knowing that their fenceline concentrations will be publicly available provides strong incentive for sources to maintain their operations in good working order. The commenter stated that if the EPA does alter the fenceline monitoring requirements for sources that consistently measure concentrations below the action level, any subsequent change in the operations at the facility should require the facility to revert to the full fenceline monitoring requirements.

Response 1: The goal of the fenceline monitoring program is to improve the management of fugitive emissions by identifying emission sources quickly and reducing these emissions through early detection and repair. Therefore, we believe that coverage of the perimeter and ongoing monitoring are necessary elements of the fenceline monitoring work practice standard. However, we do consider that there will be cases where certain “upwind” monitors may consistently monitor low levels of benzene and may not be necessary in the long term. Therefore, we are providing facilities an option, after two years of data collection, to reduce the monitoring frequency for sampling locations that consistently read background concentrations at or below 0.9 ug/m^3, which is 10 percent of the action level and approximates the benzene background concentrations we observed from pilot studies. Specifically, we are allowing refinery owners or operators to monitor every other two weeks (i.e., skip period monitoring) if over a two-year period, each sample collected at a specific monitoring location is at or below 0.9 µg/m^3. If every sample collected from that sampling location during the subsequent two-years is at or below 0.9 µg/m^3, the monitoring frequency may be reduced from every other two weeks to quarterly. After an additional two years, the monitoring can be reduced to semiannually and finally to annually, provided the samples continue to be at or below 0.9 µg/m^3 during all sampling events. If a concentration greater than 0.9 µg/m^3 is measured, the sampling frequency reverts to the biweekly monitoring frequency.

8.5 Benzene as target analyte

Comment 1: One commenter stated that while benzene is a common constituent in a number of refinery feed stocks, its concentration may vary widely from refinery-to-refinery depending upon their configuration and crude slate. The commenter stated that benzene cannot be utilized for other industrial facilities such as the chemical manufacturing industry because of the high level of variability from process-to-process and facility-to-facility. The commenter cited a number of reasons why they believe fenceline monitoring would be problematic for the other industries.

Response 1: This rule does not address requirements for the chemical manufacturing industry and concerns about a potential fenceline monitoring program for those sources can be raised in any future rulemaking in which the EPA proposes such a requirement.

Comment 2: Some commenters claimed that benzene is appropriate to monitor for refineries because it is the most ubiquitous HAP, present in all refineries, and present in most HAP streams common to basic refinery processes. They further stated that it is generally one of the higher mass HAP emitted by refineries and thus would be among the easiest to monitor with samplers. In comparison, they claimed, other HAPs would usually be present in lower concentrations and therefore be harder to analyze and result in more non-detects. They also stated that longer sample times and multiple samplers and multiple analyses would likely be required if sources are required to monitor additional HAPs and that such additional monitoring would not lead to an improvement in understanding refinery emissions though it would add to costs.

One commenter supported the use of benzene as an indicator for VOCs for two distinct reasons: First, benzene is a largely ubiquitous class A carcinogen that likely represents the majority of the human health risk associated with refineries; second, the use of benzene as a surrogate for the other VOCs presents fewer sampling and analysis problems than those associated with measuring semi-volatile PAH compounds that require different sampling media and analytical methods. However, the commenter also suggested that total hydrocarbons be measured concurrently with benzene to ensure that none of the samplers have been overloaded and therefore benzene undercounted.

A number of other commenters supported monitoring of multiple pollutants.

One commenter stated that since the EPA is legally mandated to require the monitoring of each and every toxic chemical and substance.

Another commenter stated that different fugitive sources at a refinery will have different concentrations of the various HAPs and that readings on multiple pollutants can help profile and identify the pollutant source.

Another commenter disagrees with EPA’s statement that benzene “is ubiquitous at refineries, and is present in nearly all process streams such that leaking components generally will leak benzene at some level.” The commenter raised three issues. First, the commenter contended that the EPA has not provided any analysis of the ICR data showing that benzene is present in nearly all leaking process streams. The commenter claimed that it has presented data from ambient air quality monitors that shows that there are many instances when toluene and hexane are present in the absence of benzene. Second, the commenter stated that the Act requires the EPA to set limits on all hazardous air pollutants and thus the EPA needs to assure compliance with all of the limits, not just benzene. Third, the commenter contended that EPA has not demonstrated that benzene may be used as a surrogate for all other relevant fugitive pollutants. The commenter cited *to Sierra Club v. EPA*, 353 F.3d 976, 984 (D.C. Cir. 2004) (quoting *Natl Lime Assn*, 233 F.3d at 639), and claimed that a surrogate might be reasonable only if it meets, at least, the following three conditions: (1) the target pollutant(s) must invariably be present in the surrogate (2) the control technology used to control the surrogate must indiscriminately capture both the surrogate and the target pollutant(s); and (3) control of the surrogate must be "the only means by which facilities achieve reductions in the target pollutant." The commenter stated that the same principle is applicable to monitoring for a surrogate and because benzene is not actually present in all refinery pollution streams the EPA has failed to meet the surrogacy test to require monitoring of only benzene.

One commenter stated that while benzene may be an excellent proxy for emissions of organic HAPS generally, it is a dubious indicator of emissions of heavy metals such as lead, mercury, cadmium and vanadium. These elements disperse differently in the atmosphere than organic compounds, build up in the environment differently, and accumulate in people differently. If the passive diffusive tube technology is chosen, the EPA should consider a tube that absorbs mercury or lead as well.

Response 2: We reiterate that we did not intend to measure all pollutants, especially pollutants that are emitted from point sources that are directly measurable through source tests and continuous monitoring systems. These emissions sources and pollutants are subject to other standards under these MACT.

We disagree that it is necessary to monitor for every HAP emitted from fugitive emission sources at refineries. Petroleum refining streams can contain dozens of HAP and it is very difficult for any method to detect every HAP potentially emitted from refineries. The fenceline monitoring standard was proposed as part of the technology review to improve management of fugitive emissions and not as a risk reduction measure. In order to meet that goal of improved management of fugitive emissions, it is not necessary to obtain an accurate picture of the level of all HAP emitted. In the proposal, we cited our reasons for using benzene as an appropriate HAP to monitor to meet the goal of the fenceline monitoring program (79 FR at 36924). First, benzene is present almost exclusively in emissions from fugitive emission sources (and not from point sources) and is emitted from each of the different types of fugitive emission sources; thus it is a very good indicator of fugitive emissions. It is easily measured and can be detected with good precision by passive monitors.

Hexane was considered as a potential surrogate because it is generally present in higher concentrations than benzene in many refinery process streams, but hexane is nearly insoluble in water (solubility of 12.4 mg/Liter (L) versus 1,750 mg/L for benzene) and is therefore not significantly emitted from wastewater collection and treatment systems. Therefore, we did not consider hexane to be a good general surrogate for all fugitive emissions sources. Toluene is another ubiquitous compound similar to benzene and commonly present in concentrations similar to or higher than benzene. Its water solubility is about one-third that of benzene but is still soluble enough to be regularly emitted from wastewater treatment systems. As a secondary consideration, we expected neighboring communities to be more interested in ambient benzene concentrations than other HAP because benzene is a known carcinogen and was a significant contributor to the health risks associated with refinery emissions. Therefore, benzene was selected over toluene as the surrogate compound.

Although it is technically feasible to require further speciation of HAP collected within a single sorbent tube, increasing the analyte list does increase slightly the analytical costs because additional calibration standards are required. We considered it more direct to use a single HAP as a surrogate for all fugitive HAP. It is easier to establish an appropriate action level, reduces analytical costs and simplifies the determination of compliance for refinery owners and operators. We did not include other HAP when determining modeled fenceline concentrations, and had we, there would be questions as to whether each HAP would have its own action level or if we would set a single action level for the sum of HAP measured. Of the potential HAP considered for use as a surrogate in the fenceline monitoring standard, only toluene and benzene were considered to be reasonable surrogates that were emitted from all fugitive sources (including wastewater). Given the similarities in these compounds and the similarities in concentrations across different refinery process streams, we determined it was unnecessary to require the quantification of both in the fenceline standard. We then considered our secondary purpose, which was to ensure our risk decisions were based on correct and accurate emissions inventory information. Because benzene was also a key contributor to the MIR associated with refinery emissions, we determined that monitoring of benzene as a surrogate for fugitive HAP emissions was appropriate.

8.6 Adjusting for background emissions

Comment 1: Several commenters believed that interferences and confounders and the inability of the methodology to segregate individual regulated emission sources or even emission types, suggests that fenceline benzene levels cannot be used to determine compliance with any of the applicable Refinery MACT 1 standards. One commenter also noted that Refinery MACT 2 does not address fugitive emissions, so any impact on the fenceline results from Refinery MACT 2 would be an interference with the stated purpose.

Commenters stated that throughout the preamble and proposed new regulations, the EPA has stated that refineries can collect background samples, duplicate samples, or increase the total number of sampling sites along the fenceline to rule out contributions of near-field sources of benzene. Many refineries are located in recognized industrial zones or adjacent to major highways with significant vehicle emissions. Adequately characterizing background sources of benzene will require the development and implementation of sophisticated monitoring programs that include monitoring above and beyond the proposed minimum monitoring required by 40 CFR part 63 subpart CC. Refineries will have no choice but to rule out contributions of near-field sources of benzene because the modeling performed by the EPA to establish the benzene action level did not include benzene contributions from sources outside of refineries that potentially influence fenceline benzene concentrations, and the time allowed for this analysis under the proposed rule is short, as both the root cause analysis and the corrective action analysis must be completed with 45 days after determining there is an exceedance.

On the other hand, one commenter stated that the proposal’s method to identify background sources will cause the fenceline concentration attributed to the regulated facility to be biased low. Under the proposal, each sampling period will have its own background concentration that is defined as the lowest reading during the period. Of course, as EPA recognized, a facility's own emissions will contribute to the lowest reading at the fenceline, especially during periods with calm or variable winds. This will result in the background concentration being overestimated and the facility's contribution being underestimated. One commenter echoed this concern, stating that the proposed sampling design produces refinery-attribution data which are non-conservative.

Another commenter also believes that the proposal will produce low bias of facility contribution because it allows facilities to propose site-specific monitoring options when the facility believes that a near-field source is underestimated by the general method. There is no equivalent option for the EPA, the public, or refinery communities to require an alternate method when the general methodology overestimates background concentrations.

Response 1: First, several commenters appear to have a misconception of what a Refinery MACT 1 source is and some commenters appear to suggest that Group 2 streams are not Refinery MACT 1 sources. As provided in 40 CFR 63.640(a), Refinery MACT 1 "applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section." Paragraphs (a)(1) specifies that the facility is a major source of HAP emissions and paragraph (a)(2) specifies the equipment contain or contact a HAP. Paragraphs 63.640(c)(1) through (c) (9) clarify that the rule applies to all miscellaneous process vents, all storage vessels, all wastewater streams and treatment operations, all equipment leaks, all gasoline loading racks, all marine vessel loading operations, all equipment associated with bulk gasoline terminal or pipeline breakout stations, all heat exchange systems, all releases associated with decoking operations. There are exclusions to Refinery MACT 1 applicability in paragraphs (d) and (g) of section 63.640 which exclude Refinery MACT 2 vent sources, ethylene processes and HON units, among other sources. However, it is clear that Refinery MACT 1 specifically applies to all refinery sources and not only to Group 1 sources, which is clearly seen in the emissions averaging equations in 40 CFR 63.642 and 63.652. So our first point is that Refinery MACT 1 applicability is broad and covers essentially all HAP sources at the facility that are not explicitly excluded. The fenceline monitoring program helps to ensure that the emissions from all of these sources, including Group 2 sources are managed well.

With respect to on-site contributing sources, we note that we included all emission sources from the submitted emissions inventories, which included co-located operations, such as HON units. As such, we consider that the action level should be achievable from petroleum refineries while including these sources. We provide a mechanism by which refinery owners or operators can develop and implement a site-specific monitoring plan to account for the contribution of these non-refinery MACT 1 sources to the measured concentrations at specific monitoring sites. We provided this primarily due to legal considerations as to what we have the authority to cover under the Refinery MACT 1 standard given the clear exclusions in Refinery MACT 1 for certain sources and not because we expect facilities will need this provision in order to comply with the ΔC concentration action level.

Finally, with respect to off-site sources such as highways or neighboring facilities, if these facilities are downwind based on the prevailing wind direction, these sources will likely have minimal impact on the fenceline concentrations measured by the monitor. If this source is upwind of the refinery, the monitors near these sources are likely to be affected but would then generally result in a higher correction when determining ΔC due to higher background concentrations. Furthermore, based on the API study, there was little evidence of off-site sources significantly impacting the refinery concentrations. The facilities monitored in the API study were blinded, but as this issue has been expressed previously by API, one would expect that at least one or two of the sites selected would have been in industrial locations with the types of issues the commenters suggest will require facilities to develop and use site-specific monitoring plans. We see no evidence from any of the studies to date that suggest emissions from off-site sources will somehow overwhelm the emissions contributions from the refinery when determining ΔC.

We disagree with the commenters suggesting that the time for the root cause analysis is short because the facilities must first assess background sources. We have provided up to two years to begin official monitoring for determination of ΔC. We fully anticipate that facility owners or operators will begin monitoring before this time to determine if they do have any significant issues with off-site source contributions and need to develop and submit a site-specific monitoring plan. Even if they do not have issues with off-site source contributions, the ΔC action level is determined on an annual average basis. We fully expect that facilities will investigate high monitor readings throughout the year to help identify and correct the source of elevated concentrations to prevent having an exceedance of the ΔC action level. Based on the time we provide to start official monitoring and that facilities will collect an entire year of monitoring data before calculating an actionable ΔC value, we intend that facilities will have time to determine if a site-specific monitoring plan is needed.

In the proposal we discussed the theoretical concern that a refinery's own sources of benzene could cause elevated background concentrations that, when subtracted from the highest measured concentration, would bias low the contribution of the refinery. Since the proposal, we conducted more studies and reviewed industry study data that indicate that background concentrations at refineries are low and fairly stable. In the API 12-refinery study, the average background does not change significantly from urban to rural setting, and remains relatively constant (from 0.1 to 0.3 ppb). Further, most every instance of an elevated fenceline reading is associated with a known refinery emission source located upwind and we do not see any cases where the all the readings are high, and the ΔC is very low. Therefore, we continue to believe this simple background correction is still valid and provides an accurate method to correct the highest fenceline concentration for background. While we are retaining the provisions for refinery owners or operators to develop a site-specific monitoring plan, the level of monitoring needed to quantitatively account for the contribution of an off-site source for each monitoring location (for which an adjustment is sought) is not trivial. We do not expect many refinery owners or operators will elect to develop a site-specific monitoring plan based on the monitoring studies that have been conducted to date.

8.6.1 Delta C approach

Comment 1: One commenter believed that the proposed rulemaking has appropriately recognized that ambient concentrations can be affected by many factors and other sources, although the proposed approach to adjust for background concentration is significantly flawed because in subtracting the lowest observed concentration from each of the other monitoring stations, the agency has created an artificial average concentration for the facility that may be much higher than a level that is actually measured. It could inflate the facility average by as much as 40 to 50%. The commenter believed that a more appropriate method is to use a simple arithmetic average of all readings to establish a facility wide concentration for a given period. Further the commenter believed that neighboring or co-located sources could be above the corrective action thresholds and that the procedures for adjusting the background concentrations are not sufficient and that a higher corrective action threshold may be necessary to account for these sources.

Response 1: We do not agree with the commenter’s suggestion that refinery owners or operators should calculate the average concentration from all fenceline monitors to compare against the action level. The approach is to determine the facility’s resulting fenceline concentration and the ΔC approach, which requires subtracting the lowest observed concentration at any monitoring location from the highest concentration over any given period, provides a better means to assess the facility’s impact than simply averaging the concentrations around the refinery fenceline. Refineries with co-located sources may elect to comply with the fenceline ΔC action level value for the entire facility. However, as in the proposal, the final rule allows facilities to prepare and submit a site-specific monitoring plan by which they can quantify the impact of these co-located sources on the concentrations measured at each monitoring location.

Comment 2: One commenter recommended that the rule should include provisions for excluding outliers in 40 CFR 63.658(f)(1). A record of excluded data and the reason for the exclusion should be required. Such an allowance is alluded to in the reporting requirements in proposed 40 CFR 63.655(h)(8)(iii), where reports of such exclusions are required, but the fact that such exclusions are allowed needs to also be included in 40 CFR 63.658(f). The commenter also recommended that the rule provide guidance on how to handle biased results when calculating averages from data that is flagged when field blanks contain greater than 1/3 of the measured target analyte or compliance limit for field samples. Since a root cause analysis of an average exceedance that uses such data is likely to find the exceedance is due to this biased data, this would avoid that unnecessary burden.

Commenter also recommended that section 63.658(f)(3) should clarify that the annual rolling average is defined as the 26 sampling period rolling average, rather than the 12-month rolling average to avoid confusion about the period of time reported for each rolling average point.

Response 2: We note that Method 325A at Section 9.2 includes a discussion of potential outliers. Specifically, a potential outlier is a result for which one or more sampling tube do not agree with the trend in results shown by neighboring sampling tubes or with previous and subsequent results for that sampling location. Section 9.2 (Method 325A) specifies that: “Accidental contamination by the sample handler must be documented before any result can be eliminated as an outlier. Rare but possible examples of contamination include loose or missing storage caps or contaminated storage/shipping containers.” Documented missing or loose caps could be immediately flagged as a potential outlier.

An unusually high value may be an indication of an unexpected emissions source, like a new large leak. If a facility immediately investigates the high value by using an optical imaging camera and identifies a leak or other emissions source that is corrected, then the high concentration would not be an outlier, but an accurate indication of unusual emissions. If no emissions source is identified, and the subsequent 14-day sample is again consistent with the previous (pre-outlier) measurements, then the facility owner or operator would have a basis for expecting the unusual measurement is an outlier and could cite this as part of a root cause analysis. We note that some variability can be expected due to changes in temperatures, changes in refinery operations, and changes in wind speed and direction.

Finally, we agree the use of the term "rolling 12-month average" is imprecise. For convenience, we have revised 40 CFR 63.658(f)(2) to describe the calculation of "the annual average ΔC" shall be determined as the average of the 26 most recent sampling intervals. In 40 CFR 63.658(f)(3), we now consistently use the phrase "annual average." With the clarification in 40 CFR 63.658(f)(2), it is clear that the annual average is a rolling average of 26 14-day sampling period results.

Comment 3: One commenter stated that because the term ΔC_i is used for the individual corrected sample results, proposed paragraph (iii) seems to say ΔC for this sampling episode is the maximum value of the corrected sampling rather than the difference between the maximum and minimum corrected values, which is how ΔC is defined. That is illogical, since the site-specific sampling is intended to correct for backgrounds and confounders in addition to the benzene reaching the site from upwind. The definition of uniform background (UB) in paragraph (i) makes this clear by limiting that term to the additional measurements specified included in the site-specific monitoring plan and thus does not include the basic adjustment for upwind sources.

The commenter recommended the term ΔC_i be replaced with the term C_i to represent the individual corrected sample concentrations and that $(\Delta)C$ for each sampling episode then be calculated as prescribed in 63.658(f) using the corrected values rather than the as measured values.

The commenter also noted that there is a wording error in the definition of UB in paragraph (i) that should be corrected here and in the Fugitive Emissions section of the rule preamble (page 36924). The subscripts are missing from the equation in the preamble and the multiplication symbol should be deleted, i.e. "HFC = Maximum × (MFC-OSC)" should be "HFC = Maximum (MFCi - OSCi)." The terminology and symbols that EPA decides on for 63.658(i)(2) should be used consistently in the fugitive emissions section as well to avoid confusion.

Response 3: We disagree. We expect that the site-specific plan will assess the near-field source contribution to a specific monitoring location and the UB. Subtracting these terms from the measured fenceline concentration is the ΔC_i for that monitoring location. One cannot correct the fenceline concentrations for near-field sources and UB and then subtract out the lowest ΔC_i from the highest ΔC_i. We agree that the preamble should not have the multiplication sign, but we see no error in the equation for ΔC_i in the proposed rule. We appreciate the comment regarding the definition of UB in the rule and we have deleted the word "included" from that definition (in the proposed definition of UB, the wording was "… measurements specified included in…").

8.6.2 Site-specific approach for near-field sources

Comment 1: One commenter stated that it is arbitrary and unreasonable to limit site-specific monitoring plans to dealing with only off-site upwind sources or on-site sources excluded under 63.640(g). Since winds are constantly changing "upwind" has no meaning and there is no value in including this criterion. Similarly, it is unreasonable to limit on-site concerns to only sources excluded under 63.640(g). Many on-site sources are not addressed by 63.640(g) and they may need to be addressed in this sampling program. For instance, on-site mobile sources (e.g., automobiles, trucks, and locomotives), on-site laboratories, on-site and off-site spills, and operations subject to NESHAPs other than the HON (which is called out in 63.640(g)), such as the Hazardous Waste Incineration NESHAP, the Boiler and Process Heater NESHAP, or any of the multitude of Chemical NESHAPs. Therefore the commenter recommended that the language "off-site upwind sources or on-site sources excluded under 63.640(g)" be revised to "any sources not regulated under this subpart."

Further the commenter indicated that the language in 63.658(i)(1) refers to the term "Near-field source", which is an undefined term and its use suggests some limitation on what interfering or confounding sources can be addressed through this additional monitoring. There is no sound technical or legal reason for excluding any non-Refinery MACT 1 emissions source that has the potential to bias the measured fenceline benzene level from being addressed through a site-specific monitoring plan and, therefore, the commenter recommended that the term "near-field" be replaced with "interfering or confounding" in this paragraph and at every other occurrence in the proposal. The commenter also stated that it may be impossible to identify specific sources. Sources may be multiple, transient and/or vary with wind direction. Nor should it matter whether the correction is being made to address a particular, identifiable source or to address an observed confounding action level impact. Thus, paragraph (i) should be generalized to require only a general description of the sources or emission types that are expected to be addressed by the additional monitoring.

Response 1: We disagree that most refineries will have to develop site-specific monitoring plans. We established the action level including all emission sources at the refinery facility, which included co-located operations such as HON units. We also find that ΔC approach works well based on our pilot studies and the API study and that most facilities will use this simple and direct approach.

We previously outlined that we expect all sources at the refinery are subject to the Refinery MACT fenceline standard unless explicitly excluded. We suspect that the commenter believes "regulated under this subpart" would limit the requirements to Group 1 sources, but we repeat that Refinery MACT 1 effectively includes "all" sources including Group 2 sources. We recognize that Refinery MACT 1 also specifies exclusions in paragraphs (d) of section 63.640 but note that these sources are still refinery emission sources.

We are unsure how "interfering or confounding sources" is better and more clear than "near-field sources." We use the term NFS in the equation for near-field sources and we consider that 63.658(i) effectively defines what is considered a near-field source, so no further clarification is needed.

We are retaining the requirement that the site-specific monitoring plan must identify the near-field sources for which the monitoring plan seeks to quantify; otherwise, the monitoring plan cannot be evaluated for quantitative corrections for specific monitoring sections. With respect to the uniform background concentration, as stated in the rule, if an owner or operator uses the ΔC approach, the lowest monitored fenceline concentration is used as a proxy for the UB concentration. If an owner or operator elects to use a site-specific monitoring plan, they must separately determine the UB concentration (i.e., benzene concentration far from any industrial facility, highway, or other significant source of benzene emissions). As noted in 40 CFR 63.658(i)(1)(ii)(A), a facility owner or operator may elect to assume that UB=0 rather than site-specific, remote, UB monitoring station. Facility owners or operators cannot elect to use the lowest fenceline concentration as the UB concentration if they elect to use a site-specific monitoring plan.

Comment 2: One commenter recommended that site-specific monitoring plans be valid from submission and that sites must revert to their previous plan or submit within 30 days revisions if the new plan is denied. The commenter objected to the proposed language that requires approval by the Administrator, who has 90 days to approve because sites are forbidden to use the plans until they are approved. If the need for this plan resulted from changes in the on-site or off-site confounding facilities or because of an impact found through a root cause analysis (RCA), many additional 2-week results could be high or otherwise questionable while the site-specific plan was being developed, submitted, and reviewed.

Response 2: We have provided 2 years to begin official monitoring specifically to provide adequate time for refinery owners or operators to assess the need for a site-specific monitoring plan and, if needed, time to develop the plan, submit it for approval with enough time to allow the EPA adequate time to review and comment on the plan. If we had not provided an additional year specifically to allow time to develop and implement a site-specific plan, we would consider allowing owners or operators to follow a site-specific monitoring plan prior to approval. However, the site-specific monitoring plan may be developed and submitted before exceeding the annual average ΔC value. While we will accept and review site-specific monitoring plans after the action level has been exceeded, poor planning by the refinery owner or operator does not mean facilities can modify their compliance approach (must use the high-low ΔC differential versus a site-specific monitoring plan) until they receive approval for a site-specific monitoring plan.

Comment 3: One commenter stated that section 63.658(f) should specifically indicate that the requirements of Section 12 of Proposed Draft Method 325A are superseded and do not apply to the refinery fenceline monitoring program. Section 12 of Draft Method 325A calls for calculating averages of the fenceline data, rather than the ΔC value that is the basis for the action level determination, and calls for other analyses of the data that are not specified by section 63.658, discussed or justified in the preamble or backup documents and appear not to be included in the Information Collection Request Supporting Statement. Thus, Section 12 of the Draft Method is superfluous for this purpose and should be clearly over-ridden by 63.658(f) to avoid future claims that it applies.

Response 3: Section 12 of Method 325A does not require any calculations whatsoever. For example, Section 12.1 states that the average concentration "can be calculated for any specified period at each PS location using Equation 12.1." If we had intended the use of Equation 12.1, we would have had to specify the time period and we would have used "you must" or "you shall." Sections 12.2 and 12.3 use "you may…" As such, while we agree Section 12 provides additional suggestions on how one might use or analyze the data, we do not consider it possible that the EPA or local agency could enforce any part of Section 12, particularly for facilities using the high-low ΔC approach. This section is primarily provided as guidance for things that could be considered in developing and implementing a site-specific monitoring plan and the calculations that might be needed to determine near-field source contributions. We revised Section 12.1 of Method 325A to say "you may" rather than "you can" and we revised the section title to be "Optional Data Calculations, Analysis and Documentation". We have also specified in section 63.658(i) that the procedures in Section 12 are not required, but may be used, if applicable, when determining near-field source contributions if a site-specific monitoring plan is used.

8.7 Action level

Comment 1: One commenter stated that the long-term corrective action threshold the EPA proposed would allow for shorter-term spikes in HAP emissions that endanger the health and welfare of refinery neighbors. The commenter requested that the EPA also set a short-term corrective action threshold to protect communities, including the most-exposed person under 112(f)(2), from those spikes. The commenter cited the agency's enforcement division requirements for fenceline monitoring programs to help identify sources of illegal fugitives in the Shell, Deer Park, consent decree, where the EPA is requiring corrective action based on a five minute standard and an hourly standard. Any five-minute period, where the fenceline monitor picks up benzene concentrations above 50 ppb triggers a corrective action requirement. Additionally, corrective action is required if the benzene level exceeds 15 ppb for three five minute periods during a single hour. At Flint Hills Resources in Port Arthur, the EPA's consent decree has corrective action requirements for fenceline readings of 1,3-butadiene or benzene that average above 25 ppb for an hour. By comparison, under the proposed rule, a facility could have a significant spill of benzene causing one two week sample to spike above 100 $\mu g/m^3$. Yet at all but two refineries, that accident would not cause the facility to exceed the annual corrective action requirement according to the EPA's modeling of maximum off-site ambient benzene concentrations. This is based on the EPA's model showing that only two refineries are expected to have fenceline concentrations above 4 $\mu g/m^3$. Assuming these facilities only measured benzene levels at 4 $\mu g/m^3$ for 25 out the 26 monitoring episodes and 100 $\mu g/m^3$ for the final one, the annual average would be 9.33 $\mu g/m^3$ and not subject to corrective action. Thus the EPA's proposed average will ignore the health risks of short-term exposure to high pollution levels. Therefore, to be consistent with its enforcement actions, reflecting the expertise of its enforcement division, the EPA should set a short-term corrective action level to help identify and reduce the significant health risks created by refinery malfunctions.

Another commenter disagreed, stating that the Proposed Rule should be revised to more explicitly provide that short-term, high benzene readings are not actionable, and do not require investigation or response.

Response 1: We established the fenceline monitoring requirement pursuant to the technology review provision, CAA section 112(d)(6), and not the risk review provision, CAA section 112(f)(2). While we recognize that there is some possibility for a short, larger release of HAP that might occur and that will not be detected until the end of the 14-day passive monitoring interval, we did not identify a cost-effective means for monitoring for the type of short, large releases of concern to the commenters. Furthermore, we note that this approach is more feasible on a source-by-source basis, such as was done in the individual consent decrees referred to by the commenters. We could not identify a single monitored value that would apply for all sources and that would serve the purpose advocated by the commenter.

Comment 2: One commenter stated that the environmental agency in Delaware has operated one fenceline monitor near the Delaware City Refinery. The commenter explained that the unit has not been very useful in providing real-time air quality information. Historically, releases from the refinery have been more likely to be identified by citizen complaints. It is likely that a ring of 12 or so monitors would be more effective, if the action levels are set appropriately. The commenter stated that the action level of 9 $\mu g/m^3$ of benzene (12-month rolling average) seems to be arbitrary. The commenter also asserted that such a level is very high relative to what would be expected during “compliant” operations and would not serve as an appropriate means for detecting “significant increases in emissions.” Therefore, the commenter recommended that an action level be set at 125 percent of a “background” level measured or modeled for each source. The commenter recognized that in some cases this could result in action levels being reached for reasons, such as inversions, not directly associated with a source release or malfunction. But, the objective should be to identify concerning concentrations of hazardous air pollutants.

One commenter stated that the EPA should require each facility to construct control charts from their data and use a lower value (2 sigma and 3 sigma) to identify situations where the emissions are moving toward an out of control or exceedance state. If a facility can demonstrate, through control charting of their data, that its emissions are consistently below the action level target concentrations and varies below two sigma then it might be appropriate to consider allowing it to reduce its monitoring frequency, especially if it has a consistent pattern of compliance even during startup and shut down operations.

One commenter stated that the EPA cannot promulgate a system that penalizes a source for “violating” an inaccurate emissions inventory. Moreover, the commenter stated that the proposed action level does not create a level playing field for regulated refineries. By selecting an action level with which the EPA believes that all facilities can comply, the EPA has, in fact, created significant disparity in the stringency of the requirement for different facilities. This is because the level does not account for the facility size and shape, volume of production, or the number of fugitive emissions components at any particular refinery. This means that small facilities likely have a large “compliance” margin before any corrective action measures might be triggered, while large facilities may have little to no compliance margin. The action level also does not account for inherent differences in material processed from different geographical locations. Moreover, the level does not consider future expansions or production increases, or changes in the type or nature of raw material processed in the future.

Response 2: The commenters have some intriguing ideas for establishing statistical based limits and control charts for identifying “out of control” periods. This approach would work well provided the baseline or initial emissions are well controlled. If emissions are high and concentrations are at 9 μg/m^3 or above during the initial monitoring period, this approach would not cause these facilities to trigger a corrective action. While we see benefits from a composite approach (baseline emissions approach but cannot exceed 9 μg/m^3), we have only included a trend analysis in the optional calculation and data analysis section (Section 12 of Method 325A). However, we did not elect to mandate this approach because we are concerned with mandating corrective action based on the trend analysis when the fenceline concentration is very low. However, by including this approach in Method 325A, we hope to encourage refinery owners or operators to use this or similar proactive analytics to use the fenceline monitoring data to improve management of fugitive emissions.

We disagree with the commenter that the fenceline limit puts large refineries at a disadvantage. Most large refineries have large property boundaries, so the “fenceline” is often much further from the sources. We are not moved by other arguments presented regarding refinery expansions or new crude slates. We based our risk decisions on the current emissions inventory, and with the fixed fenceline monitoring standard, we have confidence that our risk decisions are based on accurate information.

8.8 Non-compliance and Corrective Action Plan

Comment 1: Several commenters identified concerns with sources being able to identify the source for purposes of corrective action. Among the concerns raised were the wind vector, (i.e., if the wind is blowing toward the fenceline) and locations near waterways or roads where vehicle and marine traffic can contribute to fenceline levels. These commenters contended that elevated readings should not be considered compliance deviations. They also recommended that while an elevated level can trigger the obligation to perform an investigation, the investigation should be sufficient even if a definitive root cause has not been identified. One commenter also hypothesized that exceedances could be due to short-term episodic incidents or exceedances due to unusual weather conditions or sample contamination and that working with an annual average reduces the likelihood of such a situation, but does not eliminate the possibility. The commenter claimed that an annual average makes it more difficult to identify the root cause because the cause could be the result of several different unrelated events occurring over the year.

Commenters also stated that the regulations should be clear that RC/CA is triggered only if there is an exceedance of the annual average benchmark value and not in response to individual canister sampling events.

Response 1: Based on the action level we established, we see very little evidence that the roads and waterways will significantly contribute to fenceline exceedances. In addition, while the regulations do not require sources to perform RC/CA of short term high readings, we nevertheless encourage refinery owners or operators to conduct investigations of unusually high readings immediately. If a source of emissions is found and quickly remediated, then it is unlikely that the annual average action level will be exceeded.

We do recognize that an annual average that exceeds the action level could be due to more than one event. However, we note that the facility will have the 14-day monitoring data from each of the passive samplers and that information should assist the facility in identifying the root cause or causes of any annual exceedance of the action level. Reviewing the 14-day sampling data as it becomes available will aid this effort.

We disagree with the commenters that suggest that corrective action is not needed if the source (or sources) of the elevated benzene readings cannot be identified. As provided above, the data gathered through the monitoring should help the refinery owner or operator identify the cause or causes. Furthermore, providing the relief requested would eliminate the incentive for facilities to take the actions necessary to improve management of fugitive emission sources.

Comment 2: One commenter noted that 40 CFR 63.658(g) includes examples of data collections that could be done as part of an RCA/CA in response to an action level exceedance. The commenter believes that these are all highly expensive and time consuming alternatives and it is likely any identifiable source will be identified more quickly and through other, less costly and burdensome means. Furthermore, it is unlikely these examples could be completed in the 45 days allowed and, since no burdens are included in the Information Collection Supporting Statement, they are not authorized under the PRA. Thus, these examples serve no purpose and only add confusion and they should be deleted. If the examples in paragraph (g) are not deleted as recommended, the commenter suggested the following wording changes. First, the reference to paragraph (g) seems to require that the four example corrective actions at the end of paragraph (g) had to be included in the initial corrective action and have been completed. That phrase should be reworded to refer to the initial corrective actions rather than to paragraph (g). Second, the action level is an annual average and thus cannot be used to determine if the initial corrective actions were successful. Thus, the trigger for follow-up corrective action should be a one or two round action level evaluation and the appropriate trigger should be specified in place of the term “action level” in its first use in section 63.658(h).

Response 2: First, we consider the examples of methods to investigate and correct high emitting sources to be instructive and we are including paragraphs (1) through (3) in 40 CFR 63.658(g), as proposed. We are revising paragraph (4) to focus on identifying on-site sources. If a facility owner or operator wants to account for off-site sources, they must submit a request for a site-specific monitoring plan and cannot attempt to adjust the concentrations as a corrective action.

Next, we agree that the reference to paragraphs (1) through (4) in 40 CFR 63.658(g) is poorly worded and appears to require all of these examples as part of the RCA/CA. That was not our intent. Therefore, in the final rule, we reworded the phase “…as described in paragraphs (1) through (4) of this section” to “…such as those described…”. Facility owners or operators have significant latitude in determining appropriate RCA/CA and may use different methods than those listed in order to identify sources that are causing the benzene level to exceed the action level.

Finally, we agree that we intended facilities to evaluate the measured ΔC value for the next sampling period to determine if the next 14-day average ΔC remained over the 9 $\mu g/m^3$ action level threshold. It would be difficult for the results of one 14-day sample to be reduced so low that the annual average ΔC value is immediately below 9 μg/m^3. Therefore, we reworded the first sentence in 40 CFR 63.658(h) to read as follows: "If, upon completion of the corrective actions described in paragraph (g) of this section, the ΔC value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective action is greater than 9 μg/m^3 or if all corrective action measures identified require more than 45 days to implement, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures."

Comment 3: One commenter recommended that rather than being open-ended, the RCA consist of a review of the nearby fugitive emission sources that the fenceline monitoring program is designed to enhance; if no deviations are found at those nearby sources, then no further action should be required. The commenter also recommended that the site should note any nearby, off-site sources that may be contributing to the threshold from a broad list of possible sources provided by the EPA. The commenter stated that when there are no deviations found, then there should be no requirements for further review until the following year.

One commenter stated that the root cause analysis under the proposed rule contains no specific requirements, only suggestions for leak inspection or "visual inspection." The commenter claimed that EPA should, at minimum, require sources to inspect for leaks and repair all leaks found. The commenter asserted that a root cause analysis with no actual requirements is not likely to produce meaningful corrective action. The commenter also stated that an exceedance of the action level should clearly be deemed a violation of the emission standards, such that all applicable CAA penalties will apply until the facility ends and corrects the problem. The commenter claimed that anything less is a malfunction exemption, and thus is unlawful under the Act and D.C. Circuit precedent.

Response 3: With respect to the comments that assert that the RCA should consist of a review of the "nearby" fugitive emissions sources, we disagree. As an initial matter, it is unclear what the commenter means by "nearby." Regardless, we do not agree that there should be any distance limit placed on the sources that would need to be evaluated pursuant to the root cause analysis.

We disagree that corrective action should be limited to instances in which a fugitive emission source is "violating" the underlying emission standard. In general, fugitive emission sources are subject to work practice standards. One purpose of the fenceline monitoring program is to identify instances where the work practice standards in place are not effectively managing fugitive emissions. Thus, in that instance, a source may not technically be in violation of the MACT, but the evidence indicates that it needs to adjust or modify the work practice standards being implemented to provide better management of emissions. For sources subject to an LDAR program, we note that is not a violation of the standard to have an emissions leak. Thus, under the scenario suggested by the commenter, no corrective action would be required under the fenceline monitoring program if the source identifies a leak that leads to elevated benzene levels. While it is true that the source would eventually be required to repair the leak under the quarterly or semi-annual repair requirement of the LDAR program, we disagree that fenceline monitoring program should be structured to allow sources to defer addressing a leak if it has identified it as causing elevated levels of benzene at the fenceline.

Finally, we disagree with the suggestion that because there are no mandated steps for how to perform a root cause analysis that the analysis will not produce results. We expect that the cause of an elevated fenceline benzene level could vary significantly from facility-to-facility and even from event-to-event. We believe that allowing the refinery owner or operator flexibility in performing the root cause analysis will result in better identification of the source of the elevated benzene level including, if so desired by the refinery owner or operator, initially targeting a review of sources "nearby" the monitoring location with the highest benzene concentration. Mandating a detailed list of actions that a refinery owner or operator must do, regardless of what the emissions source may be, would be burdensome and could be ineffective. In addition, we disagree that an exceedance of the benzene action level must be deemed a violation. The benzene action level is not an emissions standard. The Refinery MACT 1 regulations establish the applicable emission standards that must be met on a continuous basis for fugitive emission sources. The fenceline monitoring program, including the benzene action level, is a tool for enhancing the existing standards and is not a replacement for them.

Comment 4: One commenter suggested a number of changes to the provisions of 40 CFR 63.658(h) to clarify when corrective action has been successful.

- First, because of method variability and the potential that an exceedance is due to a short-term episodic emission or confounder, it is likely that in many cases the next rolling average will no longer indicate an exceedance. The proposed 40 CFR 63.658(g) language would appear to still require the RCA/CAA and corrective action (CA) in such cases. Language should be added to 40 CFR 63.658(g) removing the RCA/CAA requirement if the rolling average returns to below the action level prior to completing the RCA/CAA.
- Second, up to 45 days is provided for completing a RCA/CAA in the event of an action level exceedance. CA may take longer than that, depending on the cause. During that time, at least two more rounds of samples will be completed and two additional action level determinations made. If the cause of the original exceedance is not yet resolved, each of these additional exceedances may also exceed the action level. Unless there is data to indicate these exceedances are due to a separate cause (e.g., occur in a different portion of the property), RCA/CAA analysis should be deferred until the initial cause can be identified and only reinstated if the initial cause is determined not to be the cause of the later occurrences. This will be apparent from the results of the follow-up monitoring after the CA is complete.
- Third, the commenter suggested that the basis for determining whether the corrective action has been successful should be the average background corrected maximum benzene concentration for two successive sampling rounds following completion of a corrective action. Two rounds are desirable to provide an allowance for the anticipated meteorological and analytical variability of these measurements. If this average is below the action level, the corrective action should be considered successful and any future annual average action level breech would be considered a new occurrence and would not trigger the second corrective action requirements in 40

CFR 63.658(h). Further, because an exceedance during the follow-up monitoring could be due to a totally different cause than the original occurrence, the conclusion that additional corrective action is needed should only be reached if the follow-up maximum benzene value is in the same area of the property boundary as the original maximum value and due to the same root cause.

- Finally, because an unusually high two-week maximum ΔC value could cause the rolling average to stay high for as long as a year, even though emissions have long since returned to normal, the commenter requested that provisions are needed to remove these high values from the average calculation in such situations and from the follow-up sampling to demonstrate that CA has been successful, so any new occurrences are not missed and so multiple deviations are not accrued because of the same, one time incident.

Response 4: The action level is based on an annual average consisting of 26 14-day samples. A previous commenter noted how one high reading would not greatly affect the annual average. Therefore, an exceedance of the action level is unlikely to surprise anyone and refinery owners or operators will have plenty of time to evaluate and complete corrective action as they approach an exceedance of the annual ΔC action level. As we have stated before, we expect and encourage refinery owners or operators to proactively use the monitoring data to identify and correct high emitting sources in order to comply with the annual average ΔC limit (i.e., to prevent an exceedance of the action level in the first place).

When the annual average ΔC exceeds the action level, we recommend a proactive approach, such as immediate screening using an optical imaging camera. If no source is identified and the subsequent 14-day concentration is back to normal without any corrective action, while a RCA is still required, the source can simply report these results as part of their RCA. If an emissions source is identified, and the issue can be corrected before it affects too many 14-day sampling period results, the owner or operator would also have records of performing the corrective action.

We do not agree the RCA/CAA should be deferred or that it is necessary to have two 14-day periods for the evaluation of the effectiveness of the corrective action, but we agree that the sampling period by which to judge the effectiveness of the corrective action must be completely after the corrective action is completed. Therefore, we revised 40 CFR 63.658(h) to clarify that the test to determine if the corrective action was effective would be based on “the next 14-day sampling period for which the sampling start time begins after the completion of the corrective action.” If the next sampling period ΔC exceeds 9 $\mu g/m^3$ at a different monitoring location (however unlikely that is), we consider that immediate corrective action should be pursued to correct this “new” emissions source. If the new emissions source is identified and corrected, this can be documented in the corrective action plan with the statement that subsequent corrective actions appear to have been effective and that no further corrective action is needed. The owner or operator must retain records of these corrective actions whenever the action level is exceeded, so documenting these in the corrective action plan is not an excessive burden.

While Method 325A includes provisions to exclude outliers and sample results with documented issues (e.g. missing or loose storage caps on tubes received for analysis), we have not included provisions to exclude data caused by known emissions events at the refinery. We recognize that a given 14-day sample (after the first year of monitoring) will remain in the average for one year. We also recognize that during the first year of monitoring, it is possible to have one high monitoring reading for an emissions event that could cause the annual average to be exceeded and to have corrected this issue by the time the first complete annual average could be calculated. Although the company would need to retain records of the corrective action performed, no additional corrective action is required at the time the annual action level is officially exceeded (i.e., once the first full year of sampling is achieved).

Comment 5: One commenter stated that the EPA is allowed 90 days to approve CA plans, while facilities are only allowed 60 days to develop those plans. If the approval requirement is maintained facilities should also be allowed at least 90 days to develop their CA plan. Developing the plan is certainly more time consuming than reviewing it. One commenter suggested that the EPA should either extend the period for submitting a plan to 60 days or more, or allow owners and operators to submit a plan within 30 days after receiving lab results of an exceedance occurring during the next two-week sampling episode following the completion of the initial round of corrective action.

Response 5: First, in most cases, we expect that the corrective action analysis will suggest that more extensive corrective action measures may be needed and that the facility already has over 90 days in most cases, including the initial time period provided to perform the corrective action analysis to start preparing the corrective action plan if the initial corrective actions, if any are identified, are unsuccessful in lowering the fenceline ΔC values. Second, the EPA did not necessarily intend to use the full 90 days for plan review and approval. We primarily included this time frame as a means to ensure that corrective action plan does not remain unexamined and we provided default approval of the plan if the Administrator fails to act (i.e., disapprove the plan in writing). We now consider it important for refinery owners or operators to submit their plans and begin corrective action as soon as possible, without having to wait for EPA approval, and therefore we are not finalizing the requirement that EPA must approve the plan. We believe that 40 CFR 63.658(h) already provides that the 60-day period for developing and submitting a corrective action plan starts after receiving the results from the subsequent 14-day sampling period. However, we are revising the second sentence in 40 CFR 63.658(h) to further clarify this point to read as follows: "The owner or operator shall submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the ΔC value for the 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 $\mu g/m^3$…".

Comment 6: One commenter stated that the relatively short period of 35 days for completion of RCA does not allow a reasonably sufficient time to complete all of these steps for multiple sampling locations at refinery facilities. The commenter asserted that EPA must carefully consider the time requirements of the actions necessary to properly conduct the analysis and evaluation of results of its proposed fenceline benzene monitoring and allow a reasonably sufficient time for regulated facilities to perform those actions prior to requiring subsequent actions and responses. The commenter stated that at the end of sampling events the passive benzene monitors would need to be collected, transported to a laboratory, undergo laboratory analysis, quality assurance and reporting of results. The reported laboratory results would then need to be incorporated into a facility's 12-month rolling average benzene concentration calculations, which is a task that would likely require a review of meteorological data collected during the sampling event to attempt to account for any background contribution.

Another commenter provided a table summarizing their recommended corrective action timeframes and requirements for events and stated that the EPA should strengthen these requirements in the following ways:

- Initial Corrective Action: The EPA must require facilities to complete the corrective action within 5 days of initiating the root cause analysis.

- Further Corrective Action: A facility should have no longer than 14 days to develop a new corrective action plan and begin to implement it. A facility also should not wait to implement that plan until receiving EPA approval.

- Specific Reporting and Action: The rules should require immediate reporting and specific corrective action, such as automatic shutdown and additional higher-quality monitoring (such as UV-DOAS), with oversight such as an inspection and audit by an EPA expert staff or an independent expert, until the problem has been fully resolved to prevent its repetition.

One commenter recommended that the final rule require refiners to submit the data at the end of each 2-week period that the passive sample tubes are replaced and not allow for 6-month or year-long intervals to go by without actionable data being relayed to state and federal enforcement divisions. The frequency of data availability to regulators will help ensure regulators can better correlate exposure data regarding increased toxic air emissions to health outcomes in response to these emissions. One commenter believes it is important that sources be required to act if their fenceline monitoring shows benzene concentrations above a certain level, and support the EPA in requiring a corrective action plan. However, the commenter is concerned about the vagueness in the proposal regarding what must be contained in a corrective action plan, the possible delays in taking corrective action that could result, and the lack of detail about the enforcement actions that will follow an exceedance. The commenter suggested that those provisions be strengthened and made more specific. Additionally, with respect to the proposal to use a one-year rolling average, the commenter recommended that the EPA call upon sources to identify problems as they are developing and take action before exceeding the action levels whenever possible

Response 6: We disagree with the commenters that suggest up to 90 days are needed to verify and validate the fenceline monitoring data before the action level can be determined. For facilities using the high-low ΔC approach, there is no further adjustment allowed based on meteorological data. If a facility has a site-specific monitoring plan, the calculation used to determine the monitoring location specific adjustments are to be included in the monitoring plan and only the calculation methods included in the approved plan may be used. Therefore, the calculations can be either automated using a computer or performed by hand with minimal personnel hours.

We added an additional 15 days to the 35 day period provided in 40 CFR 63.568(g) for a maximum of 50 days after the end of the sampling period to initiate corrective action. We consider 45 days sufficient to complete the analyses and to incorporate the results of the 14-day sampling period into the annual average ΔC value and an additional 5 days to initiate corrective action.

We provide up to 45 days from the date the action level was exceeded to complete the root cause and corrective action analysis. For corrective actions that require more time to implement, for example, if the corrective action analysis suggests the most effective corrective action would be to retrofit an external floating roof tank with a geodesic dome cover (i.e., converting the external floating roof tank into an internal floating roof tank), this action will require more than 45 days to complete. In this case, we considered refinery owners or operators would prepare and submit a corrective action plan. We disagree with commenters that suggest much shorter corrective action completion time periods are needed or appropriate. While some large leaks may be readily identifiable using optical imaging cameras and readily repaired, we consider it to be unlikely that a refinery owner or operator would be able to routinely complete a root-cause analysis within 5 days, let alone complete the corrective actions, particularly if the repair requires more than tightening a bolt or replacing a cap.

We have previously addressed comments suggesting UV-DOAS systems should be required and again note that these systems currently are not capable of detecting the concentrations needed to assess and manage refinery fugitive emissions. We do agree that facilities should act proactively to prevent an exceedance of the annual average action level and we anticipate most refineries will do so. While we do not mandate this early action, we retain the proposed time tables for corrective actions in part to encourage this proactive compliance approach.

Comment 7: Several commenters stated that it is extremely inappropriate to establish a standard time frame for compliance with actions listed in a corrective action plan. A corrective action plan is specific to the event, the refinery, and the root cause of the event. Time required to complete actions is dependent on the complexity of the action; permitting and permit approval; whether equipment can be taken out of service immediately or only during a turnaround, availability of repair equipment, materials and skilled labor to complete the action, etc. Thus, no one-size-fits-all time frame can be established. Even the consent decrees applicable to refineries do not include such a time limit.

Response 7: Actually, we only specify the time to complete the corrective action analysis. In the proposed rule we did not specify a specific time frame by which to complete the initial corrective actions; although, we intended that initial corrective actions must be completed within 45 days. We do consider that there may be instances that the corrective actions themselves may take months to complete, depending on the emissions source and the scope of a project. If the initial corrective action measures do not remedy the high fenceline concentrations, we proposed provisions to complete a corrective action plan. We are revising the second sentence in 40 CFR 63.658(g) to clarify that initial corrective action measures are also to be completed within the 45-day time period. Specifically, "The root cause analysis and corrective action analysis shall be completed **and initial corrective actions taken** no later than 45 days after determining there is an exceedance." We are clarifying 40 CFR 63.658(h) to account for cases where the owner or operator could not identify any initial corrective action measures that could be completed within 45 days. "If, upon completion of the **corrective action analysis and** corrective actions described in paragraph (g) of this section, the ΔC value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 µg/m^3 **or if all corrective action measures identified require more than 45 days to implement**, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures. The owner or operator shall submit the corrective action plan to the Administrator **within 60 days after receiving the analytical results indicating that the ΔC value for the 14-day sampling period following the completion of the initial corrective action is greater than 9 µg/m^3 or, if no initial corrective actions were identified, no later than 60 days following the completion of the corrective action analysis required in paragraph (g) of this section…"**

Comment 8: One commenter objected to proposal language that would not delegate authority for the approval of the corrective action plan under 40 CFR 63.658(h) to State, Local, or Tribal agencies or that would automatically approve the plans if the EPA failed to approve them within 90 days.

Several commenters believe while some state and local agencies may not wish to take delegation of the approval of corrective action plans, they should be provided this option, while other commenters encouraged the EPA not to delegate the responsibility to review and approve CA plans to the states.

Another commenter stated that EPA also must require corrective action plans to be submitted for notice and comment. That can occur at the same time as the EPA is reviewing the plans, without causing delay. Sources should be required to begin implementing corrective action while receiving input from the public and the EPA, and the EPA must then decide whether to add or modify corrective action requirements after considering public comment.

Response 8: We appreciate the varied comments on this issue. Upon further review of these requirements, we have finalized the provisions not to require EPA approval of the corrective action plans as proposed to avoid delays in the implementation of corrective actions. We have also elected not to delegate the approval of the site-specific monitoring plans in 40 CFR 63.658(i).

8.9 Recordkeeping and reporting requirements

Comment 1: Commenters noted that the EPA did not propose how they will take the data gathered at the fenceline and transform it into information that is useful for communities concerned about risks. The commenter recommended that the EPA should provide, on every page of the data, an explanation of the uncertainties and issues associated with this information. The commenter also stated that the EPA should explain on the website with the reported data that the action level is not based on a health risk to the public and that any individual data points above the action level are not an indication that the facility is out of compliance with any applicable requirement or permit. One commenter also recommended that the EPA provide perspective by posting on the website comparative values from the EPA and World Health Organization studies, such as the fact that indoor air levels of benzene in a home with a smoker

(10.5+ µg/m^3) and outdoor concentrations of benzene from house fires, nearby agricultural burning and from wood burning fireplaces (11 µg/m^3 or more).

Two commenters stated that the EPA is aware that any monitoring data can be subject to interpretation, and there is significant interest in communities near refineries in evaluating benzene concentrations in their communities and neighborhoods. Another commenter urged the EPA to make the information available in a form that is easy for the public to access and understand.

Response 1: We appreciate the comments and understand the concerns related to appropriate presentation of the data. We intend to provide information on the website that explains what the action level is and that it is evaluated on an annual average.

Comment 2: Commenters who advocated that EPA require open-path monitors instead of passive monitors also suggested that the data from the "real-time" open-path monitors could provide immediate feedback to the community with one commenter noting that there is a mechanism for sending this data wirelessly from the stations using 3G or 4G.

Two commenters stated that the EPA should require each facility to post data collected from the use of passive samplers on a continuous basis so that it is available as promptly as possible to fenceline communities. Other commenters suggested that it would be easy and inexpensive for refiners to make available all monitoring data, including but not limited the daily maximum readings from each fenceline monitor, CEMS and continuous opacity monitoring system (COMS) data, and other important emissions information, including unauthorized release reports, meteorological data, rain fall totals and wind directions. Another commenter stated that reporting "through EPA's electronic reporting and data retrieval portal" is not sufficient; the EPA must provide a public website that makes these data accessible to community members. One commenter suggested that another way to provide the public with real-time, transparent information is to leverage social media. Another commenter suggested mechanisms such as "robocalls" to provide real-time notice of exceedances of the action level.

Response 2: For the reasons provided in the preamble and earlier in this document, we are not requiring use of real-time monitors. We disagree that information from passive monitors should be made available "immediately." As discussed previously, refinery owners or operators will need time to analyze samples, review the data, and assess QA/QC sample results. We do not think the public interest will be served by making data available before these steps can be taken and before it can be made available in a manner that is easily understandable by the general public, as requested by one commenter. We believe that the website will be able to provide certainty regarding the information and in a manner that the public can understand. After considering the strong interest from commenters about the availability of data, we are finalizing a requirement that monitoring data be submitted on a quarterly basis, rather than on a 6-month semiannual basis, as proposed.

Comment 3: One commenter suggested that proposed 40 CFR 63.655(h)(8) be modified to clarify that the fenceline monitoring semiannual reporting period is the same as the semiannual periodic report reporting period. The commenter stated that the proposal calls for reporting results “after the end of each semiannual reporting period.” However, 40 CFR 63.655(h) covers various notice and report requirements, so it is unclear what “semiannual reporting period” is referenced.

Response 3: We intended that the semi-annual reporting period is the period covered by the periodic report. In response to other comments, we are requiring that data be reported on a quarterly basis. We revised 40 CFR 63.655(h)(8) to clarify “For fenceline monitoring systems subject to §63.658, within 45 calendar days after the end of each quarterly reporting period **covered by the periodic report**…”.

Comment 4: One commenter stated that proposed 40 CFR 63.658(d)(1) requires hourly average records for meteorological data, including wind speed, wind direction and temperature and proposed 40 CFR 63.655(i)(8)(iii) requires a record of daily unit vector wind direction, calculated daily sigma theta, daily average temperature and daily average barometric pressure measurements. However, the commenter stated that neither daily unit vector wind direction or daily sigma theta are defined or explained, so it is unclear what is required. Nor does the rule use any of this information and it is therefore unclear how this burden is justified. Another commenter recommended that the EPA explain how the burdens associated with these recordkeeping requirements are justified, rather than just generating the information if needed for source apportionment or that these recordkeeping requirements be deleted. If they are maintained, the terms “daily unit vector wind direction” and “daily sigma theta” should be defined and their units specified.

Response 4: We agree that the recordkeeping requirement in 40 CFR 63.655(i)(8)(iii) should be consistent with the requirements outlined in 40 CFR 63.658(d). We also agree that if data is not needed to demonstrate compliance with the standards, then we should not require it. The only meteorological data required for refinery owners or operators opting to comply using the direct ΔC approach is the average temperature and barometric pressure over the sampling period. Therefore, in the final rule, we are requiring that only these data be collected in this circumstance. For near-field source corrections or if alternative test methods using time resolved measurements are used, then the final rule requires collection of hourly average meteorological data, including temperature, barometric pressure, wind speed and wind direction and calculation of daily unit vector wind direction and daily sigma theta. These data provide better information regarding the origin of the air mass moving over the refinery for given time periods and we find that these data are necessary to conduct the more robust monitoring approaches refinery owners or operators may likely implement under site-specific monitoring or alternative test methods.

Comment 5: One commenter stated that proposed 655(i)(8)(v) requires, for samples that will be adjusted for background, a record of the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies. The word “simultaneously” could be interpreted to mean that all samplers must start and stop at the same time; a physical impossibility and not a significant issue for two week samples that provide concentration results. Thus, this wording should be changed to call for the background concentration to be measured over “approximately” the same two week sampling period as the samples it is used to correct.

Response 5: We find that the two monitors with similar start times and end times will be measuring the same time period "simultaneously." The language suggested by the commenter could be interpreted to suggest these samples do not have to have the same start and end days, which is not acceptable for the purpose of a background correction. We are retaining the proposed language in 655(i)(8)(v).

8.10 Cost of Fenceline Monitoring

Comment 1: One commenter pointed out that the cost of open-path monitoring is insignificant when weighed against the profits made by the average refining company or that the cost of such monitoring can be easily recouped with the shoring up of fugitive emissions (representing lost product) that is possible with open-path monitoring. The commenter stated that the EPA's cost benefit analyses included in the proposed rule determined that open path UV monitors like those used at the Chevron refinery in Richmond, California are too expensive, as are other types of gas chromatographs and remote sensing technology and requested that the final rule consider an updated cost-benefit analysis on monitoring technologies. Another commenter stated that the EPA has inflated the costs of real-time systems by relying on costs of the most expensive UV systems and underestimating the labor intensive costs of passive samplers. Several commenters provided details about the costs of different systems. One commenter was concerned that in rejecting real-time monitors, EPA was placing more importance on the bottom line of industry as opposed to the health of communities.

Response 1: While we believe that open-path systems are more costly than the passive monitors required in the final rule, our primary concern with open-path monitoring systems is that they are not capable of detecting and quantifying benzene at concentrations at or below ΔC action level.

Comment 2: Numerous commenters claimed that EPA underestimated the cost of the fenceline monitoring program in the proposed rule by underestimating the number of samplers required, unrealistically assuming the analyses are done in-house, not including any costs or burdens for the required root cause and corrective action analyses and underestimating the costs of implementing a site-specific monitoring protocol.

One commenter stated that based on the number of sample locations identified in the EPA's and the commenter's pilot studies and the significant number of additional samplers required by the revised requirements for subgrouping in the proposed Draft EPA Method 325A, the number of samplers used as the basis for the EPA's estimates is significantly understated. The commenter asserted that several refineries will likely have to have multiples of the minimum number of samplers, because they have disjointed property with the minimum number of samplers on each parcel. In addition, a commenter claimed that 63.658(c)(3) requires one duplicate sample for every ten samples and 2 field blanks per sampling round. A few commenters also claimed that many sites will also add samples to develop site-specific background correction data and in order to demonstrate that higher emissions within the refinery come from sources not subject to this rule. Thus, 40 samplers per site and 48 samples every 14 days for a large site is a much more reasonable estimate than the EPA's assumption of 24 samplers and samples per site. One commenter claimed EPA's assumption that small entities would need only 12 monitors was incorrect.

Commenters stated that analysis costs will be at least double the EPA estimates because most analyses will be done by outside laboratories in order to meet the QA/QC requirements specified in Draft Method 325B and to minimize inter-laboratory variability. One commenter focused on costs for small entities, claiming it was unreasonable for EPA to assume that small entities can hire the manpower and build the facilities necessary to conduct in-house testing.

Another commenter claimed EPA underestimated costs by not realistically assessing the process for establishing a site-specific monitoring protocol. The commenter asserted that such a process will be needed by many facilities because of their location near other industrial sources and transport corridors.

Finally, one commenter stated that EPA did not consider the costs that will be incurred for installing and maintaining the required weather station as well as for the fencing, lighting, and other infrastructure associated with locating these samplers at the property boundary.

Response 2: We agree with the commenters that stated that we need to account for the fact that facilities may need to site additional monitors and will have to analyze a few additional QA samples. However, we disagree that a typical refinery will have twice the number of monitoring stations as the number we estimated. The commenters noted that the siting guidance contains requirements to place additional monitors at locations where known emissions sources are near the fenceline and/or for irregularly-shaped sites where additional monitors are required based on the shape of the refinery's property. We agree with these comments. As the rule requires additional monitors be sited under certain circumstances, the projected costs of the monitoring program should reflect these required costs. We reviewed the number of monitoring locations used in the API pilot studies as reported in Table A-1 of the pilot study report (API, 2014). On average, 6 additional monitoring locations were used for the small facilities and 8 additional monitoring locations were used for the medium-sized facilities. Only one large facility (greater than 1,500 acres) was included in the pilot study and this facility did not require any additional monitoring locations. However, as large facilities may also be non-uniform in shape, we assumed that large facilities would require, on average, 8 additional samples (similar to the medium-sized facilities). Regarding the allegation that more monitors will be needed because facilities have segregated property, the commenter did not identify that there were a significant number of facilities for which this is the case and we do not have any evidence to suggest this is true. However, we note that the final rule places a limit on the number of extra monitoring locations needed for segregated areas, so we do not believe our costs estimates need to be revised further in response to the concern about segregated areas.

As we see no evidence that the basic ΔC approach will not work well for any given refinery, we continue to assume that refineries will use this method for compliance.

Regarding the cost concern for a weather station, the final rule does not include a requirement for an on-site meteorological station but allows for use of a USWS within 40 kilometers (25 miles) of the facility.

We disagree with the commenters' assertion that we must assume refinery owners or operators will outsource the sample analyses. The analysis requires use of gas chromatography (GC) with mass spectrometry (MS), flame ionization detectors (FID), photoionization detectors (PID) analysis, or other similar detection systems. As GC/FID and GC/PID systems are commonly used by refineries for product quality analysis, and we expect all refineries to have qualified personnel at the facility familiar with this equipment. Additionally, we included costs for automated sample feed systems, which greatly minimizes the level of manual effort needed to analyze a batch of diffusive tube samples. Therefore, we continue to project the costs of the program based on in-house analysis. A refinery owner or operator may elect to outsource the analysis, if they so choose, but as the rule does not require out-sourcing of the analysis, we do not consider it appropriate or necessary to over-estimate the analytical costs assuming all refinery owners or operators will outsource the tube analyses.

Comment 3: One commenter believes the EPA underestimated the cost of the proposed on-site meteorological monitoring requirements, which include calibration and standardization procedures incorporated by reference from the EPA's "Quality Assurance Handbook for Air Pollution Measurement Systems Volume IV: Meteorological Measurements" (EPA-454/B-08-002 March 2008). These requirements are similar to stringent and burdensome requirements for meteorological data collected for air quality modeling and ambient monitoring programs, which also require semi-annual audits of the equipment minimum instrumentation accuracy criteria. The commenter is not currently required to conduct on-site meteorological monitoring. Furthermore, most "off-the-shelf" meteorological monitoring systems that may currently be in use at other refineries may not meet these proposed required criteria. In its cost analysis the EPA did not consider the cost to regulated facilities for adding or upgrading existing on-site meteorological monitoring systems that will meet the proposed requirements, or the ongoing costs to calibrate, maintain, and operate those systems in compliance with the proposed requirements. The operation of a meteorological monitoring system adds no value to correlating short term (i.e., 14- day) ambient benzene data to refinery operations and therefore the imposition of costs related to installing or upgrading and operating a meteorological monitoring system is unreasonable.

Response 3: We included costs for monitoring stations for all refineries and although we did not expressly include costs for semi-annual calibration of these systems, we included costs for maintaining the equipment (10 percent of capital costs). In our revised cost estimate, we considered adding additional costs specifically for calibrating these systems. However, in response to another similar comment, we agreed that having an on-site meteorological station is not critical for refinery owners or operators using the basic ΔC approach if representative meteorological data are available from a USWS within 25 miles of the refinery. This provision is expected to significantly reduce the number of meteorological stations that would need to be installed, more than offsetting the added costs of semi-annual calibration. Therefore, we elected not to revise the cost assumptions for meteorological monitoring stations and we consider the costs assumptions used (i.e., every facility installing a meteorological station with annual costs for maintenance of the equipment of 10 percent of capital costs) to be a conservatively high estimate of the actual nationwide monitoring costs that will be incurred as a result of the final rule.

8.11 Other

Comment 1: A commenter raised a concern that one lab in the API study consistently reported higher benzene uptake and therefore, would have consistently calculated higher benzene concentrations had it been used for the study samples. The commenter noted that an investigation during the course of this work did not identify a reason for this difference. The commenter asked the pilot study contractor, to conduct a laboratory proficiency test (PT) on the two laboratories used in the API/AFPM pilot fenceline monitoring study in order to confirm whether a systematic bias is occurring. The commenter is concerned that systemic bias is an issue and will affect the 142 refineries that are sending samples to different laboratories. The commenter provided detailed information about the different test results and analyses.

Response 1: We reviewed the information submitted by the commenter and asked for the detailed laboratory analyses described by the commenter. In the course of this follow up, the commenter indicated that they now realize that the primary laboratory did not follow the procedure in proposed paragraph 9.13.1 of Method 325B that requires continuous calibration verification through the development of response factors determined from the daily calibration standard and provided a revised set of results that correctly calculated the benzene concentrations in accordance with proposed Method 325B. The corrected concentrations resulted in an increase in the average ΔC for all 12 refineries increasing from 4% to over 14%. Based on these results, the inter-laboratory bias described by the commenter appears to be resolved and the overall variability in the results found to be significantly lower.

9.0 Other Refinery MACT 1 Provisions

Comment 1: One commenter stated that the term “regulated pollutant” or “regulated material” in the proposal is used in subparts that contain generic requirements that are widely referenced. The commenter believes its use in these subparts is ambiguous, since it can easily be interpreted to include substances that are not regulated by these subparts and/or are not regulated by the particular paragraph using the term. The commenter recommended the term be replaced in every use with a Refinery MACT 1 or Refinery MACT 2 specific term, such as organic HAP, metal HAP, nickel, PM, etc. Where a generic term is needed such as in certain recordkeeping and reporting requirements the commenter recommended “HAP regulated by the applicable standard in this subpart.” Another commenter specifically cited proposed 40 CFR 63.655(g)(12) (Reporting) and (i)(11) (Recordkeeping) for malfunctions resulting from the removal of the historical SSM approach. The commenter stated that the term “regulated pollutant” should be replaced with a more precise term.

Response 1: We disagree that these terms should be replaced. In the “Applicability and designation of affected source” provision of section 63.640(a)(2), it states that subject sources are those that, “Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.” We believe that this provisions makes clear that the regulated pollutants are those HAP listed in table 1 of the subpart. Similarly, in Refinery MACT 2, the provision stating the purpose of the subpart in section 63.1560 “establishes national emission standards for hazardous air pollutants (HAP) emitted from petroleum refineries.” HAP is a term defined by the general provisions of part 63 in section 63.2.

The term “regulated material” is used primarily in reference to the proposed flare control device requirements. While the flare control requirements are included in Refinery MACT 1, we also proposed that flares used to control Refinery MACT 2 streams would need to comply with the flare provisions in Refinery MACT 1. Thus, the term “regulated material” as used in the requirements for flare control devices is intentionally general to accommodate the process streams for which both Refinery MACT subparts require control. To improve the clarity of the term “regulated material” we have included a definition of regulated material in subpart CC. Specifically, “*Regulated material* means any stream associated with emission sources listed in §63.640(c) required to meet control requirements under this subpart as well as any stream for which this subpart or a cross-referencing subpart specifies that the requirements for flare control devices in §63.670 must be met.”

Comment 2: One commenter stated that the proposed recordkeeping and reporting requirements in proposed 40 CFR 63.655(g)(12) (Reporting) and (i)(11) (Recordkeeping) for malfunctions are unclear and should be clarified. The commenter explained that they do not understand what “number of failures” refers to in these paragraphs, since the failure to meet an applicable standard is by its nature a single occurrence. If this is referring to the number of failures of a particular emission limitation over some time period, the time period should be indicated. Furthermore, the record of the time, date, and duration of each failure provides that information and would seem to provide a count of such occurrences. Thus, we believe the “number of failures” should be deleted from this recordkeeping requirement.

The commenter added that it is unclear how to apply these requirements to work practice deviations because in those cases there are likely no excess emissions to estimate and no information as to when the failure started, only when it was identified. The commenter provides the example of a failure to perform a required inspection which would have no emission impact and which may only be discovered after the time the inspection was due and the inspection requirement may have been to perform the inspection within some calendar period (e.g., an annual inspection). The commenter asserted that the proposed requirements should only be applicable to failures involving excess emissions and, for other failures, the requirement should be to report the failure to follow the work practice and identification of the time period when the work practice action should have been performed.

Response 2: We have thoroughly reviewed the existing and proposed recordkeeping and reporting requirements in subpart CC (including those which refer to other subparts i.e., FF, R, Y, VV, and H). During the review, we noted that reporting requirements need to be added for delayed coking units, and the requirement for reporting from bypass lines in 40 CFR 63.655(g)(6)(iii) needs clarification. With respect to delayed coking units, we are requiring owners and operators to report any 60-cycle average (for existing sources) or any direct venting event (for new sources) where the pressure of the DCU exceeds the applicable limit. We are also including a requirements to report the total number of double quenching events during the reporting period and each instance (drum, date, time and maximum temperature) of double-quench draining activity when the drain water temperature exceeds 210 °F. The reporting provision for bypass lines contained in section 63.655(g)(6)(iii), has been updated to now more clearly identify the required reporting elements. The provision in the final rule provides: "(iii) For periods in closed vent systems when the vent stream flow was detected in the bypass line or diverted from the control device, or a bypass of the system was indicated, report the date, time, duration, estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting emissions of organic HAP that bypassed the control device. For periods when the flow indicator is not operating, report the date, time, and duration." We have determined that proposed 40 CFR 63.655(g)(12) and (i)(11) are not needed because the recordkeeping and reporting requirements for the individual emission sources included in 40 CFR 63.655(g) and (i) effectively cover the "failures" expected to be reported and thus we are not included the proposed overarching "failure" recordkeeping and reporting requirements in the final rule. The recordkeeping and reporting provisions we are finalizing contain the necessary information for the EPA to assess compliance with the applicable standards for each regulated source category in Refinery MACT 1.

9.1 Applicability and Affected Sources

9.1.1 Applicability dates and Table 11 (other than for PRD)

Comment 1: One commenter stated that some required records are difficult to digitize or were created before digital records became prevalent and may not be readily available within 24 hours. The commenter requested the 24 hour availability requirement be limited to 2 year old records and up to 72 hours provided for records older than 2 years or that the current provisions in 40 CFR 63.10(b) be maintained and applied to both Refinery MACT rules. The commenter added that this would also provide better consistency with 40 CFR 63.1576(i) which references

40 CFR 63.10(b)(1), which requires records to be maintained onsite for 2 years and then allows them to be maintained offsite.

Response 1: EPA disagrees that additional time is needed to retrieve records older than 2 years. Digital record storage including the ability to scan hard copy documents is standard operating procedure and has been for arguably the last decade. Further, the commenter has not provided a reason why a record (even a non-digital record) would take more than 24 hours to retrieve and we cannot identify a reason.

9.1.2 Overlap provisions

Comment 1: One commenter noted a concern that subpart CC overlaps with the Marine Vessel and Gasoline Distribution NESHAPs because proposed sections 40 CFR 63.650(d) and 40 CFR 63.651(e) would impose new flare requirements on flares dedicated to gasoline distribution and marine facilities. The commenter stated that the new combustion control flare requirements cannot be applied to dedicated part 63 subparts R and Y flares (flares that do not also receive refinery gas) even though those facilities are part of the Refinery MACT 1 affected source because those flares are not similar to refinery flares in their use and design.

The commenter also noted that these flare types were not considered in developing the proposed combustion control requirements, and the EPA's risk and technology reviews of subparts R and Y concluded there was no technology improvement that should be applied to such facilities under section 112(d)(6). The commenter stated there is no reasonable basis for overturning that conclusion and stated that the proposed 40 CFR 63.670 flare requirements should not apply to flares that are dedicated to subpart R and/or Y operations and these two proposed new paragraphs should not be finalized.

Response 1: We disagree that these sources should not be subject to the proposed flare provisions in §63.670, because these units, when co-located at a refinery, are part of the affected source. With this rulemaking, the EPA is posing new requirements for petroleum refinery sources subject to part 63 subpart CC and UUU, including flares used to control emissions from gasoline loading and marine vessel loading operations at petroleum refineries, which, as the commenter noted, have been included as part of the "affected source" for Refinery MACT 1 since that standard was promulgated. Simply because we chose to harmonize the subpart CC requirements with those in subparts R and Y does not alter the fact that these units, when co-located at a petroleum refinery, are subject to subpart CC and are only subject to the control requirements in subparts R and Y indirectly through requirements in subpart CC and the emissions from these sources at a petroleum refinery are regulated refinery gas streams. We note that the new flare requirements do not apply for separate facilities that are directly subject to subparts R or Y, i.e., those that are not co-located at a petroleum refinery.

The commenters provided no basis for the statement that flares used for marine vessel loading operations and gasoline loading are substantively different in design or use that other flares at the refinery. As discussed in the preamble of the final rule, we find that the final flare requirements are applicable to steam-assisted, air-assisted, and non-assisted flares. If the commenters are referring to flares in dedicated service with a consistent gas composition, we have included specific monitoring provisions in the final rule for these types of flares; see the preamble to the final rule for more detail on and our rationale for these requirements. For these reasons, we disagree with the commenter that these flares are substantively different from those we considered in developing the final requirements for flares in Refinery MACT 1.

Further, the technology reviews for subparts R and Y (gasoline loading racks and marine vessel loading) did not evaluate or consider that flares may not be achieving 98 percent control efficiency; therefore, we disagree the technology review performed for those subparts somehow precludes adoption of these requirements for flares that are part of the Refinery MACT 1 affected source.

Comment 2: One commenter stated that the proposal attempted to address benzene tankage that is subject to both part 61 subpart Y and Refinery MACT 1. The commenter noted that meeting Refinery MACT 1 storage vessel requirements is more than equivalent to meeting the subpart Y requirements and it is an efficiency to only have deal with Refinery MACT 1 burdens in such situations.

Response 2: We appreciate the support of the proposed overlap provisions with part 61 subpart Y and note that we are finalizing those provisions as proposed.

Comment 3: One commenter stated that some refinery units are subject to subpart CC and part 60 subpart VVa, without being subject to subpart GGGa. As is done for part 60 subpart GGGa, the commenter recommended that proposed 63.640(p)(2) provide that if both Refinery MACT 1 and subpart VVa apply, compliance with subpart VVa is only required.

Response 3: First, the commenter does not explain and we are unclear on when a refinery source subject to CC would be also subject to VVa instead of GGGa. Based on the applicability of GGGa, we expect that all equipment leaks subject to subpart CC would only be subject to GGGa.

Second, the overlap provision for subpart GGGa was included in previous revisions to subpart CC and we did not receive comments to include VVa in this paragraph at that time. In the revisions to §63.640(p)(2) that we proposed in June 2014, we simply added specific overlap provisions related to the OGI provisions we proposed at §63.661. We expect the commenter was seeking the use of the OGI provisions at §63.661 for units subject to VVa. However, we are not finalizing the OGI provisions at §63.661 and, therefore, we are not finalizing the proposed revisions to the overlap provisions at §63.640(p)(2).

Comment 4: One commenter stated that with the addition of expanded flare requirements to subpart CC, many refinery flares will be subject to the subpart CC requirements and the General Provisions requirements of sections 60.18 and/or 63.11 for flares. The commenter requested that in order to avoid conflicts and confusion and eliminate unnecessary and wasteful burdens, compliance with the Refinery MACT 1 flare requirements should be considered compliance with 60.18 and 63.11 for flares, where 63.670 also applies. The commenter suggested the addition of a paragraph (s) to 63.640 as follows.

(s) After the dates specified in Table 11 of this subpart for compliance with 63.670, compliance with 63.670 is considered compliance with 60.18 and 60.11 flare requirements imposed by any part 60, 61, or 63 subpart, for flares subject to 63.670 and 60.18 and/or 63.11.

Response 4: We agree that compliance with the sector specific requirements contained in §63.670 for flares should be considered compliance with the general provisions for flares in 40 CFR 60.18 and 63.11 and have included regulatory text similar to that suggested by the commenter.

9.2 Wastewater

Comment 1: One commenter stated that the proposed 40 CFR 63.647(c) applies new flare provisions to Group 1 refinery wastewater streams where a flare is used to comply with 40 CFR 61.340 through 61.355 of part 61 subpart FF. However, 40 CFR 61.349(a)(2) establishes 95% removal as the requirement for Refinery MACT waste management unit control devices and the requirements in section 60.18 as the removal criterion for flares. The commenter stated that imposing 40 CFR 63.670 and it's presumptive 98% destruction efficiency is a change in the standard established in the Refinery MACT 1 rulemaking, that has not been justified under CAA section 112(d)(6). Nor is there any evidence that 95% removal is not being achieved by flares complying with section 60.18. The commenter also noted that the proposed 40 CFR 63.647(c) appears to require flares at non-refinery facilities to meet the proposed 40 CFR 63.670 requirements which will drive those facilities to refuse to accept and treat refinery subpart FF streams and impose large costs on refineries to install additional wastewater treatment facilities and even hazardous waste incinerators leading to high costs with negligible benefits. The commenter also stated that as discussed in the preamble, there is no risk driver or technology improvement that would justify revisions to the Refinery MACT 1 wastewater provisions and application of part 61 subpart FF already imposes stringent treatment and control requirements on refinery wastewater. Therefore the commenter recommends maintaining the existing 40 CFR 63.647(c).

Response 1: We disagree that the existing 40 CFR 63.647(c) should be maintained. While part 61 subpart FF establishes the 95% reduction of organic HAP and section 60.18 establishes the necessary criterion to meet this standard, neither regulation provides monitoring requirements to assure the reduction is being achieved. Further, we believe all flares should be able to meet a 98% destruction efficiency as proposed in the Refinery MACT 1 rulemaking. Finally, if a flare is located on the refinery's property and is processing refinery vent streams, the flare would be considered a refinery flare and be part of the affected source and thus subject to the provisions in the rulemaking. We do not believe that these requirements would result in non-refinery facilities to refuse to treat refinery wastewater streams.

Comment 2: One commenter stated that the EPA has acknowledged developments have occurred in controlling emissions from wastewater treatment (79 FR at 36,918-19) and claimed EPA has no valid basis for rejecting requirements for drain and tank controls, specific performance parameters for enhanced biological units (EBU), and requiring wastewater streams to be treated with stream-stripping. The commenter states that section 112(d)(6) does not allow EPA to ignore "developments". Additionally the commenter believes the EPA also has no lawful basis to refuse to update these standards based on cost since the statute contains no authorization to place cost above the statutory objectives of section 112(d).

Response 2: We disagree that EPA ignored these processes in its technology review. The “developments” described by the commenter are all existing requirements or treatment methods in part 61, subpart FF, with which many petroleum refinery wastewater treatment systems must comply. In our technology review, we evaluated these technologies for wastewater controls for small treatment systems and specific types of wastewater streams and we analyzed potential emission reductions and associated costs. Consistent with our long-standing practice, we rejected these requirements as not necessary for small treatment systems and specific wastewater streams because of the high cost. As noted elsewhere in this response to comments, EPA has broad discretion in deciding the factors to consider to determine whether it is “necessary” to revise an existing MACT standard in light of an identified “development.”

Comment 3: A commenter claimed EPA used incorrect data that is more than two decades old instead of data from the 2011 ICR (which shows refinery wastewater treatment systems have higher benzene and HAP concentrations).[97] The commenter also raised a concern that EPA’s use of the Locating and Estimating Air Emissions from Sources of Benzene document was improper because it omits several refinery processes that produce significant sources of wastewater and include benzene.[98] The commenter stated that there are inconsistencies between EPA’s estimate of the control effectiveness of biological treatment process systems and EPA’s estimate of allowable emissions because the Technology Review estimated an EBU achieves ~88% control efficiency, but EPA assumed that EBUs achieve 92% control efficiency in the allowable analysis.[99] Finally, the commenter claimed EPA must review the information collected as part of the 2011 ICR on EBU control efficiency to determine the correct pollution control potential.

The commenter claimed that these inconsistencies either underestimate the benefits of better controls or underestimates exposure.

Additionally, the commenter stated that because the EPA has recognized that wastewater is driving a significant amount of health risk, the EPA must set standards to reduce these emissions under section 112(f)(2) to provide the requisite “ample margin of safety.” The commenter believes the EPA should find risk from these emission points unacceptable and reject its cost-based determination not to require more control from these sources, to assure the “ample margin of safety” requirement is met.

Response 3: Refinery-specific wastewater generation rates, benzene, and organic HAP concentrations for the model in the technology review were taken from the EPA’s *Locating and*

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[97] ICR Component 1, supra note 103, at 64 tbl. 15-2

[98] See T-4 Table C.

[99] See infra EPA's Underlying Assumptions About Wastewater Treatment Systems Are Factually Incorrect. II.A.3.c

Estimating Air Emissions from Sources of Benzene (L&E study).[100] These data were used to estimate the total flow rate and flow-weighted average benzene and HAP concentrations for each of the modeled facilities in the technology review. Although, more recent data regarding wastewater treatment operations was obtained during the 2011 ICR, some of the data was only partially complete. Additionally, the ICR data was highly variable and contained significant outliers. We were unable to quality assure the data within the time constraints of this rulemaking process, and thus felt it was more appropriate to utilize the L&E study data. Since proposal, we were able to review the ICR data in more detail. We performed an analysis of the facilities that submitted a complete data set (meaning values for flow, benzene, and total organic HAP), and calculated the average flow factor, flow-weighted average benzene concentration, and flow-weighted average HAP concentration. We applied these factors to the model plants used in the technology review and for 5 of the 6 model plants, the benzene loading rates determined from the L&E study factors were higher than the loadings derived from the 2011 ICR factors. While there are still issues with the 2011 ICR data for wastewater, this analysis indicates that the L&E document factors provided a reasonably conservative estimate for the technology review of petroleum refinery wastewater treatment systems, and that the use of the ICR data would not change the outcome of the technology review. The analysis of the ICR wastewater data has been added to the refinery docket EPA-HQ-OAR-2010-0682.

Contrary to the commenter’s claim, the EPA’s L&E study does not omit significant sources of wastewater from refineries. It appears the commenter has attempted to match the ICR process unit type description and the process units in Table 6-10 of the L&E study. However, the list of process units the commenter attributes to Table 6-10 of the L&E study does not include all of the units in the study (i.e., tank drawdown, catalytic reforming, full range distillation, thermal cracking/vis breaking, hydrocracking). Additionally, the process units from the ICR list which are not matched to Table 6-10 in the L&E study (i.e., Aromatics production, coke calcining, ethylene production, fuel gas treatment, fuels solvent deasphalting, other petrochemical or organic chemical production, oxygenate plant - methyl tert-butyl ether (MTBE), petroleum coke storage, propylene production, product loading for container/ marine vessel/ rail car/ truck, and other (specify)) are not significant sources of wastewater at a refinery and thus we believe the list of sources from the L&E study is representative of the sources of wastewater at a refinery.

Regarding the claimed difference in the control efficiency for the technology review and that identified for allowable emissions, we surmise from the comment that the commenter back-calculated an average overall control efficiency of 88% for control option 4 for each model plant in the technology review memorandum. It appears the commenter used the baseline emissions and emission reduction quantities to calculate an overall average EBU control efficiency. This calculation method effectively attributes the emission reduction solely to the EBU, when other control options (with varying degrees of efficiency) are included (i.e., control of drain system components), thus skewing the calculated efficiency of the EBU. This data cannot be used to simply calculate the expected EBU’s efficiency. Further, as described in the technical

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[100] U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards, Research Triangle Park, NC. EPA-454/R-98-011. June 1998. Available as Docket Item No. EPA-HQ-OAR-2010-0869-0016.

memorandum, model facilities 1 and 2 are below the Benzene Waste Operations NESHAP (BWON) threshold (i.e., have a total annual benzene (TAB) less than 10 Mg/yr), and generally would not be included in the calculation of the expected EBU control efficiency as these facilities are not required to have add-on controls for wastewater. Although it is not accurate to do so, if one calculates the expected average control efficiency relative to emission reductions from control option 4 for model facilities 3, 4A, 4B, 5, and 6 and attributes it to the EBU only, the control efficiency is approximately 92%, the value we used for allowable emissions.

Finally, we reviewed the EBU data collected as part of the ICR effort. We requested that 5 refineries test their EBU. Two of these facilities either did not have control systems meeting the definition of EBU or reported sending their wastewater offsite for treatment. Three facilities did submit test data. One facility (LA3C0690) reported an EBU control efficiency in excess of 99%. The second facility reported having a steam stripper installed upstream of the EBU, therefore greatly reducing the EBU load. In this configuration, the benzene emissions were reduced by more than 95%, but the control efficiency of the EBU itself was lower. The remaining facility's Refinery Wastewater Emission Tool (RWET) model projected an efficiency of 99%.

Based on the explanations given above, we disagree that we either underestimated the benefits of better controls or underestimated exposure. Further, although these emissions drive risk, the risk was found to be acceptable and thus there is no basis for adding additional controls for wastewater irrespective of costs. Finally, although we are not adopting additional requirements specific to wastewater collection and treatment as part of the technology review, as noted in other responses, the fenceline monitoring program is designed with the specific intent to ensure proper management of fugitive emissions sources such as wastewater collection and treatment sources.

Comment 4: One commenter took issue with the EPA’s proposal to continue to use benzene as a surrogate for all other pollutants emitted by wastewater treatment (79 FR at 36,918) based on an outdated consideration of surrogacy from 1994. The commenter noted that the D.C. Circuit requires the EPA to justify the use of a surrogate based on facts in the record and that the EPA has neither attempted to meet nor has it met the test to use a single pollutant to control other emitted hazardous air pollutants. A surrogate is reasonable only if it meets three conditions: (1) the target pollutant(s) must invariably be present in the surrogate; (2) the control technology used to control the surrogate must indiscriminately capture both the surrogate and the target pollutant(s); and (3) control of the surrogate must be the only means by which facilities achieve reductions in the target pollutant.[101]

Response 4: We disagree that we have not justified the use of benzene as a surrogate for HAP for wastewater systems, benzene is present in nearly every refinery stream, has a relatively high volatility and water solubility so that it partitions into the wastewater more readily than most other organic chemicals present at petroleum refineries. The few HAP present at refineries that have higher solubility and lower octanol-water partition coefficients than benzene, such as phenol or isobutyl ketone, have relatively low Henry’s low constants (a measure of the relative volatility in dilute aqueous solutions). Thus, these compounds are not readily emitted in the wastewater collection system and are effectively removed from the wastewater during biological

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[101] *Sierra Club v. EPA*, 353 F.3d 976, 984 (D.C. Cir. 2004) (quoting Nat'l Lime Ass'n, 233 F.3d at 639).

treatment. Benzene, on the other hand, has a relatively high Henry's law constant and will readily volatilize to the atmosphere from open wastewater collection systems. Further, majority of the total HAP loading in wastewater consists of compounds that are very similar to benzene both in terms of chemical structure and volatility (from water phase to the air phase). Due to the correlation between organic HAP and benzene, it is reasonable for benzene to serve as a surrogate for HAP in wastewater. We also note that the emissions controls used to reduce benzene emissions will also reduce emissions of other organic HAP and that there is no means by which facilities can control organic HAP from wastewater without controlling benzene emissions. Finally, in our technology review, we evaluated using different wastewater stream applicability options and specifically considered using VOC as the surrogate. We concluded that the existing requirements were reasonable and that is was not necessary to revise the standards or to alter the surrogate used.

Comment 5: One commenter questioned how emissions from open waste water treatment tanks and API separators will be reduced under the proposed Refinery Rules?

The commenter gives two examples of instance when wastewater controls did not work:

- In October 2012 the local API separator emitted 32,654 pounds of pentane. This was traced to the periodic openings of the pressure relief valves on the covered bays of the API separator. Louisiana Department of Environmental Quality (LDEQ) SERC Incident 12-06692 T143678 http://www.louisianarefineryaccidentdatabase.org/pdfs/inc5670.pdf
- In December 2009, the refinery in St Bernard could not handle a large, but normal rainfall, and the wastewater treatment plant and the API separator did not function; the result was a massive amount of oily wastewater in the neighborhood canal (photo provided).

Response 5: It appears that these emissions events were unauthorized under the existing standards and they would be unauthorized under the proposed rule. The proposed rule also includes a fenceline monitoring program which will require facilities to monitor and take corrective action to minimize fugitive emissions, such as those from wastewater treatment, where the monitored emissions are above a specified action level. The fenceline monitoring program is aimed at ensuring refineries manage sources of fugitive emissions and we believe that it will incentivize refineries to ensure wastewater controls (among other things) are operating correctly.

9.3 Gasoline loading racks

Comment 1: One commenter agreed with the EPA's conclusion during the risk and technology review of subpart R (71 FR 17352 (April 6, 2006)) that there have been no "developments in practices, processes, and control technologies" that would justify revising the requirements for gasoline loading at refinery subpart R facilities. Furthermore, this conclusion also applies to flares dedicated to subpart R facilities.

Response 1: To the extent the commenter is suggesting that our conclusion for the technology review for subpart R should extend to our review for the Refinery MACT rules we disagree and stand by our analysis in this rule. Alternatively, it appears that the commenter may be suggesting that certain gasoline loading operations should be subject to the requirements of subpart R rather than subject to the requirements of the Refinery MACT rules. We note that gasoline loading racks at petroleum refineries are subject to the subpart CC. Simply because we generally coordinate the control requirements between subpart R and subpart CC does not make the gasoline loading racks at petroleum refineries “subpart R facilities.” To determine whether a specific operation is subject to the Refinery MACT rules, a person would need to refer to the applicability provisions of the different subparts of the CFR. We have discussed in more detail in Section 9.1.2 of this RTC document why we have not extended the same determination made for subpart R facilities to facilities subject to subpart CC in this action.

9.4 Marine Vessel Loading Operation Provisions

Comment 1: One commenter noted that it had submitted comments in 2010 on proposed revisions to subpart Y, which continued to exempt existing offshore loading terminals from vapor recovery requirements but did require submerged loading (40 CFR 63.650(d)(6)). The commenter supported the EPA’s action in the RTR proposal continuing this exemption for refining facilities and imposing submerged loading requirements.

Response 1: We appreciate the commenter’s support of the requirements for existing offshore loading terminals and for the proposed submerged loading requirements that we are including as part of the final rule, as proposed.

Comment 2: Two commenters questioned the need for section 63.560(a)(4) of subpart Y since the EPA stated in the preamble that the new requirement does not reduce HAP emissions or residual risk since the U. S. Coast Guard already requires marine vessels to utilize submerged loading and ensures compliance through vessel inspection and enforcement. The commenters go on to say that the EPA stated that all marine vessels are therefore presumed to already be in compliance and that this new requirement will only create duplicative recordkeeping and reporting burdens (e.g., any deviations would have to be reported to both the Coast Guard and the EPA) and duplicative enforcement burdens (i.e., both the EPA and Coast Guard will inspect for compliance.)

Response 2: While the changes to 40 CFR 63.560(a)(4) will likely not affect actual emissions, this change will reduce the allowable emissions from sources affected by the change. Though there may be some duplicity in recordkeeping or reporting requirements, it should be insignificant as facilities subject to the Refinery MACT already routinely report deviations to the EPA, and thus it seems this would just require an update to the report to include this information. Further, these are two separate programs with different drivers, and thus the information submitted will be used in different ways by each Agency.

Comment 3: Two commenters stated that the EPA says $3,900 per ton to reduce HAPs is an excessive amount, and they do not agree. The commenters also stated that the EPA should not rely upon industry-reported emissions inventories, as the EPA does, to determine cost effectiveness, because industries have shown time after time, they underestimate their emissions. These commenters argued that this is a conflict of interest.

Response 3: We disagree that EPA has determined that $3,900 per ton of HAP emissions reduced is “excessive” and we did not reject any control option with that cost-effectiveness. It appears the commenter is referring to a control option evaluated for marine vessel loading of gasoline into barges that had a cost-effectiveness of $3,900 per ton of VOC reduced. The cost-effectiveness of this option was estimated to be $77,000 per ton of HAP reduced and we did determine that it was not necessary to revise the requirement under section 112(d)(6) based on the cost per ton of HAP reduced. With respect to using emissions data provided by the industry, we note that the refinery owners and operators have access to the necessary process information to estimate the refinery emissions. We also note that we prepared an Emissions Protocol document that refinery owners and operators were required to follow in developing the emissions inventory. The fenceline monitoring requirement we are establishing in the final rule, in addition to providing improved management of fugitive emissions, will also provide additional data that will allow better verification of emission estimates in the future.

10.0 Refinery MACT 2 Amendments

Comment 1: One commenter stated that the Operating, Monitoring, and Maintenance Plan (OMMP) required by Refinery MACT 2 will need to be updated due to the new rule requirements (e.g. stack testing requirements, new monitoring requirements, etc.). The commenters asserted that currently any changes to an approved OMMP must be submitted and cannot be followed until the EPA approves the new version of the OMMP. The commenter believed this approval process puts the refiner at great risk of not being able to comply with the rule by the compliance date (in many cases in this proposal the publication date) and recommended that the EPA remove the OMMP approval requirements as follows:

§63.1574(f)(1): You must submit the plan to your permitting authority for review ~~and approval~~ along with your notification of compliance status. While you do not have to include the entire plan in your part 70 or 71 permit, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and begin complying with the revised plan once submitted.

Response 1: Generally, we disagree that we did not provide adequate time for monitoring revisions in Refinery MACT 2. We provide up to 18 months to comply with any new monitoring requirements in Refinery MACT 2, which we consider adequate time to complete the necessary steps to comply with the new provisions, including, if necessary, receiving approval of changes to the OMMP. Additionally, we are not finalizing the revisions for FCCU metal HAP emissions limits for units subject Refinery NSPS subpart J as we had proposed. Based on the requirements we are finalizing, we consider it unlikely that refinery owners or operators will have to submit changes to their OMMP. However, given that Table 41 now outlines minimum QA/QC requirements for the monitoring systems, we consider it reasonable to allow refinery owners or operators to submit revisions to the OMMP, if necessary, and to comply with the requirements of the revised plan upon submission (as requested by the commenter). Therefore, we have revised this requirement accordingly in the final rule. We are also providing an 18 month transition period to comply with the requirements in Table 41. Together, these revisions will eliminate compliance issues noted by the commenter if new monitoring systems are needed and/or approval of the revised OMMP is delayed.

Comment 2: A commenter stated that they have not had the time prior to the close of the comment period to comprehensively and systematically review the subpart UUU revised tables in detail. The commenter believed these tables are complicated, detailed, and difficult to interpret, and therefore requested that the EPA ensure that they are accurate, clear, and consistent with the rule text in the promulgated rule.

Response 2: We appreciate the commenter’s suggestion, and we extended the comment period in efforts to allow commenters sufficient time to review the rule in its entirety. We have reviewed the various tables in subpart UUU, and we have made every attempt to ensure that the final revisions to these tables are consistent and accurate.

Comment 3: A commenter believed that the proposed §63.1570(d) requirements ("During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.") is unclear, ambiguous, and unnecessary and should be deleted. The commenter went on to say, that there can be no gap between the compliance date and the availability of continuous monitoring systems because they must be installed and validated to meet applicable operating limits no later than the compliance date. Even if that time period is clarified, the commenter questioned what information and how much detail will be required to maintain in a log and what the justification for having a log is if there is no applicable emission limit or the existing emission limit and applicable compliance provisions apply.

Response 3: This phrase was previously included in §63.1570(c), and we acknowledge that moving this requirement to a separate paragraph created ambiguity. In its previous context within §63.1570(c), it is clear that this requirement refers to the general duty to minimize emissions in a manner consistent with safety and good air pollution control practices. While certain provisions of the rule may not become effective until 18 to 36 months after promulgation, owners or operators of an affected facility must still comply with this general duty to minimize emissions at all times and must operate any control equipment already installed in a manner consistent with safety and good air pollution control practices for minimizing emissions. Therefore, we are clarified in the final rule that the requirement to maintain a log in §63.1570(d) is to document the procedures used to minimize emissions according to the general duty in §63.1570(c).

Comment 4: One commenter requested that, under §63.1573, EPA add an alternative to measuring liquid flow, similar to that provided in §63.670(i)(4).

Response 4: The newly proposed flare provisions are specific to gaseous flows, understanding the limited flow restrictions or equipment that would alter the back pressure in the specific application to flares. We do not expect that this alternative would be suitable for determining liquid flow rate in all applications. For example, depending on where the flow must be monitored relative to other equipment and the possibility of blockage of the liquid flow lines, the application of this method may not be as accurate and reliable as in the application of gaseous flow to a flare. Therefore, we are not revising 40 CFR 63.1573 to provide the requested alternative. However, we do note that section 63.1573(e) and (f) provides a means for a refinery owner or operator to apply for alternative parameter monitoring. Thus, if a refinery owner or operator expects that this alternative is applicable and accurate for their specific application, then they may apply to use this alternative parameter monitoring approach.

10.1 Catalytic Cracking Units (fluid and other)

Comment 1: A commenter asserted that the proposed rule can pose significant challenges to sources that are regulated under existing state implementation plan approved rules. For example, the commenter stated, facilities regulated by the SCAQMD already have many prohibitory rules that regulate unit operations. The commenter claimed that SCAQMD Rule 1105.1 regulates the operations characteristics including flow rate, power requirements and emissions from FCCU. The commenter believed that the EPA's proposed NESHAPs could superimpose additional requirements that may be incompatible with facility operations designed to comply with Rule 1105.1 and recommended that the EPA consult with stakeholders to modify the requirements appropriately for units that are already regulated under local or state air quality rules.

Response 1: We appreciate the commenter's perspective, but the SCAQMD Rule 1105.1 requires a facility to develop a monitoring plan and operating limits so it is impossible to fully evaluate potential differences. We note that as a general rule, it would be difficult or impossible for EPA to ensure that its rules are consistent with rules from the many states and sometimes local agencies that also have authority to regulate emissions. Regarding the specific issue raised by the commenter concerning the SCAQMD rule, we reviewed the general suggested parameters to be monitored in Attachment A of Rule 1105.1 and do not find that the revisions in subpart UUU would be incompatible with these suggested requirements. Both the monitoring plan in Rule 1105.1 and the provisions in §63.1573(e) and (f) provide a means for a refinery owner or operator to harmonize the federal and local agency monitoring requirements and we find no reason to modify the subpart UUU monitoring requirements as a result of this comment.

Comment 2: One commenter stated that the standards on coke burning and sulfur emissions assume that each facility has the same catalytic cracking unit under the same air pressure and using the same O_2 enrichment in order to calculate the pollutants from the facility. However, the commenter stated that many of these facilities are old and are calibrated differently and therefore assuming that all facilities are under the same conditions is incorrect and gives facilities huge margins for compliance.

Response 2: The equations used to determine the coke burn-off rate for the FCCU require flow rate corrected to standard conditions (1 atmosphere pressure) and account for oxygen enrichment and the amount of excess oxygen in the exhaust gas. Similarly, the revisions to the SRU provisions were included specifically to account for the use of oxygen enrichment. The SRU emission limits are provided on a concentration basis corrected to 0% excess air so these limits are not subject to issues related to differences in pressure or excess air use rates. Therefore, the commenter's assertion that we are assuming all facilities are operated under the same conditions and that we provide facilities with huge margins for compliance is inaccurate.

10.1.1 Inclusion of NSPS Ja compliance option

Comment 1: A commenter requested that the amendments to §63.1564 and Tables 1-7 allowing the use of PM CPMS as the compliance demonstration for FCCUs that are also subject to NSPS subpart Ja should be made available to all FCCUs whether or not they are subject to NSPS Ja (including those required to comply with NSPS J as their PM compliance option) since it has already been demonstrated in the NSPS subpart Ja rulemaking to be an equivalent compliance assurance approach for FCCUs. The commenter stated that it may be a preferable alternative for some unit configurations to demonstrate compliance during periods of startup and shutdown.

Another commenter agreed that PM CEMS should be an optional compliance approach since currently PM CEMS have not been fully demonstrated as reliable in refinery applications. The commenter believed that by allowing this optional compliance approach the EPA can promote, voluntarily, the further development of this technology which will allow future evaluations to determine whether enhanced compliance occurred in practice. Accordingly, this technology forcing effect can yield far greater benefits than mandating subpart Ja requirements. The commenter requested that the EPA not only revise Refinery MACT 2 in this manner, but it amend subpart Ja to apply a similar, optional approach for these yet to be fully demonstrated methods of compliance. The commenters supported an annual performance test requirement for all sources.

Response 1: We did not intentionally intend to prevent an owner or operator of an FCCU subject to subpart J from using the PM concentration/PM CEMS option. We note that subpart J at 40 CFR 60.100(e) allows units subject to subpart J to demonstrate compliance using the provisions in subpart Ja, so we intended to allow all FCCU to elect to use the PM concentration limit and PM CEMS monitoring option. To clarify this, we are revising these tables (primarily Item 1) to allow units subject to NSPS subpart J the option to meet the 0.040 grains (gr)/dry standard cubic foot (dscf) PM concentration limit if a PM CEMS is used, as allowed under 40 CFR 60.100(e).

With respect to annual performance test requirements, we proposed to require that the FCCU be re-tested at least once every 5 years. Combined with the enhancement in the monitoring requirements, we concluded that testing once every five years was sufficient to ensure continuous compliance with the emission limits. However, for the reasons provided in Section 10.1.2 of this document, we are requiring owners or operators of FCCU that elect to comply with the 20 percent opacity operating limit that also have emissions greater than 0.80 lbs/1,000 lb coke burn-off to conduct performance tests annually.

Comment 2: A commenter stated that two compliance options are provided in §63.1565 and Tables 8-14 for CO emissions (as a surrogate for organic HAP) and stated that is unclear what the compliance options are for FCCUs that will become subject to NSPS subpart Ja. The commenter also noted that NSPS subpart J includes language that allows for compliance with Ja as a NSPS J compliance option and that it is confusing not to have it spelled out in Refinery MACT 2, particularly relative to changes in NSPS J requirements spelled out in Refinery MACT 2. Similar to PM, the commenter believed that replacing existing requirements for CO options cannot be done without proper justification and analysis being provided for comment and such changes should be strenuously avoided. However, referencing NSPS Ja §60.102a everywhere §60.103 is referenced in §63.1565 and Tables 8-14 would provide a clear compliance option for FCCUs subject to NSPS Ja, without changing the requirements for other FCCUs.

Response 2: Both subpart J and subpart Ja have the same emission limits for CO (hourly average less than 500 ppmv, dry basis) and both require use of a CO CEMS (unless it is demonstrated that all hourly average CO concentrations are less than 50 ppmv, dry basis, corrected to 0 percent excess air for a 30 day period). The Refinery MACT 2 emission limitations are identical to the subpart J/Ja limits, but Refinery MACT 2 provides CPMS compliance options as alternatives to the CO CEMS. We did not intend to limit or duplicate compliance requirements for units subject to subpart Ja and we agree that Item 1 of Table 8 to subpart UUU should include units subject to 40 CFR 60.102a and that Item 2 would exclude units subject to either NSPS J or Ja, and have revised these tables accordingly.

Comment 3: A commenter stated that a delay-of-repair provision is needed with the proposed 12 hour repair requirement in §60.105a of NSPS Ja and §63.1573(b)(3) for faulty atomizing spray wet scrubber air and water lines. The commenter believed that while evaluation of the problem and identification of possible fixes can be initiated within 12 hours, depending on the severity and location of the leak it may take a few days before the repair can be completed. The commenter recommended that the EPA require the site to initiate the evaluation of the repair or replacement within 12 hours, with the repair to be completed as soon as practicable but not later than 15 days. The commenter provided recommended rule text as follows:

63.1573 What are my monitoring alternatives?

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(b) *What is the approved alternative for monitoring pressure drop?* You may use this alternative to a continuous parameter monitoring system for pressure drop if you operate a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. You shall:

(1) Conduct a daily check of the air or water pressure to the spray nozzles;

(2) Maintain records of the results of each daily check; and

(3) Initiate evaluation of the repair or replacement of Repair or replace faulty (e.g., leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading. The repair or replacement shall be completed as soon as practicable but not later than 15 days after identification of the abnormal pressure reading. As an alternative, the owner or operator may demonstrate via stack testing that the inorganic HAP limit is being met at these new conditions.

Response 3: We do not consider it appropriate to allow continued operation of the wet scrubber for 15 days while there are issues with the spray nozzle system. In most cases when the water spray system is not operating properly, there will be inadequate contact between the water and PM particles, significantly reducing the PM removal efficiency of the system. We do agree that facility owners or operators can demonstrate via a stack test that the inorganic HAP emission limit is being met at the new conditions, but these provisions are already included in Refinery MACT 2 at 40 CFR 63.1571(e). We are not adopting the revisions suggested by the commenter.

Comment 4: A commenter stated that the EPA set lower PM emission levels for new, modified or reconstructed sources under subpart Ja but then pronounced that it is necessary to revise Refinery MACT 2 to incorporate this limit for new sources, because FCCUs would already be required to meet this limit under subpart Ja, and therefore there is no added cost associated with the additional requirements. The commenter stated that this reasoning is significantly flawed because a Refinery MACT 2 new source is not the same as a NSPS subpart Ja affected facility. All FCCUs constructed after 1998 are subject to new source standards under Refinery MACT 2, but few, if any, of these sources are subject to subpart Ja, which does not apply to affected facilities constructed before 2007. Thus, the commenter believed that the EPA's statement that there would be no cost for new sources to comply with Refinery MACT 2 is incorrect.

Moreover, the commenter noted, even if all new sources under the Refinery MACT 2 standard must already comply with subpart Ja requirements, this does not support the EPA's assumption that revisions to Refinery MACT 2 are then automatically necessary. In fact, arguably, revision would be unnecessary, because the revision would be a paperwork exercise with no benefits. The EPA must do more than simply profess that it is possible, and therefore it is necessary.

Response 4: First, we only established more stringent PM emissions in Refinery NSPS subpart Ja for newly constructed FCCU (after May 14, 2007); modified and reconstructed FCCU (after May 14, 2007) must still comply with the 1.0 lb/1,000 lb coke burn-off emission limit. Second, we recognized that the new source applicability dates in Refinery MACT 2 are different than in the Refinery NSPS Ja; therefore, we did not require all new FCCU based on the Refinery MACT 2 applicability date to comply with the 0.5 lb/1,000 lb coke burn-off Refinery NSPS Ja new source PM emission limitation. As seen in Table 1 to subpart UUU, the new and existing FCCU requirements (according to Refinery MACT 2 definitions) are not segregated and only FCCU that are subject to NSPS PM standards in 40 CFR 60.102a(b)(1)(ii), i.e., the newly constructed FCCU after May 14, 2007, according the Refinery NSPS Ja, must meet the 0.5 lb/1,000 lb coke burn-off PM emissions limit. Therefore, we maintain that the revisions to Refinery MACT 2 to align with the subpart Ja requirements for subpart Ja newly constructed sources will not result in additional costs based on the proposed Refinery MACT 2 revisions.

We agree that the inclusion of these provisions in Refinery MACT 2 does not result in additional emissions reductions; however, we find that there is benefit in coordinating the compliance requirements between subpart Ja and Refinery MACT 2. Therefore, we are retaining the NSPS Ja new source emissions limit, if applicable, in Refinery MACT 2.

Comment 5: One commenter stated that without certainty that the bag leak detection (BLD) will provide better assurance that the PM emissions limit is being met than existing baghouse compliance methods, the EPA should only provide this compliance approach as an optional method under Refinery MACT 2. Further, the commenter stated that proposed Table 2 for subpart UUU should clarify that the BLD is only an option for new units subject to NSPS and that these units do not have to meet both that and the opacity standard. Finally, the commenter stated that given the EPA's admission that there is no evidence that BLD is more effective than existing baghouse compliance methods, the EPA should also revise subpart Ja to provide multiple compliance monitoring options rather than mandating the bag leak detection system.

Response 5: We disagree with the statement that the EPA admitted that there is no evidence that BLD are more effective than existing baghouse compliance methods. BLD are proven technologies and have been required for baghouse control systems in many EPA rules for the past decade. We clearly stated that we consider BLD to be superior to opacity monitors for ensuring fabric filter control systems are operating efficiently, with our primary point being that there is only one baghouse currently used to control FCCU emissions and we did not consider it necessary for this one unit to upgrade their monitoring system. As discussed in the preamble to the final rule and in the next section of this document, we received numerous comments on the proposed rule that argued that opacity was not well correlated with PM emissions. In a meeting between representatives from the EPA and from API, one representative noted that the extrapolation allowed in the site-specific opacity limit results in an opacity limit of greater than

100 percent for their unit controlled with a baghouse. One could never exceed such an operating limit regardless of whether significant holes develop in the bags, leading to high PM emissions well exceeding the 1 lb/1,000 lb coke burn-off. Therefore, having investigated this issue more fully in response to comments received, we are convinced that a BLD system is the best monitoring system for baghouse control systems. In general, we are finalizing provisions for the use of BLD systems in Refinery MACT 2 and we are not revising subpart Ja to include an opacity limit alternative for FCCU controlled with a baghouse.

While we are convinced that the BLD system is superior monitoring system than a continuous opacity monitor for FCCU controlled with a baghouse, we are not revising the NSPS J compliance option in Refinery MACT 2 to the extent proposed. For the reasons provided in the preamble of the final rule and in the following sections of this document, we are finalizing a 20 percent opacity operating limit for units subject to subpart J. If an FCCU that is controlled with a baghouse is subject to Refinery NSPS J, then an opacity operating limit is provided as a compliance option. If an FCCU that is controlled with a baghouse is subject to Refinery NSPS Ja, then the owner or operator would be required to install and use a BLD system.

10.1.2 Phase-out of NSPS J compliance option

Comment 1: Several commenters requested a minimum of 18 months to comply with the revised FCCU standards (except for PM) to revise their procedures, permits, AMPs and to perform training. Several of these commenters also requested at least 3 years for changes that require a project to install new equipment, including monitoring changes. One commenter requested 3 years to comply with the new requirements of the Refinery MACT 2 if promulgated as proposed in order to coordinate compliance with ongoing plant modifications, or turnarounds.

Response 1: The proposed rule provides an 18-month period to comply with the revised standards for FCCU and 36 months to comply with the revised flare requirements, if applicable. For the revised FCCU standards, the primary requirement would be to schedule and perform a performance test, if necessary, to determine the new operating limits. As the primary emission limits are not being revised, we do not consider it necessary to provide more time to comply with the revised FCCU operating limits. We also reviewed the requirements in Table 41 for CPMS and consider the requirements provided there are reflective of industrial monitoring systems and that additional time is not needed in order to comply with the requirements in Table 41 as revised in the final rule (Note: the O_2 CPMS requirements were revised, see Section 10.4 of this document).

Comment 2: Commenters stated that FCCUs, particularly those controlled using tertiary cyclones, cannot meet the proposed opacity limitations at all times. Commenters believed that available data show that a performance test based limit would likely result in an opacity limit in the range of 10% for cyclones and such a limit cannot be maintained under normal operating conditions because variability in operations of both the FCCU and/or PM control equipment may be reflected in opacity changes with no impact on permitted PM.[102] Commenters stated that a 10% opacity limit would cause FCCUs to exceed the opacity indicator, when the actual PM

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[102] API discussed these performance issues in a meeting with Brenda Shine and staff on August 7, 2014.

emissions are well below the standard and that the EPA has not demonstrated that units with higher opacity are exceeding the 1 pound per 1,000 pound limit.

Commenters stated that parameter monitor limits established through performance testing are appropriate if there is a reasonably direct correlation between control device operating parameters and emissions, but because FCCU regenerator opacity measurements are less precise than other parameter measures and are strongly influenced by particle size (which is inversely related to mass), opacity is only a qualitative indicator for PM emission rate or mass in this service. One commenter stated that the EPA conceded in the NSPS subpart Ja (page 76 of Public Comments and Responses Dated April 2008) rulemaking that opacity does not correlate well with PM emissions but rather is an indicator of control device performance.

Two commenters included data that they believe show that opacity is not a strong indicator of PM emissions and demonstrates the difficulty in establishing an opacity limit via performance testing. One of these commenters included figures that show the R^2 statistic of PM emissions (lb/1,000 lb coke burn-off or lb/hr) versus opacity for individual FCCU that use third stage separators for PM control. The other commenter shows a summary of performance test data from Marathon Petroleum Corporation's Canton refinery from which it states Marathon Petroleum Corporation, EPA, and the Department of Justice concluded opacity was not a strong indicator of PM emissions

Commenters recommended keeping the existing 30% opacity limit but increasing the stack test frequency from every 5 years to an annual PM stack test. If EPA changes the opacity limit for these units, a minimum of 3 years is needed to comply.

Response 2: As discussed in the preamble to the final rule, studies have shown that the 30 percent opacity limit does not correlate well with the 1 g/kg coke burn-off limit and that an FCCU can comply with the 30 percent opacity limit while its emissions exceed the 1 g/kg coke burn-off PM emissions limit. This same study indicated that 20 percent opacity limit provided a better correlation with units meeting the 1 g/kg coke burn-off PM emissions limit. We also reviewed the data submitted by the commenters regarding PM emissions and opacity correlation. While the data may be used to suggest that there is variability/uncertainty in the PM/opacity correlation, the data certainly do not support that a 30 percent opacity limit would ensure compliance. We note that 4 of the 6 individual test runs that exhibited an opacity of 12 percent or higher had PM emissions greater than the 1.0 g/kg coke burn-off PM emissions limit. Even when considering the uncertainty associated with the PM/opacity correlation, the data provided would suggest an opacity limit of approximately 15- or 20-percent would be appropriate to ensure compliance for this unit and that the 1 g/kg coke burn-off PM limit would be exceeded well before 30 percent opacity is reached. Therefore, we are not including a flat 30 percent opacity limit option to demonstrate compliance with the PM (or metal HAP) emissions limit.

In our review of the PM/opacity data submitted by the commenters, we agree that the PM/opacity correlation is not perfect, however, the correlation appears to be reasonable.
Some correlations presented by the commenter showed PM emissions on a lb/hr rate rather than a lb/1,000 lb (or g/kg) coke burn-off basis, and the mass emission rate can decrease due to flow

reductions even though the PM concentrations (i.e., opacity and PM emissions in g/kg) are constant. We also note that the comments generally required the correlation to go through the x/y axis intersection (0% opacity and 0 PM emissions). While we agree that the correlation should go through the x/y axis intersection, we also consider it appropriate to consider this as a measured value (based on calibration and instrument drift checks) and including this point when determining the R^2 of the correlation leads to much higher correlation (0.62 compared to 0.07; see memorandum entitled "Analysis of FCCU Opacity Data" included in Docket ID No. EPA-HQ-OAR-2010-0682). Therefore, while we recognize that this correlation is not perfect, it is reasonable and it certainly suggests that opacity readings above 20 percent (for the FCCU/cyclone tested) would most likely indicate that the PM emissions would exceed 1.0 g/kg PM emissions limit.

We note that when analyzing the PM/opacity data, we did not use the test data from the first day of testing (April 2004). The emissions from the unit during this test well exceeded the 1.0 g/kg PM emissions limit. The tertiary cyclone had just been installed at the time of the test. It appears some adjustments were made to the system after the April 2004 tests. All subsequent test data were used. While some individual test runs exceeded 1.0 g/kg emissions limit, all three run averages met the 1.0 g/kg emissions limit. For each combination of three consecutive runs (not necessarily performed on the same month), we evaluated the variability in the 3-run average opacity limit as well as the site-specific opacity limit that would be calculated based on the source test runs. The variability analysis was predicated on the idea that the opacity limit was an indicator that the control device was operating similarly to when the performance test was conducted. Based on the variability of the 3-run average opacity limits, we determined that, if the 3-hour average opacity exceeded 20 percent, then it was highly likely (98 to 99% confident) that the FCCU emissions are exceeding the 1.0 g/kg emissions limit.

Based on our review of the comments and data submitted by the commenters, we are adding an opacity operating limit for units subject to subpart J (or that elect compliance with subpart J). To further ensure units that are required to or elect to use the subpart J option, and that are operating near the PM emissions limit during the performance test, are complying with the mass emissions limit at all times, these units will be required to conduct a performance test annually rather than once every 5 years. The commenter suggested this option be specific to units using a 30 percent opacity, but we determined that a 20 percent opacity limit determined on a 3-hour average is much more indicative of good PM emissions performance and that re-testing is only necessary when the mass PM emissions are near the emissions limits. Therefore, we are revising the on-going testing requirement to be annual when the PM emissions measured during the source test is greater than 0.8 g/kg coke burn-off for units using the fixed 20 percent opacity 3-hour average on-going compliance option. The testing frequencies for units with measured emissions at or below these levels will be once every 5 years.

Comment 3: One commenter stated that the proposed Table 2 has led to confusion regarding the types of controls that are subject to site-specific opacity limits. The commenter believed the EPA's intent was to give units equipped with fabric filters or ESPs the option of demonstrating compliance using either the specified parametric monitoring approach or the site-specific opacity monitoring approach, until such time as the site triggered NSPS subpart Ja for that unit. The commenter stated that the table does not make this clear and that the EPA should clarify that units equipped with ESPs can choose to demonstrate compliance by coke burn-off or flow rate limit and total power limit and secondary current, without the need to demonstrate compliance with the site-specific opacity limit.

The commenter suggested revising the monitoring requirements for ESPs in Table 2, item 4(b)(i) as follows, to be consistent with existing regulations and Table 2, items 1(c) and 2(c), as follows: maintain the daily average gas coke burn-off rate or daily average flow rate no higher than the limit established in the performance test; and maintain the daily 3-hour rolling average voltage total power and secondary current (or total power input) above the limit established in the performance test.

Response 3: We note that the owner or operator of an FCCU is only required to comply with a specific row in Table 2 based on the applicability of the options and the type of monitoring system and control device used. We understand that some emissions limit/control device pairs may have an option to elect one of two different monitoring options. A facility may elect to comply with whichever one option they choose (provided they have the appropriate monitoring systems), and must continue to comply with that option until he notifies the EPA (or the administrative authority) that a different option will be used to demonstrate compliance. While it is true that an owner or operator of an FCCU that has both ESP parameter monitoring systems and an opacity monitoring system is not required to comply with both sets of operating limits, it is also true that the owner or operator must elect which compliance option they will meet at all times. To clarify this, we are revising §63.1564(a)(2) to state that if two separate monitoring system options are provided for a specific control device, the owner or operator may select the monitoring option with which the facility will comply at all times. The owner or operator must provide notice to the Administrator (or designated authority) prior to changing the monitoring compliance option for the facility.

The primary reason certain requirements were divided into numbered requirements in the last column was to clarify what parameters were provisionally available while the transition to the newly proposed requirements was being made. Since this transition period is considered essential, we are maintaining the separate numbered listing of some of these requirements.

10.1.3 Startup shutdown provisions

Comment 1: One commenter was concerned about the lack of a mechanism to obtain case-by-case review and approval of separate alternative SSM limits. While the commenter recommended some alternative limits in their discussions on FCCUs and SRPs, they claimed that other alternatives will likely be needed because of 1) advancements in technology, 2) process improvements, and 3) the possibility that not all situations may be readily foreseen at this time. The commenter urged the EPA to allow a process for companies to submit an application for case-by-case alternative SSM limits to be approved by either the EPA or delegated States, similar to the case-by-case alternate NOx limits for process heaters operated under certain conditions as provided in subpart Ja.

The commenter also stated that Table 1 of Refinery MACT 2 tabulates the applicable Metal HAP emission limits and Table 8 the applicable Organic HAP emission limits. The proposed tables only include the normal operating limits. The commenter suggested, that for clarity, the alternative limits applicable during other time periods should be included in these tables.

Response 1: With respect to the application for case-by-case alternative limits to be approved by the agency, we note that this option exists for nonopacity emissions standards through the General Provisions in 40 CFR 63.6(g). We disagree that the process for establishing alternative limits for MACT standards should be modeled after that approach in NSPS Ja because section 111 allows consideration of costs in establishing limits while MACT standards are based on the best performing facilities are without consideration of cost. We note that if a source wishes to seek an alternative limit under 40 CFR 63.6(g), the owner or operator would need to demonstrate that the source would be achieving at least as much HAP emissions reductions as obtained via the SS requirements in the final rule.

We are not revising Tables 1 and 8 to specifically include the startup and shutdown (SS) emissions limitations, because we consider these provisions to be operating limits. We have specifically included these limits in Tables 2 and 9 and we are adding monitoring and compliance requirements to other tables in subpart UUU to specify the monitoring and compliance requirements associates with these SS emissions limitations.

10.1.3.1 Opacity for metal HAP

Comment 1: Several commenters stated that although some FCCUs with WGS are designed to be able to safely keep those controls on-line during periods of SS, including hot standby, there are situations where some sites are unable to meet their WGS operating parameter requirements during these periods.

One commenter stated that maintaining the 3-hour rolling average pressure drop above the limit (established in the performance test) for scrubbers utilizing Agglo-Filtering Modules I Cyclone Systems (or similar equipment) during the process unit startup is not achievable. The commenters stated that typically, the required flue gas rates necessary to achieve the pressure drop established in the performance test does not occur until the unit is near the end of the process unit startup. This startup time can last 30 to 60 hours depending on the size and design of the unit, and there is no practical monitoring alternative during this period. The commenter requested that EPA provide relief on this monitoring point during startup until such time as the process rates established in the performance test are obtained.

Another commenter stated that FCCU equipped with WGS cannot consistently satisfy the 1.0 lb PM/1,000 lb coke burn limit during all phases of the startup sequence, since there may be insufficient coke burn against which to compare the particulate matter emissions. Indeed, the coke burn rate may not even support a meaningful calculation for comparison against the standard. Instead, FCCU equipped with WGS typically demonstrate compliance during stack testing by achieving performance consistent with the desired operating parameters for the scrubber system; the commenter requested this compliance demonstration apply for both startup and shutdown scenarios.

A different commenter stated that units with WGS can also experience operational and safety issues during SS activities. Refineries do not operate the LoTOx portion of the unit used for NOx control because sulfites are needed to minimize the ozone slip. The commenter noted that unsteady state operations cause the WGS to achieve a variable rate of emissions control efficiency making it ineffective as a continuous emissions control device. Operational variability also can result in a need to bypass the wet scrubber altogether. The commenter pointed out that FCCU with scrubbers that operate under AMP may not operate within monitored parameters during these periods because of the fluctuations that are seen in the gases being processed through the unit. Accordingly, the commenter stated, the Refinery MACT 2 level of control does not represent the MACT floor for SS activities at FCCUs with WGS.

Response 1: We understand that during startup, shutdown and hot standby, gaseous flow rates and pressure drop may not be as high as during normal operation and that the emissions limit is not relevant when there is no coke burn-off. As discussed previously we established operating limits with respect to the primary cyclones that is applicable regardless of the control device used. However, we consider it feasible for that facilities that use wet scrubbers to maintain the liquid to gas ratio operating limits during periods of startup, shutdown and hot standby. Therefore, we are providing an alternative compliance option for FCCU equipped with wet scrubbers to meet only the liquid to gas ratio operating limits during startup, shutdown and hot standby. That is, during periods of startup, shutdown and hot standby, the pressure drop operating limit is not applicable. This option provides a method for owners or operators of FCCU equipped with wet scrubbers to use their existing monitoring parameters to demonstrate compliance with the emission limitations rather than using completely different parameters.

Regarding the operation of the LoTOx system, we note that NOx control is not required by the MACT standards, so there is no requirement in the MACT rule requiring that the LoTOx system be operated during startup or shutdown. Furthermore, the Refinery NSPS subpart Ja requirements have fairly large averaging periods, which we expect will allow refineries to meet the emissions limitations at all times. However, we are not establishing alternative emission limits for periods of startup and shutdown in NSPS subpart Ja at this time.

Comment 2: One commenter noted that issues can arise during the shutdown process of an FCCU when the process unit is steamed out. During these events, high volumes of steam are sent through the reactor and out the regenerator stack. This high volume of steam at high velocities has been known to cause the opacity monitors to read opacity levels well above the standard. The commenter believed these steam out periods in the FCCU shutdown process should be excluded from the opacity standards.

Response 2: We note that high steam content in the stack gas can interfere with opacity monitor readings, so it is unclear if the high opacity from these events is caused by increased PM emissions or steam interference. In any event, we are not finalizing the proposed opacity limit in favor of a minimum inlet velocity for the internal cyclones of 20 feet/sec. We expect facilities can comply with the inlet velocity limit during periods of steam out.

Comment 3: One commenter stated that the prohibition on the use of control device bypasses during start-up, shutdown, and malfunction, regardless of the safety risk associated with sending those streams to those controls, will increase the risk of fire and explosion. In particular, operating ESPs on FCCUs during SSM has caused injuries and equipment damage.

Response 3: We specifically provided emissions limits for SS events that would allow compliance with the emissions limitations during these events, acknowledging the fire hazards associated with these events. We also note that we did not revise the bypass line provisions in Refinery MACT 2 so nothing in the proposed or final rule alters the existing FCCU bypass provisions.

10.1.3.2 O_2 concentration for organic HAP

Comment 1: One commenter believed that the EPA's proposed rule requiring a minimum of 1% O_2 in the regenerator exhaust gas during startup is not appropriate or achievable because it forces refineries to choose between emissions violations. See proposed 40 CFR 63.1565(a)(5)(ii). The commenter stated that the proposed rule identifies a potential standard that refiners could use to minimize CO emissions and its surrogate organic HAP emissions, by requiring the use of excess oxygen to ensure complete combustion of CO during startup. However, by requiring refiners to add additional oxygen to the regenerator during startup, the EPA overlooks the unintended consequences associated with this practice. For example, while adding excess oxygen to the regenerator may reduce CO emissions, this practice is also likely to significantly increase NOx emissions as a result of the additional O_2 reacting with nitrogen in the regenerator. As a result, refiners will be forced to choose between violating the CO limits proposed in this rule and violating their corresponding FCCU NOx limits.

The commenter believed that a more appropriate approach to SSM events would be to require sources to craft a site-specific plan that details the best available work practices for balancing all emissions during SSM. This approach would allow the EPA and refiners to determine an achievable limit that becomes enforceable in the refinery's title V permit, while ensuring that standards are in place continuously to address all periods during which there are emissions.

Response 1: First, we note that most commenters supported the 1% oxygen limit. Second, we specifically selected this limit at 1% rather than a higher excess oxygen limit specifically to allow FCCU owners or operators to still operate with relatively low levels of excess oxygen to minimize NOx emissions during these periods. That is, based on the data we reviewed, refinery owners and operators are expected to be able to comply with the Refinery NSPS subpart Ja NOx limits at excess oxygen concentrations between 1 and 2 percent. We also note that the NOx emissions limits in subpart Ja or elsewhere generally have relatively long averaging times (7-day rolling average, in the case of NSPS subpart Ja) that would allow refinery owners or operators ability to comply even though NOx emissions might be slightly elevated during startup or shutdown. Finally, we find that the commenters' recommendation for a site-specific plan to be identical to the SSM plan provisions that the courts considered illegal. Therefore, we are retaining the 1% excess oxygen concentration limit and, as described previously, broadening it to all FCCU startup and shutdown events.

Comment 2: One commenter stated that for FCCU which elect to comply with the alternative organic HAP limit during periods of SS and hot standby, the proposed rule requires the site to also install, operate, and maintain an O_2 CPMS to measure and record the oxygen content in the catalyst regenerator vent. Most FCCUs already have oxygen analyzers in the regenerator vent as required by the EPA's GHG Mandatory Reporting Rule and sites should be allowed to use these analyzers and not be forced to replace them with expensive CPMS.

The commenter stated that the EPA has not provided any technical justification for requiring sites to replace their existing FCCU regenerator vent oxygen analyzers with an O_2 CPMS. There is no basis to suggest that the current analyzer's accuracy is not adequate for Refinery MACT 2. This is especially true given the fact that the alternative excess oxygen limit will only apply during a very small percentage of the total operating time, i.e., only during periods of SS and hot standby which, on average, may only occur a few hours a year.

The commenter noted that the requirement in Proposed Table 41 for the O_2 CPMS is twice as stringent as the current PS 3 requirement for O_2 CEMS. It requires that an O_2 CPMS must have an accuracy of at least ± 1 percent of the range (0.25% O_2), while part 60 Appendix B Performance Specification 3, Section 13 specifies that an O_2 CEMS have a calibration drift (accuracy) of 0.5% O_2.

The commenter recommended that the EPA allow sites to demonstrate compliance with the excess oxygen alternate standard using oxygen analyzers meeting GHG requirements and that the Table 41 accuracy specification be deleted. Recommended language was provided as follows (shown as revisions to the proposed new 63.1565(b)(1)(iv)):

63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(b) * * *

(1) * * *

(iv) If you elect to comply with the alternative limit for periods of startup in paragraph (a)(5)(ii) of this section, you must also install, operate, and maintain an oxygen monitor to continuously measure and record the oxygen content (percent, dry basis) in the catalyst regenerator vent.

Response 2: While we understand the commenter's concern regarding the specific accuracy requirements for the O_2 CPMS, we see no reason to have no requirements at all for the O_2 CPMS. While we understand that the direct O_2 limit may only be applicable during periods of startup and shutdown, we expect many refinery owners or operators currently use the CO_2/CO/O_2 monitoring alternative to a flow CPMS in §63.1573(a)(2). We consider the gas analyzers used for this purpose to be CPMS. If you elect to comply with a PM compliance alternative that requires determination of the coke burn-off rate, then the gas analyzers used in this case would also be considered CPMS.

We find that at least some quality control requirements are necessary for these instruments that are used to demonstrate continuous compliance. Therefore, we are clarifying these continuous gas analyzers are considered CPMS. We understand that many oxygen analyzers may be spanned using air (maximum span value of 21 or 25%), so that the requirements in Table 41 for an O_2

CPMS may be more stringent than for an O_2 CEMS. Therefore, we have revised the entry in Table 41 to be "gas analyzer sensors". The gas analyzer sensors must be located to provide a representative measurement of gas composition of the exit gas stream and the gas analyzers must be accurate to ± 1 percent of the range of the sensor or to a nominal gas concentration of ± 0.5 percent, whichever is greater.

10.1.4 Performance testing every 5 years

Comment 1: One commenter agreed with the EPA's proposal to include new performance testing requirements at a frequency of once every five years for existing sources. The commenter supported an annual performance test to enhance compliance for new and existing sources, if the EPA adjusted or eliminated the proposal to lower emission limitations and change averaging times for new and existing sources, and the proposal to require subpart Ja monitoring for all Refinery MACT 2 sources.

Response 1: We appreciate the commenter's support of the requirement to test FCCU at a frequency of once every five years for existing sources. As noted in the preamble of the final rule, we are not making any changes to the requirements to establish a 3-hour average operating limit to demonstrate continuous compliance with the emissions limit. For most compliance options, we determined that the 3-hour average operating limits provided adequate assurance of compliance without more frequent compliance testing. However, as noted in the preamble to the final rules, we are note finalizing the proposed revisions to the NSPS subpart J compliance option in Refinery MACT 2; instead, we are adding a 20 percent opacity operating limits. For this compliance options, we considered it necessary to include a requirement to test annually if PM emissions are near the emissions limit during the performance test. See the preamble to the final rule more detailed discussion of these changes.

10.2 Catalytic Reforming Units

Comment 1: One commenter argued that the limiting the applicability of the 5 psig exclusion to prohibit active CRU purging releases to the atmosphere is not authorized by CAA section 112(d)(2) or (d)(6), significantly impacts fuel production, increases net hydrocarbon emissions (particularly methane) and should not be finalized.

Two commenters argued that the 5 psig criterion represents the control floor for this vent and any revision requires a CAA section 112(f)(2) or (d)(6) evaluation and determination, neither of which was made in this proposal. Furthermore, the record for the original rulemaking identifies this exception as applying to purging and depressuring the reactor, but does not indicate that the depressuring and purging cannot be active. In fact, according to one commenter, it is clear that the purpose of this provision was to allow release to the atmosphere when there was inadequate pressure to reach control, a situation that can occur regardless of whether the purging is passive or active. One commenter stated that the EPA has not presented any evidence to demonstrate that the EPA's original intent was to apply the provision only to passive operations. Moreover, the commenter was concerned that by terming this action as "clarifying," it implies that facilities should have been complying with the interpretation all along. Clearly, the existing language does not provide fair notice of such an interpretation, and if the EPA finalizes its proposal, it must affirmatively state that this is a new interpretation that applies prospectively only.

According to the commenters, the impact of this proposal is 1) to extend purge times and thereby significantly reducing fuels production, or 2) to force sources to install facilities to compress these streams and then supplement them with natural gas to allow sending them to combustion controls, a wasteful action that increases net emissions and incurs substantial costs.

One commenter added that notwithstanding the EPA's mischaracterization of its action, if the EPA proceeds to finalize its proposal, then the EPA must provide an extended period for facilities to comply with this requirement. Section 112(i) compliance dates are inapplicable to this proposed "clarification" or re-interpretation because such an action falls outside the types of rulemaking procedures addressed by section 112(i) compliance schedule. Accordingly, the EPA has broad authority to impose reasonable compliance deadlines, and the commenter requested that the EPA provide facilities with seven years to comply. This time frame is roughly equivalent to the typical turnaround time, and industry will need at least one turnaround to re-engineer the CRU process. On the other hand, one commenter stated that three years is required if the proposed revisions to §63.1566(a)(4) are finalized, and facility costs and burdens must be added to the rule cost analyses (i.e., costs for additional compression, natural gas addition facilities, and other facilities to allow these purge streams to be controlled) and information collection supporting statement burden estimates. The commenter also suggested that the Agency should specifically allow these purge streams to be flared, despite the flare gas minimization requirements of NSPS subpart Ja and to specify that these purges are part of the base flare flow for purposes of the NSPS subpart Ja flow RCA/CAA trigger (i.e., these flows do not count towards the RCA/CAA flare flow trigger).

Response 1: As we noted in the preamble of the proposed rule, the 5 psig exclusion from the emission limitations was provided based on state permit conditions, which recognized that depressurization to an APCD is limited by the back pressure of the control system. Without active purging, the amount of gas that can be released is limited. It is clear from the emissions tests conducted on the CRU purge vents that the emissions limitations achieved by units using active purging are not at all similar to the emissions limitations achieved by units that use a series of re-pressurizations, which the industry trade organization and industry representatives stated to be the common industry practice. HAP emissions per regeneration event using active purging appear to be 100 times greater than the emissions that most CRU achieve. The 5 psig depressurization exclusion was never intended to allow vent streams with HAP concentrations averaging 1,000 ppmv for an active venting period lasting over 1 hour at much greater volumes (and therefore mass emissions) than possible for passive depressurization. Given the common industry practice was to use a series of re-pressurizations and depressuring to a control device and to depressure to the atmosphere only after this series of "purging" events, it is evident that the exemption from the emissions limitations was too broad and allowed for emissions that greatly exceed the emission limitations achieved by the best performing 12 percent of sources at the time the MACT floor was determined. Therefore, we maintain that this correction to the exclusion provision is necessary to correct this error and to require all existing CRU sources to achieve the emission levels consistent with the MACT floor units.

We do recognize that the 5 psig exclusion, as worded in the original MACT standard, does appear to allow active purging. We did not intend for our correction of this mistake to be applied retrospectively to CRU owners or operators. We also recognize that some CRU owners or operators will need to alter their purging procedures and/or divert these emissions to a control device. This may require additional time to assess the control options and, if necessary, install the systems needed to control these emissions. We consider 3 years to be adequate to complete these activities; we do not find that 7 years are needed to start complying with these MACT requirements.

Comment 2: One commenter stated that there are several MSS situations besides regenerator purging, where nitrogen purges are used in CRU operations. For instance, for safety reasons, a nitrogen purge is kept on the reformer catalyst to keep out air and moisture during unit turnarounds, including when the regenerator vent caustic scrubber is being maintained, during catalyst dumping operations. These high nitrogen purges are vented to the atmosphere for several reasons: they are low pressure, they have inadequate heating value to be routed to fuel or to the flare, there is little hydrocarbon, and control devices may be also shutdown. The commenter stated that the rule needs to clarify that such Maintenance, Startup and Shutdown nitrogen purges can be routed to the atmosphere without all of the burdens associated with MPVs being imposed.

One commenter similarly requested that the EPA recognize that an atmospheric discharge during startup of a CRU remains essential also to avoid unsafe conditions. Nitrogen purging during startup is required to assure that the parts reconnected to the reactor are air-free so that a reaction with any pyrophoric material in the reactor is avoided. The nitrogen purge needs to discharge to the atmosphere for a short period during startup because air in the flare lines would result in the same fire/explosion hazard that air in the reactors would cause. This purge may contain some VOC emissions because hydrocarbon can remain in the reactor when the catalyst is not changed before startup. To reiterate comments above, industry does not currently control the emissions at CRUs during startup operations; the EPA did not consider these activities in defining the affected facility; and the Refinery MACT 2 requirements do not represent the MACT floor.

Response 2: We note that only “catalytic reformer regeneration vents” are excluded from the definition of MPV and Refinery MACT 2 covers only the vents associated with catalytic reformer catalyst regeneration vents. It appears that the commenters consider any vent associated with the CRU to be subject to the Refinery MACT 2 requirements or are excluded altogether; however, this is not the case. For cyclic or continuous reforming units, the CRU continues to process feed, so the unit is definitely not being shut down. We recognize that semi-regenerative CRU essentially “shutdown” in order to regenerate the catalyst, which may create some confusion, but opening of reactor vessels or other process equipment is not needed to accomplish catalyst regeneration, so we consider it reasonably clear in §63.1562(b)(2) that only CRU vents associated with catalyst regeneration are specifically subject to the Refinery MACT 2 provisions. For CRU startup and shutdowns that are not associated with catalyst regeneration or for vessel openings for maintenance that are conducted during a regeneration cycle, these “vessel openings” are included in the definition of “miscellaneous process vents” and must meet the requirements for MPV. We note that we have added special startup and shutdown requirements for equipment openings (i.e., maintenance MPV) to the MPV requirements to use 10% LEL (or alternative limits under specific circumstances). See Section 4.2 of this document for more detail on these requirements.

For vents associated with catalyst regeneration, §63.1566(a)(3) makes it clear that "the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents)." We do not expect any organics to remain in the reactor after coke burn-off and catalyst rejuvenation, so reduction purges to remove air from the reactor vessels are not subject to the emission limitations in Tables 15 and 16.

10.3 Sulfur Recovery Units

10.3.1 Inclusion of NSPS Ja compliance option

Comment 1: One commenter argued that since this proposal incorporates the requirements from NSPS subparts J and Ja, compliance with this rule would be equivalent to compliance with one of the NSPS rules. It would be duplicative and wasteful for an SRP to have to demonstrate compliance and separately report under both this rule and the NSPS rule. Therefore, the commenter requested language be added to make compliance with this rule compliance with NSPS subparts J or Ja, as applicable.

Response 1: We made every attempt to coordinate compliance alternatives for the NSPS and MACT when coordination made sense. However, this is a MACT rule targeted to reduce sulfur HAP emissions and there are some differences in the compliance requirements, e.g., for small sulfur recovery plants with reduction systems not followed by an incinerator. Furthermore, there are discrepancies in what emissions may be allowable under startup, shutdown, and malfunction events. Thus, while we strived to minimize conflicting or duplicative monitoring requirements, we maintain that there is a need for specific compliance requirements in Refinery MACT 2 and we are retaining the requirement to report deviations from the requirements in Refinery MACT 2 semi-annual report.

Comment 2: One commenter stated that the EPA should ensure consistency in regulation between subpart Ja and the Refinery MACT relative to the alternative to the oxygen CEMS for determining allowable sulfur rates. Otherwise, this subpart Ja provision would be unavailable to refiners under the Refinery MACT, and thereby rendered a meaningless addition to subpart Ja.

Another commenter stated that the EPA acknowledges within the Proposed Rule that, during the development of NSPS subpart Ja, the practice was common of using "oxygen-enriched air" in Claus units to improve operational performance and reliability. The commenter argued that the EPA therefore provided compensative equations (equation 1 within 40 CFR 62.102a(f)(1)(i)). The Proposed Rule reflects the EPA's intent to revise the Refinery MACT to reference the same equation 1 from subpart Ja; the commenter supported the intent of this aspect of the Proposed Rule.

However, the Proposed Rule does not merely incorporate into the Refinery MACT the existing relevant equations from subpart Ja. Instead, the Proposed Rule also states that the EPA intends to address “incomplete provisions” from subpart Ja in this regard. The Proposed Rule manifests implementation of this statement through the proposed revisions found at §60.102a(f)(1)(i), §60.106a(a)(5), and §60.106(a)(6). Tables 31 and 32 of subpart UUU would be similar to §60.106a(a)(5) relative to the required installation of a CEMS to measure and record the oxygen concentration of the enriched air. However**,** the commenter explained that Tables 31 and 32 should be modified to include this option to measure the flow rate of inlet oxygen and air, consistent with subpart Ja. The commenter noted that purchased enriched air must meet exacting specification and the oxygen content of air does not vary. Therefore, the oxygen content of the mixture of these gases is known provided the quantity of each stream is measured and the addition of an oxygen CEMS does not improve upon the accuracy of the overall emission calculation. Consequently, there is no scientifically valid or environmentally beneficial justification in deploying CEMS to measure oxygen content under the Refinery MACT and doing so would result in significant costs which are not addressed among the economic impacts of this rule. According to the commenter’s preliminary estimates, this requirement would impose a cost of approximately $1.5 million on a single refinery, with no attendant environmental benefit.

Response 2: We intended to allow the oxygen enrichment provisions in subpart Ja for large sulfur recovery plants; however, we determined that, for the purposes of HAP control, the provisions in subpart Ja for smaller sulfur recovery plants were not appropriate. With respect to the alternative monitoring provision to measure flow rates of air and oxygen and calculate the oxygen concentration in the enriched air feed to the Claus burner, the omission of this alternative in the proposed rule was an inadvertent error. As long as the flow rates of air and oxygen are accurately monitored, the flow monitoring data provide an accurate means by which the oxygen content of the mixed feed to the Claus burner can be determined. In the final rule, we have revised Tables 31 and 32 to allow the flow monitoring option for determining the oxygen content of the mixed air feed to the Claus burner.

10.3.2 Startup shutdown provisions

Comment 1: One commenter stated that the EPA’s proposed SSM rule for SRUs is not achievable. The proposed rule would allow diversion of purge gases during shutdown of a SRU to a flare meeting the requirements of 40 CFR 63.670 (or temporarily §63.11), a measure that the EPA believes will allow refineries to comply with the 300 ppmv reduced sulfur compound limit in 40 CFR 60.102a(f)(1)(i) during periods of shutdown. According to the commenter, the sulfur loading to the flare is increased significantly during periods of shutdown and proposing to impose the 300 ppmv reduced sulfur compound emissions limit during these periods is not achievable. According to the commenter, the only way to comply with the 300 ppmv limit would be to completely eliminate flaring during periods of shutdown, a practice that is unachievable in practice. The commenter has attempted to shut down its SRU without flaring on several occasions, without success.

One commenter did not argue that the flare could not achieve the 300 ppmv reduced sulfur compound limit, but stated that the flare may not be a viable option for the proposed SRU shutdown because the resulting emissions might exceed the 500 lb/day total sulfur RCA action level. The commenter requested language be added to allow temporary MSS purges from SRPs to be flared without including the contained sulfur in the NSPS subpart Ja RCA sulfur trigger calculation.

The commenter also requested clarification in [§63.1568](a)(4)(iii) that the 1,200ºF minimum temperature specified is the firebox temperature, rather than the stack temperature. On the other hand, one commenter stated that the 1,200ºF minimum temperature is an excessively high average temperature obligation for the characteristics of the emission stream to be controlled. According to the commenter, this thermal level is consistent with the objective of controlling emission streams with high VOC concentrations. However, emission streams generated during the shutdown of the SRU will instead consist of elevated concentrations of H_2S. The auto-ignition temperature for H_2S is 500ºF, and the auto-ignition temperature for carbon disulfide is 257ºF. The commenter stated that the EPA's proposed limits were based on control system operations during normal operating conditions. Therefore, the commenter stated that the proposed temperature standard included in the Proposed Rule is excessive for this application. The commenter concluded that to the extent that any alternative standard is applied during the shutdown of an SRU, the Proposed Rule should be modified to authorize the affected source to demonstrate compliance through emission testing of incinerators or thermal oxidizers to reflect adequate destruction efficiency at reduced temperatures.

Response 1: First, we are unaware of any data, and the first commenter has not provided any data, to substantiate the assertion that a properly operated flare will not effectively reduce sulfur HAP emissions to the required limits. We recognize the difficulties associated with determining compliance with the Refinery MACT 2 emission limits when using a flare, and therefore we are relying on the performance indicators developed for organic HAP to ensure adequate destruction of the sulfur HAP. Given the lower auto-ignition temperatures of the sulfur HAP as noted by the third commenter, we consider that the flare performance indicators included in Refinery MACT 2 are adequate to ensure combustion of the sulfur HAP. The proposed rule (and as being finalized) allows the use of a flare during startup and shutdown and compliance would be determined based on the flare operating limits. Therefore, it is a mischaracterization of the proposed requirements to state that the only way to comply with the proposed rule is to completely eliminate flaring during SRU SS events.

We are not including provisions to allow flaring of SRU gases under Refinery MACT 2 to be exempt from the RCA/CAA requirements in subpart Ja. These regulations address different pollutants. While we consider that a flare will achieve effective control of reduced sulfur compounds, we note that this control method will generate SO_2. If a flare is used and the emissions exceed 500 lb/day, we maintain that it is reasonable under NSPS subpart Ja for refinery owners or operators to investigate the procedures used and to identify means to eliminate the event or minimize SO_2 emissions during such an event. Thus, while we allow the use of flaring in the case of an SRU SS event for control of HAP, we do not intend to allow refinery owners or operators to emit large quantities of SO_2 without performing an RCA/CAA. Also, we do not consider the RCA/CAA requirement to be so excessive that refinery owners or operators will not use a flare when needed for SRU SS events.

Next, we agree that the proposed 1,200ºF temperature requirement refers to the firebox temperature of the thermal oxidizer or incinerator. We do note that, if a facility elects to monitor the temperature only at the stack, then they must meet the 1,200ºF limit at the selected monitoring location. With respect to the stringency of the 1,200ºF temperature limit, we acknowledge that this temperature is based largely on thermal oxidizer and incinerator data for SRU controls during normal operation; however, we see no reason why the thermal control device cannot be operated at these temperatures during the SS event of an SRU. For SRU that are not subject to NSPS subpart J (or certain provisions of Ja), SRU owners or operators must conduct a performance test to demonstrate compliance with the 300 ppmv sulfur HAP limit and set operating limits based on the performance test results. It is possible that these owners or operators could establish a lower temperature operating limit during their performance tests and they may elect to comply with these operating limits at all times rather than use the alternative 1,200ºF limit provided for periods of startup or shutdown.

Comment 2: One commenter stated that although the EPA generally removes the unlawful SSM exemption, which it is required to remove, the EPA also proposes special standards for startup or shutdown periods for SRU during shutdown. The commenter believed that the EPA has failed to provide a reasoned explanation in the record for why these special standards are required, and why it is not unlawful, arbitrary, and capricious to authorize more toxic air emissions during these periods for these emission points.

The commenter noted that The Act requires sources to comply at all times with emission standards. There is no exemption for any time periods. Thus, special standards for emission points during any time periods are plainly unlawful.

Even if an alternate limit is permissible under the act, the commenter stated emissions event data from the TCEQ demonstrates that a special standard for SRU shutdowns is not justifiable. The commenter noted that out of 62 SRUs at refineries in Texas according to the 2011 Petroleum Refinery ICR, between 2012 and 2013, not one facility reported any reduced sulfur HAP emissions during shutdown periods from these SRUs. Facilities are required to report these emissions to TCEQ pursuant to 30 Tex. Admin. Code 101.201 and .211. The lack of any reported reduced sulfur HAP emissions demonstrates that an alternate shutdown emission limit is not necessary for SRUs.

Additionally the commenter stated that if an alternate reduced sulfur SRU limit for refinery shutdowns is supported by other evidence not provided in the record and is also deemed legally permissible, the EPA must clarify that the alternate limit only applies when a shutdown is planned and the entire facility is shutdown. First, the EPA's proposal explains that facilities are expected to run the SRU "continuously" and only shutdown its operation during a complete turnaround or shutdown of the facility. Yet the proposed rule does not clearly circumscribe the limit to complete facility shutdowns. Specifically, the proposed rule states "during periods of shutdown only, you can choose from the three options" without any further limitations or definition of a shutdown.

Second, the commenter stated that the EPA must clearly prohibit the availability of the alternate limit to planned shutdowns. An alternate shutdown limit that is available beyond planned shutdowns would create an unlawful exception to the reduced sulfur HAP limit for malfunctions and other unplanned events. Without narrowing its availability, an alternate limit for shutdowns would permit compliance with a weaker limit caused by poor maintenance, planning, or other preventable event. For example, many of the cited causes for SRU shutdowns, reported to the ICR Component 1, identify the loss of power or the loss of third-party hydrogen supply. As discussed in the context of inherently safer technologies, facilities can eliminate or reduce the frequency of power outages through maintaining back-up power sources. Further, facilities are in the best position to ensure a reliable source of hydrogen through bringing those processes on site or through the terms of their contract. The commenter believed that providing an alternate standard for all shutdowns reduces the incentive to take these measures that would ensure reliable refinery operations and the utilities that supply them. Therefore an alternate limit that is not narrowly drawn to only apply during planned shutdowns is an end-run around the CAA's mandate that standards must apply at all times and must be removed from the final rule.

The commenter emphasized that to ensure that the alternate limit is only available for planned shutdown events, the EPA's final regulation must require facilities to submit a shutdown plan for public notice and comment and approval by the appropriate authority. The plan should specifically explain the reason for the shutdown and the measures the facility will take to minimize emissions. These measures will ensure that the alternate emission limit is only utilized when absolutely necessary and that the resulting emissions are minimized to the maximum extent possible.

The commenter concluded that providing special standards during some time periods will increase the health risks during those times, and the EPA has failed to consider, much less show, how these standards could be lawful under section 112(f)(2). The EPA must prevent unacceptable risk and assure an "ample margin of safety to protect public health," under this provision. The EPA does not discuss these requirements, much less show, how the special standards will meet these, when they will allow additional toxic air pollution to be released during regular periods of startup and shutdown.

Response 2: First, we have not removed the requirement to control sulfur HAP emissions from the SRU during periods of startup or shutdown. However, we recognize that during these periods, emissions may be routed to an alternative control system (e.g., a flare) or the surrogate used to assess sulfur HAP reduction during normal operations is not applicable during startup and shutdown. For startup and shutdown, removing sulfur from the vessels is different than SRU tail gas during normal operations and the concentration of SO_2 produced from the combustion of this shutdown gas is different than the combustion of the tail gas produced during normal operations. During normal operations, SO_2 is an indicator of sulfur recovery efficiency and high sulfur recovery efficiency limits the amount of sulfur HAP that can be emitted. During startup and shutdown, sulfur recovery efficiency may be highly variable and potentially meaningless (e.g., in the case of shutdown when no feed is added to the unit). However, in Refinery MACT 2 we did not limit the applicability of the HAP requirements to Claus sulfur recovery units greater than 20 long tons per day as was done in Refinery NSPS subpart J, because sulfur HAP control could still be accomplished through the use of thermal oxidizers or incinerators even when sulfur recovery efficiency was not as high as required by NSPS J/Ja. That is, in the development of the Refinery MACT requirements, we recognized as MACT the control efficiency of thermal oxidizers or incinerators for SRU regardless of the overall sulfur recovery efficiency. The primary reason to provide the set temperature and oxygen content limits during startup and shutdown was to provide a compliance option for units that might use an SO_2 CEMS during normal operations and would not have developed incinerator operating limits based on source test data.

We reviewed reports submitted under 30 Tex. Admin. Code section 101.201 and found numerous instances of emission reports associated with SRU startup or shutdown. We note that none of the reports provide sulfur HAP emission estimates, but that appears to be due to the emission calculation procedures (i.e., accounting methods appear to consider only H_2S and SO_2). As discussed previously in this response to comment document, we expect that combustion of these gases, while potentially leading to high SO_2 emissions, is effective in reducing sulfur HAP emissions. That is, we do not consider that the alternative compliance options provided for SRU are allowing for greater sulfur HAP emissions and therefore we disagree with the commenter's assertion that these alternative limits are authorizing "more toxic air emissions during these periods for these emission points."

Because these thermal devices are effective at controlling sulfur HAP emissions, we also do not feel compelled to put further restrictions on the use of the startup/shutdown provisions to planned shutdowns only. We find it reasonable to allow this compliance alternative during a shutdown caused by power outages or other "unplanned" events. In fact, in response to comments received, we are expanding the allowance for this alternative to startups as well as shutdowns. We understand that using incineration during these events may lead to potentially high SO_2 emission releases, but they will not result in high sulfur HAP emissions, so we are not further limiting the applicability of startup and shutdown alternatives in Refinery MACT 2 in response to these comments. As mentioned in a previous response, owners or operators using these provisions may have higher SO_2 emissions and are still required to conduct an RCA/CAA under subpart Ja if the SO_2 emissions exceed the allowable emissions by 500 pounds per day or more, so the owner or operator has an incentive to limit the potential for excess SO_2 emissions.

Sulfur HAP are not considered cancerous so they do not contribute to maximum exposed individual cancer risk or population cancer incidence. The highest hazard quotient for emissions from sulfur recovery plants are several orders of magnitude less than 1, so we have no evidence that there are adverse health effects associated with sulfur plant HAP emissions. Furthermore, since we maintain that the SS provisions we have provided for SRU do not yield higher HAP emissions, we conclude that further emissions reductions are not required or warranted under CAA section 112(f)(2).

10.4 CPMS Requirements in Table 41

Comment 1: One commenter stated that the gas flow rate accuracy requirements in proposed Table 41 are even less feasible for FCCU than they are for flare gas flow measurement. FCCU regenerator stacks are typically larger in diameter than almost any flare header (8 to 12 foot diameters are typical) and it is infeasible to measure 10 cfm in such large diameter stacks. Nor are instruments available that can measure the entire flow regime with ±5% accuracy. For

FCCUs, a typical and reasonable accuracy requirement is ±5% over the normal flow range, if an instrument is used.

The commenter stated that because of the difficulty in measuring flow in such large ducts, the blower speed or power is often monitored and the air flow is based on the blower design curve. This monitoring alternative should be provided to avoid forcing the installation of questionable flow monitors. If flow monitoring is required and the Table 41 specification is not changed, the commenter stated that all new FCCU flow instrumentation involving multiple instruments will be required. In addition to very high capital costs, this new instrumentation will require out-of-sequence FCCU outages and associated production loss.[103]

Response 1: The accuracy requirement for air/gas flow rate is intended to apply to the normal operating flow rate range and we do not consider that flows anywhere near 10 cfm would be considered normal operating range for an FCCU. Additionally, we note that 40 CFR 63.1573(a)(1) and (2) contain approved alternatives to monitoring exhaust air flow rate. These alternatives allow the use of "control room instrumentation" for determining air flow rate and other gaseous flow rates to the regenerator. We expect that these air flow rates would be commonly determined using blower speed/power curves or similar methods. Therefore, if blower speed/power curves are used by the control room for determining FCCU air flow rate, Refinery MACT 2 at 40 CFR 63.1573(a)(1) and (2) already contains the alternative requested by the commenter. We also note that owners or operators have the ability to submit a request for an AMP on a case-by-case basis, if needed. Based on the provisions already included in Refinery MACT 2, we disagree with the commenter's assertion that the proposed requirements will have high costs and/or result in production losses.

Comment 2: One commenter recommended that the EPA should not reference NSPS subpart Ja in Table 41 for coke burn monitors. The commenter stated that in Table 41, the EPA proposed to require that CO_2, O_2, and CO monitors for coke burn-off rate meet the requirements of 40 CFR 60.105a(b)(2). Yet, Table 41 already contains requirements for CO and O_2 monitors and there are differences between the two sets of requirements, including a significant increase in the frequency of performance testing the monitors. Furthermore, it is unclear that existing monitors will meet the new requirements and, thus, some may have to be replaced.

The commenter stated that since the EPA provides no justification for imposing NSPS requirements on existing units and the new requirements conflict with existing requirements, the changes should not be finalized. The commenter recommended that if the EPA believes these changes are necessary, they develop a justification including cost estimates for any required replacements, provide three years compliance time, and publish their justification for comment.

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[103] FCCU outages are massive undertakings, involving years of planning, scheduling large cranes and armies of workers. These outages require extensive scheduling and lead times to redirect feeds and provide for replacement product supplies and usually many other process units must be shutdown coincidently because of the loss of the FCCU steam production. Every such shutdown also risks equipment damage due to the thermal cycling of the equipment.

Response 2: In the proposed rule, the CO_2, O_2 and CO monitor requirements for coke burn-off were listed in Table 40 (CEMS table) rather than Table 41 (CPMS table). This was an inadvertent error on our part as we consider these systems to be control device CPMS rather than CEMS. As such, these requirements should have been included in Table 41 rather than in Table 40. Therefore, we are moving these requirements to Table 41 in the final rule and we are clarifying that all concentrations need to be determined on a dry basis. We are allowing facilities that follow the requirements in 40 CFR 60.105a(b)(2) to use those requirements in order to harmonize the requirements for units subject to Refinery NSPS subpart Ja, but we are not requiring sources to meet the NSPS performance specifications for these monitors for existing FCCU (i.e., units not subject to Refinery NSPS subpart Ja).

10.5 General provisions applicability (Table 44)

Comment 1: One commenter stated that there are discrepancies in the proposed QA/QC requirements set forth in proposed Tables 40 and 44. Table 40 in subpart UUU references part 60 Appendix F in several places both directly and indirectly. Table 44, meanwhile, references 40 CFR 63.8(c)(7) as applicable to all sources subject to subpart UUU. However, section 63.8(c)(7) and part 60 Appendix F define “out of control” (OOC) periods differently. Appendix F references back to the last good validation to start the OOC period, whereas section 63.8(c)(7) starts the OOC period beginning with a “bad” validation. The commenter requested the EPA resolve this discrepancy in the regulations, perhaps by specifying which OOC definition should be used in Table 44.

Response 1: We appreciate the commenter pointing out the discrepancy in the QA/QC requirements. We reviewed the requirements and when owners or operators are required to comply with part 60 for NSPS subpart J/Ja, it makes sense to require owners or operators to use the QA/QC procedures in Appendix F to part 60 so they have a consistent set of QA/QC requirements between the NSPS and Refinery MACT 2. In order to clarify this in the final rule, we have added a note to the entry for section 63.8(c)(7) in Table 44 to indicate “Except when subpart UUU specifies use of 40 CFR part 60, Appendix F, out of control periods are to be defined as specified in part 60 Appendix F.”

11.0 General Compliance Requirements for MACT standards

Comment 1: Commenters raised concern with the structure of the rule, noting that compliance requirements for Refinery MACT 1 are indicated in Table 11, whereas recordkeeping and reporting requirements are indicated in section 63.655, and they suggested revisions to the regulatory structure. Other commenters noted that the revisions proposed are so comprehensive that compliance dates can only be clarified by establishing new subparts (i.e., subparts CCa and UUUa)..

Response 1: We appreciate the commenters' suggestions on how to clarify the rule requirements. We have considered these comments as we developed the final rules to make sure that they are clear as to who has to comply with which provisions and by when. We added Table 11 to Refinery MACT 1 (subpart CC) because there are several dates that the owners or operators must consider in determining when construction/ reconstruction occurred, and therefore, by when they must comply with applicable rule requirements. However, since we are amending the subpart CC rule already in place, we retained the structure of section 63.655, which indicates when the NOCS Reports, Periodic Reports and Other Reports are due.

Comment 2: Some commenters argued that the compliance deadlines for many of the proposed requirements are simply not feasible and significantly more time will be required. One commenter stated that 10 years are needed for changes requiring flare outages. One commenter stated that a process to grant additional compliance extensions should be in place to handle delays that may occur due to reasons outside of the control of a refinery. Another commenter stated that the EPA has not met the test under CAA section 112(i)(3) showing that the 3-year compliance period for all of the existing source standards being proposed under CAA section 112(d) [79 FR 36950-51] is "as expeditious as practicable," and that the EPA only has included conclusory statements about the proposed compliance time frames, unsupported by evidence. : This commenter supported the compliance date the EPA proposed for the new storage vessel standards, claiming that the EPA appropriately recognized that it does not have authority to extend this compliance date beyond 90 days, as section 112(f) provides. [See *ABR v. EPA*, 716 F.3d 667, 672 (D.C. Cir. 2013); 79 FR at 36,950.] In support, the commenter quoted section 112(f)(3) ("[a]ny emission standard established pursuant to this subsection [section 112(f)] shall become effective upon promulgation)" and section 112(f)(4) establishes a prohibition on violating the new standard, stating that ("[n]o air pollutant to which a standard under this subsection applies may be emitted from any stationary source in violation of such standard, except that in the case of an existing source . . . such standard shall not apply until 90 days after its effective date.)"

Response 2: As explained in the proposal preamble (see 79 FR36950, June 30, 2014), amendments to Refinery MACT 1 and 2 for adoption under CAA section 112(d)(2) and (3) and 112(d)(6) are subject to the compliance deadlines outlined in the CAA under section 112(i). For existing sources, CAA section 112(i) provides that the compliance date shall be as expeditiously as practicable, but no later than 3 years after the effective date of the standard. For new sources, compliance is required by the effective date of the final amendments or upon startup, whichever is later. We are finalizing the compliance dates, as proposed, for the reasons given at proposal, with the exceptions of the fenceline monitoring standard, for which we are requiring the owners or operators to have the monitors in place within 2 years of the effective date of the rule instead of 3 years, as proposed, and the work practice standards for PRDs and emergency flaring, as explained in the final rule preamble and earlier in this document. In addition, as proposed, we are retaining the requirement that storage vessels comply with the requirements in this final rule 90 days from the effective date of this rule since those requirements are being finalized under authority of both CAA section 112(d)(6) and 112(f)(2). As provided in CAA section 112(f)(4), risk standards shall not apply to existing sources until 90 days after the effective date of the rule, and we are not granting the waiver for up to 2 years, as explained in the proposal preamble. However, we disagree with the commenter's statement that the EPA does not have the authority to extend this compliance date beyond 90 days.

Comment 3: One commenter stated that 18 months to 3 years is required to implement new and revised monitoring requirements. The commenter stated that where new, replacement, relocated or significantly revised instrumentation is required to meet the new requirements, 3 years is necessary. Where existing instrumentation is able to meet the new requirements with little revision, 18 months, at a minimum, is needed. Commenters also stated that 18 months will be needed to put most of the new recordkeeping and reporting systems in place, to develop the required monitoring plans, revise procedures, obtain approval for AMP, to implement maintenance procedures, QA/QC and other requirements specified, and to obtain permits and approvals for the changes.

Response 3: Where new monitoring requirements were added to the rule, we included time for the owners or operators to implement the new monitoring requirements. Therefore, the refinery owner or operator would have time to implement any recordkeeping and reporting requirements associated with that monitoring system (and/or to request an AMP) because the recordkeeping and reporting requirements would not apply until the monitoring system is in place. In general, where we significantly revised the monitoring requirements, particularly when new operating limits need to be established, we did not propose to require compliance within 90 days of the effective date. Instead, for new monitoring requirements that require sources to develop monitoring plans, develop specifications for the CPMS, receive and analyze vendor quotes, select and schedule CPMS installation, and test the monitoring system (and software), we have provided 18 months for compliance. This should provide the facilities ample time to work through any state or local permits, although owners or operators should reach out to their permitting authorities as soon as possible. Under the federal operation permit program under Title V of the CAA, these final MACT requirements would be added to their operation permit as part of their five-year permit renewal, but compliance on or before the dates specified in the final rule must be met without regard to when the Title V permit is reopened. Other CPMS requirements generally allow 90 days from the effective date of this final rule, but in most of those cases, the added CPMS requirements follow generally established manufacturers' operating specifications, and should not require the longer timeframe.

Comment 4: Several commenters expressed concern that the rule requires refiners to comply with revised SSM and some other requirements as soon as the rule becomes effective. The commenters stated that EPA provides no justification for making such changes in the existing regulations effective immediately. These commenters argued that it would be arbitrary and capricious to require compliance immediately, when CAA section 112(i) allows a compliance deadline of up to three years. The commenters stated that elimination of the SSM provisions of the existing rules and the prohibition on atmospheric release of PRDs will require plants to make significant changes to their facilities and procedures, which would take significant time to execute and to permit. The commenters more specifically identified four actions that would need to be taken prior to implementation: 1) extensive permit revisions; 2) identification and evaluation of hundreds of new emission sources; 3) extensive procedural changes in light of the revised SSM requirements, including all new equipment preparation procedures; and 4) revision of all monitoring procedures. The commenters stated that while some activities can be started based on the proposal, procedures cannot be finalized, permit revisions applied for, and retraining of site personnel cannot begin until the rule is final. Furthermore, the commenter stated changes that require permit revisions and OMMP revisions cannot legally be implemented until the revisions are approved. One commenter stated the burden will be heavier for small business refiners due to smaller staffs and less capability to adjust work priorities. Conversely, another commenter opposed what they referred to as a 3-year compliance delay that applies to the EPA’s new prohibition on currently uncontrolled emissions from pressure relief devices and bypass lines. The commenter stated that all uncontrolled emissions of this kind are unlawful and allowing them to continue for three additional years is equivalent to allowing the unlawful malfunction exemption to continue for another 3 years. For the same reasons that the EPA must require and assure that emission standards apply “at all times,” it may not allow an exemption to continue for an additional three years, such that they will apply at no time until three years from the final rule date. See *Sierra Club v. EPA*, 551 F.3d at 1028.

Response 4: First of all, although the proposed rule eliminated all exemptions associated with SSM events, separate standards were proposed for startup and shutdown conditions associated with certain Refinery MACT 2 vents, such as the FCCU and the SRU. In those cases, we proposed immediate compliance upon the effective date of this final rule. For all other situations, we did not establish separate standards during periods of startup and shutdown and required immediate compliance with the MACT standards upon the effective date of the final rule. The commenter is incorrect in stating that we proposed a 3-year delay for PRDs. In fact, we proposed that the removal of the malfunction exemption was immediate; however, we did propose additional time necessary for the refinery owners and operators to install equipment, as necessary, sufficient to detect a release from a PRD. As discussed later in this section, although we do not interpret the Sierra Club decision on SSM to require the EPA to set separate standards during periods of malfunction, and in most cases, we are not able to do so and do not deem it appropriate or necessary, we do not interpret the decision to preclude the EPA from doing so if sufficient information is available and separate standards are appropriate. For this final rule, we are setting work practice standards for PRD releases and emergency flaring. As explained previously, we are doing so because we have a somewhat unique situation with this source category in that we collected a substantial amount of information via our comprehensive 2011 Refinery ICR, information submitted by commenters during the comment period and precedents for standards for these types of events issued by SCAQMD and California Air Resources Board that provided us information on PRDs and emergency flaring such that we are able to estimate what the best performing facilities are achieving. As explained further in the preamble, we are providing 3 years for facilities to comply with these new standards.

We disagree with the commenters that the SSM requirements should not be immediately effective. Where we determined that no separate standards are necessary for periods of SSM, owners or operators should already be in compliance with the applicable MACT standards under subparts CC and UUU and are required to comply with these standards at all times. In addition, for malfunctions other than those associated with PRD releases and emergency flaring, accounting for the myriad of potential malfunctions within a refinery would be difficult, if not impossible, and the courts have generally given the EPA wide latitude in determining the extent of data gathering necessary to solve a problem and nothing in section 112 requires the EPA to consider malfunctions in establishing standards. The alternate work practice standards for certain startup and shutdown situations and the work practices standards for PRDs and emergency flaring in this final rule should resolve most of the other issues raised by the commenters regarding compliance timing (see further discussion at 79 FR 36944-36945, June 30, 2014).

11.1 Removal of SSM plan/exemptions

Comment 1: Several commenters seemed to suggest that the decision in *Sierra Club* was wrong or does not apply to the Refinery MACT rules. Some commenters argued that the *Sierra Club* decision interpreted the NESHAPs General Provisions, but did not address what the EPA may or may not include in category-specific MACT standards, such as Refinery MACT 1 and 2. The commenters noted that in reviewing source-category-specific MACT standards, the court in *Sierra Club* emphasized the need for those standards to recognize and accommodate higher emission levels that occur at times other than normal operations.

Commenters stated that when Congress enacted the “continuous basis” language in section 302(k) in 1977 the EPA’s emissions standards under section 111 exempted SSM periods. The commenters argued that there is nothing in the legislative history of the 1977 amendments to the CAA that suggests Congress intended to overturn that practice and instead the history suggests the language was meant to address intermittent controls. Moreover, the commenters noted that court decisions both before and after the CAA Amendments of 1977 affirmed the appropriateness of including special SSM provisions in standards issued under section 111 despite the “continuous basis” language in the definition of “emission limitation.” The commenters stated that there is nothing in the legislative history of the Clean Air Act Amendments of 1990 that suggests Congress meant something completely different when it used the same defined terms, “emission standard” and “emission limitation,” in directing the EPA to establish MACT standards.

Response 1: We disagree with the commenter’s suggestion that *Sierra Club v. EPA,* 551 F.3d 1019 (D.C. Cir. 2008) is not relevant because it addressed the SSM exemption in the General Provisions rather than source category-specific MACT standards. The holding in *Sierra Club* that emissions limitations under section 112 must apply continuously and meet minimum stringency requirements, even during periods of startup, shutdown and malfunction, is clearly applicable to source category-specific MACT standards. The decision was based on the definition of emission limitation in section 302(k) and the commenters have not provided and we see no basis for interpreting that term differently for the refinery MACT source category than for source categories which cross-reference the General Provisions.

The EPA disagrees with the commenter's suggestion that the existence of an SSM exemption in rules implementing section 111 in 1977 when Congress enacted the "continuous basis" language in the definition of "emission standard" is evidence that Congress approved of that regulatory SSM exemption. We do not believe the legislative history cited supports that Congress was aware of or approved that exemption. Regardless, the legislative history does not alter or trump the court's decision in *Sierra Club* regarding the meaning of that term.

Comment 2: Multiple commenters stated that the EPA has misinterpreted the *Sierra Club* decision and that the decision did not say that the same emission limits the EPA has derived for normal operations must also apply during SSM events. Some commenters contended that while a blanket, open-ended exemption from any standard under section 112 is inconsistent with that decision, the decision does not preclude the EPA from applying different standards during SSM events than apply during normal operations. Commenters further noted that the court acknowledges that the broad phrase "any requirement relating to the operation or maintenance of a source to assure continuous emission reduction" in the definition of "emission standard" suggests that the EPA can establish MACT standards consistent with CAA section 112 "without necessarily continuously applying a single standard." Commenters claimed that the implication of *Sierra Club* is that alternative SSM standards, including the inapplicability during SSM events of otherwise applicable MACT emission standards, can be authorized when based upon consideration of the relevant MACT criteria to specific source types.

Commenters stated that the *Sierra Club* decision did not address whether the EPA could use a "design, equipment, work practice, or operational standard," as authorized under CAA section 112(h) and included in the definition of "emission limitation" and "emission standard" in CAA section 302(k), in lieu of a numerical emission limitation during SSM events. One commenter noted that the decision stands for the simple proposition that emission limits under section 112 must be apply during all periods of operation but that the emission limit may be numerical or, where the statutory criteria are met, a work practice standard.

Several commenters stated that there is ample precedent for the EPA applying a different standard during SSM events. In particular, the commenters claimed that the EPA has not required sources to meet NSPS emission limitations established for normal operations during SSM events.

Commenters claimed that the Agency expressly concluded that the SSM provisions of the Refinery MACT were not affected by the *Sierra Club* decision and referred to the Letter from Adam M. Kushner, Director, Office of Civil Enforcement for the Agency, to American Chemistry Counsel, et al, July 22, 2009. The commenter stated that, even if the EPA's current position with respect to the scope of the holding in *Sierra Club* had merit, the Agency must justify the legal basis for its change in policy in the context of this rulemaking proceeding.

Response 2: To the extent that the commenters are suggesting that EPA took the position in the proposed rule that section 302(k) and the *Sierra Club* decision bar EPA from establishing alternative limits for periods of SSM, we disagree. In fact, in the proposed rule, where we determined it was appropriate, we proposed specific alternative emission limitations that would apply during certain startup and shutdown events. As explained in the preamble to the final rule, we have included alternative emissions limitations for startup and shutdown for additional emission sources beyond those in the proposal where we have determined that the standard that applies during normal operations cannot be met and where the startup and shutdown standards are achievable by the best performing units.

In the preamble to the proposal, the EPA explained that it was not proposing alternative limits to apply during periods of malfunction because it was not required to do so under CAA section 112(d)(2) & (3) and because of the difficulties in identifying the myriad types of malfunctions and in predicting the frequency, degree and duration of such events. 79 FR at 36944. While we continue to believe that is true for malfunctions in general, for the reasons provided in the preamble to the final rule, we are establishing emission limitations for PRD releases to the atmosphere and emergency flaring events.

The Adam Kushner Letter referred to by the commenters identified rules that were directly affected by the court's decision in *Sierra Club* because those rules only cross-referenced the SSM exemption in the General Provisions and did not contain any category-specific standards or exemptions for periods of SSM. Thus, for those rules, once the mandate issued in *Sierra Club*, the SSM exemption in §§63.6(f)(1) and 63.6(h)(1) was rendered null and void. Thus, at that time, there was no longer an SSM exemption available for standards which incorporated those provisions by reference rather than including separate language establishing an SSM exemption. The Adam Kushner Letter also identified rules, such as the two Refinery MACT standards that included specific language establishing an SSM exemption (see 63.655(g)(6)(iii) and 63.1560(g) for subparts CC and UUU, respectively) instead of only cross-referencing the General Provisions. For these rules, the court's mandate did not have the effect of rendering the SSM exemption null and void. EPA has not changed its position regarding the effect of the *Sierra Club* decision. Rather, EPA is simply amending the Refinery MACT rules to remove language that the court has found is inconsistent with the definition of emission limitation in CAA section 302(k).

Comment 3: Several commenters stated that the proposal does not account for the differences between normal emissions and maintenance, startup and shutdown emissions and that the EPA must revise many existing floor determinations to include maintenance, startup and shutdown emissions or set separate maintenance, startup and shutdown standards. Commenters stated that at the time the MACT standards were promulgated, startup, shutdown and malfunction activities were exempt from the standard and not included in EPA's evaluation. Commenters asserted that the EPA codified the affected source definitions with the understanding that SSM was an activity separate from the "affected source" for which it set MACT standards. Commenters asserted that the EPA must: 1) explain why its original definitions of activities included in the affected source definition are no longer technically valid and new activities should be included in the defined affected source; and 2) determine how this revised scope of the activities included within the affected source definition affects its original MACT floor finding. Commenters suggested that facilities minimize emissions differently during startup and shutdown and that it is likely that including maintenance, startup and shutdown activities under the standard would lower the MACT floor for the affected sources, or require a change in the averaging period to account for emission fluctuations. Commenters cited *NRDC v. EPA*, 859 F.2d 156, 210 (D.C. Cir. 1988) and argued that the default assumption must be that "special" provisions are needed for maintenance, startup and shutdown and EPA cannot conclude that special provisions for these emissions are not needed based on “mere speculation.” Commenters stated that the EPA previously determined, when establishing the existing standards applicable to refineries, that the best performers on which the MACT standards were based may not achieve those standards during MSS and that the EPA cannot change its mind without providing a factual analysis supporting the conclusion that MACT standards can be achieved as well during all MSS periods. [See, e.g., *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996).] Commenters claimed EPA must conduct a thorough analysis for maintenance, startup and shutdown and justify applying the existing emission standards under CAA section 112(d)(2) and (3) or instead develop an alternative numerical emission standard or 112(h) work practice during maintenance, startup and shutdown.

Commenters took exception to the EPA’s assertion that, “[w]e expect facilities can meet nearly all of the emission standards in Refinery MACT 1 and 2 during startup and shutdown, including the amendments we are proposing in this action,” or that, for process vents and transfer operations, it is common practice to start an APCD prior to startup. Commenters stated that there are numerous reasons why during startup and shutdown a source might not be able to comply with emission limitations established based on performance during steady-state operation, even if the control devices used are started up before the process units and are operational during the shutdown phase of a process. Commenters gave the example of a control that is less efficient until it reaches its design operating temperature, or is less efficient when the pollutant concentrations in the gases to be treated are lower than during steady-state operation. See, e.g., 68 FR1276 at 1287-88 (Jan. 9, 2003). One commenter stated that until a manufacturing process reaches steady-state operation, that process may generate substantially higher emissions, either on a total-mass basis or on a mass-per-unit-of-production basis. See, e.g., 76 FR 63878, 63883 col. 2 (Oct. 14, 2011). Commenters claimed if flammable gases are involved, routing the gases to a thermal destruction device before the concentration of the flammable compounds in the vent gas stream has exceeded the Upper Explosive Limit can result in an explosion.

Response 3: As explained previously, in removing the SSM exemptions in the Refinery MACT standards, we evaluated whether separate standards were necessary during periods of SSM, as well as during maintenance activities. As such, we have included alternative emissions limitations for startup and shutdown for additional emission sources beyond those in the proposal where we have determined that the standard that applies during normal operations cannot be met and where the startup and shutdown standards are achievable by the best performing units. In addition, as discussed previously, we are also establishing work practice standards for PRDs and emergency flaring, based on the best performing units. Also, we are finalizing requirements for opening process equipment to the atmosphere during maintenance events after draining and purging to a closed system. As explained further in the final rule preamble, these requirements will ensure that the maximum amount of material in the process equipment is sent to control before the equipment is opened for maintenance, consistent with practices at the best performing units. Regarding malfunction emissions, as provided in the preamble and elsewhere in this response to comments, exempting periods of malfunction from complying with emissions standards is not consistent with CAA section 302(k). We do not consider malfunction emissions in setting MACT standards, which are based on the best performers whether or not the affected source is defined as included periods of malfunction.

Comment 4: Several commenters supported the proposal to provide alternative emission limits for certain startup and shutdown activities at petroleum refineries. Another commenter stated that the EPA has offered no basis for the statement that control devices will be operating normally for certain startup and shutdown activities. First, the commenter raised a concern that thermal destruction control devices, such as catalytic oxidizers, often need to achieve a certain temperature before optimal destruction occurs, and that specific provisions for startup might be required for that type of equipment. Second, the commenter claimed that absorbers may need to be operated at different liquid/gas ratios during times of startup or shutdown where gas flow rates can vary and the commenter recommended that the final rule allow for the use of engineering calculations to establish a different liquid/gas limit during start-up and shutdown if the calculations demonstrate that the standard applicable during normal operations cannot be met.

Some commenters urged the EPA to allow a process for companies to apply for case-by-case limits to be approved by either the EPA or delegated States. The commenters suggested that advancements in technology and process improvements may occur in the future as well as the possibility that not all situations may be readily foreseen at this time. The commenters suggested a process similar to the case-by-case alternate NOx limits for process heaters operated under certain conditions as provided in Ja. Commenters noted that small refiners' equipment may be more constrained in flexibility due to its smaller size, and thus these requirements may pose a larger burden on small refiners.

Response 4: While we agree with the general proposition that sources may not be able to meet the limit applicable during normal operations during some startup and shutdown activities, we disagree that this is the case for the examples provided by the commenter. Thermal oxidizers can and should be brought up to temperature using natural gas fuel (or other non-HAP containing fuel) prior to being used as a HAP control device. There is no technical reason why the thermal oxidizer cannot be brought up to temperature prior to the startup of the unit that requires HAP control. With respect to absorbers, these units generally have a liquid-to-gas ratio that they cannot fall below. During startup, we anticipate that the gas flow rate will be small, so a normal (or even reduced) liquid injection/circulation rate would allow compliance with the operating limit. Thus, we do not believe it is necessary to allow "engineering calculations" as suggested by the commenter. We further note that we are concerned with such an approach since such calculations cannot easily be verified. Absorbers may also have a pH requirement, which again can be established and maintained during the startup of the absorber prior to introduction of the gas stream requiring control.

As discussed previously in this document in chapter 7, there is already a mechanism in place by which refinery owners or operators can request an alternative means of emissions limitation if after notice and opportunity for public hearing, the owner or operator establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the MACT standards. It is unclear that there is a circumstance in which it would be appropriate to set an alternative to a MACT standard for a single source since MACT is set at a prescribed level under CAA section 112(d)(2) and (3). We anticipate that the reason a source might wish to request an alternative limit is because for any number of reasons, they prefer to meet a less prescriptive requirement and not because they prefer to meet an equivalent or more prescriptive requirement. We do not agree that it is appropriate to establish a mechanism whereby small sources can request less prescriptive alternatives to the MACT limit. Again, the mechanism for prescribing the MACT level is set by statute and there is no exception for small sources.

We addressed the analogy to the NOx limits in Refinery NSPS Ja in chapter 10 of this document.

Comment 5: Commenters stated that the EPA needs to conduct a MACT floor analysis and when the EPA does so it is likely to conclude that section 112(h) work practice standards represent the only reasonable approach for regulating startup and shutdown activities. The commenter stated that a work practice is appropriate for startup and shutdown activities because it is not possible to safely measure compliance with numerical standards for startup and shutdown activities. Specifically, commenters asserted, performance testing is required to show compliance with applicable emissions standards if a continuous emissions monitor is not installed. The commenters alleged that because the process units are not at a steady state during startup and shutdown, it is not safe to perform a performance test. Commenters noted that that the applicable regulations generally prohibit testing during startup and shutdown and require that startup and shutdown data not be used for compliance purposes.

Response 5: We disagree with the commenter that a one-size-fits-all work practice standard approach should apply to startup and shutdown for all emission sources. For each separate emission source addressed in this rulemaking, we have evaluated and explained the basis for the emissions limitation that applies for startup and shutdown.

Comment 6: Commenters stated that if the standard applies continuously, then the EPA must evaluate emissions on a continuous basis, including emissions during malfunctions. The commenters charged that applying the same emission standards during malfunctions is not compelled by the statute or by applicable case law.

Commenters objected to the EPA assertions that “CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards” and that “[t]here is nothing in CAA section 112 that directs the agency to consider malfunctions in determining the level ‘achieved’ by the best performing or best controlled sources when setting emission standards.” The commenters countered that nothing in CAA section 112 allows the EPA to ignore malfunctions and set MACT standards based on a level of emissions that even best-performing sources only achieve part of the time. The commenters stated that even the best performing units in the source categories covered by the proposal are subject to a wide variety of potential malfunctions (e.g., power failures, equipment breakdowns) and that the EPA cannot rationally defend the view that applying the concept of “best performing” is inconsistent with a source experiencing a malfunction. The commenters argued that the EPA cannot ignore the requirement that MACT floor standards reflect performance actually achieved. Some commenters contended that EPA is going beyond the MACT floor by proposing standards that even the best performing sources cannot achieve part of the time and that EPA did not do a beyond-the-floor analysis.

Other commenters stated that the absence of a reference to specific operating conditions in CAA section 112 means that *all* operating conditions must be considered in setting the standards. Commenters noted that the case cited by EPA for recognizing that the Agency has discretion in setting MACT standards under section 112 makes clear that EPA's prior interpretation has been to consider all operating conditions in setting emission standards. *See Nat'l Ass'n of Clean Water Agencies v. EPA*, 734 F.3d 1115, 1143 (D.C. Cir. 2013) ("EPA believes that it must set MACT floors 'that the best performing sources can meet' every day and under all operating conditions..." (quoting 75 FR 63269 (emphasis added)).

Commenters argued that the courts have long recognized that a "technology based standard discards its fundamental premise when it ignores the limits inherent in technology." [See *NRDC v. EPA*, 859 F.2d 156, 208 (D.C. Cir. 1988] The commenters noted that the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), that "start-up" and "upset" conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id. at 399. The commenters also cited *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), cert. denied, 416 U.S. 969 (1974) in which the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." Finally, the commenters cited *National Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir. 1980) in which the court held that the CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "on a regular basis," including "under most adverse circumstances which can reasonably be expected to recur," including during periods of SSM. In addition to citing CAA cases addressing periods of SSM, the commenters cited similar cases under the Clean Water Act.

Commenters stated that the only decision that has dealt directly with how the EPA should address SSM issues in setting section 112 standards is consistent with these cases. The commenters claimed that in *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 872 (D.C. Cir. 2001) the court vacated MACT standards in part because of concerns about the EPA's failure to exempt hazardous waste combustors from numerical emission limits during SSM periods and because the Court had "doubts about EPA's decision to require sources to comply with standards even during openings of emergency safety valves caused by events beyond the sources' control." The commenter noted that in response to that decision, the EPA revised the rule to exempt facilities from the limitations during SSM events. See 40 CFR 68.1206(b)(1); 67 FR 6792, 6798, 6813 (February 13, 2002).

Commenters argued that the EPA's decision to disregard emissions during malfunction periods in the proposal is unreasonable in light of *NRDC v. EPA*, 749 F.3d 1055 (D.C. Cir. 2014) in which the court vacated the EPA's inclusion of an affirmative defense to emission violations during periods of malfunction. The commenters cited to a March 2014 rulemaking, 79 FR 17,340, 17,347 (Mar. 27, 2014), in which EPA explained the importance of the affirmative defense in the absence of an SSM exemption. The commenter noted that while the EPA questioned whether the cases the Agency relied on remained legally binding, the EPA noted that decisions "support the EPA's view that a system that incorporates some level of flexibility is reasonable and appropriate."

Response 6: Commenters assert that the EPA has failed to develop standards that are “achieved in practice” if the best performing sources are expected to have malfunctions, and those malfunctions result in emissions that exceed the standard. As an initial matter, the commenters appear to concede that the term “achieved” as used in section 112(d) is ambiguous. They make an argument that the statute as written clearly requires EPA to consider malfunctions in establishing MACT standards or to set separate standards for malfunctions. In fact, the terms “malfunction” is not used at all in section 112(d); rather that provision, when read in its entirety focuses on setting standards that reflect “best performing sources,” “maximum degree of reduction,” and “best controlled similar source.”

We disagree that the term “achievable” or “achieved in practice” must be read to mean that the standard must be capable of being met under any circumstance, such as during a malfunction. The argument that this term means that EPA must account for any type of malfunction in setting a MACT standard goes too far. Malfunctions of widely ranging severity and due to a wide variety of causes and can occur at any facility. The fact that these events may occur at some time during the life of a facility does not mean that a standard based on the operation of a best performer is “unachievable” simply because it does not reflect emissions levels that can occur during these events as a result of a lack of control. Hurricanes and malfeasance can occur at well-maintained and well-managed sources and can cause upset conditions that result in violations of emission standards, but this does not warrant factoring such unpredictable events into revised emission standards. Even if malfunctions were inevitable for all sources, including the best-performing sources, that does not make it possible to take them into account when establishing MACT emission standards, because they are still unknown in frequency, length, magnitude and, most importantly, effect on emission levels.

Rather, we interpret “achievable” as used in section 112 to mean that when a source is operating as it should that the standard is capable of being achieved. The fact that there may be a malfunction or other event that may cause an exceedance of the standard does not transform a standard that is achievable by a best performing source into unachievable standard. Under such reasoning, every MACT standard is potentially invalid because it does not reflect emission levels that may result from any possible event that might occur. We continue to take the position that it is reasonable to interpret section 112(d) as not requiring that standards take into consideration such unpredictable events because EPA cannot anticipate the frequency, length, magnitude and, most importantly, effect on emission levels. The EPA’s approach both accounts for variability associated with a reasonably foreseeable range of operating conditions and recognizes that enforcement mechanisms can address emission exceedances due to unpreventable equipment or process failures. While commenters may seek greater accommodation for malfunctions, such accommodation is not compelled by the Act.

Commenters cite to several cases to support their argument that EPA must consider malfunction emissions when setting standards under section 112. We disagree that those cases support an argument that EPA must consider undefined “malfunctions” in setting standards. Rather, those cases focused on more predictable events, such as startups and shutdowns and do not stand for the broad proposition advocated by the commenters. For example, the *National Lime* decision relied on by the commenters simply provides that the standards must be capable of being met “on a regular basis,” including “under most adverse circumstances which can reasonably be expected to recur.” Yet, the types of events that the commenters are suggesting must be addressed go well beyond events that happen “regularly” or that are likely to “recur.” Other cases, such as *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) upheld case-by-case enforcement discretion approach to addressing malfunctions because interjecting factors dependent on “murky determinations concerning the sequence of events in the plant, whether those events would have been avoidable” and similar factors, is inconsistent with the intent of Congress to require numeric emission standards that are measurable and easily enforceable. We further note that the cases relied on by the commenters (as well as the *Weyerhaeuser* case) are from the 1970s and 1980s and we believe that the court has refined its view since those decisions. As recognized by the court in *NRDC*, arguments that violation was caused by unavoidable technology failure can be made to the courts if an enforcement proceeding is initiated.

We disagree with the commenter’s argument regarding the decision in *Cement Kiln*. Nothing in *Cement Kiln* suggests that EPA has a duty to reflect in its emission standards emission levels that might occur during unpredictable malfunction events. To the contrary, *Cement Kiln* cuts to the heart of commenters’ argument. The fundamental principle of the commenters’ argument is that due to malfunctions, the MACT emission standards may be “unachievable” if specific sources experience a malfunction. However, the court rejected the notion that because a MACT standard may not be achievable by some sources, it is invalid. *Cement Kiln*, 255 F.3d at 861 (“EPA may not deviate from section 7412(d)(3)’s requirement that floors reflect what the best performers actually achieve by claiming that floors must be achievable by all sources using MACT technology.”). See also *Sierra Club v. EPA*, 479 F.3d at 878; *NACWA*, 734 F.3d at 1150 (explaining that the argument that a MACT standard is invalid because it is not achievable by all sources at all times has been “roundly rejected” by the Court).

Thus, unlike start-up and shut-down, which are foreseeable operations, no one can predict the nature, scope, severity, timing, length, number or likely recurrences of malfunctions a source may – or may not – experience. Although the EPA bases emission standards on different manners of operations and circumstances, in setting MACT standards, the EPA only takes into account conditions that are “foreseeable” and “which can reasonably be expected to recur.” *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999); see also *Nat’l Lime Ass’n v. EPA*, 627 F.2d. 416, 431 n.46 (1980).

Although EPA may have authority to address malfunctions through different mechanisms – albeit limited by the *Sierra Club* (striking down exemptions for malfunctions) and *NRDC* (striking down an affirmative defense for malfunctions) decisions, EPA is not required by section 112 to account for malfunction emissions by resetting MACT standards (e.g., with long averaging times) or by setting separate MACT standards (e.g., work practice standards) as suggested by the commenter. We note that in the final rule, based on detailed information submitted by industry for two types of malfunction events – PRD releases to the atmosphere and emergency flaring events - we established work practice standards.

Comment 7: Commenters raised a concern that EPA is not establishing alternative emission limits for malfunctions involving flares, relief valves, and control bypasses, which the commenters identify as critical safety devices. The commenters stated that these safety devices are designed to operate with emissions to the atmosphere under emergency or significant process upset situations. Commenters asserted that prohibiting atmospheric releases or subjecting use of this equipment to standards applicable during normal operations would place operators in the position of operating their units in potential non-compliance in order to protect plant personnel, the community, and equipment. One commenter stated that malfunctions are a “normal” operating mode for these systems.

Response 7: As provided in a previous response, we do not believe that section 112 requires EPA to consider malfunctions in setting MACT standards. However, for the reasons provided in detail in the preamble to the final rule, we have determined to set work practice standards for malfunction emissions vented to PRDs and flares, which serve as safety devices.

Comment 8: Several commenters stated that there are work practices - such as monitoring of operating parameters to identify a malfunction and stopping or cutting back the process - that represent the best practices for minimizing emissions during a malfunction. Commenters stated that while the measures that represent these best practices will depend on facility-specific issues, such as process design, pollution control train, and other factors, they nonetheless represent as required by CAA section 112(d)(2) & (3) “the maximum degree of reduction in emissions of the hazardous air pollutants...achievable...through application of measures, processes, methods, systems or techniques” and reflect “the emission control that is achieved in practice by the best controlled similar source[s].” Other commenters stated that a reasonable approach would be to gather data from the best performing sources on what operational “best practices” they have put in place to mitigate any excess emissions during a malfunction event and return to normal operating mode as soon as practicable. This could include things like: (1) preparing a plan or checklist to address possible malfunctions of equipment which would include operational procedures to be taken in the event of a malfunction; identification of back-up controls, monitors, etc.; reporting and recordkeeping requirements and (2) prompt investigation or root cause analysis to help prevent a recurrence of the malfunction.

Some commenters recommended that to address emissions during SSM the EPA could require every MACT source to prepare an SSM plan for minimizing emissions as close to the normal limit as practicable, and submit that plan to the EPA. The commenter stated that upon submission to the EPA, the plan would be an enforceable term of the applicable permit, and would provide for limits that are “continuously applicable.” The commenter suggested that the EPA would not need to approve the plans, but could reserve the right to comment on them, and to request changes where needed. Commenters claimed these SSM Plans would provide enforceable requirements to follow when unforeseeable startups or shutdowns or malfunctions, make it impractical or unsafe to monitor or meet numerical limits. Commenters claimed that an SSM plan requirement would be consistent with the *Sierra Club* decision, and noted that case addressed a challenge to the 2002, 2003 and 2006 changes to the SSM plan rules that gradually stripped away compliance requirements and public access to SSM plans to the point that the court concluded the EPA had eliminated the enforceability of their content altogether.

Response 8: We disagree that we should require sources to develop an SSM plan to address all emissions during SSM. As an initial matter, we believe that startup and shutdown are part of planned and expected operation of equipment and that an emissions limit can be established for those periods of operation. The emission limit will vary by emissions source and for different sources may be the same standard as applies during normal operations or may be an alternative standard that is a numerical limit, work practice standard or operational standard. We see no basis under section 112(d)(2) and (3) for allowing sources to establish in a separate planning document not subject to EPA approval how each emission source will address startup and shutdown emissions.

Regarding malfunctions, we believe that these events are generally varied and unpredictable and it is difficult or impossible to anticipate what actions a source might need to take during the different types of malfunction events that might occur. This is true both in terms of EPA developing emission limitations that would apply during these events and also in terms of a source identifying the actions it might take if such an event occurs. For that reason, we do not believe that a generic work practice standard or an SSM plan would be an effective tool for regulating emissions during a malfunction. Moreover, these approaches could possibly lead to a situation where significant HAP emissions are released and the public has no recourse because such emissions are "allowed" under the MACT standard.

Comment 9: One commenter urged the EPA to clarify that activation of an automatic shutdown system does not automatically mean that the event is a malfunction. The commenter claimed that automatic shutdown systems meet the definition of shutdown and/or startup. The commenter noted that there are conditions that occur within the process units that may necessitate that the unit shut down in a quick manner without significant planning beforehand, such as actions that will prevent or mitigate significant equipment damage, protect personnel safety, or protect the environment. The commenter contended that shutdowns that are triggered by an automatic shutdown system, including Safety Instrumented Systems (SIS) meet the definition of "shutdown" and "startup" as defined in the MACT general provisions (40 CFR 60.2).

Response 9: Shutdown means the cessation of operation of an affected source or portion of an affected source for any purpose. Therefore, if a safety instrumented system causes a cessation of operation of an affected source or portion of an affected source, then the phrase "for any purpose" covers that event and it would be considered a shutdown.

Comment 10: Several commenters agreed that EPA should not establish an "affirmative defense" to civil penalties for malfunction emissions that exceed the standards. One commenter, citing *NRDC v. EPA*, 749 F.3d 1055, 1062-63 (D.C. Cir. 2014), claimed the EPA has no authority to create such a defense by rule under the Act. Commenters asserted that affirmative defenses have been widely abused in Texas and claimed one refinery assumes that every single one of its emissions events will qualify for an affirmative defense.

Other commenters raised a concern that the proposal suggested that the *NRDC* decision somehow precludes the EPA from including an affirmative defense to penalties in an administrative enforcement action. The commenters asserted that the court specifically recognized that the EPA has authority to limit the situations in which it will impose administrative penalties in that manner. See 749 F.3d at 1063 ("By contrast, the EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court."). The commenters concluded that the EPA should affirmatively state in the final rule that the EPA will not seek administrative penalties for excess emissions caused by malfunctions.

Response 10: We appreciate the support for not proposing to include an affirmative defense for malfunctions. As the commenters note the court in *NRDC* vacated an affirmative defense in one of the EPA's section 112(d) regulations. The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the Court found: "As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.'" See *NRDC*, 749 F.3d at 1063.

Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. NRDC, 749 F.3d at 1064 (arguments that violation was caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.

Comment 11: Commenters contended that the EPA has provided no explanation for changing its position that it is inappropriate to rely on enforcement discretion, rather than establishing regulatory language addressing the inability of sources to comply with technology-based standards during SSM events. Commenters claimed courts have adopted the same view and cited *Portland Cement*, 486 F.2d at 398 n.1; *National Lime*, 627 F.2d at 431 n.46 ("the flexibility appropriate to enforcement will not render 'achievable' a standard which cannot be achieved on a regular basis, either for the reasons expressly taken into account in compliance determination regulations (here startup, shutdown and malfunction), or otherwise."); *Marathon Oil Co. v. EPA*, 564 F.2d at 1273 (EPA's statement that it would not take enforcement action against sources that exceeded effluent limitations because of upset events is "not an adequate response" to the argument that standards that cannot be met during unavoidable upsets fail to reflect available technology). Also, the commenters contended that the EPA's statements that the EPA will "determine an appropriate response" to reported exceedances based on, "among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions" (79 FR 36945), are not in any way a substitute for the EPA setting the standards at an achievable level in the first place. Commenters argued that the EPA should address the issues raised by the inherent conflict between continually applicable emission standards and the capability of the identified technology by promulgating some sort of alternative standard for SSM events.

One commenter stated that the EPA's statement that it would "use its case-by-case enforcement discretion" is woefully inadequate and questioned when and why would it ever be appropriate for the EPA not to use its enforcement discretion if the source is unable to comply with emission standards because of a malfunction, which the EPA defines as an event the source could not have avoided through better design or operation and maintenance. Commenters also raised a concern that the EPA's exercise of its enforcement discretion does nothing to prevent a source from having to defend itself from a citizen suit or state enforcement action for the same malfunctions.

Response 11: We addressed in a previous response the comments regarding that a standard needs to be "achievable" and our decision not to either consider malfunctions in establishing the MACT standard or set an alternative emissions limitations for most types of malfunctions.

Regarding the concerns that enforcement discretion is "woefully inadequate" from a facility's perspective and that sources may be required to defend against a citizen suit or state enforcement, as the court recognized in *NRDC*, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. *NRDC*, 749 F.3d at 1064 (arguments that violation was caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). Under section 113(e) of the CAA, the Administrator or the court considers a wide variety of factors in determining what penalty to assess, including compliance history and good faith efforts to comply.

Comment 12: Multiple commenters supported elimination of the SSM exemption and EPA's proposal to prohibit the release to the atmosphere from PRDs and stated that the CAA requires emission standards to apply continuously. Commenters asserted that exemptions for emissions during SSM does not encourage better control technology because it is easier to use a relief vent as a control device than to design and install equipment to give facilities better control of the process. Commenters stated eliminating the SSM exemption for flaring should drive a better maintenance program at refineries. Commenters stated that some refineries have frequently relied on the SSM exemptions in the past to avoid reducing their emissions and that it is important to "remove this unlawful loophole."

Commenters provided examples of where they believe emissions from SSM events can have significant air quality impacts. For example, commenters contended that emissions from a single flare incident, even with 99% destruction efficiency, could potentially equal or exceed routine emissions for the year, because of the large flows. Commenters also provided examples of SSM events that led to SO_2 emissions over the permit level and led to ambient air monitor readings exceeding the SO_2 NAAQS.

Some commenters asserted that all emissions, planned and unplanned, must be subject to emission limits. Commenters stated that the EPA has failed to limit flaring emissions from unplanned SSM events and asserted that Texas emission data shows a significant percentage of flaring occurs as unplanned events. One commenter requested that the EPA include requirements to prevent uncontrolled leaks, flaring, and explosions.

A few commenters stated that emissions from "emergency flaring" and other SSM emissions should be accounted for in regulatory permits and that the EPA should reject permit applications that fail to include all emissions.

Response 12: We appreciate the support for the elimination of the provisions that exempted sources from applicable emission limits during SSM. Regarding startup and shutdown, we are including in the final rule provisions to make the rule more practical and reflective of the emission limitations achieved by the best performing facilities.

As provided in previous responses, we disagree that section 112 requires EPA to set standards that apply to all malfunction events. However, in the final rule, we are establishing work practice standards that would apply to certain emergency flaring events and atmospheric releases from pressure relief devices (PRDs) because we believe that these types of releases are easily identifiable because flares, in part, and PRDs are devices that are designed to handle emissions from malfunctions in order to prevent safety risks to personnel and equipment.

The comments regarding what should be included in federal and state permits are beyond the scope of this rulemaking; those comments concern the requirements of the permit programs. However, in general, we note that the purpose of permits is to specify the regulatory requirements applicable to a source and to the extent that malfunctions result in emissions in excess of what is required by regulation, such emissions likely would not be identified as a regulatory requirement that is enforceable as part of a permit.

Comment 13: One commenter stated that history of the SSM exemption and compliance problems for refineries demonstrate the need for stronger and more frequent monitoring, testing, and reporting requirements, and additional enforcement provisions. The commenter stated that the EPA must implement strong enforcement provisions to prevent and remedy emission spikes, malfunctions and other violations in a way that will be enforceable by citizens in the Title V permits for refineries.

A commenter stated that the EPA must promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs. The commenter noted that while EPA is requiring reporting for certain releases in excess of the emissions standards, EPA proposed to delay reporting for much of these until the “periodic report,” which may occur as long as 8 months after the alleged malfunction. The commenter suggested EPA adopt a list of reporting requirements focused on providing information to the community within 24 hours and providing a more formal report to EPA within 7 days.

The commenter stated that a prohibition on malfunctions or other exceedances and quick reporting when malfunctions do occur are not enough to protect the most exposed people from refineries. The commenter stated that the EPA also must promulgate additional requirements that apply in the event of a malfunction or violation of the emission standards to protect local communities from health risk caused by refineries, and that facilities must not be able to emit in an unlimited manner for an unlimited period of time. The commenter provided a list of actions that it claimed EPA must require when a malfunction occurs, including automatic shut-off of equipment, specific corrective measures, and written authorization from EPA to restart in certain circumstances.

Another commenter encouraged the EPA to review best practices like near-miss incident reporting to ensure that malfunctions are prevented and minimized as much as possible.

Response 13: This final rule does not broadly address the issue of catastrophic events and safer practices, but as discussed previously, does establish standards for emergency releases to the atmosphere via PRDs and emergency flaring. Under a separate program, the EPA implements the mandates of CAA section 112(r) through its Risk Management Program (RMP). Among other things, this program requires facilities to develop and follow risk management plans so that there are plans in place setting out how a facility will respond to and mitigate emergency releases and how they will contact their local and state authorities so that in turn, the communities can be notified in a timely manner, if necessary in order to take further actions and precautions. The EPA, in coordination with the Department of Homeland Security and the Occupational Safety and Health Administration, has been working to solicit public input through notices for comment, community engagement and listening sessions on how to improve facility safety and security requirements in response to the President's August 2013 Executive Order 13650 "Improving Chemical Facility Safety and Security." On July 31, 2014, the EPA issued a Request for Information (see 79 FR 44604) to solicit public comments on potential revisions to its Risk Management Program (RMP) regulations and is currently evaluating those comments.

11.2 Testing and monitoring requirements

Comment 1: One commenter stated that the EPA has not justified eliminating application of the NESHAP General Provisions at 63.7(e) regarding performance tests, noting that the General Provisions require that performance tests be conducted under "representative performance" conditions. The commenter noted that, rather than reference the General Provisions requirements, the EPA proposed to amend requirements already in Refinery MACT 1 and 2, and in doing so for Refinery MACT 2, included regulatory language indicating that performance tests can be conducted during startup or shutdown if "specified by the Administrator." The commenter stated that such a regulatory change would allow the EPA to direct a source to conduct performance testing during abnormal operations, including startups and shutdowns. The commenter stated that, as the EPA and the courts have recognized, the manner prescribed for performance testing affects the stringency of the emission standard, and that requiring sources to demonstrate compliance using performance tests while the source is in startup or shutdown mode can have the effect of making those existing MACT standards more stringent. The commenter claimed that the EPA must provide a justification for such an amendment in light of EPA's previous judgment about the appropriate level of the standards and the appropriate conditions for performance testing. The commenter stated that the EPA must also demonstrate that the revised standards would still meet the criteria of CAA section 112(d). The commenter stated that it would only be appropriate for EPA to make this change if it first collects data during periods of startup and shutdown that are used to re-establish the MACT standard, and only after proposal and opportunity for public comments.

Response 1: As the commenter points out, rather than reference the performance testing requirements in the General Provisions at 63.7(e), we included requirement directly in Refinery MACT 1 and 2. We note that requirements were already in Refinery MACT 1 and 2, but as the commenter notes, we proposed amendments to that regulatory language. We did not directly reference the General Provision requirements. First, we wanted to be specific in the Refinery MACT standards that while performance testing should be conducted under normal operating conditions, those test should encompass the most challenging set of circumstances that occur under normal operating conditions. Second, the phrase in the General Provisions requirements stating, "emissions in excess of the level of the relevant standard...[are not] considered a violation of the relevant standard..." is inconsistent with the Sierra Club decision. However, we do not consider that the performance testing requirements that we added in Refinery MACT 1 and 2 are otherwise significantly different than those provided in the General Provisions. We note that we had intended to amend the requirements in both Refinery MACT 1 and 2 in a similar manner, consistent with the intent of the General Provisions; however, we inadvertently included the language about testing during periods of startup and shutdown in Refinery MACT 2. We have revised that language to remove that reference in this final rule.

Comment 2: A number of commenters disagreed with the quality assurance/quality control (QA/QC) requirements specified in subparts CC and UUU. Commenters claim that despite the logic and proven results of relying on manufacturer's recommendations and field experience for QA/QC, the proposal specifies instrument QA/QC requirements in Table 13 of Refinery MACT 1 and Tables 40 and 41 of Refinery MACT 2. The commenters stated the proposed requirements reflect an outdated and theoretical understanding of process instrumentation and do not reflect the capabilities of modern instrumentation or refinery experience. Because of the diversity of situations, the vast array of instrument technologies now available, the experience industry has developed in assuring high quality measurements, and the most efficient match with current practices and other applicable QA/QC requirements, a monitoring plan approach is the best way to deal with CPMS QA/QC. Commenters stated that other rules and permits applicable to this same equipment commonly include a requirement that manufacturers' recommendations be met. For example, Refinery MACT 2 already requires such CPMS monitoring plans; they are already in place and reflected in site permits and have been providing successful compliance assurance for decades. These plans require monitoring equipment to be "installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately." The commenter contend where manufacturer's specifications are available and appropriate to the actual installation, sources should be allowed to use these methods in place of the generic QA/QC requirements included in the proposed rule.

Additionally, commenters stated that the EPA has put forth no justification for overlaying the proposed new prescriptive requirements on top of the existing plans or for imposing the burdens on sources and regulators for modifying existing plans or for imposing the costs and burdens for additional QA/QC. The EPA has made no demonstration to justify these changes under section 112(d)(6) or (f)(2), including evidence that compliance assurance problems justify these extensive changes.

Commenters generally believed that these QA/QC requirements should be deleted from the tables in favor of their inclusion in a CPMS monitoring plan. However, if the EPA believes there is any justification for these high burden requirements in a modern facility, it should estimate costs and burdens, identify the justification, and publish those analyses for comment, in order to provide the analyses as part of the rulemaking record. If the EPA finalizes the proposed Refinery MACT 1 Table 13 and Refinery MACT 2 Tables 40 and 41 QA/QC requirements, then monitoring should be removed from the current operation, maintenance, and monitoring plan provisions throughout the current Refinery MACT 2, and the proposed monitoring plan requirements for Refinery MACT 1 should not be finalized, since these plans would only be documenting the requirements already specified in these rule tables. Additionally, commenters stated that 3 years are needed for compliance to allow evaluation of the many monitors currently in use; to design and install upgrades and/or replacement monitors as needed; to revise procedures, OMMPs and permits to reflect these changes; or to obtain alternate monitoring approvals where the requirements are infeasible or not appropriate. The commenter also stated that delay provisions to the next scheduled shutdown should be provided for those situations where a process or control device shutdown is required to complete a QA/QC activity.

Response 2: While we believe that it is essential for facilities to maintain a monitoring plan, we disagree that a monitoring plan overrides the need for minimum standards for instrumentation. Both subparts CC and UUU require that facilities develop monitoring plans. While it is often necessary and prudent to rely on manufacturer recommendations, the minimum standards outlined in the CPMS QA/QC requirements are meant to supplement manufacturer's recommendations in order to ensure the monitoring systems maintain the required levels of accuracy and reliability needed for continuous compliance. We believe that the general QA/QC requirements provided in these tables are very reasonable and achievable. If these requirements are more stringent than manufacturer's recommendations, we maintain that these minimum requirements should be followed and can be implemented fairly quickly. If a manufacturer recommends further QA/QC, more stringent QA/QC or more frequent QA/QC than is required by the applicable subpart, the regulations in no way inhibit a facility from performing the extra QA/QC. We also agree that each facility is unique and that diversity exists among the source category, which is another reason why site-specific monitoring plans are crucial. While a site-specific monitoring plan must still incorporate the minimum QA/QC requirements in the applicable subpart, it allows facilities based upon their own knowledge of their operations to determine what additional QA/QC is necessary and whether the QA/QC should be performed more frequently. For these reasons, we also disagree that because we have maintained the QA/QC requirements in Table 13 and Table 41 that we should remove the requirements for a site-specific monitoring plan. In addition to the possible need to supplement the QA/QC requirements specified by this rule, the site-specific monitoring plan should include information beyond what is included in these tables. For example, subpart CC explicitly lays out what should be in a monitoring plan, including a description of the equipment, the location, program of corrective action, how data acquisition systems handle out-of-control periods, etc. None of this is covered in Table 13, yet it is all integral to how the monitoring system operates and is maintained.

We do not believe that outlining minimum QA/QC expectations for CPMS will conflict with other rules or permits that have been issued. While these other rules and permits may specify that the facility should follow manufacturer's specifications, the requirements in this rule do not prohibit a facility from performing any QA/QC recommended by a manufacturer, although the QA/QC outlined in this rule should also be implemented if it differs from that recommended by the manufacturer as we believe that the requirements outlined in this rule are the basic QA/QC necessary to ensure the accuracy and reliability of the monitors. While commenters assert that relying on facility knowledge and manufacturer's recommendations have provided successful compliance assurance for decades, we believe that it necessary to ensure a consistent level of QA/QC across the industry. This is particularly important in order to decrease instances of monitor downtime and to ensure continuous compliance. Commenters stated that it was unnecessary to check monitor connections and to check for corrosion because loss of signal to the control room indicates when there is an issue with the connections; likewise commenters stated that normal industry practice is run-to-failure for certain temperature indicators. We believe that these are poor QA/QC practices that lead to preventable instances of monitor downtime, which in turn lead to periods where there is no assurance of compliance. Therefore, we believe it is appropriate to set minimum expectations for QA/QC in this rule.

We do not believe that the outlined QA/QC requirements pose a large burden on sources, as these are the types of procedures that facilities should be performing to ensure the reliability and accuracy of their instrumentation. We expect that facilities will have been performing these types of procedures for some time. We expect that if a facility has not been performing these types of procedures then they should see a decrease in downtime of their monitors by implementing these basic QA/QC procedures. A decrease in monitor downtime will increase compliance assurance and decrease periods of noncompliance, thereby benefitting the facility, the delegated authority and the public.

We disagree that 3 years are needed for sources to comply with the accuracy requirements we proposed (and are finalizing) in the tables. These accuracy requirements are very achievable for the different monitoring systems, with the exception of the proposed oxygen sensor monitor requirements in Table 41, which we have revised based on our review of these tables. The specified QA/QC requirements do not require installation of new monitors or alternative monitoring plans. Because manufacturer specifications should still supplement the specified QA/QC, we do not expect that facilities will be performing less stringent QA/QC than they were previously performing, and these new procedures should be able to be implemented while the facility updates its monitoring plan. We also do not believe that any of the specified QA/QC should require a unit shutdown. We have revised some of the proposed QA/QC requirements that were identified as problematic (e.g., checking pressure taps). We have also added in allowances for use of redundant sensors; redundant sensors would allow facilities to reduce the amount of QA/QC that is required.

We maintain that the requirements in the final rule are reasonable for existing monitoring systems; however, we reviewed these requirements to determine which, if any, may need additional time to meet. The provisions in Table 13 of Refinery MACT 1 apply predominately to new flare or DCU monitoring systems and 3 years are provided for those requirements. The temperature QA/QC requirement would apply immediately to temperature monitoring systems on MPV certain combustion control systems (other than flares). We expect any continuous temperature monitoring system would be able to meet the QA/QC requirements, so we are not providing additional time to comply with the requirements in Table 13. The only revision to Table 40 is the addition of QA/QC requirements for PM CEMS. These are identical to the PM CEMS requirements in Refinery NSPS Ja. We do not expect many units will have a PM CEMS and only FCCU subject to NSPS Ja are expected to have a PM CEMS, so we expect any FCCU with a PM CEMS would already be complying with the requirements in Table 40. Therefore, more time is not being provided for compliance with Table 40. However, there are numerous existing CPMS requirements in Refinery MACT 2 and new QA/QC requirements were proposed for flow monitors, composition monitors (for determining coke burn-off rates) in addition to new requirements for pressure and temperature sensors. While we expect that most monitors should be capable of meeting the QA/QC requirements in Table 41, we consider it likely that as least some monitoring systems may need to be upgraded in order to comply with the requirements in

Table 41. Therefore, we are providing an 18-month transition period for compliance with the requirements in Table 41.

Comment 3: One commenter stated that the EPA must require continuous monitoring of emissions from refineries. The commenter provides a weblink to the Institute of Clean Air Companies and stated that EPA is aware there is technology available to perform CEMS for Hg, HCl, HF, PM, and opacity. The commenter asserted that the EPA should require the use of all developments in continuous emission monitoring under section 112(d) and section 112(f) to assure continuous compliance with emission standards, to implement the clean air act's enhanced monitoring requirements, to take into consideration new developments in monitoring technologies, and to assure an ample margin of safety. The commenter claimed stronger emission monitoring is particularly needed due to the problematic compliance and exceedance history. Finally, the commenter claimed EPA should require immediate reporting on the Internet of all monitoring reports.

Response 3: We disagree that it is necessary to require continuous monitoring of all refinery emissions as part of the risk and technology review. The monitoring requirements in this final rule consist primarily of a combination of periodic compliance emission testing and continuous parameter monitoring systems which we believe to be appropriate and sufficient for assuring ongoing compliance with these standards. While we have provided an alternative to use a PM CEMS for the FCCU regenerator, we also note that these systems have not been used or verified on the FCCU source. Therefore, we are not requiring it as the only monitoring alternative at this time. We also note that the web page cited by the commenter does not suggest that there are CEMS for PM and mercury for refinery sources. The PM and mercury links from this page are for control systems for these pollutants, not CEMS. Although we disagree that it is necessary to require CEMS for all refinery emissions as part of the risk and technology review, we note that we are enhancing the monitoring requirements for certain provisions, such as finalizing additional continuous opacity monitoring requirements for FCCU complying with NSPS J, revising averaging times for monitoring data, and finalizing continuous monitoring of pressure relief devices to identify releases, as part of the final rule.

Regarding the request that we should require immediate reporting on the Internet of all monitoring results, we disagree that "immediate" reporting of results is necessary or useful. Although we are moving towards providing compliance data to the public through WebFIRE these data must be quality assured, which requires time to conduct necessary checks to maintain the integrity and accuracy of the information we make available to the public. In general, public access to electronic data submitted to the EPA would be available in WebFIRE within 60 days of submission.

Comment 4: Commenters stated that, if retained, Refinery MACT 1 Table 13 and Refinery MACT 2 Table 41 should be made consistent based on the least burdensome requirement in each table, and the language should be changed such that the same terminology is used in both tables. The commenters noted that the inconsistencies range from fairly minor points (e.g., using metric units in one table and English units in the other) to major differences (e.g., frequency of instrumentation checks). The commenters contend that the differences are confusing and lead to compliance and enforcement problems.

A commenter noted that some of the QA/QC requirements specified in the tables in part 63 subparts CC and UUU differ from the QA/QC requirements specified for the same flare instrumentation in part 60 subpart Ja. The specifications for the flow monitors in NSPS Ja do not coincide clearly with the specifications of available instrumentation or the proposed requirements in Table 13 of subpart CC. Ultrasonic flow meters are the bulk of the new and existing flow instrument in this service. The commenter recommended the flow meter specification should mimic the Shell Deer Park Flare consent decree.

Additionally, the commenter stated there are similar issues in the specifications for FCCU Regenerator flow meters and for sulfur recover plants (SRP) flow meters, through the proposed specifications in Table 41 of subpart UUU and the proposed additions of section 60.106a(a)(6) and (7) to NSPS subpart Ja. Relative to FCCU, the commenter recommended an accuracy requirement of ±5% over the normal flow range. For SRPs, the commenter requested that the provisions be made consistent with those in Table 13 of subpart CC. The commenter requested that the EPA clarify all NSPS Ja flow monitor specifications and provide clear specifications that are consistent with available instrumentation specifications and that avoid unjustified replacement of existing instruments.

Two commenters noted concern with the term “measurement sensitivity” in proposed sections 60.106a(a)(6)(i)(B) and 60.106a(a)(7)(i)(B) in both the sulfur recovery unit oxygen (O_2) alternative and flare flow standards in existing regulations 40 CFR 60.l07a(f)(l)(ii). One commenter believes this term requires clarification since “sensitivity” is not a term found on typical data sheets and requested that the terminology used in these paragraphs be amended to match the wording found in Table 13 of subpart CC.

Response 4: While we agree that the requirements for CPMS in Table 13 of subpart CC and Table 41 of subpart UUU should be made consistent for the same type of CPMS, we do not agree that the reconciliation must be made using the least burdensome requirement. We have reviewed the requirements in these tables as well as the requirements for existing CMS in NSPS subpart Ja and part 60 Appendix F to identify those minimum QA/QC requirements needed to ensure accurate data are available for the CPMS. Based on this review, we have made revisions to the requirements in these subparts and have reconciled the differences in the requirements to address the concern that differing requirements are burdensome and lead to compliance issues.

For flare flow meters, specifications in Table 13 of subpart CC and NSPS Ja have been updated to ±20% for a velocity range of 0.1-1ft/s and ±5% of reading for a velocity > 1 ft/s in order to better align with what is achievable, considering the widespread use of ultrasonic flow monitors. The requirements in Table 41 of subpart UUU and the requirements for the flow sensors for SRP in NSPS Ja have been updated to be consistent with those in Table 13 of subpart CC (i.e., ± 5% over the normal range of flow measured or 280 liters per minute (10 ft^3/min) whichever is greater, for gas flowrate). Additionally, we have updated the requirements for flare and SRP flow meters in NSPS subpart Ja to refer to monitor accuracy rather than measurement sensitivity.

Comment 5: Commenters were concerned about the new QA/QC requirements for CMS being applied retroactively based on the EPA’s claim in the proposed rule that these requirements reflect what the EPA “always intended”. Clearly identified applicability dates are needed to ensure that the changes are not interpreted to apply retroactively. This could be achieved by adding a paragraph below the title for Refinery MACT 1 Table 13 and Refinery MACT 2 Tables 40 and 41 to indicate that these tables only apply after the compliance date for these amendments. Another commenter suggested the changes to Table 40 should be included in a new Table (e.g., Table 40a) with a clear applicability date for the new requirements specified.

Additionally, commenters stated the EPA should make clear the applicability of the tables. Refinery MACT 1 Table 13 should clearly indicate that the table only applies to monitoring instrumentation for flares as specified in 40 CFR 63.671, for Group 1 MPV combustion controls as specified in 40 CFR 63.644(a), and for monitors used to monitor for flow in potential bypasses around Group 1 MPV control devices as specified in 40 CFR 63.644(c).

Response 5: The revisions to the CMS QA/QC procedures are new requirements that apply to the facility owners and operators only after the applicable dates provided in the final rule. While we have not listed the applicability dates in the header of the tables, we have indicated the applicability dates in the referencing regulatory text. For flare monitoring systems for example, the requirements of Table 13 in subpart CC are referenced in §63.671(a)(1) and (e)(1). §63.670 clearly indicates when the requirements of §63.671 become effective.

The changes in Table 40 to subpart UUU are minor clarification changes or changes that address compliance options that were added to the rule. For example, a PM CEMS option was provided in the rule so QA/QC requirements for this is a new CEMS needed to be added to Table 40 to ensure that the monitor is calibrated for the appropriate range over which it will be used. Because the changes in the table are minor and the changes are linked to the changes in the emission limit alternatives, the applicability dates are better suited to be placed on the emission limits, and we do not see a need to create a new Table 40a. As noted in a previous response in this section, we are providing an 18-month transition period for Table 41 because the revisions in Table 41 were significant and impact a wide variety of existing monitoring systems.

Additionally, we believe that the regulatory text is clear on where these tables apply. Adding applicability notations can become extremely cumbersome, especially if the list grows in the future, and adds additional room for error and confusion if a specific reference is inadvertently left out. We believe that it is most clear to let the regulatory text reference the tables when they are applicable.

Comment 6: One commenter stated that Table 13 of subpart CC allows relief from certain QA/QC flow meter requirements if “redundant” sensors are available; this provision should be clarified and extended to Table 41 of subpart UUU. It is unclear what this term means, particularly relative to flow monitors. In response to a similar question relative to a similar requirement in NSPS subpart Ja, the commenter noted that the EPA stated the following:

> Any meter or collection of meters that can provide a continuous measure of the cumulative flow at the location of the required flare flow meter would qualify as a “redundant flow sensor” in 40 CFR 60.107a(f)(1)(iv).

> [Reference: Letter from P. Tsirigotis, EPA to Matt Todd, API/AFPM, *NSPS Ja Clarifications and Corrections,* August 27, 2013, Response to Question 14.]

The commenter requested this same clarification be made in the response to comments for this rule or that the regulatory text be revised to make clear what a redundant flow monitor is.

Additionally, the commenter requested clarification that a redundant temperature or pressure monitor would be one that measures the required temperature or pressure, even if it is not located on the same pressure tap or in the same thermowell. Alternatively, to alleviate the need for clarification, the commenter stated that the EPA should replace the word “redundant” with “alternative” in Table 13 of subpart CC.

Response 6: We have reviewed the requirements in the tables to improve the consistency in the CPMS requirements between subparts CC and UUU. The redundant flow monitor provision in Table 13 of subpart CC (which we are also finalizing in Table 41 of subpart UUU) is analogous to the requirement in 40 CFR 60.107a(f)(1)(iv), and the clarification provided in the letter from P. Tsirigotis also applies here. As stated in that letter, the purpose of the inspection requirement is to ensure that the flare flow measurements are not lost due to physical or operational integrity problems, especially for reasons that could be avoided with appropriate preventive maintenance. A redundant monitor can be a single meter, or if the flow measurement can be determined by summing the flow from a series of other meters, the series of meters could serve as a redundant flow monitor. The determination for whether a redundant flow monitor exists is whether the required flow measurement is lost when the primary flow meter is down. If the required measurement is not lost, then a redundant monitor exists.

We also agree that the same situation applies for the pressure or temperature monitor. The redundant sensor does not need to be on the same pressure tap or thermowell, as long as the required measurement is not lost when the primary meter is down. The redundant sensor must meet the CPMS requirements in the applicable subpart. The owner or operator must also comply with the operating limits using this redundant monitor. Thus, if an owner or operator elects to use a temperature monitor at the incinerator exit as a redundant sensor to a temperature monitor in the incinerator firebox, then the owner or operator must comply with the temperature operating limit at the redundant monitoring location (i.e., at the incinerator exit) if the signal for the firebox temperature sensor is lost.

We are retaining the word redundant in the tables, as we believe the intent is clearer with the word redundant than with the word alternative. We are also concerned that the use of the word alternative may cause confusion between a redundant monitor and a monitor approved under an alternative monitoring plan.

Comment 7: Several commenters disagreed with specific QA/QC requirements for CPMS:

- Pressure tap pluggage would be highly unusual in a refinery flare system or other combustion based control device. Where pluggage is a problem, engineering fixes (such as adding blow back steam or nitrogen) are usually preferable to daily or other routine checks because they avoid environmental releases and potential personnel exposure. The requirement in Table 13 of MACT 1 and Table 41 of MACT 2 to check for pressure tap obstructions should be replaced with the requirement to check that the pressure instrument is responding (i.e., review straight-line readings), as a check of instrument response covers the situation of a plugged pressure tap

- Checking for pluggage of a pressure tap generally requires purging the pressure sensor, thereby releasing VOC and HAPs to the atmosphere. If the requirement to check for pressure tap obstruction is maintained, it should be changed to a weekly check, and the resulting emissions to the atmosphere or to the flare should be specifically authorized.
- The costs and burdens for checking for pressure tap obstructions have not been considered in the rulemaking record and are significant. The commenter estimated a typical incremental burden of 30 minutes per day of operator time for each pressure CPMS. For delayed cokers, there are an average of 3.2 drums per unit and approximately 80 units resulting in an annual industry burden of over 46,000 hours per year for this one set of pressure instruments. Since no emission reduction is associated with this activity, the cost per ton of emissions reduction is infinite.
- The requirements to check continuity on wiring and electrical connections and visually check for corrosion are pointless, as are daily, weekly, monthly, and quarterly instrument inspections for integrity issues. For most instrument transmitters, if the continuity fails on any wiring the signal will no longer show in the control computer, and a work notification will be created to fix the problem. For most noncritical temperature indications, run-to-failure is the normal industry practice. The replacement of critical temperature indicators is typically done on a turn-around cycle to prevent failure during normal operation.
- Manometers are unsafe to use and should not be required for pressure instrument calibration. NIST traceable digital instrumentation is generally used instead of manometers for most pressure instrument types. Because calibration practices change over time, facilities should be allowed to determine the appropriate technology to be used for calibration, based on recommendations from instrument manufacturers.
- Annual calibration is a reasonable calibration frequency and all that should be required for most monitors. Currently, annual calibration is performed in most cases, so moving to more frequent calibrations is burdensome.

Response 7: We have reviewed the QA/QC requirements in subparts CC and UUU in response to these comments. Based upon our review and consideration of the comments received we have updated certain CPMS QA/QC requirements.

We agree that weekly checks of system response are sufficient to ensure the pressure monitoring system is not plugged. We have revised the requirements in Table 13 of subpart CC and Table 41 of UUU to remove the requirement to specifically check for pressure tap obstructions and to require weekly checks that the system is responding and to check for straight line (unchanging) pressure.

We disagree that it is unnecessary to perform physical inspections of wiring and connections associated with CPMS for integrity issues (e.g., corrosion, continuity, leakage, etc.). Although it is true that when the connection is lost a signal will no longer show in the control room, the point of the inspection is to catch issues before they reach the point of causing a lost signal. Once the

CPMS reaches the point of losing signal to the control room, the problem may be substantial such that the monitor will need to be taken out of service in order to fix it. It is prudent to inspect the connections prior to this point in order to minimize monitor downtime. However, in the final rule we have changed the requirements from monthly checks of pressure, temperature, oxygen and flow rate sensors for leakage, galvanic corrosion, and continuity to quarterly checks. We believe that quarterly checks will provide sufficient inspection of these systems for potential issues prior to the point of failure of the signal to the control room.

We agree that some systems may operate at pressure ranges that are not suitable for measurements with monometers and that NIST traceable instruments are acceptable alternatives for performance evaluation of these pressure CPMS. We have removed references to the use of a manometer for the performance evaluations.

In reviewing the QA/QC requirements for pressure CPMS in subparts CC and UUU, we noted that the proposed rule contained an annual performance evaluation in Table 13 of subpart CC but quarterly performance evaluation in Table 41 of subpart UUU. We agree that an annual performance evaluation should be frequent enough to ensure adequate operation of the pressure monitors covered by these subparts. As part of the reconciliation review of these requirements, we have revised the calibration check for these devices to annually in both tables. However we retain, with modifications, a requirement to review the pressure monitor output at least once per week to verify that it is still operating properly and to perform corrective action if the pressure readout suggests that there is blockage of the pressure tap (e.g., straight-line readings). We have also revised the flow rate sensor calibration check requirements from semiannual to biennial (every two year) and the oxygen content sensor calibration check requirements from quarterly to annually. We believe that these frequencies provide adequate assurance that the monitors are operating appropriately.

Comment 8: One commenter stated that approval should not be required for data compression systems meeting rule requirements. The commenter stated that 40 CFR 63.655(h)(5)(iii) and 63.1573(d) specify requirements for use of digital data compression systems. [40 CFR 63.1573(d) is currently 40 CFR 63.1573(c), but proposed to be renumbered.] While such systems were fairly new in 1994, they are standard now and data compression meeting the requirements listed in these paragraphs is standard. Data compression is critical to assuring adequate data storage and response time, because of the vast amount of data obtained by digital process data systems and the large number of parameters monitored in a modern process operation. Many requests for approval to use such systems have been submitted under Refinery MACT 1 and 2 and approved and we believe the burdens associated with obtaining such approval is no longer justified if the criteria listed in each paragraph is met. The commenter therefore requested that the requirement for obtaining approval to use these standard systems be changed to maintaining a record that such a system is being used.

Response 8: We agree with the commenter and we have removed the requirement to obtain approval to use these systems. We are not removing the requirements that the data compression system must meet; we are only revising the requirement to obtain approval with a recordkeeping requirement that the system meeting those criteria is being used.

11.3 General duty provisions

Comment 1: One commenter stated that the EPA has not justified adding new “General Duty” language to the existing subparts CC and UUU and should not finalize those proposed revisions. The commenter noted that the EPA proposes to replace the NESHAPs General Provisions section that establishes a “general duty” to operate a source consistent with safety and good air pollution control practices for minimizing emissions, 40 CFR 63.6(e)(1), with somewhat different “general duty” language in proposed sections 63.642(n) and 63.1570(c). The commenter charged that this change is not being proposed under CAA sections 112(d)(6) or 112(f), and the EPA, therefore, lacks authority to make this change to the existing NESHAPs. The commenter stated that the EPA’s only explanation for these changes is that “[s]ome of the language ... is no longer necessary or appropriate in light of the elimination of the SSM exemption.” See 79 FR 36945.

The commenter stated that D.C. Circuit did not vacate the provision the EPA proposes to replace, 40 CFR 63.6(e)(1), in *Sierra Club v. EPA* and, contrary to the EPA’s assertion in the preamble to the Proposed Rule, 40 CFR 63.6(e)(1) does not reference provisions that were vacated in *Sierra Club v. EPA*. [Compare Table 6, 79 FR 36990, and Table 44, 79 FR 37043 of the Proposed Rule with 79 FR 36945.] The commenter stated that even if the EPA had authority to change the existing MACT standards in ways not required to address residual risk or new technology, the Agency would have to provide a cogent explanation of why the old rule was unacceptable and the new rule is necessary. The commenter stated that the EPA has not done so here.

The commenter stated that the EPA should not include proposed sections 63.642(n) and 63.1570(c) in the final rule. Alternatively, the commenter stated that the EPA needs to re-propose the provision with some explanation of the basis and purpose for the provision, to allow the public an opportunity to provide meaningful comments, as required by CAA section 307(d)(3). The commenter noted that the general duty language contained in the General Provisions and the proposed general duty language are inconsistent with the EPA’s insistence that “releases” from relief valves are a violation of the proposed standards. The commenter asserted that it would be arbitrary and capricious for the EPA to promulgate regulations that require operation of relief valves (because they are necessary for the operation of the source consistent with safety and good air pollution control for minimizing emissions) and simultaneously state that it is a violation of the standards when those relief valves perform their intended function.

Response 1: We did not propose these revisions pursuant to either CAA section 112(d)(6) or 112(f)(2). Rather, we proposed these revisions pursuant to our general authority to revise regulations previously promulgated by the Agency. As we explained in the preamble to the proposed rule, in order to ensure consistency with the court’s decision in Sierra Club, we proposed to remove provisions that exempted sources from compliance with emission standards during periods of SSM. Because we are requiring that emission standards be met during periods of SSM, we also proposed to remove the applicability to refinery MACT 1 and 2 sources of the “general duty” provision, which provides: “The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices.” We are including all of the requirements for periods of SSM for Refinery MACT 1 and 2 sources in subparts CC and UUU rather than continuing to cross reference the General Provisions.

Regarding the concern that a general duty provision is inconsistent with the proposed ban on the atmospheric releases from PRDs, we note that we are not finalizing the PRD provision as proposed; instead, we are establishing work practice standards that apply to PRD releases.

11.4 Electronic reporting requirements

Comment 1: A few commenters stated that the proposed use of the Electronic Reporting Tool (ERT) is not appropriate because the costs and burdens imposed are additive to the costs of producing and submitting the written report, and there is no benefit that justifies the additional cost. One commenter also stated that the EPA has not developed or articulated a reasonable approach to using information that would be uploaded to the ERT. The commenters recommended that the EPA remove this portion of the proposal until the ERT is demonstrated to handle all the information from refinery performance tests (rather than only portions), thereby eliminating the need for both written and electronic reporting and until the Agency demonstrates that it is using the electronic data to develop improved air quality emission factors.

The commenters stated that there is essentially no likelihood the ERT systems will be able to handle entire part 63 performance tests in the foreseeable future, and the added ERT burden makes submission of reports within the short, required time (60 days) more difficult. One commenter noted that the EPA proposed (in 40 CFR 63.655(9)(i)(B)) to require submittal of performance test results to the EPA for tests conducted that are not compatible with the ERT. The commenter stated that this added requirement complicates the cost and logistics of test reporting for the industry and testing contractors by having to submit a report to the state agency, enter partial information into the ERT, and then perhaps also having to send a full copy of the test report to the EPA regional office. Another commenter similarly stated that the ERT requirement does not supersede or replace any state reporting requirements and thus the regulated industry will be subject to dual reporting requirements. Both commenters disagreed with the preamble claim that eliminating the recordkeeping requirements for performance test reports is a burden savings, and state that it may duplicate burdens already borne by the regulated community.

The commenters expressed further concern that duplicative reporting requirements will strain the regulated industry to comply with deadlines established by the rules for report submittals. One commenter stated that there is no mechanism for obtaining extensions for special circumstances. Under proposed 40 CFR 63.655(h)(9)(i), all reports are due in 60 days. By not referencing reporting requirements to the General Provisions in 40 CFR 63.10(d)(2), there is no allowance for obtaining additional time due to unforeseen circumstances or due to the difficulties involved with completing particularly complex reports.

One commenter stated that the primary performance test method (Method 18) required for determining compliance is not currently included in the list of methods supported by the ERT. The commenter stated that the regulated community’s experience with Method 18 is that it is a very broad methodology and can be exceptionally complex to execute and to report. The commenter stated that the EPA is aware that Method 18 reporting is complex; that it may be difficult to incorporate into the ERT; and that no time schedule has been defined for development or implementation for this method.

The commenter also stated that without formal notice of changes to the ERT, the regulated community is at risk of non-compliance. The only way for the regulated community to know that changes have occurred within the ERT is to directly monitor the web site. Changes made to the ERT are not formally announced by the EPA in the Federal Register so it will be possible for a regulated entity to be unaware of changes made such as the incorporation of Method 18. The commenter expressed concern that the proposal language is an open-ended commitment subject to change without notice. The commenter stated that the EPA should clearly indicate when facilities would be required to use the ERT when new test methods are included in the ERT.

Response 1: We disagree that use of the ERT for completing stack test reports is an added cost and burden. To the contrary, based on the analysis performed for the Electronic Reporting and Recordkeeping Requirements for the New Source Performance Standards Rulemaking (ERRRNSPS) (80 FR 15100), electronic reporting results in an overall cost savings to industry when annualized over a twenty year period. The cost savings is achieved through means such as standardization of data, embedded quality assurance checks, automatic calculation routines, and reduced data entry through the ability to reuse data in files instead of starting from scratch with each test. As outlined in the ERRRNSPS, there are many benefits to electronic reporting. These benefits span all users of the data – the EPA, state and local regulators, the regulated entities, and the public. We note that in the preamble to the proposed rules we provided a number of reasons why the use of the ERT will provide benefit going forward and that most of the benefits we outlined were longer-term benefits (e.g., reducing burden of future information collection requests). Additionally, we note that in 2011, in response to Executive Order 13563, the EPA developed a plan[104] to periodically review its regulations to determine if they should be modified, streamlined, expanded, or repealed in an effort to make regulations more effective and less burdensome. The plan includes replacing outdated paper reporting with electronic reporting. In keeping with this plan and the White House's Digital Government Strategy[105], in 2013 the EPA issued an agency-wide policy specifying that new regulations will require reports to be electronic to the maximum extent possible. By requiring electronic submission of stack test reports in this rule, we are taking steps to implement this policy. We also disagree that we have not developed or articulated a reasonable approach to using information that would be uploaded to the ERT. To the contrary, we have discussed at length our plans for the use of stack test data collected via the ERT. In 2009, we published an advanced notice of proposed rulemaking (74 FR 52723) for the Emissions Factors Program Improvements. In that notice, we first outlined our intended approach for revising our emissions factors development procedures. This approach included using stack test data collected with the ERT. We reiterated this position in our *Recommended Procedures for the Development of Emissions Factors and Use of the WebFIRE*

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[104] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: http://www.epa.gov/regdarrt/retrospective/documents/eparetroreviewplan-aug2011.pdf.

[105] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: https://www.whitehouse.gov/sites/default/files/omb/egov/digital-government/digital-government-strategy.pdf

Database (http://www.epa.gov/ttn/chief/efpac/procedures/procedures81213.pdf), which was public noticed before being finalized in 2013. Finally, we discussed uses of these data in the preamble to the proposed rule and at length in the preamble to the ERRRNSPS.

We think that it is a circular argument to say that the Agency should eliminate the use of the ERT until it demonstrates that it is using the electronic data. It would be impossible for the agency to use data that it does not have. We can only use electronic data once we have electronic data. We do note that we are nearing completion of programming the WebFIRE database with our new emissions factor development procedures and anticipate running the routines on existing data sets in the near future.

We continue to improve and upgrade the ERT on an ongoing basis. The current version of the ERT supports 41 methods, including EPA Methods 1-4, 5, 5B, 5F, 25A 26, and 26A. We note that the ERT does not currently support EPA Method 18, and for performance tests using Method 18, the source will still have to produce a paper report. However, we are aware of the need to add Method 18 to the ERT, and we are currently looking at developing this capability. As noted in the ERRRNSPS, when new methods are added to the ERT, we will not only post them to the website; we will also send out a listserv notice to the Clearinghouse for Inventories and Emissions Factors (CHIEF) listserv. Information on joining the CHIEF listserv can be found at http://www.epa.gov/ttn/chief/listserv.html#chief. We are requiring the use of the ERT if the method is supported by the ERT, as listed on the ERT website (http://www.epa.gov/ttn/chief/ert/ert_info.html) at the time of the test. We do not agree that it is overly burdensome to check a website for updates prior to conducting a performance test.

While the requirement to report the results of stack tests with the ERT does not supersede state reporting requirements, we are aware of several states that already require the use of the ERT, and we are aware of more states that are considering requiring its use. We note that where states will not accept an ERT submittal, the ERT provides an option to print the report, and the printed report can then be mailed to the state agency. We believe that the time savings in the ability to reuse data elements within reports is more than equivalent to the cost incurred by printing out and mailing a copy of the report.

Comment 2: Two commenters expressed interest in 24/7 emissions information. One commenter asked for a public website reporting daily air pollution and flaring events, while another commenter asked a public website posting real-time fenceline monitoring data. The commenter described LACEENonline.org which gives citizens an opportunity to call or enter online notification of episodes (e.g., flare-ups, explosions, fume releases). The commenter noted that LACEEN is being used as a demonstration project all over California through the Department of Toxic Substances Control (DTSC) agencies. The commenter recommended a comprehensive plan with the EPA overseeing the AQMD, DTSC, and ARB, and all of our non-profits working together to build a communication and data sharing system. The commenter suggested they would be able to give each agency pertinent information and ensure data are displayed in libraries, churches or city halls on a monthly basis. The commenter contended that the public is not getting enough information.

Response 2: The commenter is requesting monitoring data to be posted that goes beyond the scope of the monitoring requirements in Refinery MACT 1 and 2, as amended by this final, which we have determined is sufficient to demonstrate compliance with the standards. We note that we are providing a website where the fenceline monitoring data will be available to the public. However, as we have discussed previously in chapter 8 of this document and in the preamble to this final rule, those fenceline data are not real-time data. In terms of the commenter's suggestion that the EPA provide a system where citizens can report episodes, we note that the EPA already has a mechanism for individuals to report what appears to be a possible violation of an environmental regulation at http://www2.epa.gov/enforcement/report-environmental-violations. However, many environmental programs have been delegated to the states and they have primary responsibility for them. Often, it is most appropriate for an individual to contact their local city, county, or state environmental agency (or health department) rather than the EPA. We also note that much of what the commenter is requesting fall within the scope of the EPA's RMP, which is discussed in more detail earlier in this chapter.

12.0 Refinery NSPS Subpart Ja

Comment 1: One commenter stated that if the proposed rule is finalized many atmospheric RVs will be routed to flares that will have to meet the new section 63.670 flare requirements, but making the additional connections to the flare header for RVs will also trigger NSPS Ja requirements for that flare and any interconnected flares because of the unique modification definition in NSPS Ja for flares. The commenter believes it is unreasonable to force flares into NSPS Ja sulfur and other requirements, through this rulemaking, which deals with organic HAPs and assures their destruction and of any associated VOC. The commenter recommended EPA add language to NSPS Ja to exclude the tie-in of atmospheric RVs to an existing flare header as an NSPS Ja modification.

Response 1: First, we note that we have revised the proposed requirements such that the final rule includes a requirement for refinery owners or operators to provide a minimum of 3 prevention measures to ensure atmospheric PRDs do not release rather than requiring all atmospheric PRDs to be vented to the flare. We note that some refinery owners or operators may elect to connect these PRDs to a flare header, but the final rule does not require all PRDs to be vented to a flare or other control system. Second, we estimated that all flares would be subject to subpart Ja within the time frame associated with the compliance with the final MACT requirements. As such, we see no need to exclude any new connections made to a flare header as a result of the MACT rule revisions.

Comment 2: One commenter notes that with respect to the flow measurement QA/QC standards in proposed sections 60.106a(a)(6)(i)(D), 60.106a(a)(7)(i)(D), 63 subpart CC Table 13 and 40 CFR 60.107(f)(l)(iv), most electrical connections associated with flow meters are in NEC Class I, Division 2 areas. This, the commenter states, is to provide a degree of protection from corrosion (versus nonsealed applications). The commenter states that conducting intrusive inspections could add risk which would not otherwise occur. Examples of intrusive inspection risk include the introduction of material into the connection, improper re-sealing of the connection enclosure, or loosening of connections. The commenter requests that due to the low risk of connection failure and the burden of quarterly inspections, the inspection requirement be changed to a requirement for an initial inspection, followed by an annual (or longer) inspection schedule thereafter.

Response 2: As noted in our response to similar comment on the MACT provisions, the purpose of the inspection requirement is to ensure that the required CPMS measurements are not lost due to physical or operational integrity problems with the monitoring system. We find that this requirement is effective in identifying problems that could prevent monitoring system failures and are reasonable maintenance requirements. The commenter can provide training to inspection personnel to prevent the issues outlined by the commenter. We also note that we have provided provisions not to conduct the quarterly inspections if you have a redundant flow sensor. Since we desire to have CMPS data available at all times to assess compliance with the rule provisions, we have determined that the proposed requirements are reasonable and we are finalizing these requirements as proposed.

Comment 3: One commenter notes that Table 8 requires that for FCCUs subject to NSPS J, compliance is demonstrated by meeting the NSPS requirements. NSPS J specifies that the measured CO value be adjusted to 0% O_2. The commenter states that the equation used for correcting measured FCCU regenerator CO values to 0% O_2, as required by the NSPS J, does not work properly for FCCUs that use oxygen enrichment, a common practice. Particularly, the equations for correction measured CO in NSPS J and Ja to 0% O_2 fails if the O_2 concentration in the regenerator off-gas is near or above 20.9, which occurs as FCCUs transition from normal operation to startup and shutdown or into and out of hot standby, where O_2 enrichment is in use by the FCCU. Additionally the commenter stated that with O_2 enrichment the O_2 concentration will exceed the normal air concentration during these transitions and result in large negative CO concentrations being calculated.

Response 3: We did not propose to revise the CO limits in subparts J or Ja, so the CO limits in those rules are not open for revision in these amendments. While we understand oxygen enrichment is used, it is rarely used to the extent that the correction to the oxygen correction equation would be significant. Additionally, we expect most FCCU to be operated with limited excess oxygen in order to comply with NOx limits (either in subpart Ja or due to state/local or consent decree requirements), so the oxygen correction is expected to be quite small even if it is slightly overestimated because it does not consider less nitrogen entrainment due to oxygen enrichment. With respect to transitioning during startup, shutdown, or hot standby, we see no reason why a refinery would use oxygen enrichment in these cases. Oxygen enrichment is primarily used to help increase the capacity of the unit. It would seem to be a complete waste of money to use oxygen enrichment during these periods where air alone will provide enough oxygen to combust the fuel/coke in these transitions. Thus, if the refinery owner or operator uses oxygen enrichment when needed and not during these transitions, they can save money and the correction equation would work fine. For all of these reasons, we deem it unnecessary to revise the CO limits and oxygen correction terms in subparts J and Ja. Finally, in Refinery MACT 2, we proposed and we are finalizing, with some modification from what was proposed, requirements specific to startup and shutdown where the oxygen concentration must be maintained above 1 percent. Therefore, the oxygen correction to the CO concentration is not applicable for owners or operators electing to comply with the oxygen concentration alternative for organic HAP control during periods of startup, shutdown, or hot standby.

Comment 4: One commenter states that the performance test in paragraph (ii) of sections 60.107a(e)(l)(iii) and (e)(2)(iii) allows the use of Cylinder Gas Audits (CGA) in lieu of relative accuracy test audits (RATA) and specifies that "it is not necessary to include as much of the sampling probe or sampling line as practical." The commenters requests that for CGAs required under Appendix F (60.107a(e)(l)(iii) and (e)(2)(iii)), the same language be included to state: "It is not necessary to include as much of the sampling probe or sampling line as practical." If it is not required for the performance test (RATA-CGA), it should not be required for the quarterly CGA under Appendix F. EPA should use this opportunity to make this correction.

Response 4: Thank you for the comment. We have had other questions (both internal within EPA and from outside groups) about this provision and the primary reason we stated that it is not necessary to use as much of the sampling probe or sampling line as possible were primarily motivated by safety reasons, not wanting cylinder gases too near the flare, where radiant heat might be an safety issue. However, as a QA/QC matter, cylinder gas audits should generally include as much of the sampling probe and sampling line as practical. We are clarifying in this response that safety considerations when operating near a flare were our primary motivation for providing this exemption within Refinery NSPS Ja. We were concerned that issues may arise when determining how much of the sampling probe and sampling line is “practical” to include when considering safety issues related to sampling lines near a flare. We note that Appendix F provisions apply to a wide variety of sources that do not have this issue and should be required to use as much of the sampling probe and sampling line as practical. Therefore, we do not want to edit Appendix F to remove this requirement. Also, we did not propose to modify Appendix F or the paragraphs the commenter requested that we revise, so we could not at this time make the edits the commenter is requesting. We also considered removing this exclusion in Refinery NSPS Ja and require the CGA for flares to use as “much of the sampling probe and sampling line as practical considering worker safety.” However, since we did not propose these revisions, we do not consider it appropriate to finalize the removal of this exemption in Refinery NSPS Ja at this time. However, as a practical matter, refinery owners or operators may and generally should use as much of the sampling probe as practical, but the owner or operator may fully consider worker safety for sampling lines near a flare when considering how much of the sampling line to include.

Comment 5: One commenter states that the annual interval defined in proposed section 60.104a(b), 79 FR at 36,957, differs from the proposed interval contained in proposed section 65.280(b) of EPA’s proposed National Uniform Emissions Standards/or Heat Exchange Systems. 77 FR 960, 976 (January 6, 2012). The commenters state that the EPA should maintain consistency between these provisions or explain the reason for its decision to apply different interval definitions.

Response 5: The Uniform Emission Standards proposed a definition of “reasonable interval” for tasks to be conducted periodically; the proposed “reasonable interval” for monitoring required annually was that the activities must be separated by at least 120 calendar days. First we note that this “reasonable interval” was provided in the proposed general provision to the Uniform Emission Standards in part 65 (and they were not proposed in parts 60 or 63). Furthermore, it is always possible for the EPA to elect to override general provisions requirements in certain subparts, so even if this definition was in the part 60 general provisions, the EPA has the authority to specify alternative intervals that apply to a specific provision in subpart Ja. On considering a reasonable interval for annual performance tests, we considered it better to provide a 120 day (4 month) allowance from the exact annual PM testing date in NSPS subpart Ja. Therefore, we proposed an 8 to 16 month interval for annual PM testing in NSPS subpart Ja. We note that this interval would be compliant with the “reasonable interval” requirements proposed in part 65. We find this 8 month window provides sufficient time to coordinate the testing activities with plan operations, accounting for turnaround and other maintenance activities. Therefore, we are finalizing this requirement as proposed. If the EPA does move forward with the Uniform Emission Standards we may consider the commenters suggestion for consistency and promulgate different requirements for the definition of “reasonable interval.”

12.1 Sulfur Recovery Plant Provisions

Comment 1: One commenter requested that the EPA define the term SRU "release points" in proposed 40 CFR 60.102a(f) (79 FR at 36,956-957).

Response 1: Release points can differ for different types of sulfur recovery units or different sulfur recovery plant configurations. The primary release points from a Claus sulfur recovery unit are the tail gas stack and, if not diverted to the tail gas stream, purge gas from sulfur recovery pits. As noted in the definition of sulfur recovery plant, the plant can consist of numerous sulfur recovery trains and each train may have a separate tail gas stack and some refineries may have to employ a separate release point(s) for their sulfur pits. For LoCat systems, the primary release point is the off gas from the oxidation chamber. If a refinery owner or operator is unsure what release points are associated with their specific sulfur recovery plant, we recommend that they contact EPA or the delegated state authority for their assistance in resolving their questions regarding their specific sulfur recovery plant configuration.

Comment 2: One commenter requested that the EPA clarify how to calculate allowable emissions against the RQ of 500 pounds of sulfur dioxide over 24 hours. The commenter stated that there are inconsistencies in determining exceedances of the RQ. The commenter stated that some permits have a limit of average hourly emission rates plus the RQ as their allowable emissions, meaning the actual emissions could exceed the RQ without requiring reporting.

Response 2: RQs are generally determined as emissions above permitted levels. For example, permitted emissions from a sulfur recovery plant can exceed 500 lbs per day of SO_2 for plants recovering 300 long tons of sulfur per day. If the permitted emissions for a sulfur recovery plant is 600 lbs per day, then the sulfur recovery plant would have to emit 1,100 lbs per day SO_2 to exceed the reportable quantity (or trigger an RCA for the sulfur recovery plant).

12.2 Performance Test Requirements (for flares for H_2S)

Comment 1: One commenter stated that the proposed amendment to 60.104a(a) to require a flare performance test to demonstrate initial compliance with the H_2S limit on flare gas was purposely not included in the NSPS Ja rule, because it is unnecessary in light of the requirement for continuous H_2S monitoring. The commenter believes it is not reasonable to require such testing since H_2S levels in flare gas vary substantially and a representative sample is not likely for many flares during the short three hour performance test period. The commenter noted that for most flares there is no continuous flow to test, and it would be environmentally imprudent to require flare flows just to test.

Response 1: The commenter is mistaken that the H_2S performance test for flares was purposefully not included in the NSPS Ja rule. The performance test requirement has always been a part of the NSPS subpart J requirements and was included in the original final subpart Ja rule (6/24/2008). In the final amendments on 9/12/2012, when we separated flares from fuel gas combustion devices, we specifically included flares as requiring performance tests. However, late in the process of finalizing the NSPS Ja amendments, we moved the H_2S limits for flares from section 60.102a to 60.103a and inadvertently did not make the change in 60.104a(a) because the reference to section 60.102a in that section was general. We note that our intent was to maintain this long-standing requirement and had we intentionally meant to exclude this requirement, section 60.104a(a) would not have a reference to flares and section 60.104a(j) would not have a specific reference to the concentration limit for flares in 60.103a(h).

We find that it is essential that, prior to the use of the H_2S CEMS, a performance test be conducted to ensure the CEMS is operating accurately. Typically, the H_2S monitor will be located somewhere in the flare header system and there will be some gas flow through the header (purge or sweep gas) to prevent oxygen intrusion into the system. Therefore, the owner or operator does not need to supplement this flow with additional gases just to perform the initial test, but can perform the test using the gases present in the header system at the time of the performance test.

Comment 2: One commenter stated that the limits in NSPS Ja imposing H_2S and TRS concentration limits for flare gas are specified on a dry basis, but flare gas is wet and any sample system that removes water will also remove at least some H_2S and TRS, making the values measured using such a sample system questionable at best. The commenter recommended that the NSPS Ja specify alternatives for the measurement of moisture content for adjusting the wet readings for flare gas measurements, as follows to clarify how these corrections are to be made, rather than leaving a source in limbo as to whether a particular approach is acceptable. Incorporating these alternatives would also clarify that measurement of moisture contents is not required.

Option 1: Monitor the temperature of the waste gas exiting the knock out drum and assume the waste gas is saturated with moisture at that temperature. Use that volume % moisture to correct the wet gas concentration to a dry gas concentration, or

Option 2: Determine the moisture content of the waste gas (under typical flaring conditions), through bomb samples, wet and dry bulb temperatures, or similar means, to determine the moisture content of the flare gas and use that to correct the wet basis correction factor, or

Option 3: Develop a flare gas moisture content correction (based on typical to conservatively high waste gas temperature from the knock out drum and saturated conditions) for applicable scenarios (e.g., flare gas recovery compressor outage, steaming equipment to the flare, individual safety valve release). This would be a conservative moisture correction factor, but would not require any additional monitoring or calculations) by the facility.

Response 2: First we note that the H_2S concentration/emission limit has always been on a dry basis (in subpart J, the limit was expressed as 230 grams per dry standard cubic meter). While we express the limit in different measurement units in subpart Ja (162 ppmv), the actual emissions limit did not change and the need to assess the emissions on a dry basis has always applied for subpart J, so this is not a new issue that only pertains to subpart Ja. Second, we did not propose to amend this requirement in subpart Ja, so this comment is out of scope. Third, we note that the requirement in 60.107a(a)(2) is to "install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare." Thus, it is unclear if a wet gas monitoring system is compliant with this requirement and, at the very least, if a wet gas system is used, the wet gas concentration must be corrected for the moisture content. We generally agree that the options noted by the commenter are reasonable methods for determining the percent moisture in fuel gas discharged to the flare and therefore find these methods to be acceptable for correcting to a dry basis. Since the system must be corrected to a dry basis on a "continuous" basis, the saturated assumption is likely the easiest to implement while ensuring the correction is not underestimated.

Comment 3: One commenter stated that section 60.102a(g)(iii) of NSPS Ja concludes that sulfur limits for combustion of fuel gas do not apply to portable generators combusting gas from tank degassing and/or cleaning. The commenter however, noted that "Portable generator" is not defined and the explanation for this exception in Section 2.1 of the Response to Comments is unclear whether thermal incinerators and diesel engines, the commonly used controls, are considered portable generators. For these short term control situations, portable engines, thermal oxidizers, and flares are typically used, depending on availability, gas composition, utility availability and other factors. Additionally, portable flares are sometimes used. The commenter believes EPA should address flares used for this purpose and revise NSPS Ja to allow temporary use of flares, thermal oxidizers, and engines for tank degassing with spot sulfur sampling. The commenter stated that given the small amount of gas generated from this type of activity, the low concentration of H_2S in these gases, and their infrequent occurrence, there is no justification for limiting the types of VOC controls by imposing extensive compliance assurance requirements. The commenter believes that the use of portable thermal oxidizers should be encouraged, since these are the most energy and environmentally efficient choice. While some AMPs have been approved for these situations, the burdens of obtaining AMPs on owners/operators and regulators are excessive and can introduce delays in tank maintenance or lead to the use of less than optimum controls.

The commenter suggested the following revision to section 60.102a(g)(iii):

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section. The combustion of fuel gas in a portable engine or thermal oxidizer released as a result of tank degassing and/or cleaning is exempt from the requirements of section 60.107a. Compliance with the emissions limits in paragraphs (g)(1)(i) and (ii) of this section shall be demonstrated through an initial sample analysis or the average of three hourly sample analyses using either an H_2S colorimetric tube or a portable H_2S meter to determine the concentration of H_2S in gases entering the portable unit. A record of the date and time of each sample and the sample results shall be maintained.

Response 3: We did not propose to amend section 60.102a(g)(iii), so this comment is out-of-scope for these amendments. The provision was provided based on comment received on the initial subpart Ja rule because these gases could be discharged to a flare and we deemed it preferable to burn the gases in a device that could provide useable energy. With that understanding, a diesel engine could qualify as a portable generator.

Comment 4: One commenter stated that the limit of 162 ppm for H_2S for fuel drums seems high given the state of Louisiana has a high ambient air standard for H_2S (237 ppb 8 hour). The commenter inquired if other refineries in the USA have a lower limit for H_2S fuel drums and whether the limit is contingent on the total number of drums.

Response 4: The concentration of H_2S in the fuel gas is designed to limit SO_2 emissions from fuel gas combustion devices. These streams are not released directly to the atmosphere.

12.3 Other Revisions

Comment 1: One commenter believes the EPA should address the API NSPS Ja reconsideration petition item relative to the applicability of fuel gas combustion device requirements to flares that only handle wastewater treatment unit off gas. The commenter states that by removing the "fuel gas combustion device" description from the definition of flares when finalizing the 2012 NSPS Ja reconsideration amendments there is no longer a tie to the definition of fuel gas which specifically says that "Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units ..." As a result flares that are used to comply with NSPS QQQ and/or part 61 subpart FF, and flares that combust other gases that are not considered fuel gases under subpart Ja are no longer excluded from subpart Ja fuel gas combustion device requirements. The commenter believe this change was not proposed and is presumably inadvertent. The needed rule revisions to make NSPS Ja consistent with NSPS J flare applicability should be included in the Refining Sector Rule final rule. The commenter recommends adding a paragraph (2) to section 60.103a(g) as follows (based from the definition of fuel gas in section 60.101a) and renumbering the existing section 60.103a(g) as section 60.103a(g)(1): (2) Flares that are only used to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (i.e., asphalt blowing stills) are excluded from the requirements of section 60.103a.

Response 1: We did not propose to revise subpart Ja based on the issues noted in the 11/13/12 petition for reconsideration. As such, this comment is out-of-scope for these amendments. Furthermore, we disagree with the commenter that the flares suggested by the commenter should be excluded from the flare minimization and root cause analysis requirements.

During the development of subpart Ja, we determined that it was not cost-effective for combustion devices used to control vapors from marine vessel loading or wastewater operations to install and operate sulfur removal (amine treatment) equipment in these locations because they are generally remote and not easily piped to existing sulfur removal systems. Thus, the exclusion from the definition of fuel gas was specifically targeted to the H_2S concentration limits and was not restricted to flares. The rationale to exclude combustion devices from the H_2S limits does not apply to the other flare gas work practice requirements.

We also disagree that the definition of modification of a flare does not limit the connections to those meeting the definition of fuel gas. Thus, we contend that the definition of modification and the other flare work practice standards were not necessarily restricted to "fuel gas." As such, we find that it is appropriate for all new or modified flares at a refinery to prepare a flare minimization plan and conduct RCA if the flares exceed the RCA thresholds. Also, we provided additional compliance time for flares requiring the installation of monitoring equipment to comply with the work practice standards. Therefore, even though refinery owners or operators may have expected that certain flares were excluded from all work practice standards, it was not our intent to exempt these flares, and we provided time for the refinery owners or operators to comply with these provisions.

Comment 2: One commenter states that in the proposed revisions to 40 CFR 60.100a, (79 FR at 36,956), EPA proposes to remove the phrase “and delayed coker units” from section 60.100a(b). However, the compliance date for both flares and delayed coker units are given separately in the same paragraph. The commenter believes EPA should explain the reason for and implications of the removal of this phrase.

Response 2: The removal of the phrase “and delayed coking units” from the first sentence in 60.100a(b) was an inadvertent error. The only revision that we intended to make in 60.100a was to allow owners or operators subject to subpart J to elect to comply with the requirements in subpart Ja. In the final amendments, we have included the phrase “and delayed coking units” in the first sentence in 60.100a(b).

13.0 Economic Impacts

13.1 Economic Impact Analysis

Comment 1: One commenter stated that significant man hours will be needed to collect samples, appropriately maintain all the data, analyze the data and perform required calculations, and to perform required reporting and the commenter expects to have to add at least one additional employee to manage responsibility of these increased requirements. This cost will be in addition to the required equipment installation and maintenance, sampling resources and laboratory fees incurred for compliance with the proposed rulemaking. The commenter argued that as a small refinery, the regulatory costs and burdens in the Proposed Rule threaten to impose a disproportionate economic hardship. The commenter urged the EPA to consider whether the proposed regulation imposes a disproportionate economic hardship on small refineries and, if so, to provide exceptions or mitigations from the Proposed Rule in order to mitigate that harm.

Response 1: As part of our economic impact analysis for the proposed and final rules (for the economic impact analysis for the proposed rule see Docket Item No. EPA-HQ-OAR-2010-0682-0228 and for the economic impact analysis for the final rule see Docket ID No. EPA-HQ-OAR-2010-0682), we specifically evaluated impacts on small businesses. In the analyses for the proposed and final rules, we found that no small business would be subject to costs greater than 1 percent of sales. In the analysis for the final rule, the average cost-to-sales ratio of 0.16 percent for small businesses is slightly higher than the average cost-to-sales ratio for large firms of 0.01 percent, and the maximum cost-to-sales ratio of 0.80 percent for small businesses is slightly higher than the maximum cost-to-sales ratio for large firms of 0.64 percent (not considering recovery credits). In the analyses for both the proposed and final rules, we determined that, because no small business/firms are estimated to have cost-to-sales ratios greater than one percent, the cost impacts for the risk and technology reviews for existing Refinery MACT 1 and MACT 2 standards will not have a significant economic impact on a substantial number of small entities.

Comment 2: One commenter stated that the EPA should finalize the rules, but allow industry to charge $8.00 per gallon to compensate for the costs of rule compliance. On the other hand, another commenter stated that the rule will have no noticeable effect on the price of produced petroleum.

Response 2: As part of our economic impact analysis for the proposed rule (see Docket Item No. EPA-HQ-OAR-2010-0682-0228), we specifically evaluated prices for five different refinery products (motor gasoline, jet fuel, diesel fuel, residual fuel oil and liquefied petroleum gas). We performed a similar analysis for the final rule (see Docket ID No. EPA-HQ-OAR-2010-0682). In the analyses for both the proposed and final rules, we projected that the prices for these products would rise by two one-hundredths of a penny or less per gallon. We do note that the EPA has no jurisdiction on what prices a refinery or gasoline retailer charges for their products. However, in a competitive, free-enterprise market, we agree with the commenter that suggested that this rule will not have a noticeable effect on the price of gasoline or the other petroleum products evaluated.

Comment 3: One commenter discussed specific circumstances in the community of Wilmington California. The commenter explained that the local refinery has made significant strides towards pollution control and is a good steward in the community by providing high paying jobs and donations to charity. The commenter also stated that they do not believe some of the rates of illness or monitoring data presented by environmental justice organizations. The commenter referenced a specific air quality monitoring study which is published on http://www.laceen.org/. The commenter questioned whether the data presented in this study is reflective of the emissions from the refinery alone and whether it excludes other sources of pollution such as the highway. Finally, the commenter discussed how importing oil from countries such as China is under consideration in their community and they do not believe that the pollution emitted from producing the same refined product in China is better for the environment. Additionally, importing fuel would do harm to the local community's economy and possibly result in higher fuel prices which would disproportionally affect the poor.

Response 3: As part of our economic impact analysis for the proposed and final rule (for the economic impact analysis for the proposed rule see Docket Item No. EPA-HQ-OAR-2010-0682-0228 and for the economic impact analysis for the final rule see Docket ID No. EPA-HQ-OAR-2010-0682), we include a discussion of a conceptual framework for considering the potential influence of environmental regulation on employment in the U.S. economy and a discussion of the limited empirical literature that is available. We concluded that deriving estimates of how environmental regulations will impact net employment is a difficult task, requiring consideration of labor demand in both the regulated and environmental protection sectors. Economic theory predicts that the total effect of an environmental regulation on labor demand in regulated sectors is not necessarily positive or negative. Peer-reviewed econometric studies that use a structural approach, applicable to overall net effects in the regulated sectors, converge on the finding that such effects, whether positive or negative, have been small and have not affected employment in the national economy in a significant way. Based on our economic analysis for the final rule, it is unlikely that this rule will materially affect the "good stewardship" of refineries in Wilmington, CA or elsewhere.

13.2 ICR Burden Estimates

Comment 1: One commenter stated that none of the costs and burdens associated with the massive effort required to revise the procedures and permits to reflect the proposed changes are reflected in the Information Collection Supporting Statements or other analyses. Sites and permitting authorities will spend countless hours implementing these changes and that burden should not be ignored. In fact, it is likely the required Prevention of Significant Deterioration, New Source Review and Permit reviews for the required added facilities will be extended and highly burdensome.

Response 1: It is unclear what aspect of the rule the commenter is suggesting will require such a massive re-permitting issue. We anticipate that much of this concern was related to identifying additional Group 1 MPV that were previously excluded due to the "periodically discharged" exemption or developing procedures to ensure vessel openings for maintenance purposes remained below the Group 1 MPV threshold. We have developed specific requirements for maintenance MPV during start-up and shutdown that we expect to resolve this issue and reduce or eliminate the need to individually permit these sources.

Comment 2: One **c**ommenter stated that the production impacts, costs and burdens due to the revised averaging time and startup and shutdown restrictions on catalytic crackers and the new restriction on catalytic reformer operation imposed by the proposed Refinery MACT 2 revisions are not included in the record. Nor are any of the costs or burdens associated with the extensive monitoring revisions proposed for catalytic crackers reflected in the Information Collection Supporting Statement.

Response 2: At proposal, we included costs for performing performance tests for each FCCU. New operating parameter limits would be established during these tests, so the cost of developing the new operating limits are included in the costs to conduct the source test. Since the parameters to be monitored remain the same, we projected no additional costs for these parameters. We established specific operating limits for FCCU startup and shutdown using parameters that we anticipate all FCCU owners or operators would use to operate the process, so we did not project any additional costs to comply with these provisions. In the final rule, we are adding a 3-hour average 20% opacity operating limit for refineries complying with subpart J for PM. Because these facilities are already required to comply with the 30% opacity emissions, no new monitoring systems are required. limit to a control device operating limit, we contend that the operating parameters that we require to be monitored are routine parameters that are used to operate these control systems, so no additional monitors would be required. While the records that need to be maintained may change, we do not project any net increase or decrease in the recordkeeping and reporting burden, so we did not include these unchanging burdens in the Supporting Statement. Finally, with respect to the operational changes imposed for catalytic reformers, we anticipated that an appropriate control device would be available, since the initial depressurization is sent to a control system and only minor modification to the purging protocols would be needed to comply with this requirement. However, we do acknowledge that these changes will require some engineering evaluation and operator training to implement. Therefore, we have revised the supporting statement to include these one-time costs. We do not anticipate that this requirement would have on-going recordkeeping and reporting burdens beyond those already imposed.

14.0 Statutory and Executive Orders

Comment 1: Several commenters stated that this rulemaking is a significant Agency action that must meet all of the requirements imposed on such rulemakings by a variety of laws and Executive Orders because they claim that it will exceed the $100 million per year threshold. One commenter estimated the required cost for the industry to be in excess of $20 - 40 billion in new investment, and in excess of $1 billion if new flare investments can be avoided, all for a very minimal reduction in risk and HAP emissions. The commenter argued that the EPA has not provided statutory analysis and record support to justify the new requirements, nor has the EPA met its other legal obligations. The commenters recommended that the EPA complete reviews under Executive Order 12866, the Regulatory Flexibility Act, the Congressional Review Act, and the Paperwork Reduction Act for comment because they consider the reviews done to support the current proposal to be incomplete and unrepresentative of the precedents, issues, costs and burdens imposed. Two commenters added that reviews under Executive Orders 13211 and 13650 are also necessary. Finally one commenter commented that a Regulatory Impact Analysis (RIA) be completed consistent with Executive Order 13563, Executive Order 12866, and Circular A-4.

Two commenters highlighted the Congressional Review Act, pointing out its stipulation of providing at least 60 days between the final publication date of the rule and its effective date for Congressional Review. The commenters stated that all references to the compliance date as the date of publication in the Federal Register must be changed to the rule Effective Date, which must be at least 60 days after publication of the final rule.

Response 1: We note that we did not anticipate the requirements proposed would not have a significant impact on refinery operations. Based on the comments received, we have made a number of revisions to the proposed rule to address issues that commenters suggested would cause the need to build hundreds of new flares and to pipe all atmospheric PRDs to a flare. These revisions are consistent with our proposed cost impacts and our original intent to improve the performance of these systems without the need to build hundreds of new flares. We have revised our cost estimates based on comments received, considering the requirements in the final rule, and we continue to project that the annualized cost of this rule will be well below $100-million/yr. However, due to the high capital costs of the rule, we are classifying the rule as a major rulemaking. Therefore, we agree that this rulemaking is subject to the Congressional Review Act and we have revised the effective date of the rule to be 60 days after publication of the final rule in the *Federal Register*.

Comment 2: Several commenters asserted that the proposed rule is a “significant energy action” as defined under Executive Order 13211 (66 FR 28355, May 22, 2001), because of its potential to have a significant adverse effect on the supply, distribution or use of energy. They stated that not only is the current timeframe for compliance too narrow (currently the date of rule promulgation), but that the three years provided for compliance in NESHAP rules is as well, estimating that up to a decade is needed to carry out the flare modifications and new flare construction necessary for compliance with the proposed rule. Coupled with this, they both explained that flare outages are typically scheduled to coincide with large planned maintenance outages, but this narrow timeframe does not allow for such coordination and will result in many “out-of-cycle” production outages. These production outages will likely be extended due to reduced fuels production resulting from the lack of alternative limits for startup, shutdown, and equipment preparation venting and bypassing.

Response 2: We disagree with the commenters that this rule will have a significant adverse effect on the supply, distribution or use of energy. We have provided additional alternative limits for startup and shutdown for certain emission sources based on the public comments received and we consider up to 3 years an appropriate time interval to install the necessary control and monitoring systems for flares. Based on our economic impact analysis, there will be a very minimal increase in the price of refined petroleum products (0.02 cents/gallon) and only an unperceptively small (0.0001 percent) decrease in the supply of refined petroleum products. Consequently, we maintain that this rule is not a “significant energy action.”

Comment 3: One commenter stated that significant policy issues raised by this rulemaking require review under Executive Order 12866. The commenter outlined several issues such as the proposed ban on PRDs, requirements for fenceline monitoring, DCU provisions, and new flare requirements. Another commenter stated that the proposed fenceline monitoring is not a technology development for equipment leak, storage vessel or wastewater sources. According to the commenter, addition of fenceline monitoring on top of the existing Refinery MACT requirements is contrary to the Executive Order 12866 mandate to avoid redundant, costly regulatory requirements that provide no emission reductions.

Response 3: We note that this rulemaking is considered a significant regulatory action under EO 12866 because it raises novel legal and policy issues as noted in the preamble. Office of Management and Budget (OMB) was provided a 90-day comment period for the proposed rule and comments received from OMB were addressed prior of the proposal of the Sector rule. The OMB also reviewed the final rule as required under EO 12866 for significant regulatory actions.

The specific issues noted by the commenter are addressed in the appropriate emission source-specific sections of this Response to Comment document.

Comment 4: One commenter argued that the proposal impacts safety systems that protect workers and the community. The commenter stated that the proposal must be fully vetted, and, under Executive Order 13650, coordinated with the OSHA and EPA’s Risk Management Office. The commenter stated that releases required for safety should not be prohibited or declared violations. According to the commenter, significant safety concerns include:

- Requiring control of all atmospheric safety valves increases the chance of a catastrophic equipment failure due to inadequate relieving capacity, particularly during the period between promulgation of these amendments and completion of the new flare systems and installation of the additional safety valves that will be required.

- Imposing the normal operations velocity limits on flares designed to be used at their hydraulic limit during emergencies will place operators in an untenable position until additional flares can be installed--managing the emergency safely while risking enforcement for violating environmental requirements.

- Proposing to treat relief valves on vapor collection systems as potential bypasses, requiring them to be car-sealed closed or otherwise blocked, will expose the system to potentially catastrophic failure.

- The prohibition on the use of control device bypasses during start-up, shutdown, and malfunction, regardless of the safety risk associated with sending those streams to those controls, will increase the risk of fire and explosion. In particular, operating ESP on FCCUs during SSM has caused injuries and equipment damage.

- Requiring routine instrument QA/QC for unsafe to access instruments puts workers at risk (e.g., the proposed QA/QC requirements on flare pilot thermocouples).

Response 4: We disagree that further review of this final rule is needed under EO 13650. We have made a number of revisions to the proposed rule to address public comments received. Most notably, we have revised the provisions for atmospheric PRD to require a minimum of three prevention measures. This requirement is similar to requirements to improve the safety of chemical processes, and will improve refinery safety rather than cause safety issues. We have also provided emergency shutdown provisions for flares which ensure the safe destruction of gases needing disposal at these times without the need to build new flares or cause operators to choose between plant safety and environmental violations. We specifically proposed alternative limits to avoid unsafe operations during startup of an FCCU and we have generalized and extended that provision to include startup as well, regardless of control device configuration. Therefore, we find that the final rule will not have significant adverse impact on chemical facility safety and should improve chemical facility safety by incorporating prevention measures to reduce the likelihood of a chemical release. As such, further review under EO 13650 is not required.

15.0 Other Comments

15.1 General Support

Comment 1: Many commenters expressed general support for the rulemaking including removal of SSM exemptions, stricter limits for delayed coking units, flares, storage tanks, and the implementation of a fenceline monitoring program.

Response 1: We appreciate the commenters support for the proposed rule to reduce air emissions from petroleum refineries.

15.2 Editorial Corrections

Comment 1: Some commenters stated that section 63.670(c) incorrectly references paragraph (b) when it should reference paragraph (h) of this section.

One commenter stated that the reference in section 63.670(b) to paragraph (h) should be paragraph (g).

One commenter also stated that the reference in section 63.660(i) to (c)(1)-(3) should be (i)(1)-(3).

Another commenter stated that the reference to (f)(1), (2), or (3) should be (e)(1), (2), or (3) in proposed section 63.670(e).

A third commenter stated that the flare section (k)(2)(ii) should say “owner or operator”, but currently reads “owner of operator”.

Response 1: We appreciate the editorial corrections noted by the commenters and these corrections have been made in the final rule.

15.3 Miscellaneous Other Comments

Comment 1: Many commenters suggested the EPA adopt practices to reduce emissions and increase safety using its 112(d) and (f) authority including:

- Phase-out of HF
- Requiring back-up power system to reduce emissions from power failure
- Stronger leak monitoring including use of best available fence-line monitoring techniques
- Adoption of an anonymous work reporting system to encourage workers who are closest to the issues a confidential way to protect their neighbors and families. Some of the commenters cited a few examples of these types of systems as a proof of concept including the Confidential Incident Reporting and Analysis System developed by the Federal Aviation Administration.
- Requiring mandatory maintenance and parts replacement plans to prevent breakdowns and malfunctions.

Response 1: Please see Comment 3 in this chapter for our response regarding HF alkylation and Sections 6.1 and 8.3 for our response regarding stronger leak monitoring and "best available" fenceline monitoring techniques.

Requiring back-up power is a very significant capital expenditure. Facilities that produce more fuel gas than they consume may elect to build a co-generation unit to utilize their excess fuel gas and produce electricity for sale to the grid (and for internal use). However, refineries that do not have excess fuel gas would need to use natural gas for their "back-up power" plant. Due to economies of scale, it will generally be cheaper to purchase electricity than to produce it, so the "back-up power systems" requirement would cause most facilities to make large capital investments to build an electricity generation plant that would be used only once or a few times per year, for only a few hours at a time. For the plant to generate power to be used immediately upon a power failure, the unit would likely need to be operated in hot standby, resulting in additional combustion (CO_2) emissions on a continual basis in hopes to reduce or eliminate very infrequent emission episodes from power interruptions. This is not an environmentally efficient or beneficial solution.

Facilities should already have confidential reporting systems in-place and we believe "whistle blower" laws are in-place to protect employees that report incidences of violations.

We are not specifically requiring detailed mandatory maintenance and parts replacement programs. However, we are requiring redundant prevention measures for PRV and root cause analysis for PRV releases and emergency flaring, which may result in such measures being implemented. We note that, if an event recurs that is based on the same root cause or if an event is caused due to poor maintenance, those events are considered violations of the emissions standards. As such, refinery owners or operators have significant incentive to develop and implement effective maintenance and parts replacement programs rather than a one-size fits all federal requirement that would be either ineffective or unnecessarily burdensome.

Comment 2: A few commenters stated that a mandatory phase-out plan for hazardous and toxic chemicals should be developed and would begin with the identification and annual public notification of all hazardous and toxic chemicals, the publication of health impact data and risk for every toxic chemical and substance released by oil refineries, and the identification of alternative safe and acceptable chemicals and processes.

Response 2: Refineries produce petroleum products largely through the distillation of crude oil, which is primarily the separation of naturally occurring mixture of chemicals by different boiling point ranges. While some processes "crack" the larger hydrocarbon compounds into smaller hydrocarbon compounds (e.g., C18 compound broken into two C9 compounds) for the "reform" hydrocarbon compounds (e.g., converting hexane into benzene), nearly all of the basic components of petroleum products are naturally occurring chemicals. Many of the issues that have arisen from petroleum products has been associated with chemical additives, such as tetraethyl lead and MTBE. We have phased these chemicals out of gasoline due to environmental impacts of these chemicals. We have also required refineries to produce fuel products with lower sulfur content to minimize emissions associated with the use of petroleum products.

Petroleum products have been widely studied and we have a good understanding of the key risk drivers associated with crude oil refining and petroleum refining products. While we have phased out certain gasoline additives and establish other requirements for petroleum products, those standards are beyond the scope of this rulemaking. Outside of the alternatives to HF alkylation, which are addressed in Comment 3 of this section, we are not aware of any means to reduce or eliminate specific HAP emissions through product or process substitution.

Comment 3: Two commenters stated that the EPA must set standards that will limit and assure the phase-out of HF. One commenter made recommendations for requiring plants and refineries to switch to cleaner and safer alternatives than HF during the listening sessions on improving chemical safety as related to Executive Order 1350.

Another commenter explained that HF is a very corrosive and toxic inorganic acid. It can cause severe health problems including death, permanent organ damage to the eyes, skin, nose, throat, respiratory and bone systems. It can cause lung congestion, inflammation, and severe burns of the skin and digestive tract.

The commenter cited an EPA report to congress detailing the “Goldfish Studies” in which certain facilities and the Lawrence Livermore National Laboratory conducted a series of experiments involving the atmospheric release of HF in discussing the risks to populations living near the refineries (EPA Report at 1-2, http://www.epa.gov/oem/docs/chem/hydro.pdf). The commenter also stated that 50 refineries across the nation still use the toxic chemical HF including some which are near major cities including Houston, Philadelphia, Salt Lake City, and Memphis (USW Report, supra note 617, at xvi). The commenter also added that a joint investigation of the Center for Public Integrity and ABC News found that “[a]t least 16 million Americans” live in an area where they would be exposed to HF from a refinery, if it were to be released in an accident or a terrorist attack, according to refinery owners’ worst case scenario reports (which the Center analyzed but are not publicly released)[106]. And the Center also found that 23 refineries using HF had at least 29 fires since the start of 2009. A majority - 32 of the 50 refineries using HF - were cited “for willful, serious or repeat violations of rules designed to prevent fires, explosions and chemical releases, according to U.S. OSHA data analyzed by the Center,” over a recent 5-year period. The United Steelworkers' (USW) survey found that over a five year period, there were about 131 HF releases or near misses (USW Report, supra note 617, at vi-vii). Additional evidence shows violations at other refineries.

The commenter stated that the EPA requires refineries using HF to estimate lives at risk from a release, and half have a radius endpoint greater than 20 miles. The commenter argued that the EPA has these reports, which it should consider and use in this rulemaking to phase out HF.

The commenter explained that the best available information shows that refineries can reduce the catastrophic impacts of HF if it is used, and avoid the resulting threats to community and worker

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[106] Jim Morris & Chris Hamby, Ctr. for Pub. Integrity, Use of toxic acid puts millions at risk (Feb. 28, 2011), http://www.publicintegrity.org/2011/02/24/2118/use-toxic-acid-puts-millions-risk (“CPI HF Report”)

health and safety, with various mitigation techniques or simply by not using HF at all.[107] For example, refineries using HF can:

- Change the alkylation process to use a solid acid catalyst;
- Convert the HF alkylation unit into a sulfuric acid unit; or
- Add modifiers to the HF that decrease the gaseous nature of hydrofluoric acid and install mitigation systems.[108]

The commenter asserted in view of these facts, the EPA must set a limit on HF that protects public health, under section 112(f)(2), and addresses developments in reducing HF emissions, under section 112(d)(2)-(3) and (d)(6). There is no current emission standard for refineries that directly controls HF. The commenter argued this violates the Act, as the D.C. Circuit explained in *National Lime Association* (233 F.3d at 642.). Moreover, the commenter asserted that the EPA has not satisfied the surrogacy test for HF (*Sierra Club v. EPA*, 353 F.3d 976, 984 (D.C. Cir. 2004)). Even if it had done so, the developments in the ability to reduce HF emissions would require at least the following actions. First, the EPA must set as the standard for new sources an emission limit of zero, to satisfy section 112(d)(3)’s requirement that the EPA set a standard based on the best-performing single source. There are refineries that do not use HF and the EPA has data on HF emissions from only 24 refineries, showing that many refineries are not currently emitting HF (Draft Risk Assessment (-0225) at 33.). The EPA should also follow the Act's floor and beyond-the-floor requirements in section 112(d)(2), (3) to set an HF limit for existing sources that assures that if there is a catastrophic release, this will plainly violate those standards, to provide additional incentive for sources to take steps needed to protect public health and safety, and encourage more refineries to use safer alternatives to pure HF (section 112(d)(2)). Finally, as the use of HF is associated with such a high health threat, EPA has strong grounds to require ultimate phase-out of its use. The EPA has done this under section 112 in another rule, and should follow the same approach here. Specifically, in the chrome plating rule, the EPA recognized that the health hazards associated with perfluoroctane sulfonic acid-based fume suppressants were substantial enough that it should be phased out, and ultimately banned.[109] Section 112(d)(2) requires the EPA to assure the “maximum achievable degree of emission reduction,” and this includes consideration of whether emissions can be “eliminated.” Moreover, phasing out the use of HF would dramatically reduce the health threats associated with potential releases of this dangerous pollutant at refineries, and thus would satisfy the section

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[107] See USW Report, supra note 617 at 3, 8; Meghan Purvis & Margaret Herman, U.S. PIRG Education Fund, Needless Risk at 16-20 (Aug. 2005), http://www.uspirg.org/reports/usp/needless-risk (?U.S. PIRG Report?); CPI HF Report, supra note 660

[108] U.S. PIRG Report, supra note 667, at 16.

[109] Final Rule, Chromium Electroplating, 77 FR 58,220, 58,230, 58,243-44 (Sept. 19, 2012) (40 CFR 63.342(c)(1)) (finalizing phase-out of PFOS-based fume suppressants, also described as perfluorooctyl sulfonate); Proposed Rule, 75 FR at 65,068, 65,094 (Oct. 21, 2010) (citing report, EPA-HQ-OAR-2010-0600-0072).

112(f)(2) requirement to assure an “ample margin of safety to protect public health.(quoting *Nat’l Lime Ass’n*, 233 F.3d at 639).”

Response 3: While HF is a HAP, our assessment of the remaining (or residual) risk after application of the MACT standards does not indicate that there is unacceptable risk from HF emissions. As one commenter notes, HF releases as a result of accidents and other catastrophic events are among the scenarios evaluated under EPA’s risk management program worst-case release scenario in 40 CFR 68.25, and as a result of the concern about HF releases, refinery owners and operators employ a number of redundant prevention measures to protect against a significant release of HF. Based on the data we have evaluated, we do not find it necessary to impose additional controls (or require refinery owners or operators to use alternative alkylation processes) under CAA section 112(f)(2) because these emissions are adequately reduced under section 112(r) of the CAA was amended in 1990. We currently have a petition for rulemaking to address IST under section 112(r) and part 68. Also, pursuant to Executive Order 13650, EPA has issued a “Request for Information” soliciting public views on the appropriateness of IST regulations and is considering pursuing rulemaking as part of the regulation, standard and guidance modernization effort called for by the Executive Order. Historically, EPA’s authority to address catastrophic releases under the NESHAP program was viewed as limited under the pre 1990 CAA. Congress added section 112(r) to address this gap. In light of the extensive history and efforts of the agency on IST specifically and catastrophic accidents generally under the section 112(r) program, and in light of the statutory structure of section 112, we view the request to enact IST provisions in this rule to be outside the scope of section 1112(d)(2), section 112(f)(2) and section 112(d)(6). Therefore, this comment is outside the scope of the current rulemaking.

Comment 4: One commenter stated that current standards only require testing for pollutants every 5 years for air quality standards and 8 years for water quality standards. The commenter added that there has been an increase in pollution in north central South Dakota related to the discovery and extraction of oil. Based on the increase in pollution, the commenter recommended that air and water quality studies be conducted semi-annually throughout the country and they should be paid for by the industries or companies. Another commenter stated that the EPA should require monitoring of all chemicals released by refineries on an ongoing basis.

Response 4: While specific performance tests are only required periodically, we generally have continuous emission or parameter monitoring systems that are used to ensure the emission limitations are achieved on a continuous basis. In many cases, we use surrogate compounds, such as PM for metal HAP or total hydrocarbons or benzene as a surrogate for organic HAP, to cost-effectively test and monitor for the large variety of pollutants potentially released from petroleum refinery process units. By using these continuous emissions, parameter, and surrogate monitoring systems, we effectively require monitoring of all chemical released by refineries on an ongoing basis.

With respect to upstream (oil production) emissions and water quality issues, these are beyond the scope of this rulemaking.

Comment 5: One commenter asserted that there is a need for public health impacts research data on all chemicals. This would include determining and reporting all carcinogenic, neurological, non-carcinogenic, bio-cumulative, physical and developmental public health impacts for all chemicals.

The commenter further stated that there should be public health and safety limits for all chemicals per the National Academy of Sciences. The commenter added that mandatory public health exposure limits on all chemicals and substances released by oil refineries should be established, as well as public safety limits for all potential public hazard scenarios on-site and off-site. The commenter also stated that Worst Case Scenario Disaster Studies including cascading and cumulative scenarios should be mandatory.

Response 5: We appreciate the desire to have health impacts data and health-based limits for all HAP. As seen in our draft residual risk assessment for this source category (Docket Item No. EPA–HQ–OAR–2010–0682-0225), we do have health effects benchmark levels for nearly all HAP emitted from petroleum refineries and we are confident that we have fully characterized the key risk drivers for the petroleum refining industry. While we have not established "public health and safety limits for all chemicals" we have evaluated the projected ambient concentrations of HAP near refineries based on refinery HAP emissions and compared these concentrations with the health benchmark levels (which can be thought of public health limits) and refinery emissions do not cause an exceedance of these levels (Hazard Index or HQ greater than 1).

Comment 6: Two commenters stated while the EPA included costs to the industry, a cost/benefit analysis relating to health benefits was omitted. One commenter stated that this is a serious omission. The commenter argued that the EPA went to great length to conclude that the health effects of the releases after the rule is in place are essentially negligible based on current information and added surely there is information available to determine the health benefits that arise from this rule, particularly since the EPA states that the rule will result in a reduction of 5,600 tons per year of toxic air pollutants, and 52,000 tons per year of VOCs.

Response 6: We did not state that the health effects are negligible, but that the risks were acceptable. We also discussed in the preamble of the proposed rule that the proposed rule is expected to reduce the number of people exposed to risks exceeding 1-in-1 million by 1 million people and reduce the cancer incidence by 0.05 cases per year (a 15 percent reduction in the overall cancer incidence associated with refinery emissions). Therefore, we agree that there are health benefits associated with these HAP emissions reductions. Due to methodology and data limitations, we were unable to estimate the benefits associated with HAP or VOCs that would be reduced as a result of this rule. This is not to imply that there are no benefits of this rule; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

Comment 7: One commenter inquired if there are calculations supporting the statement in the Fact Sheet regarding the reduction of 5,600 tons per year of toxic air pollutants and 52,000 tons per year of VOC.

Response 7: In the preamble to the proposed rule, we projected 1,760 tons per year of HAP and 18,800 tons per year of VOC reductions achieved by the storage vessel and delayed coking unit. We also projected significant emission reductions associated with the new flare operating limits and monitoring parameters designed to ensure all flares achieve 98 percent destruction efficiency. These reductions of 3,810 tons per year of HAP 33,100 tons per year of VOC are documented in the memo “Petroleum Refinery Sector Rule: Flare Impact Estimates”, which was included in the docket (see Docket Item No. EPA-HQ-OAR-2010-0682-0209). The Fact Sheet considered both the “new” reductions from storage vessels and delayed coking units and the “old” reductions that we expected to be achieved when flares were used as a MACT control device, with the emissions reductions rounded to two significant figures.

Comment 8: One commenter asserted that the new major proposed rulemaking amendments justify having a Health Impact Assessment (HIA) prepared, and suggested that HIA be a requirement in Title V permits in addition to Health Risk Assessments (HRAs). The commenter suggested including a public health survey requirement in the HIA to establish the Public Health Baseline. The commenter also recommended that HRAs be updated every 4 years and use the worst year annual emissions as the baseline (not allowing the selection of the best or lowest emissions year). The commenter also requested that the HRA show 5 consecutive years of data for trending of the results. The commenter also stated that the EPA has failed to adequately assess and underestimated the health impacts to pregnant women and prenatal fetuses. And finally, the commenter suggested that the EPA sponsor health research on oil refineries.

Response 8 Section 112 of the CAA mandates a single risk review for MACT standards. Ongoing risk assessment requirements suggested by the commenter are not authorized under section 112 of the CAA.

Comment 9: One commenter stated that the proposed amendments to the MACT standards will place an onerous and unnecessary burden on refineries that are not major sources of HAP emissions, but are subject to the MACT standards as a result of the agency’s 1995 “once in always in” policy. The commenter argued that the proposed amendments should not apply to a minor source of HAPs and the EPA could revoke the “once in always in” policy as considered in 2007 or more narrowly, the proposed rule could apply to refineries that were a major sources on the effective date of the rule modifications, rather than the first substantive compliance date of the original rule. Alternatively, the commenter added that if the EPA is concerned about backsliding, there could be an exemption for non-major sources of HAP in Refinery MACT 1 and 2 standards.

The commenter is an asphalt refinery and stated that due to the proposed amendments their storage tanks would have to comply with the Generic MACT standards even though these standards were never meant to apply to sources that are not major sources of HAPs. Further, the facility’s benzene emissions are very low and thus fenceline monitoring is nonsensical. The commenter added that their greatest concern are the proposed changes to subpart A affecting flares. The commenter argued that the proposed flare provisions are wholly unnecessary and unintended for a facility that is not a major source of HAP emissions.

Response 9: We disagree with the commenter that this would apply to area sources of HAP emissions. We note that we identified 7 refineries that applied for synthetic minor permits (to reduce their federally enforceable PTE to less than 10 tpy of a single HAP and less than 25 tpy of total HAP). If a facility did not obtain a synthetic minor permit prior to the applicability date of the MACT standard, then the refinery is a major source of HAP emissions regardless of whether the facility reduces its emissions to below the major source threshold once it complies with all of the MACT provisions. The "once in always in" policy requires facilities to continue to comply with the MACT standard in this case.

Comment 10: One commenter requested information on how the EPA will ensure refineries are in compliance with the new rule. The commenter suggested that the rule identify and define the type of oversight (i.e., inspections, monitoring, penalties) the EPA will perform for compliance assurance. Another commenter suggested that a third party be responsible for oversight. A third commenter suggested that there is a correlation between higher fines and the number of violations, and suggested that the EPA enforce higher fines to assure compliance. One commenter suggested a similar correlation between the number of lawsuits and resulting emission reductions, and recommended that stricter regulations be put in place to require these types of reductions without the use of litigation. Another commenter agreed that compliance assurance and transparency of requirements is key in the providing the public with the ability to understand what is being gained through this proposed rule.

Response 10: The new rule requirements will apply at all times after the applicability date of the requirement (although we are finalizing reduced fenceline monitoring requirements under special cases). We generally require continuous emission or continuous parameter monitoring systems to ensure refinery owners or operators are complying with the rule requirements at all times. Facility owners and operators with deviations of the emission limitations in the final rule may be subject to enforcement actions, including the imposition of fines ($25,000 per day).

Comment 11: One commenter expressed concern that the EPA does not have the ability to evaluate and adopt current technologies or address technology-related comments on this rulemaking with the closure of its Environmental Technology Verification program.

Response 11: The Environmental Technology Verification (ETV) program concluded operations in early 2014, but the ETV program only evaluated very specific technologies under specific conditions. Most new and innovative control technologies that have been developed and employed in the petroleum refining industry were not developed through or tested in the ETV program. Therefore, we do not agree that the closure of the ETV program significantly limits EPA's ability to evaluate current or innovative technologies or to address technology-related comments on this or other rulemakings.

Comment 12: Two commenters stated that the public should be notified of incidents at a refinery directly and one of these commenters added that such a system could be analogous to those used for floods or missing children.

Another commenter stated that there are inconsistencies with how incidents are reported to the NRC. Some refineries report all incidents and others repot only those to the LDEQ unless the

Coast Guard is required to be involved. The commenter added that residents have more access to the reports sent to the NRC.

Response 12: We have reviewed the emergency notification procedures currently required to be provided by refinery owners and operators to local safety officials. We find these requirements to be timely (typically within 15 minutes of the onset of an occurrence) and appropriate (including the agencies contacted). If the release is significant enough to notify the surrounding communities to implement an evacuation of other activity, the local safety officials would use available means (sirens, emergency broadcast signal, etc.). The EPA considers the current reporting requirements for emergency releases adequate and sufficient to protect the communities near a petroleum refinery. We do note that local agencies can implement different reporting thresholds than those specified for reporting to the NRC, so there may be instances where the local agency may be contacted without a required NRC report.

Comment 13: One commenter stated that the EPA should oversee funds that are given to Community Benefits Trust Fund to ensure that they go to children with conditions such as respiratory illness caused by the refineries, such as the one implemented and utilized in the South Bay.

Similarly, another commenter stated that industries should be mandated to put money into an escrow account to provide environmental health professional services in those communities that incur pollution as a result of industry operation. These environmental health professionals would also examine patients and report data from conditions related to pollution.

Response 13: We disagree with the commenters that petroleum refineries (or other manufacturing industries) should be mandated to put money in a fund to pay for the health care of people living near the facilities and we certainly do not have the authority under the CAA to mandate such a fund.

Comment 14: One commenter requested clarification on whether the Federal or state government would have presiding authority over the rule. The commenter recommended that the proposed rule be monitored from the Federal level.

Response 14: Generally, the delegated authority is the state agency (assuming they have an approved program). There are some items, such as requests for alternative emissions limitations for flares and site-specific monitoring plans for fenceline monitoring, where we also require submission to the federal agency because we would like to provide technical assistance and ensure consistency across these site-specific alternatives. Except for these cases, we consider the state agency to be the appropriate authority for permitting and MACT enforcement.

Comment 15: A commenter requested clarification on whether the emission limits in the proposed regulation would be subject to further reductions in the future. The commenter recommended that if this is the case, the EPA should impose stricter standards now.

Response 15: The EPA is required to review MACT standards for developments in practices, processes and control technologies every 8 years. Therefore, subsequent technology reviews may lead to stricter standards for certain sources. However, there is no on-going requirement to perform risk reviews beyond this rulemaking.

Comment 16: One commenter inquired as to whether companies who comply or exceed the reduction of emissions requirement will be given incentives. The commenter stated they believe in incentives because history has shown allowing a company to receive incentives or grants would entice compliance to the new rule.

Response 16: There are no specific incentives (beyond not being subject to enforcement actions) for sources to comply with the requirements in the final rule. We have addressed suggestions that we should reduce the burden of fenceline monitoring if refiners can demonstrate that portions of the fenceline are significantly and consistently below action levels by allowing them to apply for alternative monitoring approaches, as discussed in the fenceline monitoring chapter. We believe this allowance will provide some incentive to achieve and maintain emission reductions.

Comment 17: One commenter stated that there should be a limit on total emissions from a facility regardless of other sources within the facility. The commenter argued that the health effects are not based on process chemistry or how the benzene was released into the local community. The community is affected by cumulative exposure and regulatory efforts should be to limit that exposure wherever it is economically practical to do so.

The commenter stated that all emissions within a particular facility, even when tied to product shipping operations, are still emissions to which their surrounding communities are exposed. Allowing a facility to deduct such emissions without a cap reduces their incentive to improve those processes and prevent unnecessary exposure within the surrounding communities. The commenter stated that allowing such emissions to go unabated is counter to the stated goals of the new proposals.

Response 17: In Refinery MACT 1, most emissions sources that are co-located at the refinery, such as gasoline loading operations and marine vessel loading operations, are part of Refinery MACT 1 source category. We acknowledge that refineries may also have units subject to the HON, but these are not unregulated sources. Thus, it is unclear to us what emission sources we are allowing to go unabated. We expect that this may be due to provisions in the fenceline monitoring corrective action requirements that allow facilities to correct for contributions from non-refinery MACT sources. So, if a benzene storage tank subject to the HON provision is leading to high fenceline concentration, the facility is allowed to correct for the contributions of this HON tank. However, that tank would still have to meet the abatement criteria required by the HON. If the HON requirements are not being met, then that facility owner or operator would still be subject to compliance violations. In summary, we do not believe that there are any "unabated sources" at a refinery facility that we are exempting from any MACT requirements.

Comment 18: One **c**ommenter asserted that the EPA has failed to evaluate the effect these rules will have on the cumulative employment impact of EPA's rules. This requirement is set out in section 321(a) of the CAA, which states that "the Administrator shall conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement" of the law. The commenter argued that the EPA has failed to comply with this section and should amend the rules to account for (1) the cumulative employment impact of all its existing regulations, and (2) how these rules will add to that.

Response 18: We disagree with this comment. Section 321(a) does not require the EPA to evaluate the cumulative employment impacts of its rules, nor does it require the EPA to conduct evaluations as part of the rulemaking process or as a prerequisite to the issuance of a rule. The broad language of section 321(a) does not address the scope, frequency, or timing of employment evaluations, leaving these matters to the discretion of the EPA. In the exercise of its discretion, however, the EPA does routinely evaluate employment impacts when it conducts new rulemaking. For example, in the EIA accompanying this final rule, the EPA provided a qualitative assessment of employment impacts, describing the current state of knowledge based on the peer-reviewed literature and the analytical challenges associated with determining the direction of net employment effects of regulation on both the regulated sector and other industries. In addition, the EPA has conducted similar assessments for other rulemakings and continues to evaluate employment impacts generally and to refine its employment-analysis methods. Together, these efforts constitute "continuing evaluations of potential loss or shifts in employment" for the purposes of section 321(a). Finally, to the extent that the commenter is suggesting that section 321(a) requires the EPA to amend the substantive requirements of the rule to account for cumulative employment impacts, section 321(d) clearly states that nothing in section 321 shall be construed to "require or authorize" the EPA "to modify or withdraw any requirement" proposed under the Act.

Comment 19: One commenter stated that the purpose of the CAA is to protect public health by preventing air pollution and that the statutory test for the health risk rulemaking under section 112(f)(2) is two-fold: (1) the EPA must prevent all unacceptable health risks; and (2) the EPA must assure an "ample margin of safety to protect public health" and "prevent…an adverse environmental effect (Id. section 112(f)(2)(A))." The commenter stated that the D.C. Circuit has recognized that the "aspirational goal" of this provision includes reducing lifetime cancer risk to the most-exposed person to be one-in-one million or lower. The commenter notes that EPA has recognized that this provision directs the EPA to "protect the greatest number of persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million" and "limit to no higher than approximately 1-in-10 thousand [i.e., 100-in-1 million] the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years."

The commenter asserted that the technology review required by section 112(d)(6) aims to continue to reduce toxic air pollution and exposure to air toxics as greater emission reductions become achievable.

The commenter claimed that under section 112(d)(6), when "developments" exist, EPA must update the standards, as developments are the "core requirement" of section 112(d)(6). The commenter added that revised standards must be governed by the plain text and statutory test provided for all section 112(d) emission standards in section 112(d)(2)-(3). The commenter argued that EPA must follow the plain text of section 112(d)(2)-(3) because those provisions govern "emissions standards promulgated under this subsection," i.e., subsection 112(d), and that EPA must set floor and beyond-the-floor standards.

The commenter argued that although the D.C. Circuit rejected this argument in 2013, neither the EPA nor any court has addressed the plain text of the statutory provisions. The commenter concluded that because neither EPA or the court has addressed the statutory interpretation or reasoning they believe that the EPA and the court wrongly decided this issue.

The commenter asserted that the EPA has a responsibility to provide a statutory interpretation supporting its policy decision. For that reason and all of the reasons provided in the attachments to the original comment**,** the EPA should set revised technology standards based on CAA section 112(d)(2) &(3). The commenter contended that refusing to recognize that revised air toxics standards follow the same test as other section 112(d) standards would conflict with the EPA's policy and interpretation in the electric utility MACT standards. The commenter asserted that for the utility MACT standards, EPA recognized that section 112(n)(1)(A) provides the test for whether standards are needed and then section 112(d)(2)-(3) provides the test for the actual standards. The commenter stated that similarly section 112(d)(6) provides the test for whether standards are needed and section 112(d)(2)-(3) provides the test for the standards.

The commenter also claimed that in *White Stallion v. EPA*, Both the court and EPA rejected the same policy the EPA uses here. The commenter asserted that in that case, industry petitioners argued that section 112(n)(1)(A) governed both the decision to set standards for coal-fired power plants and the stringency of those standards, just as the EPA does for 112(d)(6), and that EPA's approach for 112(d)(6) should fail for the same reason that argument failed in White Stallion -- that is not what section 112 says and the interpretation disregards Congress's careful structure.

The commenter also argued that even if the Act were ambiguous, the EPA should interpret it to apply the same test to revised air toxics standards as other emission standards because doing so would better serve congressional intent and provide more health benefit which is the core of the Act's objective.

The commenter cross-referenced previous comments they had submitted on this issue and their briefs in *NASF v. the EPA*). The commenters stated that if the EPA does not follow the commenter's interpretation of the Act, communities around the nation living in air toxics hot spots will suffer. The commenter asserted that these communities are more likely to be communities of color and lower income communities. The commenter cited EPA's recently released Second Integrated Urban Air Toxics Report (Aug. 21, 2014) as recognizing that there continue to be elevated areas with high cancer and other health risks and that the EPA would "continue to address urban air toxics…through regulations called for under the CAA." The commenter concluded that rulemakings where the EPA finds developments in pollution control have occurred, and there is significant disparity in risk and health impact distribution - are exactly the context in which the agency should take action to make its policy mirror what federal law actually requires.

Response 19: As recognized by the commenter, the court in *Association of Battery Recyclers v. EPA*, 716 F.3d 667 (ABR), rejected the statutory interpretation they make here. That court also rejected a petition for rehearing en banc that the commenters filed on this same issue. More recently, the court also rejected the argument, when raised again, in *NASF v. EPA* (D.C. Cir. No. 12-1459). As provided in previous rules and in the briefs in the cited cases, we continue to disagree with the position that the EPA must recalculate MACT floors under CAA section 112(d)(2)-(3) as part of the section 112(d)(6) review.

We read section 112(d)(6) as providing the EPA with substantial latitude in weighing a variety of factors and arriving at an appropriate balance in considering revisions to standards promulgated under section 112(d)(2) & (3). Nothing in section 112(d)(6) expressly or implicitly requires that EPA recalculate the MACT floor as part of the section 112(d)(6) review. The interpretation that the commenters urge is far from clear based on the statutory text. Nothing in the language requires EPA to apply the criteria in section 112(d)(2)-(3) every time it reviews and revises MACT standards. See NRDC, 529 F.3d at 1084. Although the language in section 112(d)(2)-(3) may appear to be broad it cannot be read to apply to govern revised standards addressed in a separate provision. See ABR, 716 F.3d at 672 ("It is a well-established principle of statutory construction that '[g]eneral language of a statutory provision, although broad enough to include it, will not be held to apply to a matter specifically dealt with in another part of the same enactment.'") (citation omitted). Importantly, section 112(d)(2)-(3) apply to promulgation of standards while section 112(d)(6) applies to a revision of standards that were already "promulgated" within the meaning of section 112(d)(2)-(3). See Natural Res. Def. Council v. EPA, 902 F.2d 962, 982 (D.C. Cir. 1990) (concurring opinion of Wald, C.J., vacated on other grounds, 921 F.2d 326 (D.C. Cir. 1991), noting CAA's distinction between "promulgation" and "revision"). For this reason, EPA's interpretation in the utility MACT, which was challenged in White Stallion Energy Center, LLC v. EPA, 748 F.3d 1222 (D.C. Cir. 2014), is different from EPA's interpretation in this and other rules issued under section 112(d)(6). EPA's promulgation of the Utility MACT under CAA section 112(n)(1)(A) is precisely that – promulgation of a MACT standard – not revision of an already promulgated standard. Further interpretation of this provision in light of the arguments that the commenters make in their cross-referenced briefs can be found in EPA's brief in the NASF case, which is located in the docket for this rule.

To the extent that the commenters raise health and risk concerns to advocate that EPA adopt their preferred interpretation, we note that EPA has taken the position that it could consider those factors as part of its analysis whether it is "necessary" to revise the standard under section 112(d)(6). However, in this rulemaking, we simultaneously performed the risk review required under CAA section 112(f)(2), and we considered residual risk and health effects as part of that review. We see no reason to duplicate that effort as part of the technology review in this rulemaking.

Comment 20: One commenter stated that the agency has a long-standing federal CAA duty to promulgate greenhouse gas emissions standards for refineries under section 111 of the CAA, and has missed statutory and settlement deadlines to do so and argued that the EPA should take advantage of the information it has collected for this rule to accelerate its progress towards greenhouse gas controls for this very large pollution source. Another commenter stated that there should be regulations to limit greenhouse gases from refineries and influence the use of carbon sequestration. A third commenter also agrees that greenhouse gases should be limited and that the U.S. should work towards total divestiture from fossil fuels. The third commenter expresses concerns over global warming from a human rights perspective and makes other comments related to limiting poverty and the development of projects like Keystone XL Pipeline or Trans-Pacific Partnership.

Response 20: We did not propose nor are we promulgating GHG standards as part of the Refinery Sector Rule. We did collect data on energy use and other operating characteristics as part of the information collection request performed to support the Sector rulemaking efforts that may be useful if the EPA decides to propose and promulgate GHG standards for petroleum refineries in future rulemakings.

15.4 Out-of-Scope

Comment 1: One commenter stated that there has been a large increase in the cost of fuel especially for Ethanol Free gasoline which is used for recreational fishers and for lawn equipment. Recreational fishing is a large portion of the St. Bernard's economy and the increased fuel cost is negatively affecting economic development in this area. The commenter argued that the surrounding refineries make supplies of Ethanol Free gasoline, but do not support the local fuel needs while the community incurs the pollution associated with the refining process. The commenter suggested that the refineries enter into a community benefits agreement which would include meeting the local community's need for Ethanol free gasoline along with access to real time monitor readings electronically, public admittance to monthly Community Advisory Panel meetings, reinvestment of Louisiana DEQ penalty payments back into the community, and funding for community identified projects, such as: sidewalks, bicycle paths, including the Connect the Nine improvements to the Industrial Canal Bridge in New Orleans and the Mississippi River Trail bike path along the river in Meraux and Violet (St Bernard); skate-parks, dog parks, other parkways with added trees to help clear the air; public health clinics, work force initiatives, and educational and cultural programs for youth.

Response 1: This comment is beyond the scope of this rulemaking.

Comment 2: One commenter argued that petroleum refineries are not significant source of HAPs and that the EPA's efforts should be directed at the more significant sources of HAP emissions - nonpoint and mobile sources.

The commenter supported their argument by stating that Texas accounts for about 15 percent of the nation's HAP emissions since 1988. (See David Adelman, Environmental Federalism When Numbers Matter More Than Size, 32 UCLA J. ENVT'L L. & POL'Y at 290) Harris County's HAP emissions exceeded statewide emissions for all states other than Louisiana and Texas. Id. Yet even in the Houston area, industrial HAP emissions are dwarfed by emissions from nonpoint and mobile sources, representing only 25% of all HAP emissions. Id. at 280, 292. Further, HAP emissions from petroleum refineries represent less than five percent of all industrial HAP emissions. Id. at 288, Figure 11. While petroleum refineries will continue to work to further decrease their resulting 1.25% contribution of HAP emissions in Harris County, EPA's efforts should be directed at the more significant sources of HAP emissions - nonpoint and mobile sources.

Response 2: Control of non-point or mobile sources is beyond the scope of this rulemaking. CAA section 112 require MACT standards from all major sources of HAP emissions. Because refineries are major sources of HAP emissions, the CAA requires us to develop MACT standards for petroleum refineries.

Comment 3: One commenter stated that the emission factor update proposal for flares and petroleum refinery emissions should not be allowed to prejudice this rulemaking and any emission factor changes must be delayed until after this rulemaking. The commenter pointed out that the EPA posted an updated version of the Emissions Estimation Protocol for Petroleum Refineries concurrently with its proposed AP-42 revisions, incorporating those proposed AP-42 emission factor revisions in it. The commenter claimed that for flares, the EPA's proposal of new emission factors that are the same as those used in the Refinery Sector rulemaking prejudices the evaluation of comments on the Refinery rulemaking since the Emission Factor Consent Decree requires the new emission factors to be finalized prior to finalizing the Refinery Sector rule. The commenter stated that the emission factor evaluation is prejudiced because the EPA would not want to finalize anything different from the refinery rule basis, otherwise it would have to redo the refinery emissions analyses and thus be unable to meet the deadlines in that Consent Decree.

The commenter stated that the Emission Factor Review schedule is unreasonable and provides inadequate time for the EPA and the public to conduct a proper and thorough review of the emission factors for the emission sources affected by the proposed revisions. The commenter suggested that the EPA allow at least one year for completing an emission factor review for these sources after the Refinery Sector Rule is finalized as well as at least a 180-day comment period to provide adequate time for the multitude of interested parties to file sound comments on the new emission factor proposal, including consideration of the comments received on the Sector Rule proposal.

Response 3: This comment is beyond the scope of this rulemaking. We note that we did provide an extension to the comment period for the proposed updates to the refinery emission factors. We also note that we did not propose a correlation equation or other means to adjust control efficiency based on flare operating parameters, so we disagree that the proposal and subsequent finalization of new flare emission factors prejudiced the Refinery Sector rulemaking.

Comment 4: Two commenters stated that the EPA should review noise and vibrations from a national performance standards perspective. The commenters added that currently noise ordinances are regulated by local governments and they lack the resources and knowledge to protect human health from the negative effects of noise pollution. One of the commenters explained that high noise levels will cause hearing loss, sleep deprivation, and prevent children from being able to read, study, or finish school assignments. The commenter also stated that the vibrations have caused structural damage claims to houses. The commenter also explained that are reported more frequently with "emergency flaring" and SSM activities as well as "temporary" boilers, low NOx burners, and even compressors, steam pressure relief valves, and flare tip atomizers.

Response 4: We appreciate the concerns expressed by the commenters, but sections 111 and 112 of the CAA are specific to criteria and hazardous air pollutants. As such, noise and vibration standards are beyond the scope of this rulemaking.